S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
	)	

EXHIBITS

OF

SARA T. WALZ

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Assumption	Business As Usual	Emerging Technologies	Environmental Policy	Carbon Reduction
Load Forecast Base Scenario	May 2020 Load Forecast	Same as BAU	Same as BAU	1.5% year over year load growth vs May 2020 Load Forecast
Required Sensitivities	1.5% year over year load growth vs the Base Scenario	Same as BAU	Same as BAU	None
Renewable Energy Base Scenario	Includes MPSC Orders approving Gratiot Farms, Crescent Wind Projects; Cross Winds Phase III and River Fork PPA	Same as BAU	Same as BAU	Same as BAU
• PTC Credits • ITC Credits	Current Law, with updates from 2020 CAA[1] Current Law, with updates from 2020 CAA			
Required Sensitivities	None	25% RPS by 2030	None	None

[1] Consolidated Appropriations Act

Energy Waste Reduction Base Scenario	*EWR Plan (2021-2023):* 2.0% year over year annual savings (retail sales) 2021-2023 1.5% year over year annual savings 2024-2040 (Base plan)	Same as BAU	Same as BAU	Same as BAU
Incremental EWR Offerings to Model	• 0.5% incremental (retail sales) in 2024 to achieve 2.0% year over year annual savings through study period • 0.25% incremental (retail sales) in 2030 to achieve 2.25% year over year annual savings *Assumptions based on 2017 MPSC Statewide Potential Study and 2016 CE Potential Study*			
Required Sensitivities	2.5% EWR ramp over a four year period	Same as BAU	Same as BAU	None

Demand Side Management Base Scenario	Direct Load Control: • 75 MW in 2022-2040 Dynamic Peak Pricing: • 20 MW in 2022-2040 Bring Your Own Device • 16 MW in 2022-2040 Summer Time of Use • 122 MW in 2022-2040 Commercial & Industrial • 217 MW in 2022-2040 Interruptible Tariff • 106 MW in 2022-2040 Metal Melting • 50 MW in 2022-2040 Conservation Voltage Reduction ("CVR") • 20 MW by 2021 • 113 MW by 2030 *Growth remains flat 2030+	Same as BAU	Same as BAU	Same as BAU
Incremental Demand-Side Management	*MPSC Statewide Potential Study 2017*	*MPSC Statewide Potential Study 2017 –* ***(-35% Cost)***	*MPSC Statewide Potential Study 2017*	*MPSC Statewide Potential Study 2017*
Incremental DR Offerings to Model	Expansion of approximately 615 MW in 2 price tranches, offered starting in 2023	Expansion of approximately 1,185 MW in 3 price tranches,	Same as Emerging Technologies	Same as Emerging Technologies

		offered starting in 2023		
2018 IRP Approved Resources Base Scenario	1,100 MW of solar capacity added 2022-2024 584 MW of PURPA solar by 2023	Same as BAU	Same as BAU	Same as BAU
Retail Open Access (ROA) Base Scenario	10% ROA – Same as May 2020 Load Forecast	Same as BAU	Same as BAU	Same as BAU
Required Sensitivities	50% Return of ROA	None	None	None
Emissions Base Scenario	None	None	30% CO_2 reduction by 2030 from 2005 baseline	28% CO_2 reduction by 2025 from 2005 baseline
Required Sensitivities	None	None	50% CO_2 reduction by 2030 from 2005 baseline	32% CO_2 reduction by 2025 from 2005 baseline

Consumers Energy's Retirement Dates Base Scenario Sensitivities	2023 DEK12 2031 JHC1, JHC2, DEK34 2039 JHC3 Model operation dates for JHC1, JHC2, JHC3, DEK34 determined by CE Scenarios	Same as BAU Same as BAU	Same as BAU Same as BAU	2023 DEK12, DEK34 2025 JHC1, JHC2, JHC3 None
Capital Costs Base Scenario Required Sensitivities	National Renewable Energy Laboratories 2019 Annual Technology Baseline No required sensitivities	NREL 2019 ATB • -15% in Wind Costs • -35% in Solar Costs • -35% in Battery Costs	NREL 2019 ATB • -35% in Wind Costs • -35% in Solar Costs • -35% in Battery Costs	NREL 2019 ATB • -35% in Wind Costs • -35% in Solar Costs • -35% in Battery Costs
Natural Gas Prices Base Scenario Required Sensitivities	EIA-2020 AEO Natural Gas Price Forecast 200%X BAU by end of study period	Same as BAU Same as BAU	Same as BAU Same as BAU	Same as BAU None

Power Purchase Agreements and Purchased Capacity Base Scenario	Palisades Contract: Expires My 31, 2022, Capacity reflected through Planning Year 2021 MCV Contract: Expires May 31, 2030, Capacity reflected through Planning Year 2029 Other NUGs (excl. PURPA): Terminate at contract expiration dates PURPA QF NUGS: Existing contracts assumed to be renewed indefinitely unless otherwise indicated	Same as BAU	Same as BAU	Same as BAU

Assumption	Business As Usual	Emerging Technologies	Environmental Policy	Advanced Technologies
Load Forecast Base Scenario	May 2020 Load Forecast	Same as BAU	Same as BAU	31% increase in electric vehicle consumption; Expansion of behind-the-meter generation customer solar adoption
Sensitivities	None	Same as BAU	Same as BAU	None
Renewable Energy Base Scenario	Includes MPSC Orders approving Gratiot Farms, Crescent Wind Projects; Cross Winds Phase III and River Fork PPA	Same as BAU	Same as BAU	Same as BA
• PTC Credits • ITC Credits	Current Law, with updates from 2020 CAA[1] Current Law, with updates from 2020 CAA			
Energy Waste Reduction Base Scenario	*EWR Plan (2021-2023):* 2.0% year over year annual savings (retail sales) 2021-2023 1.0% year over year annual savings 2024-2040 (Base plan)	Same as BAU	Same as BAU	Transformational potential achieving 2.0% year over year annual savings 2020-2040
Incremental EWR Offerings to Model	Incremental plus base amounts to reach an average of 1.6% year over year savings through 2030; declining to an average of 1.0% year over year 2031-2040 *Assumptions based on 2020 CE Potential Study*	Same as BAU	Same as BAU	None
Sensitivities	None	Same as BAU	Same as BAU	None

[1] Consolidated Appropriations Act

Demand Side Management Base Scenario	Direct Load Control: • 75 MW in 2022-2040 Dynamic Peak Pricing: • 20 MW in 2022-2040 Bring Your Own Device • 16 MW in 2022-2040 Summer Time of Use • 122 MW in 2022-2040 Commercial & Industrial • 217 MW in 2022-2040 Interruptible Tariff • 106 MW in 2022-2040 Metal Melting • 50 MW in 2022-2040 Conservation Voltage Reduction ("CVR") • 20 MW by 2021 • 113 MW by 2030 *Growth remains flat 2030+	Same as BAU	Same as BAU	Same as BAU
Incremental Demand-Side Management	*CE Potential Study 2020*			
Incremental DR Offerings to Model	Expansion of approximately 480 MW in 6 price tranches, offered starting in 2023	Same as BAU	Same as BAU	Same as BAU

2018 IRP Approved Resources Base Scenario	1,100 MW of solar capacity added 2022-2024 584 MW of PURPA solar by 2023	Same as BAU	Same as BAU	Same as BAU
Retail Open Access (ROA) Base Scenario Sensitivities	10% ROA – Same as May 2020 Load Forecast None	Same as BAU Same as BAU	Same as BAU Same as BAU	Same as BAU Same as BAU
Emissions Sensitivities	None	None	None	None
Consumers Energy's Retirement Dates Base Scenario	2023 DEK12 2031 JHC1, JHC2, DEK34 2039 JHC3	Same as BAU	Same as BAU	Same as BAU
Sensitivities	2024, 2025, 2026 and 2028 JHC1, JHC2 2025 JHC3 2025 DEK34	Same as BAU	Same as BAU	2025 JHC1, JHC2, JHC3 2025 DEK34

Capital Costs Base Scenario Sensitivities	National Renewable Energy Laboratories 2019 Annual Technology Baseline No required sensitivities	NREL 2019 ATB • -15% in Wind Costs • -35% in Solar Costs • -35% in Battery Costs	NREL 2019 ATB • -35% in Wind Costs • -35% in Solar Costs • -35% in Battery Costs	NREL 2019 ATB • -50% in Distribution-Connected Solar Costs • -35% in Transmission-Connected Solar Costs • -50% in Battery Costs by 2040
Natural Gas Prices Base Scenario Sensitivities	CE Specific Natural Gas Price Forecast None	Same as BAU Same as BAU	Same as BAU Same as BAU	EIA 2020 Annual Energy Outlook – High Gas/Oil Supply Case
Power Purchase Agreements and Purchased Capacity Base Scenario	Palisades Contract: Expires My 31, 2022, Capacity reflected through Planning Year 2021 MCV Contract: Expires May 31, 2030, Capacity reflected through Planning Year 2029 Other NUGs (excl. PURPA): Terminate at contract expiration dates PURPA QF NUGS: Existing contracts assumed to be renewed indefinitely unless otherwise indicated	Same as BAU	Same as BAU	Same as BAU

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Existing Assets Zonal Resource Credits and Projected Generation

Case No.: U-21090
Exhibit No.: A-6 (STW-3)

Witness: STWalz
Date: June 2021

ZONAL RESOURCE CREDITS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
Line No.	Electric Generator Name	Resource Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Owned																					
1	Alcona 1-2	Run of River Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
2	Allegan 1-3	Run of River Hydro	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
3	Cadillac Solar Garden	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Campbell 1	Coal	248	250	252	252	252	252	252	252	252	252	-	-	-	-	-	-	-	-	-	-
5	Campbell 2	Coal	317	326	336	337	336	335	335	335	335	335	-	-	-	-	-	-	-	-	-	-
6	Campbell 3	Coal	747	743	757	757	757	757	756	756	756	756	756	756	756	756	756	756	756	756	-	-
7	Campbell A	Oil	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Circuit West	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Cooke 1	Reservoir Hydro	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
10	Cooke 2	Reservoir Hydro	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
11	Cooke 3	Reservoir Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
12	Crescent Wind	Wind	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
13	Cross Winds Phase 1	Wind	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
14	Cross Winds Phase 2	Wind	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
15	Cross Winds Phase 3	Wind	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
16	Croton 1-4	Run of River Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
17	Five Channels 1	Reservoir Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
18	Five Channels 2	Reservoir Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
19	Foote 1-3	Run of River Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
20	Gaylord 1	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Gaylord 2	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Gaylord 3	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Gratiot Farms Wind Project	Wind	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
24	GVSU Solar Garden	Solar	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
25	Hardy 1	Reservoir Hydro	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
26	Hardy 2	Reservoir Hydro	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
27	Hardy 3	Reservoir Hydro	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
28	Hodenpyl 1-2	Run of River Hydro	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
29	Jackson Plant	Natural Gas	538	537	538	538	538	538	538	538	538	538	538	538	538	538	538	538	538	538	538	538
30	Karn 1	Coal	196	190	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Karn 2	Coal	195	194	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	Karn 3	Natural Gas/Oil	440	437	444	450	448	449	449	450	450	450	-	-	-	-	-	-	-	-	-	-
33	Karn 4	Natural Gas/Oil	327	332	344	335	336	338	340	340	340	340	-	-	-	-	-	-	-	-	-	-
34	Lake Winds Energy Park	Wind	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
35	Loud 1	Reservoir Hydro	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
36	Loud 2	Reservoir Hydro	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
37	Ludington 1	Pumped Storage	188	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186	186
38	Ludington 2	Pumped Storage	164	179	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180	180
39	Ludington 3	Pumped Storage	177	186	184	184	184	184	184	184	184	184	184	184	184	184	184	184	184	184	184	184
40	Ludington 4	Pumped Storage	192	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191	191
41	Ludington 5	Pumped Storage	185	188	190	189	189	190	190	190	190	190	190	190	190	190	190	190	190	190	190	190
42	Ludington 6	Pumped Storage	189	188	186	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185	185
43	Mio 1-2	Run of River Hydro	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
44	Rogers 1-4	Run of River Hydro	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
45	Straits 1	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Tippy 1-3	Run of River Hydro	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
47	Webber 1-2	Run of River Hydro	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
48	WMU Solar Garden	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
49	Zeeland 1A	Natural Gas	157	156	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155	155
50	Zeeland 1B	Natural Gas	153	153	152	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151
51	Zeeland 2A	Natural Gas	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154
52	Zeeland 2B	Natural Gas	154	153	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154	154
53	Zeeland 2C	Natural Gas	212	210	211	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210	210
	Non-Utility Generators (NUGs)																					
54	River Fork Solar	Solar	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
55	Ada Cogeneration LP	Natural Gas	29	29	29	29	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	Adrian Energy Associates, LLC	Landfill Gas	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-
57	Bay Windpower I (Mackinaw)	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	Beaverton, City of	Run of River Hydro	0	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Beebe Renewable Energy	Wind	10	10	10	10	10	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-
60	Black River Power	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Boyce Hydro Power, LLC (Edenville)	Reservoir Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
62	Boyce Hydro Power, LLC (Sanford)	Reservoir Hydro	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
63	Boyce Hydro Power, LLC (Secord)	Reservoir Hydro	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	Boyce Hydro Power, LLC (Smallwood)	Reservoir Hydro	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Cadillac Renewable Energy, LLC	Biomass	34	34	34	34	34	34	34	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Commonwealth Power Company (Irving)	Run of River Hydro	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-
67	Commonwealth Power Company (LaBarge)	Run of River Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-

ZONAL RESOURCE CREDITS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
Line No.	Electric Generator Name	Resource Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
68	Commonwealth Power Company (Middleville)	Run of River Hydro	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-	-	-
69	Brook View Dairy	Anaerobic Digester	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-
70	Scenic View Dairy (Fennville)	Anaerobic Digester	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-
71	Green Meadow Farms	Anaerobic Digester	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-
72	EARP Solar (Expansion)	Solar	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-
73	EARP Solar (Original)	Solar	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
74	Elk Rapids Hydroelectric Power, LLC	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
75	Entergy Nuclear Power Marketing, LLC (Palisades)	Nuclear	772	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	Fremont Community Digester, LLC	Anaerobic Digester	2	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-
77	Gas Recovery 1 (C&C 1)	Landfill Gas	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-
78	Gas Recovery 2 (C&C 2)	Landfill Gas	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79	Genesee Power Station LP	Biomass	26	26	26	26	26	26	26	26	26	-	-	-	-	-	-	-	-	-	-	-
80	Geronimo Huron Wind, LLC (Apple Blossom)	Wind	17	17	17	17	17	17	17	17	17	17	17	-	-	-	-	-	-	-	-	-
81	Energy Developments (Grand Blanc), LLC	Landfill Gas	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-
82	Energy Developments (Ottawa), LLC	Landfill Gas	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-	-	-	-
83	Energy Developments (Seymour), LLC	Landfill Gas	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-
84	Energy Developments (Byron Center), LLC	Landfill Gas	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
85	Energy Developments (Pinconning), LLC	Landfill Gas	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-
86	Grayling Generating Station LP	Biomass	35	35	35	35	35	35	-	-	-	-	-	-	-	-	-	-	-	-	-	-
87	Grenfell Hydro, Inc	Run of River Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-
88	Harvest II Windfarm, LLC	Wind	10	10	10	10	10	10	10	10	10	10	10	-	-	-	-	-	-	-	-	-
89	Heritage Garden Wind Farm I, LLC (Wind Portion)	Wind	3	3	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-
90	Heritage Garden Wind Farm I, LLC (Solar Portion)	Solar	0	0	0	0	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-
91	Heritage Stoney Corners Wind Farm I, LLC (Phase 2)	Wind	2	2	2	2	2	2	2	2	2	2	-	-	-	-	-	-	-	-	-	-
92	Heritage Stoney Corners Wind Farm I, LLC (Phase 3)	Wind	1	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-
93	Hillman Power Company LLC	Biomass	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
94	Kent County	Solid Waste	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
95	Michigan Power LP 1	Natural Gas	73	73	73	73	73	73	73	73	73	-	-	-	-	-	-	-	-	-	-	-
96	Michigan Power LP 2	Natural Gas	50	50	50	50	50	50	50	50	50	-	-	-	-	-	-	-	-	-	-	-
97	Michigan Wind 1, LLC (PPA 1)	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
98	Michigan Wind 1, LLC (PPA 2)	Wind	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-
99	Michigan Wind 2, LLC	Wind	15	15	15	15	15	15	15	15	15	15	-	-	-	-	-	-	-	-	-	-
100	Midland Cogeneration Venture LP	Natural Gas	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	1,214	-	-	-	-	-	-	-	-	-	-	-
101	North American Natural Resources (Lennon), Inc	Landfill Gas	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-
102	North American Natural Resources (Rathbun), Inc	Landfill Gas	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-	-
103	North American Natural Resources (Venice), Inc	Landfill Gas	2	2	2	2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
104	North American Natural Resources (Peoples), Inc	Landfill Gas	3	3	3	3	3	3	3	3	3	-	-	-	-	-	-	-	-	-	-	-
105	STS Hydropower Ltd (Ada)	Run of River Hydro	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
106	STS Hydropower Ltd (Cascade)	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
107	STS Hydropower Ltd (Fallasburg)	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
108	STS Hydropower Ltd (Morrow)	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
109	TES Filer City Station LP	Coal	58	58	58	58	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
110	TES Filer City Repower	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Viking Energy of Lincoln A LP	Biomass	17	17	17	17	17	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112	Viking Energy of McBain A LP	Biomass	18	18	18	18	18	18	-	-	-	-	-	-	-	-	-	-	-	-	-	-
113	White's Bridge Hydro Company	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
114	WM Renewable Energy (Northern Oaks)	Landfill Gas	1	1	1	1	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-
115	WM Renewable Energy (Pine Tree Acres)	Landfill Gas	12	12	12	12	12	12	12	12	12	12	-	-	-	-	-	-	-	-	-	-
116	WM Renewable Energy (Venice)	Landfill Gas	1	1	1	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	New Contracts w/ Existing PURPA QFs																					
117	Adrian Energy Associates, LLC	Landfill Gas	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1
118	Bay Windpower I (Mackinaw)	Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
119	Beaverton, City of	Run of River Hydro	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
120	Black River Power	Run of River Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
121	Boyce Hydro Power, LLC (Edenville)	Reservoir Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
122	Boyce Hydro Power, LLC (Sanford)	Reservoir Hydro	-	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
123	Boyce Hydro Power, LLC (Secord)	Reservoir Hydro	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
124	Boyce Hydro Power, LLC (Smallwood)	Reservoir Hydro	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
125	Commonwealth Power Company (Irving)	Run of River Hydro	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0
126	Commonwealth Power Company (LaBarge)	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
127	Commonwealth Power Company (Middleville)	Run of River Hydro	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0
128	Brook View Dairy	Anaerobic Digester	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1
129	Scenic View Dairy (Fennville)	Anaerobic Digester	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0	0	0
130	Green Meadow Farms	Anaerobic Digester	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	1	1
131	EARP Solar (Expansion)	Solar	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	2	2	2	2	2
132	EARP Solar (Original)	Solar	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
133	Elk Rapids Hydroelectric Power, LLC	Run of River Hydro	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
134	Fremont Community Digester, LLC	Anaerobic Digester	-	-	-	-	-	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2
135	Gas Recovery 1 (C&C 1)	Landfill Gas	-	-	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2

ZONAL RESOURCE CREDITS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
Line No.	Electric Generator Name	Resource Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
136	Gas Recovery 2 (C&C 2)	Landfill Gas	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
137	Energy Developments (Grand Blanc), LLC	Landfill Gas	-	-	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2
138	Energy Developments (Ottawa), LLC	Landfill Gas	-	-	-	-	-	-	-	-	3	3	3	3	3	3	3	3	3	3	3	3
139	Energy Developments (Seymour), LLC	Landfill Gas	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1
140	Energy Developments (Byron Center), LLC	Landfill Gas	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
141	Energy Developments (Pinconning), LLC	Landfill Gas	-	-	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2
142	Grenfell Hydro, Inc	Run of River Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	0
143	Hillman Power Company LLC	Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
144	Kent County	Solid Waste	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
145	North American Natural Resources (Lennon), Inc	Landfill Gas	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1
146	North American Natural Resources (Rathbun), Inc	Landfill Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1
147	North American Natural Resources (Venice), Inc	Landfill Gas	-	-	-	-	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
148	North American Natural Resources (Peoples), Inc	Landfill Gas	-	-	-	-	-	-	-	-	-	3	3	3	3	3	3	3	3	3	3	3
149	STS Hydropower Ltd (Ada)	Run of River Hydro	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
150	STS Hydropower Ltd (Cascade)	Run of River Hydro	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
151	STS Hydropower Ltd (Fallasburg)	Run of River Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
152	STS Hydropower Ltd (Morrow)	Run of River Hydro	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
153	Viking Energy of Lincoln A LP	Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
154	Viking Energy of McBain A LP	Biomass	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
155	White's Bridge Hydro Company	Run of River Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
156	WM Renewable Energy (Northern Oaks)	Landfill Gas	-	-	-	-	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1
157	WM Renewable Energy (Pine Tree Acres)	Landfill Gas	-	-	-	-	-	-	-	-	-	-	12	12	12	12	12	12	12	12	12	12
158	WM Renewable Energy (Venice)	Landfill Gas	-	-	-	-	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
	New Contracts w/ Solar PURPA QFs																					
159	Cement City	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
160	Letts Creek	Solar	-	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
161	Pullman	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
162	Thorn Lake	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
163	Good Fruit Storage LLC	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
164	Workman Solar	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
165	NextSun Energy LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
166	Morey Solar	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
167	Lake City Solar	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
168	Hazel Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
169	Hendershot Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
170	Jack Francis Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
171	May Shannon Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
172	13 Mile Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
173	Angola Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
174	Captain Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
175	Coldwater Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
176	Geddes 2 Solar, LLC	Solar	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
177	Interchange Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
178	Bullhead Solar, LLC	Solar	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
179	Geddes 1 Solar, LLC	Solar	-	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
180	Stoneheart Solar, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
181	Macbeth Solar	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
182	Woodley Solar	Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
183	Bingham Solar, LLC	Solar	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
184	Temperance Solar, LLC	Solar	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Existing Assets Zonal Resource Credits and Projected Generation

Case No.: U-21090
Exhibit No.: A-6 (STW-3)

Witness: STWalz
Date: June 2021

ZONAL RESOURCE CREDITS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
Line No.	**Electric Generator Name**	**Resource Type**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
185	Albion North Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
186	Allegheny Solar	Solar	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
187	Aluminum Solar	Solar	-	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
188	Bamboo Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
189	Beaverton Solar	Solar	-	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
190	Burns Park Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
191	Byrne Solar	Solar	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
192	Cloudbreak Solar	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
193	Congo Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
194	Hogan Solar	Solar	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
195	Johnsfield Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
196	Lightfoot Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
197	Lyons Road Solar	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
198	Rosco Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
199	Shipsterns Solar	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
200	Surbrook Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
201	Blue Elk Solar VII	Solar	-	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
202	Aurthur Solar Farm, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
203	Golden Solar Farm, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
204	Robert Swift Solar Farm, LLC	Solar	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
205	Swede Solar	Solar	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
206	Topanga Solar	Solar	-	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16	16
207	Wilford Solar	Solar	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
208	TART Solar, LLC	Solar	-	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
209	Blue Elk Solar I	Solar	-	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
210	Blue Elk Solar III	Solar	-	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
211	Blue Elk Solar IV	Solar	-	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
212	Greenstone Solar, LLC	Solar	-	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
213	Midcontinent Solar, LLC	Solar	-	-	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
214	Durban Solar	Solar	-	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
215	Esmarelda Solar	Solar	-	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
216	Shady Solar	Solar	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	Expansion Plans																					
217	2018 IRP Solar	Solar	-	150	300	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550
218	Heartland Wind Park	Wind	-	-	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35	35
219	Other Bilateral ZRC Purchases	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

PROJECTED GENERATION (GWH)

Line No.	(a) Electric Generator Name	(b) Resource Type	(c) 2021	(d) 2022	(e) 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029	(l) 2030	(m) 2031	(n) 2032	(o) 2033	(p) 2034	(q) 2035	(r) 2036	(s) 2037	(t) 2038	(u) 2039	(v) 2040
	Owned																					
1	Heartland Wind Park	Wind	-	-	530,936	532,724	530,936	530,936	530,936	532,724	530,936	530,936	530,936	532,724	530,936	530,936	530,936	532,724	530,936	530,936	530,936	532,724
2	5 Channels 1	Hydro	24,155	24,155	24,155	24,217	24,155	24,155	24,155	24,217	24,155	24,155	24,155	24,217	24,155	24,155	24,155	24,217	24,155	24,155	24,155	24,217
3	Alcona 12	Hydro	26,978	26,978	26,978	27,048	26,978	26,978	26,978	27,048	26,978	26,978	26,978	27,048	26,978	26,978	26,978	27,048	26,978	26,978	26,978	27,048
4	Allegan 13	Hydro	13,011	13,011	13,011	13,053	13,011	13,011	13,011	13,053	13,011	13,011	13,011	13,053	13,011	13,011	13,011	13,053	13,011	13,011	13,011	13,053
5	Campbell 1	Coal	1,744,446	1,738,865	1,731,398	1,606,921	1,696,638	1,698,383	1,696,004	1,558,474	1,680,083	1,667,054	735,533	-	-	-	-	-	-	-	-	-
6	Campbell 2	Coal	1,504,879	1,813,078	1,816,000	1,673,253	1,770,472	1,760,411	1,756,811	1,759,361	1,738,726	1,722,632	766,152	-	-	-	-	-	-	-	-	-
7	Campbell 3	Coal	5,984,843	5,983,623	5,995,363	4,922,880	5,938,623	5,974,511	6,013,250	6,024,144	6,005,264	6,022,408	6,017,665	6,038,302	6,024,375	4,903,905	6,016,002	5,978,791	5,896,189	5,766,261	6,219,881	-
8	CE Community Solar Gardens	Solar	8,944	8,944	8,944	8,961	8,944	8,944	8,944	8,961	8,944	8,944	8,944	8,961	8,944	8,944	8,944	8,961	8,944	8,944	8,944	8,961
9	CE Existing DR	DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Cooke 1	Hydro	26,217	26,217	26,217	26,283	26,217	26,217	26,217	26,283	26,217	26,217	26,217	26,283	26,217	26,217	26,217	26,283	26,217	26,217	26,217	26,283
11	Crescent Wind	Wind	401,355	401,355	401,355	402,708	401,355	401,355	401,355	402,708	401,355	401,355	401,355	402,708	401,355	401,355	401,355	402,708	401,355	401,355	401,355	402,708
12	Crosswinds phase 1	Wind	404,577	404,577	404,577	405,881	404,577	404,577	404,577	405,881	404,577	404,577	404,577	405,881	404,577	404,577	404,577	405,881	404,577	404,577	404,577	405,881
13	Crosswinds phase 2	Wind	159,308	159,308	159,308	159,821	159,308	159,308	159,308	159,821	159,308	159,308	159,308	159,821	159,308	159,308	159,308	159,821	159,308	159,308	159,308	159,821
14	Crosswinds phase 3	Wind	276,693	276,693	276,693	277,585	276,693	276,693	276,693	277,585	276,693	276,693	276,693	277,585	276,693	276,693	276,693	277,585	276,693	276,693	276,693	277,585
15	Croton 14	Hydro	38,835	38,835	38,835	38,960	38,835	38,835	38,835	38,960	38,835	38,835	38,835	38,960	38,835	38,835	38,835	38,960	38,835	38,835	38,835	38,960
16	EARP AD	Other	6,887	6,887	6,887	6,907	6,887	6,887	5,357	3,837	3,826	3,826	3,826	3,837	3,826	3,826	3,826	-	-	-	-	-
17	EARP Solar	Solar	2,207	2,196	391	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	EARP Solar Expansion	Solar	5,114	5,104	5,082	5,099	5,082	5,082	4,986	4,553	1,869	-	-	-	-	-	-	-	-	-	-	-
19	Foote 13	Hydro	30,186	30,186	30,186	30,261	30,186	30,186	30,186	30,261	30,186	30,186	30,186	30,261	30,186	30,186	30,186	30,261	30,186	30,186	30,186	30,261
20	Gratiot Wind Farm	Wind	413,918	413,918	413,918	415,312	413,918	413,918	413,918	415,312	413,918	413,918	413,918	415,312	413,918	413,918	413,918	415,312	413,918	413,918	413,918	415,312
21	Hardy 1	Hydro	99,269	99,269	99,269	99,565	99,269	99,269	99,269	99,565	99,269	99,269	99,269	99,565	99,269	99,269	99,269	99,565	99,269	99,269	99,269	99,565
22	Hodenpyl 12	Hydro	41,344	41,344	41,344	41,453	41,344	41,344	41,344	41,453	41,344	41,344	41,344	41,453	41,344	41,344	41,344	41,453	41,344	41,344	41,344	41,453
23	Jackson	Natural Gas	2,700,001	2,700,001	2,700,001	2,700,002	2,700,001	2,700,002	2,700,002	2,700,002	2,613,051	2,607,538	2,539,448	2,352,235	2,270,174	2,110,572	2,278,457	2,105,920	2,014,884	2,044,015	1,965,709	1,929,174
24	Karn 1	Coal	1,331,674	1,316,454	588,833	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Karn 2	Coal	1,417,337	1,402,454	634,798	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Karn 3	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Karn 3_Oil	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Karn 4	Natural Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Lake Winds Energy Park	Wind	267,715	267,715	267,715	268,617	267,715	267,715	267,715	268,617	267,715	267,715	267,715	268,617	267,715	267,715	267,715	268,617	267,715	267,715	267,715	268,617
30	Loud 1	Hydro	18,176	18,176	18,176	18,223	18,176	18,176	18,176	18,223	18,176	18,176	18,176	18,223	18,176	18,176	18,176	18,223	18,176	18,176	18,176	18,223
31	Ludington 1	Storage	(22,195)	(24,509)	(28,294)	(27,851)	(26,681)	(33,363)	(34,161)	(30,724)	(31,228)	(34,902)	(30,088)	(35,681)	(35,852)	(31,108)	(23,270)	(39,477)	(41,410)	(48,194)	(45,167)	(39,731)
32	Ludington 2	Storage	(24,388)	(30,721)	(32,057)	(27,473)	(34,261)	(38,232)	(35,562)	(36,268)	(35,645)	(27,861)	(20,688)	(39,700)	(40,474)	(41,802)	(40,622)	(44,110)	(46,842)	(55,736)	(51,175)	(48,816)
33	Ludington 3	Storage	(18,170)	(36,106)	(39,100)	(36,627)	(40,617)	(45,864)	(45,234)	(42,728)	(42,224)	(42,663)	(39,118)	(44,476)	(45,834)	(45,068)	(45,812)	(54,264)	(43,604)	(24,313)	(61,090)	(56,678)
34	Ludington 4	Storage	(27,775)	(35,815)	(39,564)	(36,310)	(41,766)	(46,002)	(40,862)	(45,182)	(43,073)	(38,570)	(33,675)	(24,103)	(47,110)	(50,570)	(48,303)	(52,416)	(59,173)	(62,148)	(60,428)	(64,340)
35	Ludington 5	Storage	(22,570)	(29,034)	(28,981)	(29,774)	(31,604)	(31,750)	(34,132)	(33,527)	(28,519)	(35,673)	(33,593)	(28,629)	(22,095)	(39,330)	(35,401)	(40,356)	(44,903)	(46,981)	(48,869)	(43,927)
36	Ludington 6	Storage	(25,446)	(32,355)	(31,922)	(33,391)	(35,950)	(36,704)	(39,322)	(38,083)	(34,303)	(38,293)	(37,234)	(36,761)	(34,129)	(25,300)	(40,585)	(48,823)	(50,743)	(53,999)	(57,479)	(50,296)
37	Mio 1-2	Hydro	14,490	14,490	14,490	14,528	14,490	14,490	14,490	14,528	14,490	14,490	14,490	14,528	14,490	14,490	14,490	14,528	14,490	14,490	14,490	14,528
38	Rogers 14	Hydro	27,111	27,111	27,111	27,188	27,111	27,111	27,111	27,188	27,111	27,111	27,111	27,188	27,111	27,111	27,111	27,188	27,111	27,111	27,111	27,188
39	Tippy 13	Hydro	60,007	60,007	60,007	60,165	60,007	60,007	60,007	60,165	60,007	60,007	60,007	60,165	60,007	60,007	60,007	60,165	60,007	60,007	60,007	60,165
40	Webber 12	Hydro	12,854	12,854	12,854	12,897	12,854	12,854	12,854	12,897	12,854	12,854	12,854	12,897	12,854	12,854	12,854	12,897	12,854	12,854	12,854	12,897
41	Zeeland 1A	Natural Gas	152,069	153,581	338,477	98,518	177,945	96,942	95,338	169,634	-	-	-	24,161	23,405	-	-	-	-	6,097	21,930	4,273
42	Zeeland 1B	Natural Gas	152,133	152,631	337,269	98,144	178,571	96,339	94,994	171,535	-	-	-	24,016	23,519	-	-	-	-	6,732	21,804	4,273
43	Zeeland CC	Natural Gas	4,240,750	4,370,452	4,314,402	4,327,650	4,291,931	4,174,720	3,474,591	3,890,197	3,705,296	3,421,266	3,842,285	3,901,803	3,889,198	3,708,800	3,350,062	3,826,364	3,858,110	2,281,508	2,344,471	2,815,706
	Non-Utility Generators (NUGs)																					
44	TES Filer City Station LP	Coal	489,544	489,544	489,544	490,885	242,760	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	Beaverton City of	Hydro	2,369	2,369	2,369	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Boyce Hydro Power, LLC	Hydro	34,150	14,128	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Commonwealth Power Company (Irving)	Hydro	1,503	1,503	1,503	1,507	1,503	1,503	1,503	1,507	1,503	1,000	-	-	-	-	-	-	-	-	-	-
48	Commonwealth Power Company (LaBarge)	Hydro	4,159	4,159	4,159	4,170	4,159	4,159	4,159	4,170	4,159	4,159	4,159	4,170	4,159	4,159	4,159	4,170	4,159	4,159	1,720	-
49	Commonwealth Power Company (Middleville)	Hydro	825	825	825	828	825	825	825	828	825	825	-	-	-	-	-	-	-	-	-	-
50	Grenfell Hydro, Inc	Hydro	2,091	2,091	2,091	2,096	2,091	2,091	2,091	2,096	2,091	2,091	2,091	2,096	2,091	2,091	2,091	2,096	2,091	2,091	865	-
51	STS Hydropower Ltd (Morrow)	Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	STS HydroPower Ltd-Ada Dam	Hydro	5,643	5,643	2,334	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Ada Cogeneration LP	Natural Gas	146,548	147,263	148,168	151,069	150,936	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Michigan Power LP 1	Natural Gas	1,012,831	1,012,831	1,012,831	1,015,606	1,012,831	1,012,831	1,012,831	1,015,606	1,012,831	843,564	-	-	-	-	-	-	-	-	-	-
55	Midland Cogeneration Venture LP	Natural Gas	6,724,545	6,296,022	6,912,422	7,468,130	7,209,650	5,092,091	4,344,736	3,415,274	3,055,041	1,052,768	-	-	-	-	-	-	-	-	-	-
56	Entergy Nuclear Power Marketing, LLC (Palisades)	Nuclear	6,871,815	2,885,902	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57	Adrian Energy Associates, LLC	Other	17,279	17,279	17,279	17,326	17,279	17,279	17,279	17,326	17,069	-	-	-	-	-	-	-	-	-	-	-
58	C&C 1	Other	13,182	13,182	13,182	13,218	13,182	13,182	13,182	13,218	13,182	2,131	-	-	-	-	-	-	-	-	-	-

PROJECTED GENERATION (GWH)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
Line No.	Electric Generator Name	Resource Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
59	C&C 2	Other	17,375	17,375	17,375	17,423	17,375	17,375	2,809	-	-	-	-	-	-	-	-	-	-	-	-	-
60	Cadillac Renewable Energy, LLC	Other	116,248	116,248	116,248	116,802	116,324	116,324	116,270	68,000	-	-	-	-	-	-	-	-	-	-	-	-
61	Fremont Community Digester, LLC	Other	13,673	13,673	13,673	13,682	13,673	13,673	13,673	13,682	13,673	13,673	13,673	11,108	-	-	-	-	-	-	-	-
62	Genesee Power Station LP	Other	89,363	89,363	89,363	89,608	89,363	89,363	89,363	89,689	89,441	88,514	-	-	-	-	-	-	-	-	-	-
63	Granger Electric Company (Grand Blanc)	Other	25,295	25,295	25,295	25,365	25,295	25,295	25,295	25,365	14,692	-	-	-	-	-	-	-	-	-	-	-
64	Granger Electric Company (Ottawa)	Other	31,290	31,290	31,290	31,376	31,290	31,290	31,290	31,376	15,516	-	-	-	-	-	-	-	-	-	-	-
65	Granger Electric Company (Seymour)	Other	6,280	6,280	6,280	6,297	6,280	6,280	6,280	6,297	6,280	5,747	-	-	-	-	-	-	-	-	-	-
66	Granger Electric of Byron Center	Other	27,038	27,038	27,038	27,112	27,038	7,619	-	-	-	-	-	-	-	-	-	-	-	-	-	-
67	Granger Electric of Pinconning	Other	19,581	19,581	19,581	19,635	19,581	19,581	19,581	1,663	-	-	-	-	-	-	-	-	-	-	-	-
68	Grayling Generating Station LP	Other	84,066	83,628	82,860	84,039	83,267	83,507	83,387	-	-	-	-	-	-	-	-	-	-	-	-	-
69	Hillman Power Company LLC	Other	153,044	63,314	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Kent County	Other	101,204	13,032	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
71	North American Natural Resources (Rathbun)	Other	9,012	9,012	9,012	9,037	9,012	9,012	9,012	9,037	9,012	9,012	9,012	9,037	9,012	9,012	9,012	9,037	9,012	9,012	3,728	-
72	North American Natural Resources (Venice)	Other	17,582	17,582	17,582	17,630	17,582	2,071	-	-	-	-	-	-	-	-	-	-	-	-	-	-
73	North American Natural Resources Lennon	Other	12,276	12,276	12,276	12,312	12,276	12,276	12,276	12,312	12,276	12,276	-	-	-	-	-	-	-	-	-	-
74	North American Natural Resources, Inc (Peoples)	Other	18,260	18,260	18,260	18,310	18,260	18,260	18,260	18,310	18,260	12,371	-	-	-	-	-	-	-	-	-	-
75	PURPA Aggregate 1	Other	23,660	24,643	27,950	30,362	30,286	30,286	30,286	30,362	30,286	30,286	30,286	30,362	30,286	30,286	30,286	30,362	30,286	30,286	30,286	30,362
76	PURPA Aggregate 4	Other	4,129	94,981	115,758	118,524	118,259	146,328	174,672	200,198	229,360	299,226	344,555	424,202	454,448	454,448	454,448	458,806	461,353	461,353	471,867	480,193
77	Viking Energy of Lincoln A LP	Other	144,135	144,135	144,135	144,530	144,135	144,135	59,629	-	-	-	-	-	-	-	-	-	-	-	-	-
78	Viking Energy of McBain A LP	Other	142,401	142,401	142,401	142,791	142,401	142,401	58,911	-	-	-	-	-	-	-	-	-	-	-	-	-
79	WM Renewable Energy (Venice)	Other	11,792	11,792	11,792	11,824	11,792	11,792	3,877	-	-	-	-	-	-	-	-	-	-	-	-	-
80	WM Renewable Energy Northern Oaks	Other	11,770	11,770	11,770	11,801	11,770	11,770	11,770	11,801	11,770	10,429	-	-	-	-	-	-	-	-	-	-
81	WM Renewable Energy Pine Tree Acres	Other	96,221	96,221	96,221	96,527	96,221	96,221	96,221	96,527	96,221	96,221	96,221	45,283	-	-	-	-	-	-	-	-
82	13 Mile Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
83	Albion North Solar	Solar	3,970	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
84	Allegheny Solar	Solar	4,248	24,007	24,007	24,054	24,007	24,007	24,007	24,054	24,007	24,007	24,007	24,054	24,007	24,007	24,007	24,054	24,007	24,007	24,007	24,054
85	Aluminum Solar	Solar	4,873	17,949	17,949	17,984	17,949	17,949	17,949	17,984	17,949	17,949	17,949	17,984	17,949	17,949	17,949	17,984	17,949	17,949	17,949	17,984
86	Angola Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
87	Aurthur Solar Farm, LLC	Solar	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046
88	Bamboo Solar	Solar	1,817	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
89	Beaverton Solar	Solar	-	17,127	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
90	Bingham Solar, LLC	Solar	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
91	Blue Elk Solar I	Solar	-	-	34,058	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
92	Blue Elk Solar III	Solar	-	-	34,058	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
93	Blue Elk Solar IV	Solar	-	-	34,058	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
94	Blue Elk Solar VII	Solar	-	-	20,946	27,651	27,596	27,596	27,596	27,651	27,596	27,596	27,596	27,651	27,596	27,596	27,596	27,651	27,596	27,596	27,596	27,651
95	Bullhead Solar, LLC	Solar	864	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
96	Burns Park Solar	Solar	1,817	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
97	Byrne Solar	Solar	4,282	11,218	11,218	11,240	11,218	11,218	11,218	11,240	11,218	11,218	11,218	11,240	11,218	11,218	11,218	11,240	11,218	11,218	11,218	11,240
98	Captain Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
99	Cement City	Solar	-	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
100	Cloudbreak Solar	Solar	7,940	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
101	Coldwater Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
102	Congo Solar	Solar	1,817	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
103	Durban Solar	Solar	-	20,435	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976
104	Esmarelda Solar	Solar	1,454	17,949	17,949	17,984	17,949	17,949	17,949	17,984	17,949	17,949	17,949	17,984	17,949	17,949	17,949	17,984	17,949	17,949	17,949	17,984
105	Geddes 1 Solar, LLC	Solar	864	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
106	Geddes 2 Solar, LLC	Solar	864	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
107	Golden Solar Farm, LLC	Solar	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Existing Assets Zonal Resource Credits and Projected Generation

Case No.: U-21090
Exhibit No.: A-6 (STW-3)

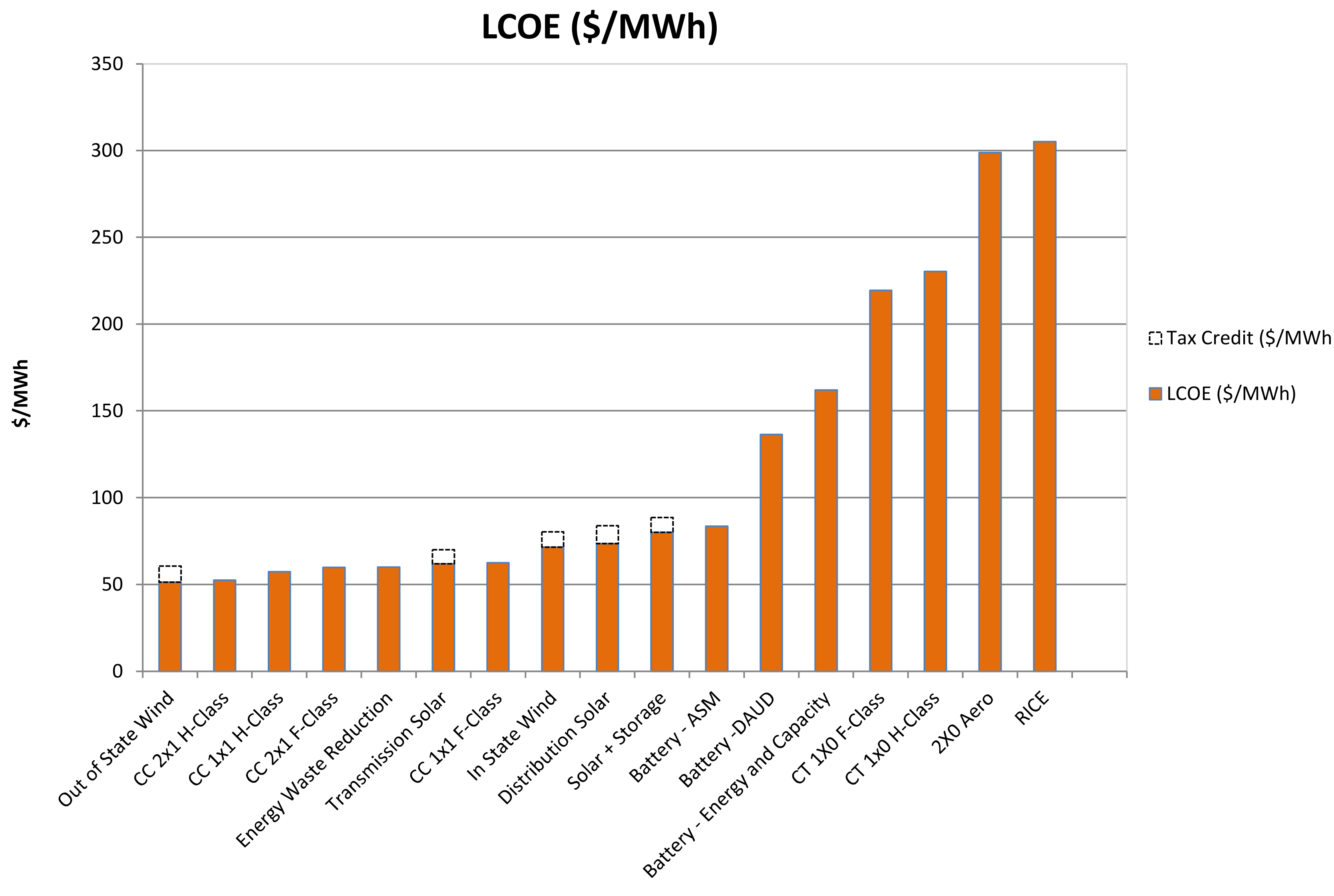
Witness: STWalz
Date: June 2021

PROJECTED GENERATION (GWH)

Line No.	Electric Generator Name	Resource Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
108	Good Fruit Storage LLC	Solar	449	449	449	450	449	449	449	450	449	449	449	450	449	449	449	450	449	449	449	450
109	Greenstone Solar, LLC	Solar	-	-	34,058	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
110	Hazel Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
111	Hendershot Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
112	Heritage Garden Wind Farm I LLC Solar portion	Solar	968	968	968	970	968	968	968	970	968	968	968	824	-	-	-	-	-	-	-	-
113	Hogan Solar	Solar	7,309	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976
114	Interchange Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
115	Jack Francis Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
116	Johnsfield Solar	Solar	6,091	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
117	Lake City Solar	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
118	Letts Creek	Solar	-	33,654	33,654	33,720	33,654	33,654	33,654	33,720	33,654	33,654	33,654	33,720	33,654	33,654	33,654	33,720	33,654	33,654	33,654	33,720
119	Lightfoot Solar	Solar	1,817	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
120	Lyons Road Solar	Solar	12,182	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
121	Macbeth Solar	Solar	-	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
122	May Shannon Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
123	Midcontinent Solar, LLC	Solar	-	-	34,058	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
124	Morey Solar	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
125	NextSun Energy LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
126	Pullman	Solar	-	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
127	Robert Swift Solar Farm, LLC	Solar	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046	4,038	4,038	4,038	4,046
128	Rosco Solar	Solar	6,091	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
129	RPS Solar 2021	Solar	174,318	174,318	174,318	174,682	174,318	174,318	174,318	174,682	174,318	174,318	174,318	174,682	174,318	174,318	174,318	174,682	174,318	174,318	174,318	174,682
130	Shady Solar	Solar	-	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
131	Shipsterns Solar	Solar	-	28,259	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
132	Stoneheart Solar, LLC	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
133	Surbrook Solar	Solar	1,817	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480	22,436	22,436	22,436	22,480
134	Swede Solar	Solar	2,180	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976	26,923	26,923	26,923	26,976
135	TART Solar, LLC	Solar	9,588	19,071	19,071	19,108	19,071	19,071	19,071	19,108	19,071	19,071	19,071	19,108	19,071	19,071	19,071	19,108	19,071	19,071	19,071	19,108
136	Temperance Solar, LLC	Solar	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
137	Thorn Lake	Solar	-	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
138	Topanga Solar	Solar	11,910	67,308	67,308	67,440	67,308	67,308	67,308	67,440	67,308	67,308	67,308	67,440	67,308	67,308	67,308	67,440	67,308	67,308	67,308	67,440
139	Wilford Solar	Solar	12,182	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960	44,872	44,872	44,872	44,960
140	Woodley Solar	Solar	1,795	1,795	1,795	1,798	1,795	1,795	1,795	1,798	1,795	1,795	1,795	1,798	1,795	1,795	1,795	1,798	1,795	1,795	1,795	1,798
141	Workman Solar	Solar	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496	4,487	4,487	4,487	4,496
142	Apple Blossom	Wind	284,698	284,698	284,698	285,616	284,698	284,698	284,698	285,616	284,698	284,698	284,698	285,616	133,678	-	-	-	-	-	-	-
143	Bay Windpower I (Mackinaw)	Wind	982	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
144	Beebe Renewable Energy	Wind	186,713	186,713	186,713	187,490	186,713	186,713	186,713	187,490	186,713	186,713	186,713	107,232	-	-	-	-	-	-	-	-
145	Harvest II Windfarm LLC	Wind	174,038	174,038	174,038	174,736	174,038	174,038	174,038	174,736	174,038	174,038	174,038	98,706	-	-	-	-	-	-	-	-
146	Heritage Garden Wind Farm I LLC Wind portion	Wind	55,321	55,321	55,321	55,495	55,321	55,321	55,321	55,495	55,321	55,321	55,321	37,753	-	-	-	-	-	-	-	-
147	Heritage Stoney Corners Wind Farm I LLC Phase 2	Wind	30,908	30,908	30,908	31,015	30,908	30,908	30,908	31,015	30,908	30,908	15,415	-	-	-	-	-	-	-	-	-
148	Heritage Stoney Corners Wind Farm I LLC Phase 3	Wind	20,884	20,884	20,884	20,956	20,884	20,884	20,884	20,956	20,884	20,884	10,275	-	-	-	-	-	-	-	-	-
149	Michigan Wind 1, LLC	Wind	28,288	28,288	28,288	28,365	28,288	28,288	28,288	28,365	-	-	-	-	-	-	-	-	-	-	-	-
150	Michigan Wind 2 LLC	Wind	260,226	260,226	260,226	261,348	260,226	260,226	260,226	261,348	260,226	260,226	152,991	-	-	-	-	-	-	-	-	-
151	PCA_CE Solar_2024_500MW	Solar	-	-	-	1,124,008	1,121,804	1,121,804	1,121,804	1,124,008	1,121,804	1,121,804	1,121,804	1,124,008	1,121,804	1,121,804	1,121,804	1,124,008	1,121,804	1,121,804	1,121,804	1,124,008
152	PCA_CE Solar_2022_300MW	Solar	-	673,083	673,083	674,405	673,083	673,083	673,083	674,405	673,083	673,083	673,083	674,405	673,083	673,083	673,083	674,405	673,083	673,083	673,083	674,405
153	PCA_CE Solar_2023_300MW	Solar	-	-	673,083	674,405	673,083	673,083	673,083	674,405	673,083	673,083	673,083	674,405	673,083	673,083	673,083	674,405	673,083	673,083	673,083	674,405

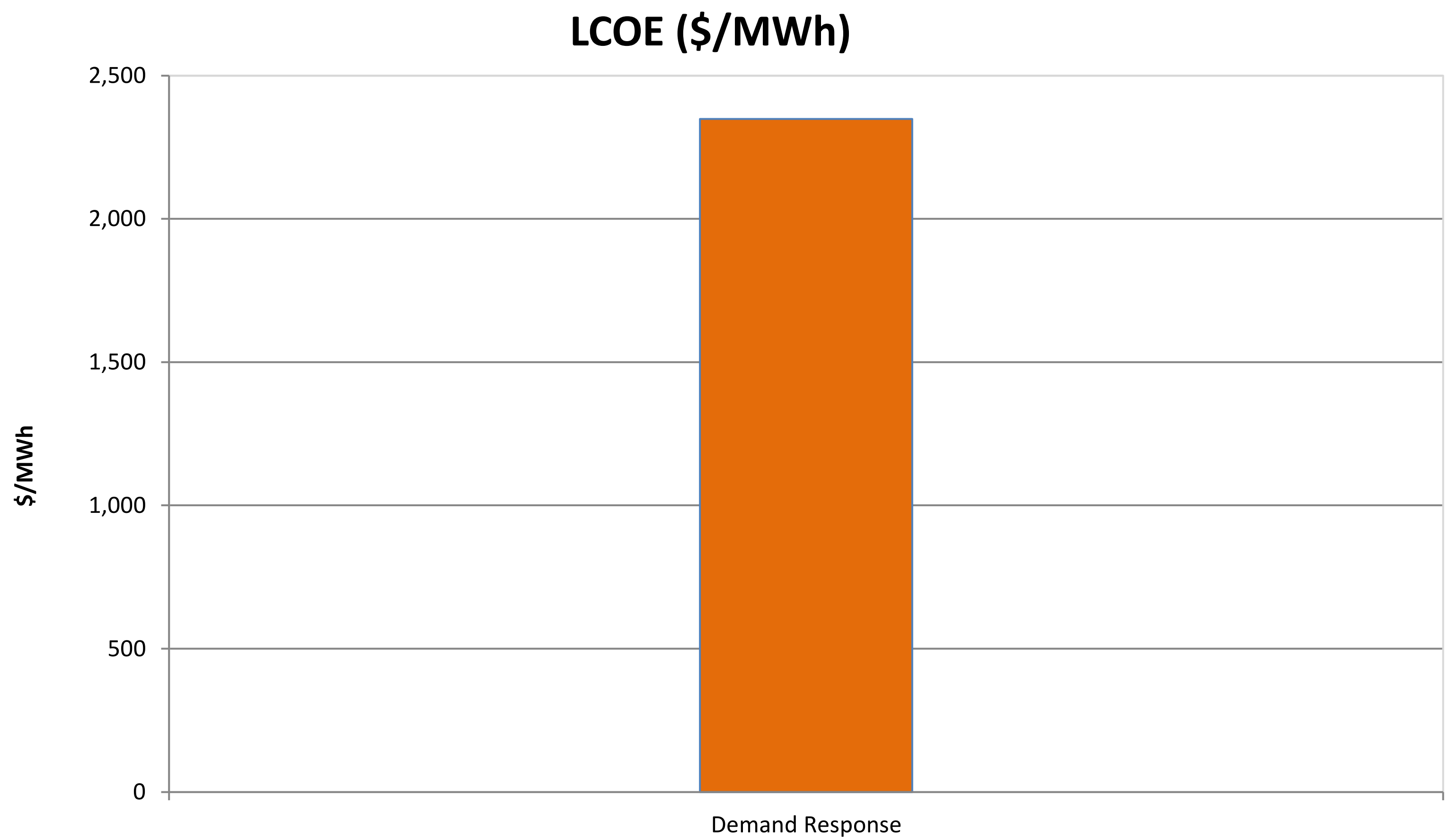
MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Levelized Cost of Energy – Resource Screening

Case No.: U-21090
Exhibit No.: A-7 (STW-4)
Page: 1 of 2
Witness: STWalz
Date: June 2021



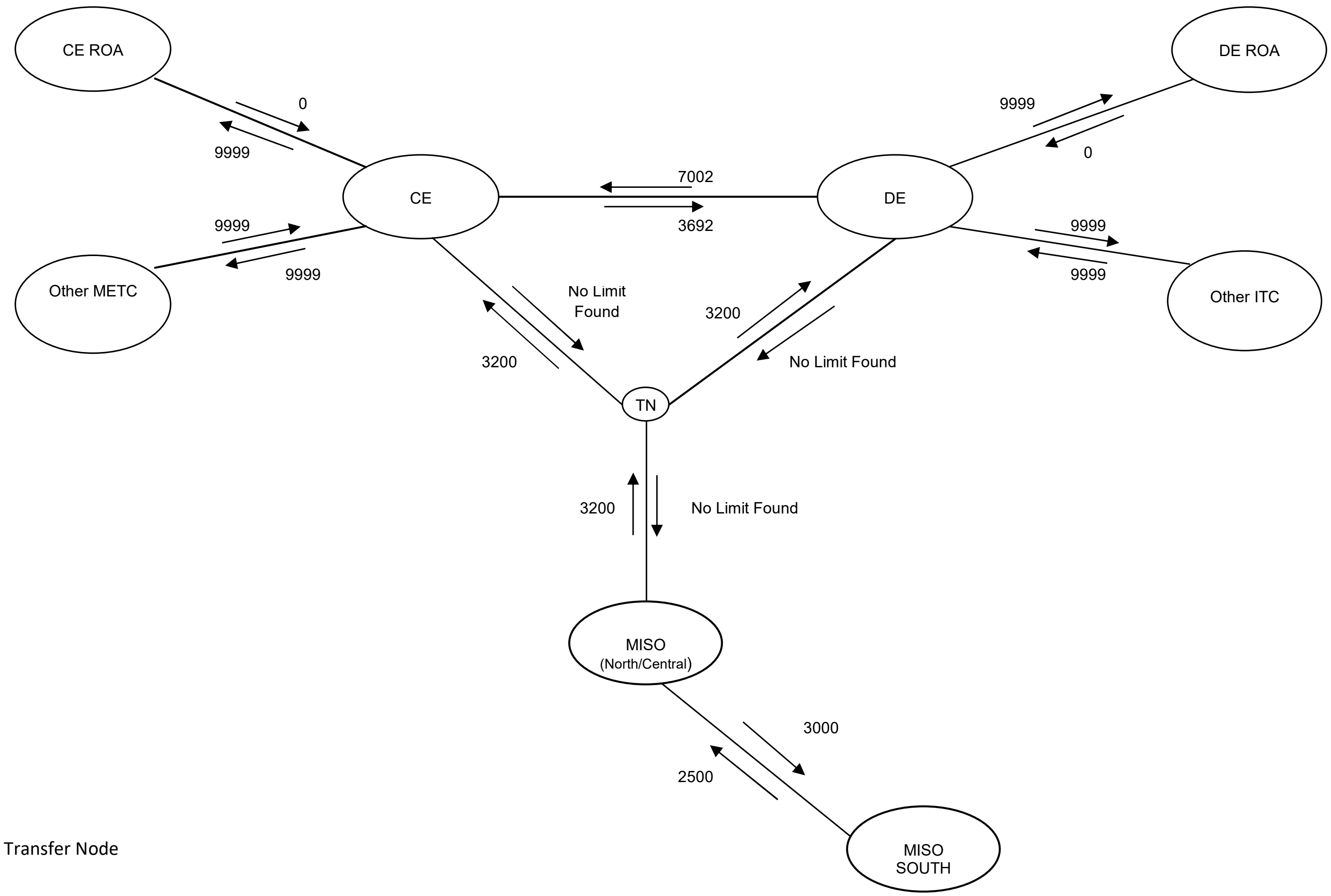
MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Levelized Cost of Energy – Resource Screening

Case No.: U-21090
Exhibit No.: A-7 (STW-4)
Page: 2 of 2
Witness: STWalz
Date: June 2021



MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP MISO Market Topology

Case No.: U-21090
Exhibit No.: A-8 (STW-5)
Page: 1 of 1
Witness: STWalz
Date: June 2021



TN = Transfer Node

CE ROA = Consumers Energy Retail Open Access (customers taking service from alternative energy suppliers)
DE ROA = Detroit Edison Retail Open Access
Other METC / Other ITC indicates remaining load areas within Zone 7

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP CVR and EWR Economics

Case No.: U-21090
Exhibit No.: A-9 (STW-6)
Page: 1 of 1
Witness: STWalz
Date: June 2021

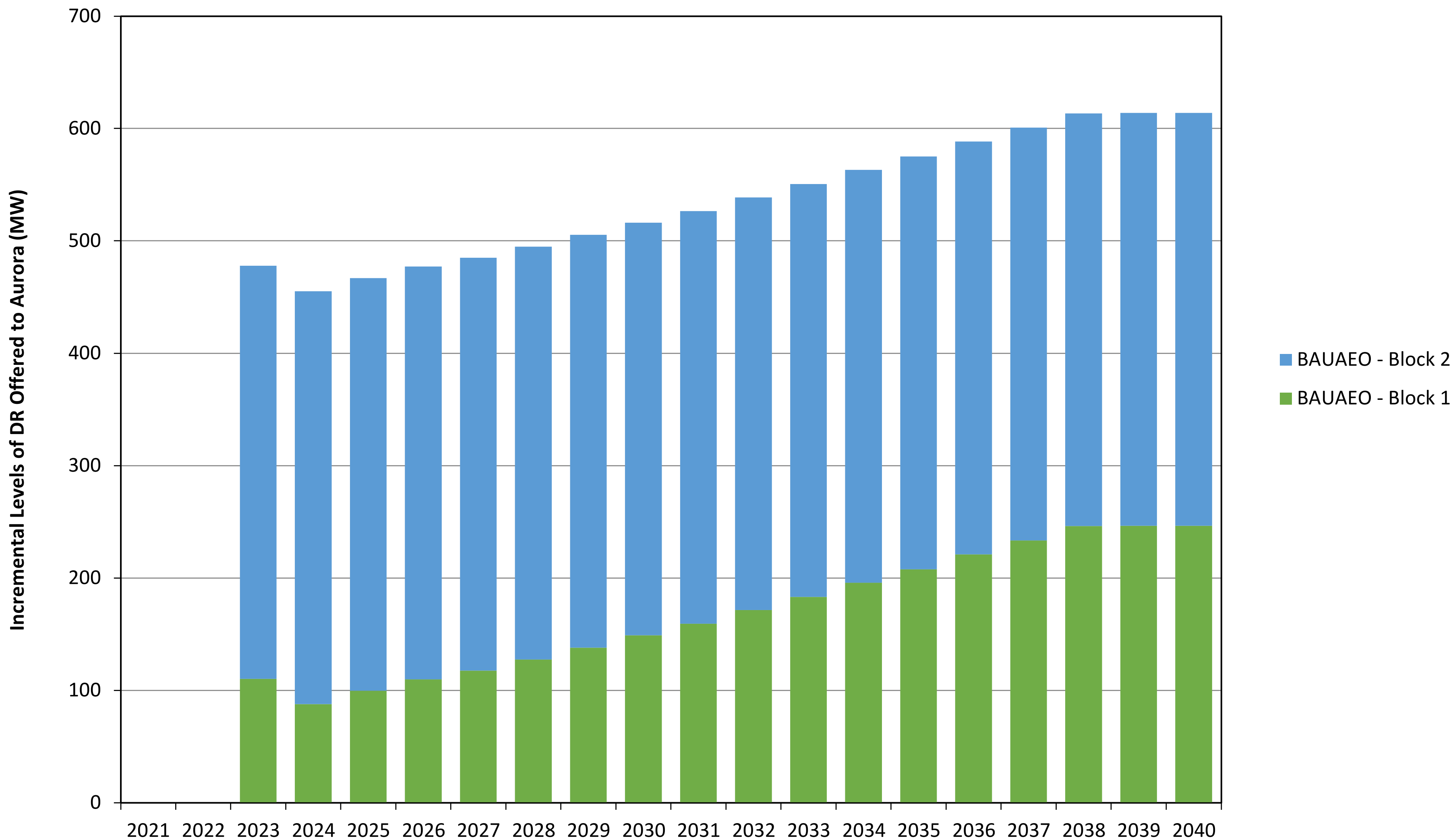
NPV Savings of Conservation Voltage Reduction and Energy Waste Reduction (K$)

Line No.	(a) CASE	(b) CVR	(c) EWR
1	BAU CE	(89,956)	110,138
2	BAU AEO	(113,528)	
3	ET CE	(112,455)	(15,307)
4	ET AEO	(106,530)	
5	EP CE	(107,559)	5,321
6	EP AEO	40,134	

A negative value indicates that the portfolio that includes CVR or EWR is projected to be at a lower cost than a portfolio that does not have those resources included.

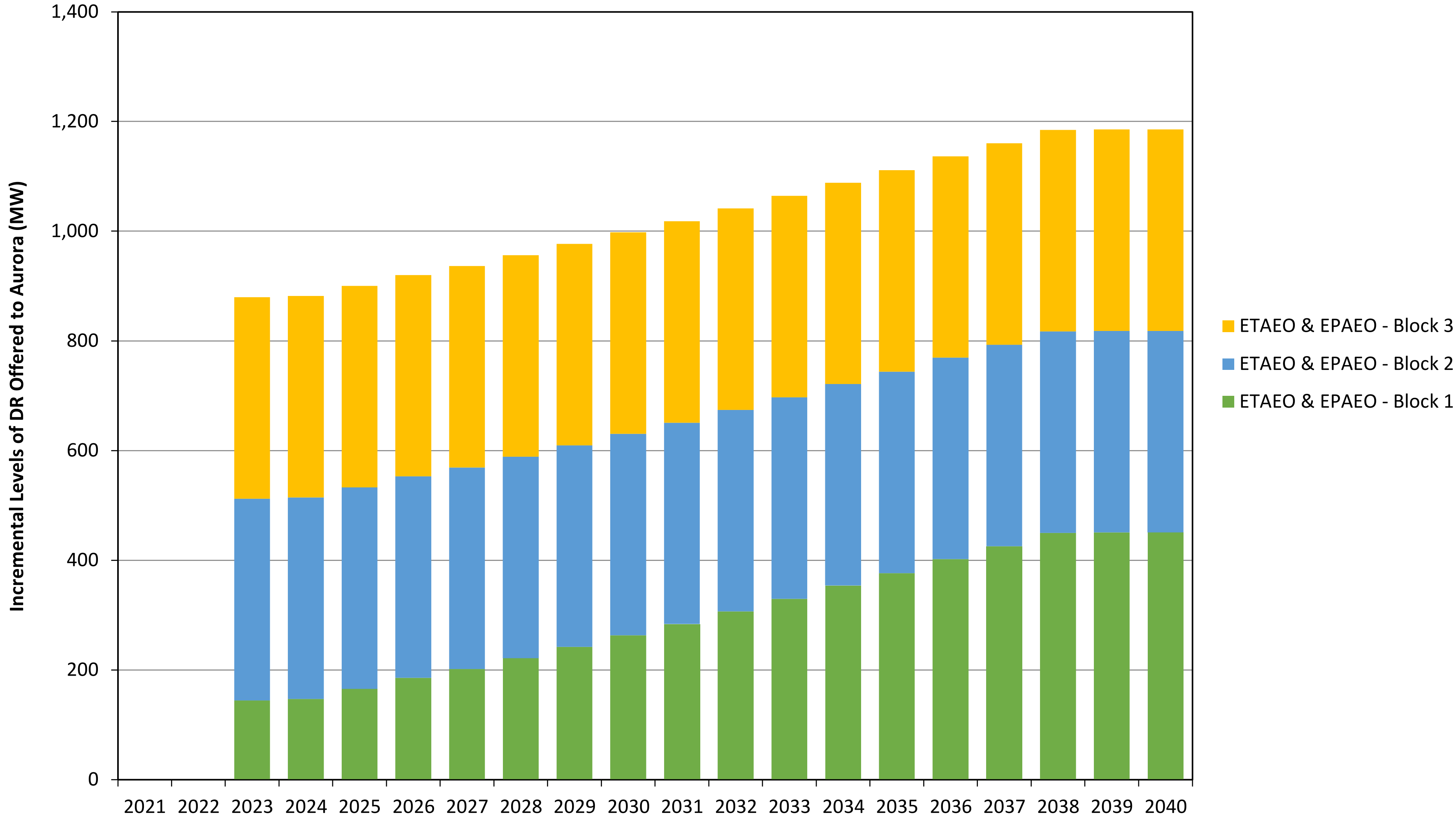
MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Demand Response Resource Blocks, by Scenario, for Aurora
BAU AEO Scenario

Case No.: U-21090
Exhibit No.: A-10 (STW-7)
Page: 1 of 3
Witness: STWalz
Date: June 2021



MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Demand Response Resource Blocks, by Scenario, for Aurora
EP AEO, ET AEO Scenarios

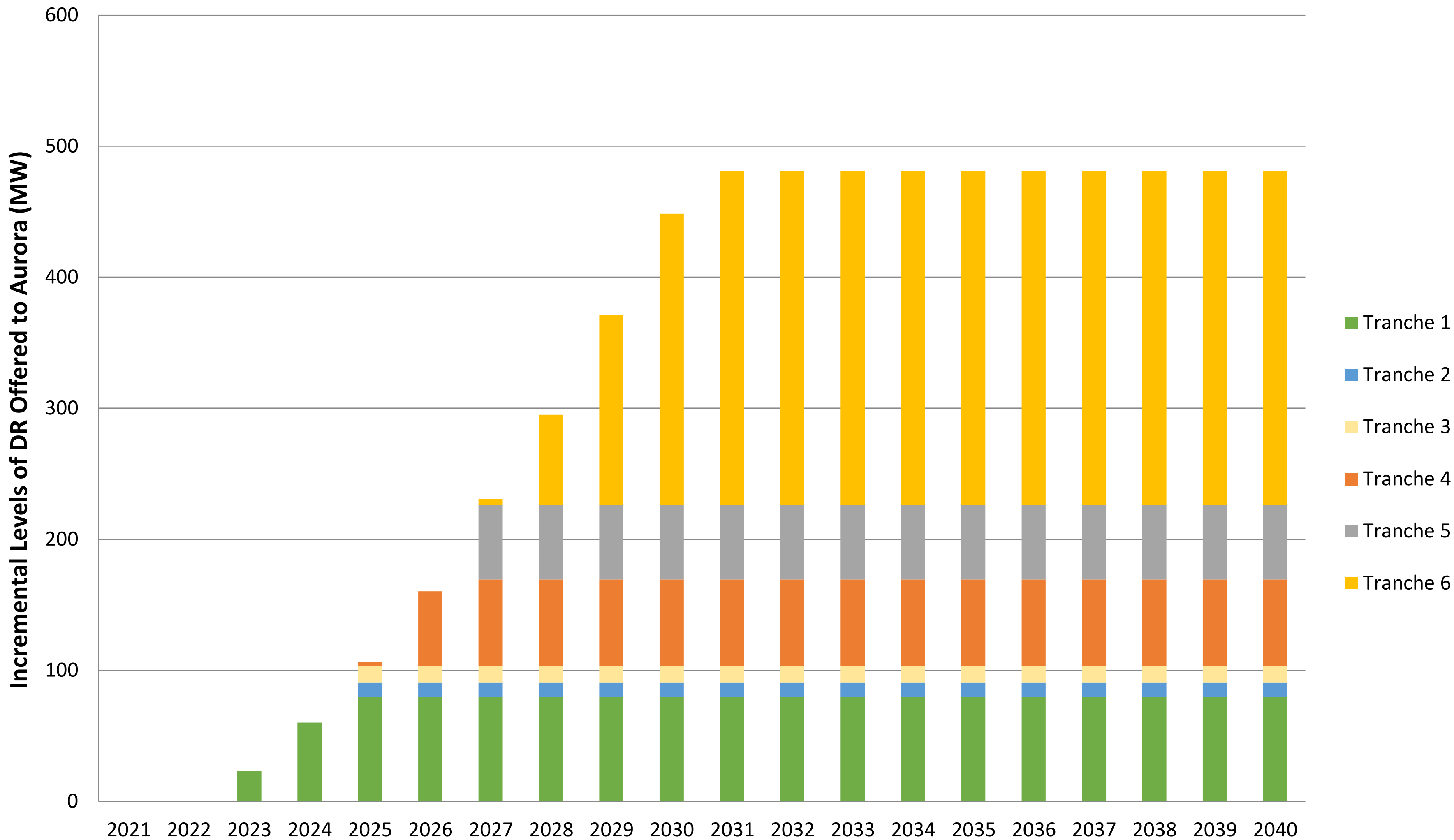
Case No.: U-21090
Exhibit No.: A-10 (STW-7)
Page: 2 of 3
Witness: STWalz
Date: June 2021



MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Demand Response Resource Blocks, by Scenario, for Aurora
CE Scenarios - Glide Path

Case No.: U-21090
Exhibit No.: A-10 (STW-7)

Witness: STWalz
Date: June 2021



MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Portfolio Design

Case No.: U-21090
Exhibit No.: A-11 (STW-8)
Page: 1 of 1
Witness: STWalz
Date: June 2021

IRP REFERENCE AND OPTIMIZED PORTFOLIO DESIGNS

Table 1

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Portfolio Design**	**Description**	**Market Purchase**	**Aurora LTCE Optimization[1]**	**Glide Path[2]**	**Optimal Plan Fixed Portfolio[3]**
1	1	Market Purchases	X	-	-	-
2	2	Full Optimization Overnight Build	-	X		
3	3	Full Optimization Glide Path	-		X	
4	4	Proposed Course of Action	-		X	X
5	5	BAUCE Optimal Plan	-		X	X
6	6	ETCE Optimal Plan	-		X	X
7	7	EPCE Optimal Plan	-		X	X
8	8	BAUAEO Optimal Plan	-		X	X
9	9	ETAEO Optimal Plan	-		X	X
10	10	EPAEO Optimal Plan	-		X	X

Table 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Portfolio	**Fixed Portfolio**	**Scenarios under which the Fixed Portfolio is Evaluated**					
			BAUCE	ETCE	EPCE	BAUAEO	ETAEO	EPAEO
11	4	PCA	X	X	X	X	X	X
12	5	BAUCE Optimal Plan		X	X			
13	6	ETCE Optimal Plan	X		X			
14	7	EPCE Optimal Plan	X	X				
15	8	BAUAEO Optimal Plan					X	X
16	9	ETAEO Optimal Plan				X		X
17	10	EPAEO Optimal Plan				X	X	

Notes:
1 LTCE is the long term capacity expansion simulation in Aurora
2 A glide path portfolio is developed from results of the LTCE optimizations
3 An optimal plan fixed portfolio is a specified portfolio of resources evaluated within other sensitivities (as shown on Table 2)

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
			BUSINESS AS USUAL CE Gas															
Line No.	**Portfolio No.**	**Net Present Value Results (M$)**	**Base**	**CA1 2024**	**CA1 2025**	**CA1 2026**	**CA1 2028**	**CA2 2024**	**CA2 2025**	**CA2 2026**	**CA2 2028**	**CA12 2024**	**CA12 2025**	**CA12 2026**	**CA12 2028**	**KA34 2025**	**Alternate Plan[2]**	**Retirement Base Case[4]**
		Sensitivity Number	201	203	204	205	206	207	208	209	210	211	212	213	214	218	236	240
1	1	Market Purchases	18,339	18,339		18,310		18,340	18,314	18,306	18,364	18,326	18,324	18,309	18,372			
2	2	Full Optimization Overnight Build	18,370	18,503	18,480	18,473		18,416	18,477	18,470	18,441	18,518	18,486	18,472	18,537			18,584
3	3	Full Optimization Glide Path	18,726	18,721	18,701	18,692	18,740	18,721	18,657	18,690	18,746	18,680	18,697	18,683	18,749	18,812	18,530	18,690
4	4	Proposed Course of Action[1]																18,588
5	5	BAU CE Optimal Plan																
6	6	ET CE Optimal Plan																18,690
7	7	EP CE Optimal Plan																18,702

			BUSINESS AS USUAL CE Gas DELTAs															
	Portfolio No.	**Delta to Base (M$)**	**Base**	**CA1 2024**	**CA1 2025**	**CA1 2026**	**CA1 2028**	**CA2 2024**	**CA2 2025**	**CA2 2026**	**CA2 2028**	**CA12 2024**	**CA12 2025**	**CA12 2026**	**CA12 2028**	**KA34 2025**	**Alternate Plan[3]**	**Retirement Base Case**
			201	203	204	205	206	207	208	209	210	211	212	213	214	218	236	240
8	1	Market Purchases	0	0		-29		1	-25	-32	25	-13	-15	-30	33			
9	2	Full Optimization Overnight Build	0	133	110	103		46	107	100	71	148	116	102	167			
10	3	Full Optimization Glide Path	0	-5	-26	-34	14	-6	-69	-36	20	-46	-30	-44	23	85		160

[1]The PCA includes a 200 ZRC overbuild.
[2]The Alternate Plan also includes a 200 ZRC overbuild (like the PCA).
[3]A delta to base calculation is not provided for the Alternate Plan; instead, the Alternate Plan is used as the base from which to compare the Retirement Base Case.
[4]The Retirement Base Case includes retirement of Karn Units 3 and 4 on May 31, 2023, Campbell Units 1 through 3 on May 31, 2025, the addition of the Covert Plant on May 31, 2023, and the addition of the CMS Plants on May 31, 2025.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Aurora NPV Results
CE Scenarios and Sensitivities

Case No.: U-21090
Exhibit No.: A-12 (STW-9)

Witness: STWalz
Date: June 2021

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
			EMERGING TECHNOLOGIES CE Gas															
Line No.	**Portfolio No.**	**Net Present Value Results (M$)**	**Base**	**CA1 2024**	**CA1 2025**	**CA1 2026**	**CA1 2028**	**CA2 2024**	**CA2 2025**	**CA2 2026**	**CA2 2028**	**CA12 2024**	**CA12 2025**	**CA12 2026**	**CA12 2028**	**KA34 2025**	**Alternate Plan**	**Retirement Base Case[4]**
		Sensitivity Number	401	403	404	405	406	407	408	409	410	411	412	413	414	418	436	440
1	1	Market Purchases	18,622	18,629	18,609	18,601	18,647	18,628	18,604	18,597	18,626	18,623	18,621	18,607	18,665			
2	2	Full Optimization Overnight Build	17,767	17,763	17,743	17,909	17,785	17,759	17,736	17,727	17,783	17,716	17,727	17,712	17,781			18,376
3	3	Full Optimization Glide Path	17,693	17,695	17,671	17,664	17,712	17,689	17,666	17,658	17,715	17,918	17,666	17,658	17,725	17,750	17,497	17,640
4	4	Proposed Course of Action[1]																17,573
5	5	BAU CE Optimal Plan																17,638
6	6	ET CE Optimal Plan																
7	7	EP CE Optimal Plan																17,638

			EMERGING TECHNOLOGIES CE Gas DELTAs															
	Portfolio No.	**Delta to Base (M$)**	**Base**	**CA1 2024**	**CA1 2025**	**CA1 2026**	**CA1 2028**	**CA2 2024**	**CA2 2025**	**CA2 2026**	**CA2 2028**	**CA12 2024**	**CA12 2025**	**CA12 2026**	**CA12 2028**	**KA34 2025**	**Alternate Plan[2]**	**Retirement Base Case**
			401	403	404	405	406	407	408	409	410	411	412	413	414	418	436	440
8	1	Market Purchases	0	8	-13	-20	25	6	-18	-24	4	2	-1	-15	44			
9	2	Full Optimization Overnight Build	0	-4	-25	142	17	-8	-31	-40	15	-51	-40	-56	13			
10	3	Full Optimization Glide Path	0	2	-22	-29	19	-3	-27	-35	22	225	-27	-35	32	57		143

[1]The PCA includes a 200 ZRC overbuild.

[2]The Alternate Plan also includes a 200 ZRC overbuild (like the PCA).

[3]A delta to base calculation is not provided for the Alternate Plan; instead, the Alternate Plan is used as the base from which to compare the Retirement Base Case.

[4]The Retirement Base Case includes retirement of Karn Units 3 and 4 on May 31, 2023, Campbell Units 1 through 3 on May 31, 2025, the addition of the Covert Plant on May 31, 2023, and the addition of the CMS Plants on May 31, 2025.

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
			ENVIRONMENTAL POLICY CE Gas															
Line No.	Portfolio No.	Net Present Value Results (M$)	Base	CA1 2024	CA1 2025	CA1 2026	CA1 2028	CA2 2024	CA2 2025	CA2 2026	CA2 2028	CA12 2024	CA12 2025	CA12 2026	CA12 2028	KA34 2025	Alternate Plan	Retirement Base Case[4]
		Sensitivity Number	701	703	704	705	706	707	708	709	710	711	712	713	714	718	736	740
1	1	Market Purchases	18,268	18,264	18,247	18,239	18,290	18,265	18,245	18,237	18,293	18,247	18,250	18,237	18,302			
2	2	Full Optimization Overnight Build	17,825	17,809	17,792	17,785	17,836	17,806	17,786	17,778	17,836	17,682	17,775	17,763	17,834			17,735
3	3	Full Optimization Glide Path	17,812	17,801	17,783	17,777	17,829	17,800	17,780	17,772	17,831	17,942	17,771	17,764	17,835	17,753	17,603	17,568
4	4	Proposed Course of Action[1]																17,619
5	5	BAU CE Optimal Plan																17,589
6	6	ET CE Optimal Plan																17,589
7	7	EP CE Optimal Plan																

			ENVIRONMENTAL POLICY CE Gas DELTAs															
	Portfolio No.	Delta to Base (M$)	Base	CA1 2024	CA1 2025	CA1 2026	CA1 2028	CA2 2024	CA2 2025	CA2 2026	CA2 2028	CA12 2024	CA12 2025	CA12 2026	CA12 2028	KA34 2025	Alternate Plan[2]	Retirement Base Case
			701	703	704	705	706	707	708	709	710	711	712	713	714	718	736	740
8	1	Market Purchases	0	-4	-21	-29	22	-3	-23	-32	25	-21	-18	-31	34			
9	2	Full Optimization Overnight Build	0	-15	-33	-39	12	-18	-39	-47	11	-143	-50	-62	9			
10	3	Full Optimization Glide Path	0	-11	-29	-35	17	-13	-32	-40	19	130	-41	-49	23	-59		-35

[1]The PCA includes a 200 ZRC overbuild.

[2]The Alternate Plan also includes a 200 ZRC overbuild (like the PCA).

[3]A delta to base calculation is not provided for the Alternate Plan; instead, the Alternate Plan is used as the base from which to compare the Retirement Base Case.

[4]The Retirement Base Case includes retirement of Karn Units 3 and 4 on May 31, 2023, Campbell Units 1 through 3 on May 31, 2025, the addition of the Covert Plant on May 31, 2023, and the addition of the CMS Plants on May 31, 2025.

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Consumers Energy Company
2021 IRP Aurora NPV Results
MPSC Scenarios and Sensitivities

Case No.: U-21090
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			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
			BUSINESS AS USUAL AEO Gas - Aurora Modeling Results												
Line	**Portfolio No.**	**Net Present Value Results (M$)**	**MPSC Base**	**Karn 3&4 RET 2025**	**High Load**	**50% ROA**	**2.5% EWR**	**High Gas**	**CT only**	**Retirement Base Case ("RBC")[2]**	**RBC High Load**	**RBC 50% ROA**	**RBC 2.5% EWR**	**RBC High Gas**	**RBC CT only**
		Sensitivity Number	101	102	103	104	105	106	107	108	109	110	111	112	113
1	1	Market Purchases	18,395	18,796	20,975	19,495		21,051							
2	2	Full Optimization Overnight Build	18,499	18,819	21,442	19,943	18,064	20,357	19,437	19,695	22,097	20,741	18,970	22,069	20,089
3	3	Full Optimization Glide Path	18,855	18,929	21,470	20,041	18,218	20,397	19,437	19,728	22,156	20,749	18,996	21,895	20,092
4	4	Proposed Course of Action[1]								19,689				21,944	
5	8	BAU AEO Optimal plan													
6	9	ET AEO Optimal plan								19,740					
7	10	EP AEO Optimal plan								19,741					

			BUSINESS AS USUAL AEO Gas - Aurora Modeling Results DELTAs												
	Portfolio No.	**Delta to Base (M$)**	**MPSC Base**	**Karn 3&4 RET 2025**	**High Load**	**50% ROA**	**2.5% EWR**	**High Gas**	**CT only**	**Retirement Base Case**	**RBC High Load**	**RBC 50% ROA**	**RBC 2.5% EWR**	**RBC High Gas**	**RBC CT only**
		Sensitivity Number	101	102	103	104	105	106	107	108	109	110	111	112	113
8	1	Market Purchases	0	401	2,179	699		2,255							
9	2	Full Optimization Overnight Build	0	321	2,623	1,123	-755	1,537	618	876	2,402	1,046	-725	2,374	394
10	3	Full Optimization Glide Path	0	73	2,542	1,113	-711	1,468	509	799	2,428	1,021	-732	2,167	365
11	4	Proposed Course of Action[1]												2,254	

[1]The PCA includes a 200 ZRC overbuild.
[2]The Retirement Base Case includes retirement of Karn Units 3 and 4 on May 31, 2023, Campbell Units 1 through 3 on May 31, 2025, the addition of the Covert Plant on May 31, 2023, and the addition of the CMS Plants on May 31, 2025.

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MPSC Scenarios and Sensitivities

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			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			EMERGING TECHNOLOGIES AEO Gas - Aurora Modeling Results										
Line	**Portfolio No.**	**Net Present Value Results (M$)**	**MPSC Base**	**Karn 3&4 RET 2025**	**High Load**	**25% Renew**	**2.5% EWR**	**High Gas**	**Retirement Base Case[2]**	**RBC High Load**	**RBC 25% Renew**	**RBC 2.5% EWR**	**RBC High Gas**
		Sensitivity Number	301	302	303	304	305	306	307	308	309	310	311
1	1	Market Purchases											
2	2	Full Optimization Overnight Build	17,958	17,869	20,478		17,497	18,867	18,904	21,475	18,904	18,385	20,646
3	3	Full Optimization Glide Path	17,892	17,938	21,151	17,938	17,350	17,605	18,661	21,176	18,661	18,109	20,382
4	4	Proposed Course of Action[1]							17,991				19,622
5	8	BAU AEO Optimal plan							17,989				
6	9	ET AEO Optimal plan											
7	10	EP AEO Optimal plan							17,995				

			EMERGING TECHNOLOGIES AEO Gas - Aurora Modeling Results DELTAs										
	Portfolio No.	**Delta to Base (M$)**	**MPSC Base**	**Karn 3&4 RET 2025**	**High Load**	**25% Renew**	**2.5% EWR**	**High Gas**	**Retirement Base Case**	**RBC High Load**	**RBC 25% Renew**	**RBC 2.5% EWR**	**RBC High Gas**
		Sensitivity Number	301	302	303	304	305	306	307	308	309	310	311
8	1	Market Purchases											
9	2	Full Optimization Overnight Build	0	-88	2,609		-372	998	1,035	2,570	0	-520	1,741
10	3	Full Optimization Glide Path	0	46	3,214	0	-587	-333	723	2,515	0	-552	1,721
11	4	Proposed Course of Action[1]											1,631

[1]The PCA includes a 200 ZRC overbuild.
[2]The Retirement Base Case includes retirement of Karn Units 3 and 4 on May 31, 2023, Campbell Units 1 through 3 on May 31, 2025, the addition of the Covert Plant on May 31, 2023, and the addition of the CMS Plants on May 31, 2025.

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2021 IRP Aurora NPV Results
MPSC Scenarios and Sensitivities

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			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
			ENVIRONMENTAL POLICY AEO Gas - Aurora Modeling Results										
Line	**Portfolio No.**	**Net Present Value Results (M$)**	**MPSC Base**	**Karn 3&4 RET 2025**	**High Load**	**50% CO2 2030**	**2.5% EWR**	**High Gas**	**Retirement Base Case[2]**	**RBC High Load**	**RBC 50% CO2 2030**	**RBC 2.5% EWR**	**RBC High Gas**
		Sensitivity Number	601	602	603	604	605	606	607	608	609	610	611
1	1	Market Purchases	18,847	18,941	20,634		18,356	19,017					
2	2	Full Optimization Overnight Build	18,132	18,134	20,768		18,093	19,092	19,132	21,370		19,966	20,741
3	3	Full Optimization Glide Path	18,046	18,098	20,803	18,362	17,387	18,954	18,855	21,171	18,855	18,279	20,384
4	4	Proposed Course of Action[1]							18,985				20,560
5	8	BAU AEO Optimal plan							18,886				
6	9	ET AEO Optimal plan							18,865				
7	10	EP AEO Optimal plan											

			ENVIRONMENTAL POLICY AEO Gas - Aurora Modeling Results DELTAs										
	Portfolio No.	**Delta to Base (M$)**	**MPSC Base**	**Karn 3&4 RET 2025**	**High Load**	**50% CO2 2030**	**2.5% EWR**	**High Gas**	**Retirement Base Case**	**RBC High Load**	**RBC 50% CO2 2030**	**RBC 2.5% EWR**	**RBC High Gas**
		Sensitivity Number	601	602	603	604	605	606	607	608	609	610	611
8	1	Market Purchases	0	93	1,694		-584	76					
9	2	Full Optimization Overnight Build	0	2	2,634		-41	958	998	2,238		834	1,609
10	3	Full Optimization Glide Path	0	52	2,705	264	-711	857	757	2,316	0	-576	1,529
11	4	Proposed Course of Action[1]											1,575

[1]The PCA includes a 200 ZRC overbuild.

[2]The Retirement Base Case includes retirement of Karn Units 3 and 4 on May 31, 2023, Campbell Units 1 through 3 on May 31, 2025, the addition of the Covert Plant on May 31, 2023, and the addition of the CMS Plants on May 31, 2025.

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2021 IRP Aurora NPV Results
Advanced Technologies Scenario

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Line	Portfolio No.	Net Present Value Results (M$)	(A) Advanced Technologies: Karn 3&4 2025	(B) Advanced Technologies: Retirement Base Case[1]
		Sensitivity Number	503	504
1	1	Market Purchases	17,162	16,978
2	2	Full Optimization Overnight Build	15,316	16,072
3	3	Full Optimization Glide Path	15,208	15,786

Line	Portfolio No.	Delta (M$)	Advanced Technologies DELTAs: Karn 3&4 2025	Advanced Technologies DELTAs: Retirement Base Case
		Sensitivity Number	503	504
4	1	Market Purchases	0	-185
5	2	Full Optimization Overnight Build	0	756
6	3	Full Optimization Glide Path	0	578

[1]The Retirement Base Case includes retirement of Karn Units 3 and 4 on May 31, 2023, Campbell Units 1 through 3 on May 31, 2025, the addition of the Covert Plant on May 31, 2023, and the addition of the CMS Plants on May 31, 2025.

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2021 IRP Aurora NPV Results
Carbon Reduction Scenario

Case No.: U-21090
Exhibit No.: A-12 (STW-9)

Witness: STWalz
Date: June 2021

			(A)	(B)
			Carbon Reduction	
Line	Portfolio No.	Net Present Value Results (M$)	Retirement Base Case[1]	Load Growth, CO2 Reduction
		Sensitivity Number	607	612
1	1	Market Purchases		
2	2	Full Optimization Overnight Build	19,132	20,614
3	3	Full Optimization Glide Path	18,855	20,204

			Carbon Reduction DELTAs	
	Portfolio No.	Delta (M$)	Retirement Base Case[1]	Load Growth, CO2 Reduction
		Sensitivity Number	607	612
4	1	Market Purchases		
5	2	Full Optimization Overnight Build	0	1,481
6	3	Full Optimization Glide Path	0	1,349

[1]The Retirement Base Case includes retirement of Karn Units 3 and 4 on May 31, 2023, Campbell Units 1 through 3 on May 31, 2025, the addition of the Covert Plant on May 31, 2023, and the addition of the CMS Plants on May 31, 2025.

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2021 IRP Aurora Resource Selections, by New Technology Resource
Transmission- or Distribution-Connected Solar

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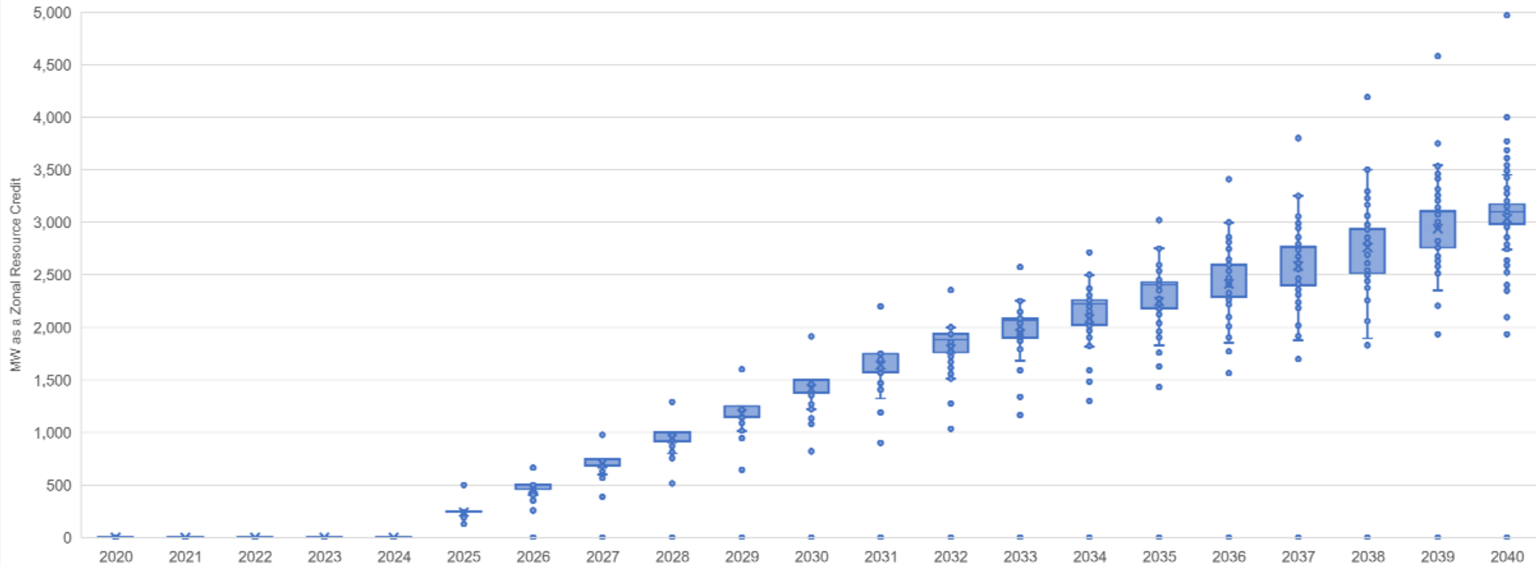

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2021 IRP Aurora Resource Selections, by New Technology Resource
Battery Storage

Case No.: U-21090
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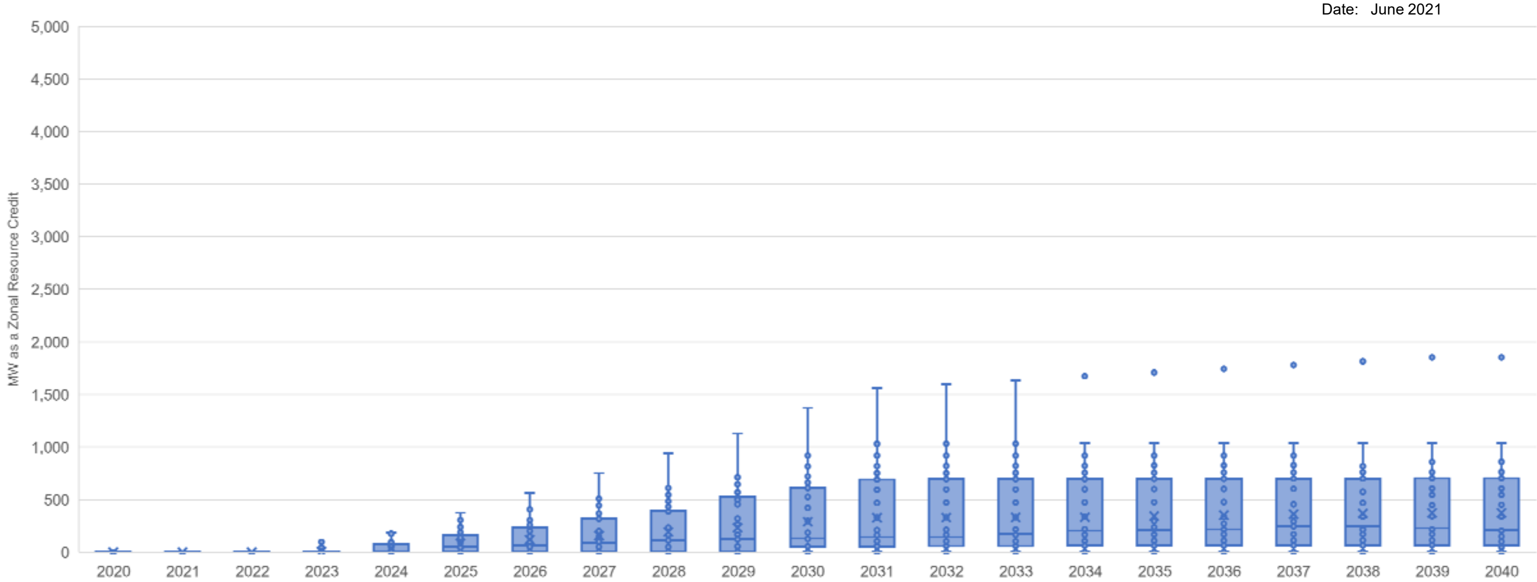

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2021 IRP Aurora Resource Selections, by New Technology Resource
Demand Response

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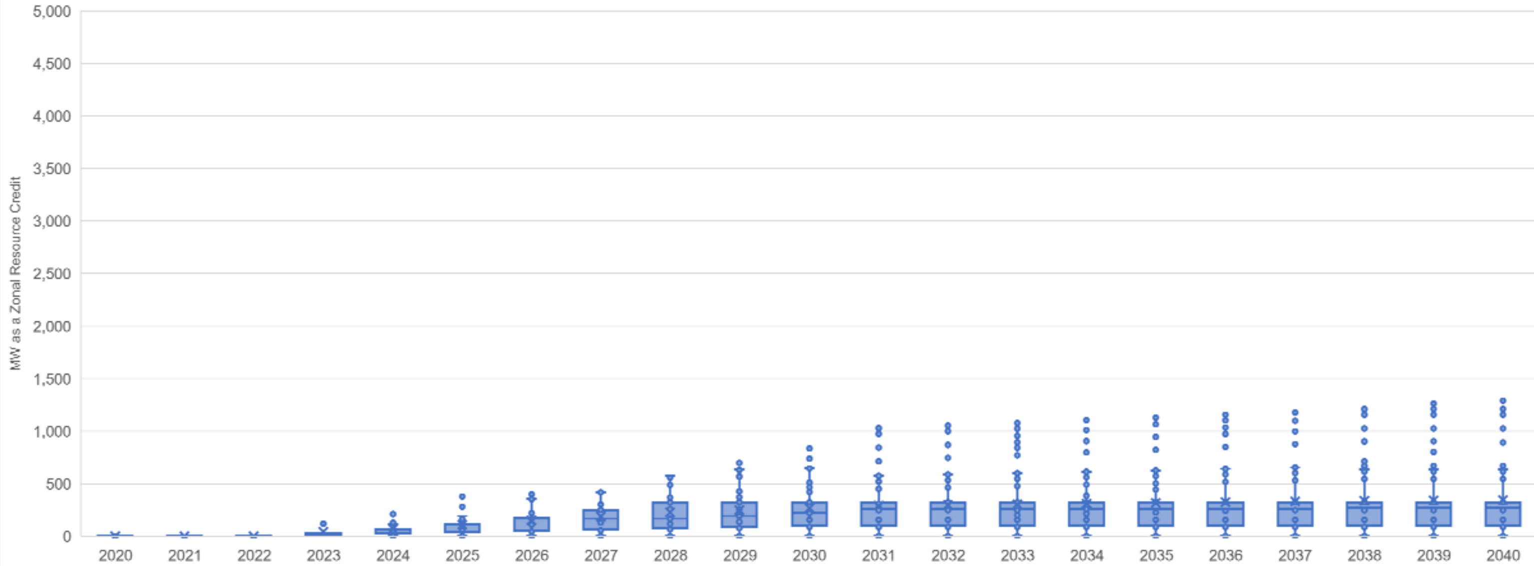

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2021 IRP Aurora Resource Selections, by New Technology Resource
In-State and Out-State Wind

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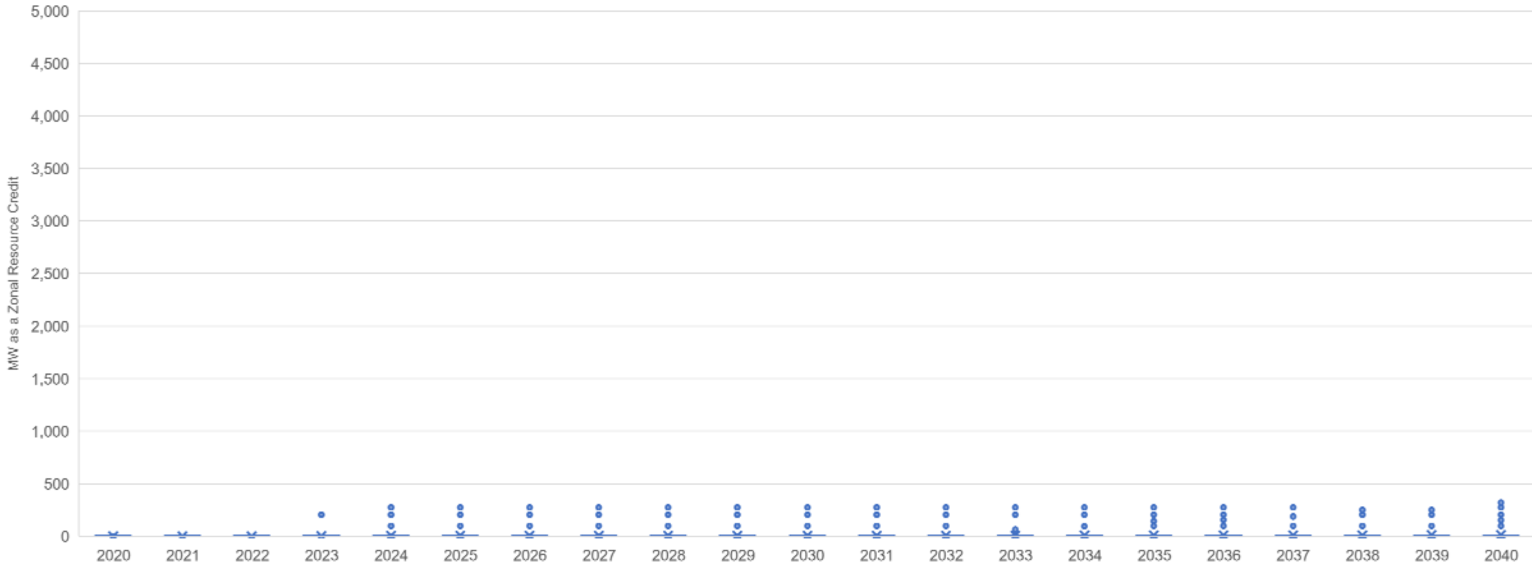

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2021 IRP Aurora Resource Selections, by New Technology Resource
New Natural Gas

Case No.: U-21090
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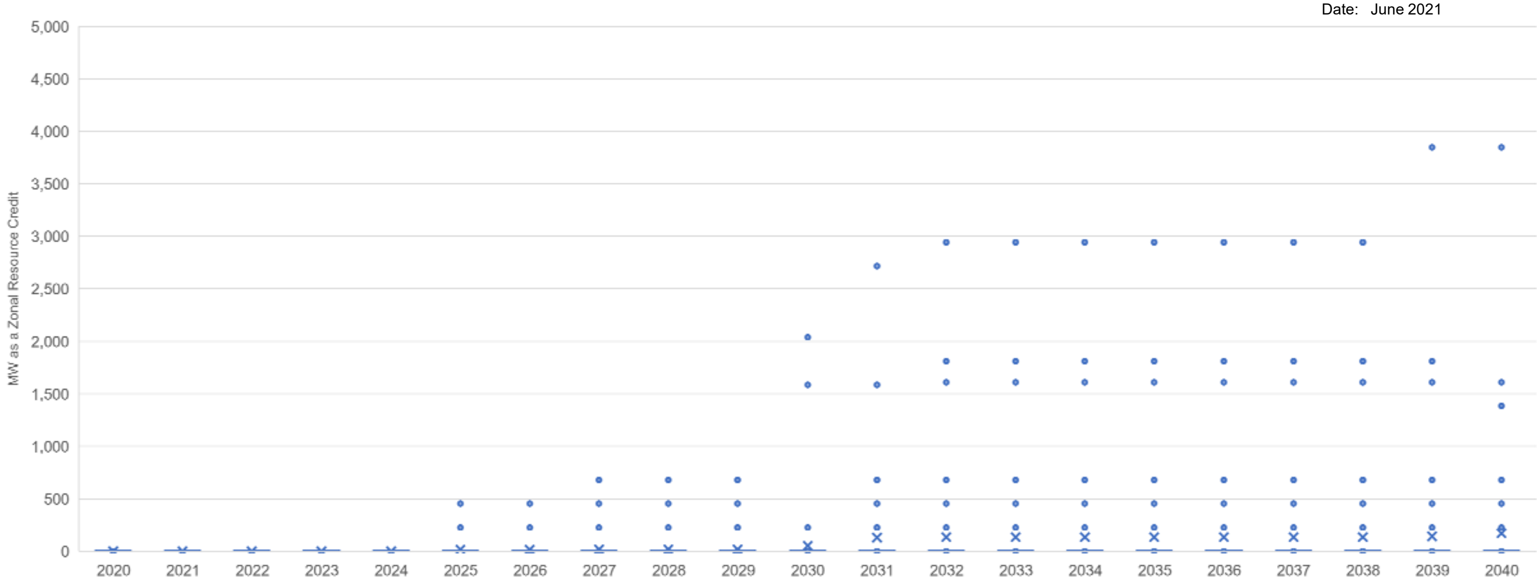

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2021 IRP Aurora Retirement Base Case Optimal Plans, PCA, and Alternate Plan
BAU CE Optimal Plan: Retirement of Campbell 1-3 2025; Karn 3&4 2023

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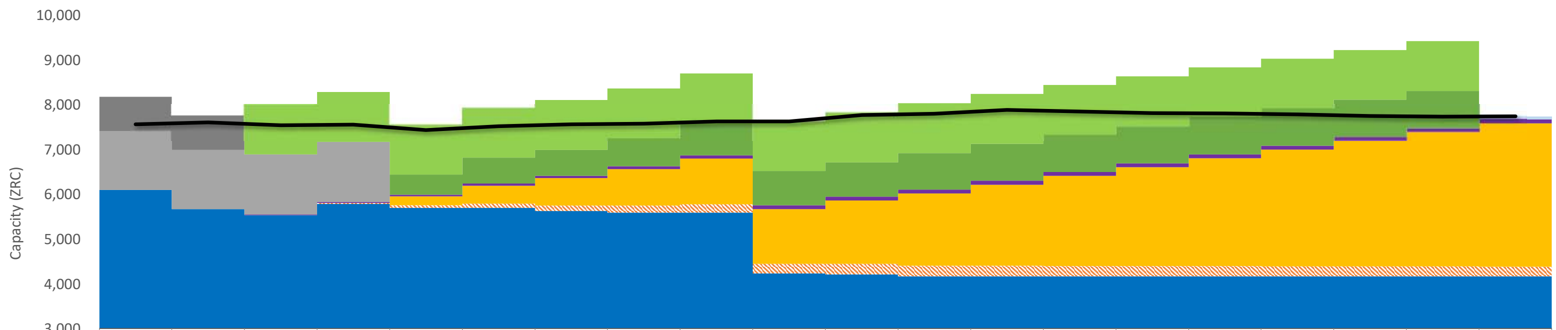

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1100 MW Purchased Gas	-	-	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	
1000 MW Purchased Gas	-	-	-	-	451	579	579	619	711	767	767	817	828	828	828	828	828	828	828	
Karn 3&4	767	769	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,344	1,346	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68
New DR	-	-	11	22	33	44	54	65	76	87	87	87	87	87	87	87	87	87	87	87
New solar	-	-	-	-	203	406	610	813	1,016	1,219	1,418	1,616	1,815	2,013	2,211	2,410	2,608	2,806	3,005	3,203
New solar (D)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New EWR	-	-	-	20	57	91	123	157	187	216	231	232	229	229	225	222	220	218	215	213
Remaining Existing Portfolio	6,095	5,667	5,533	5,781	5,694	5,694	5,624	5,589	5,589	4,227	4,209	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168
PRMR	7,558	7,600	7,542	7,553	7,435	7,516	7,558	7,575	7,627	7,625	7,770	7,796	7,883	7,844	7,807	7,804	7,785	7,745	7,734	7,739
Capacity position	617	154	460	729	116	412	547	782	1,067	6	57	238	358	595	826	1,025	1,240	1,477	1,683	0

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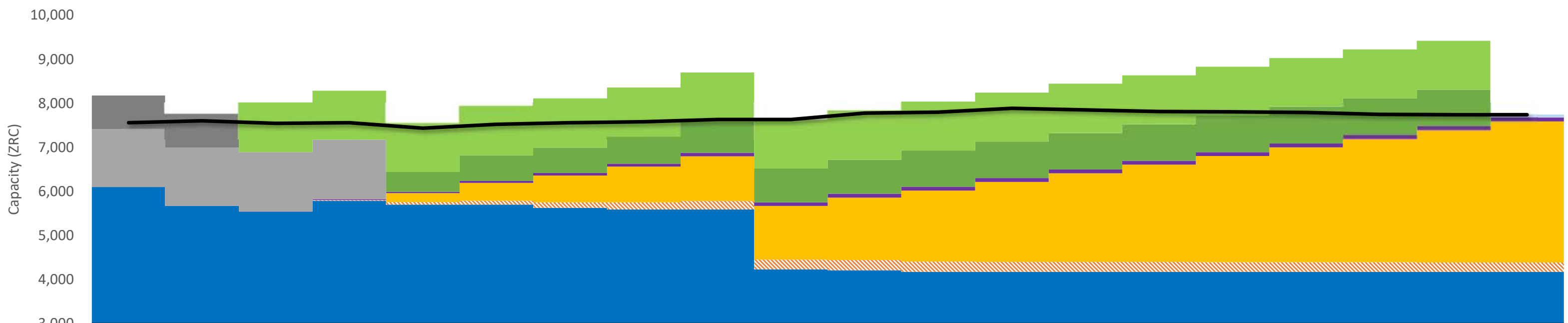
Consumers Energy Company

2021 IRP Aurora Retirement Base Case Optimal Plans, PCA, and Alternate Plan

ET CE Optimal Plan: Retirement of Campbell 1-3 2025; Karn 3&4 2023

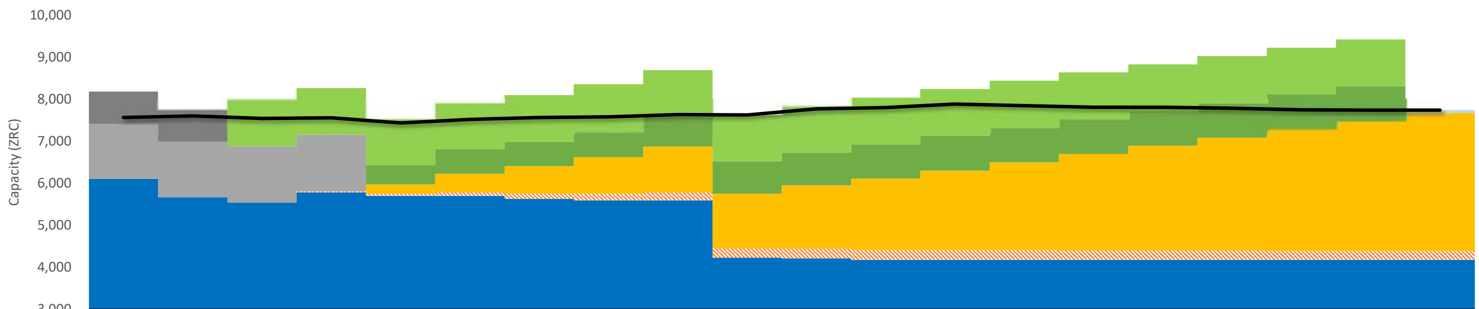


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1100 MW Purchased Gas	-	-	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	
1000 MW Purchased Gas	-	-	-	-	451	579	579	619	711	767	767	817	828	828	828	828	828	828	828	
Karn 3&4	767	769	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,344	1,346	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68
New DR	-	-	11	22	33	44	54	65	76	87	87	87	87	87	87	87	87	87	87	87
New solar	-	-	-	-	203	406	610	813	1,016	1,219	1,418	1,616	1,815	2,013	2,211	2,410	2,608	2,806	3,005	3,203
New solar (D)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New EWR	-	-	-	20	57	91	123	157	187	216	231	232	229	229	225	222	220	218	215	213
Remaining Existing Portfolio	6,095	5,667	5,533	5,781	5,694	5,694	5,624	5,589	5,589	4,227	4,209	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168
PRMR	7,558	7,600	7,542	7,553	7,435	7,516	7,558	7,575	7,627	7,625	7,770	7,796	7,883	7,844	7,807	7,804	7,785	7,745	7,734	7,739
Capacity position	617	154	460	729	116	412	547	782	1,067	6	57	238	358	595	826	1,025	1,240	1,477	1,683	0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Aurora Retirement Base Case Optimal Plans, PCA, and Alternate Plan
EP CE Optimal Plan: Retirement of Campbell 1-3 2025; Karn 3&4 2023

Case No.: U-21090
Exhibit No.: A-14 (STW-11)

Witness: STWalz
Date: June 2021



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1100 MW Purchased Gas	-	-	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	
1000 MW Purchased Gas	-	-	-	-	451	579	579	619	711	767	767	817	828	828	828	828	828	828	828	
Karn 3&4	767	769	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,344	1,346	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68
New DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New solar	-	-	-	-	218	435	653	871	1,089	1,306	1,505	1,703	1,902	2,100	2,298	2,497	2,695	2,893	3,092	3,290
New solar (D)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New EWR	-	-	-	20	57	91	123	157	187	216	231	232	229	229	225	222	220	218	215	213
Remaining Existing Portfolio	6,095	5,667	5,533	5,781	5,694	5,694	5,624	5,589	5,589	4,227	4,209	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168
PRMR	7,558	7,600	7,542	7,553	7,435	7,516	7,558	7,575	7,627	7,625	7,770	7,796	7,883	7,844	7,807	7,804	7,785	7,745	7,734	7,739
Capacity position	617	154	449	707	98	397	536	775	1,064	5	57	238	358	595	826	1,025	1,240	1,477	1,683	0

MICHIGAN PUBLIC SERVICE COMMISSION

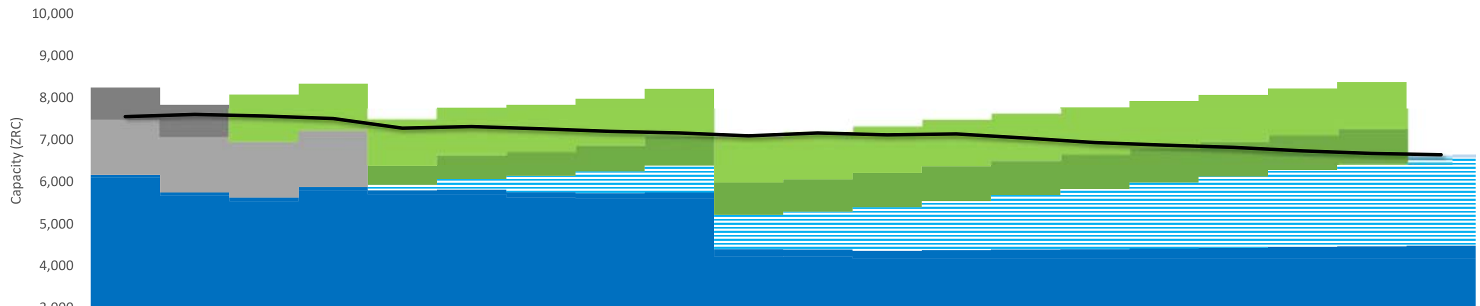
Consumers Energy Company

2021 IRP Aurora Retirement Base Case Optimal Plans, PCA, and Alternate Plan

AT CE Optimal Plan: Retirement of Campbell 1-3 2025; Karn 3&4 2023

Case No.: U-21090
Exhibit No.: A-14 (STW-11)

Witness: STWalz
Date: June 2021



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1100 MW Purchased Gas	-	-	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	
1000 MW Purchased Gas	-	-	-	-	451	579	579	619	711	767	767	817	828	828	828	828	828	828	828	
Karn 3&4	767	769	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,344	1,346	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68
New solar (D)	-	-	-	-	129	257	386	515	644	820	901	1,034	1,166	1,299	1,432	1,564	1,697	1,830	1,962	2,095
New BTMG	66	75	83	93	102	113	125	136	150	163	173	185	199	213	227	242	258	276	294	310
Remaining Existing Portfolio	6,095	5,667	5,533	5,781	5,694	5,694	5,624	5,589	5,589	4,227	4,209	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168
PRMR	7,543	7,603	7,561	7,498	7,270	7,311	7,260	7,196	7,157	7,086	7,159	7,115	7,133	7,037	6,928	6,871	6,812	6,734	6,668	6,642
Capacity position	698	226	514	835	219	447	569	778	1,050	5	6	204	344	585	840	1,046	1,254	1,482	1,698	1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Aurora Retirement Base Case Optimal Plans, PCA, and Alternate Plan
BAU AEO Optimal Plan: Retirement of Campbell 1-3 2025; Karn 3&4 2023

Case No.: U-21090
Exhibit No.: A-14 (STW-11)

Witness: STWalz
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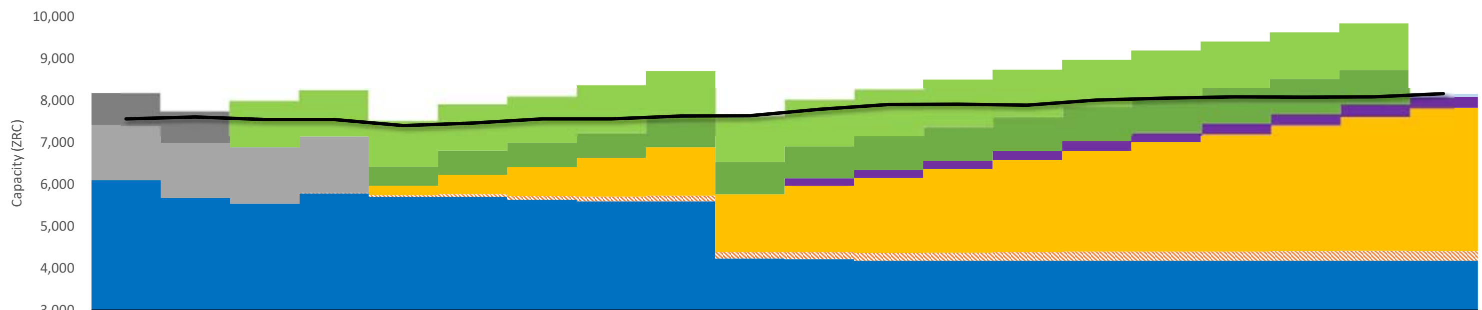


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1100 MW Purchased Gas	-	-	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	
1000 MW Purchased Gas	-	-	-	-	451	579	579	619	711	767	767	817	828	828	828	828	828	828	828	
Karn 3&4	767	769	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,344	1,346	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68
New DR	-	-	-	-	-	-	-	-	-	-	173	187	199	213	226	241	254	268	269	269
New solar	-	-	-	-	230	461	691	921	1,152	1,382	1,586	1,791	1,995	2,199	2,403	2,608	2,812	3,016	3,220	3,425
New solar (D)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New EWR	-	-	-	13	39	64	89	113	136	150	165	186	192	207	223	225	223	231	238	231
Remaining Existing Portfolio	6,095	5,667	5,533	5,781	5,694	5,694	5,624	5,589	5,589	4,227	4,209	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168
PRMR	7,558	7,600	7,542	7,539	7,396	7,456	7,556	7,554	7,626	7,635	7,783	7,897	7,909	7,880	8,007	8,051	8,084	8,073	8,082	8,161
Capacity position	617	154	449	714	131	456	541	803	1,077	6	232	366	588	849	957	1,133	1,315	1,553	1,755	0

MICHIGAN PUBLIC SERVICE COMMISSION

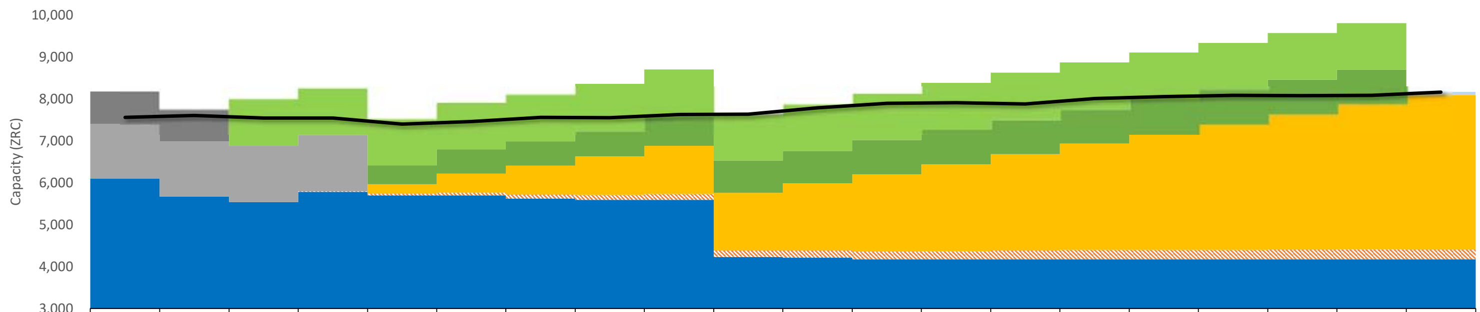
Consumers Energy Company

2021 IRP Aurora Retirement Base Case Optimal Plans, PCA, and Alternate Plan

ET AEO Optimal Plan: Retirement of Campbell 1-3 2025; Karn 3&4 2023

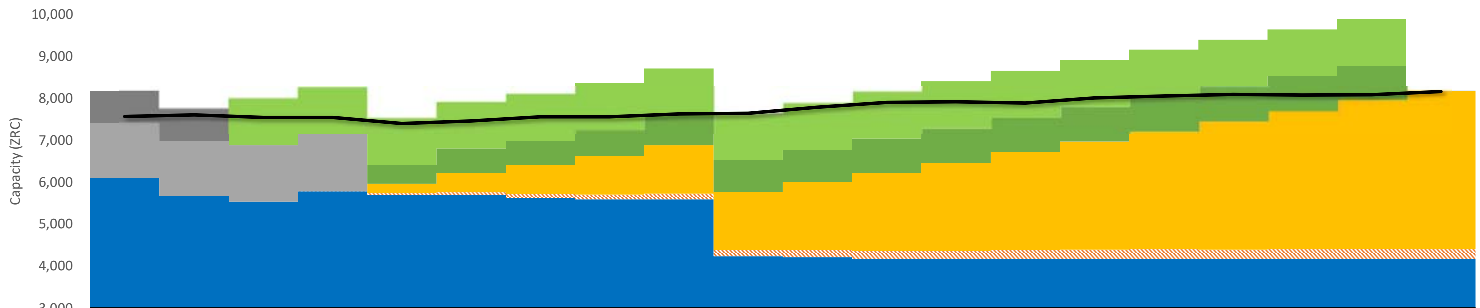
Case No.: U-21090
Exhibit No.: A-14 (STW-11)

Witness: STWalz
Date: June 2021



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1100 MW Purchased Gas	-	-	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	
1000 MW Purchased Gas	-	-	-	-	451	579	579	619	711	767	767	817	828	828	828	828	828	828	828	
Karn 3&4	767	769	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,344	1,346	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	68
New DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New solar	-	-	-	-	230	461	691	921	1,152	1,382	1,613	1,844	2,075	2,307	2,538	2,769	3,000	3,231	3,462	3,693
New solar (D)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New EWR	-	-	-	13	39	64	89	113	136	150	165	186	192	207	223	225	223	231	238	231
Remaining Existing Portfolio	6,095	5,667	5,533	5,781	5,694	5,694	5,624	5,589	5,589	4,227	4,209	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168
PRMR	7,558	7,600	7,542	7,539	7,396	7,456	7,556	7,554	7,626	7,635	7,783	7,897	7,909	7,880	8,007	8,051	8,084	8,073	8,082	8,161
Capacity position	617	154	449	714	131	456	541	803	1,077	6	85	233	470	744	865	1,053	1,249	1,499	1,728	0

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Aurora Retirement Base Case Optimal Plans, PCA, and Alternate Plan
EP AEO Optimal Plan: Retirement of Campbell 1-3 2025; Karn 3&4 2023

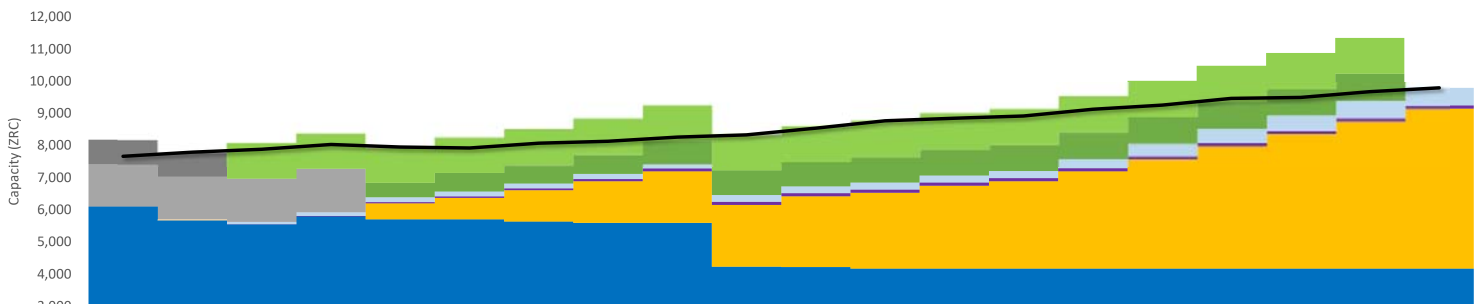


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1100 MW Purchased Gas	-	-	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	
1000 MW Purchased Gas	-	-	-	-	451	579	579	619	711	767	767	817	828	828	828	828	828	828	828	
Karn 3&4	767	769	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,344	1,346	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New storage	-	-	-	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0
New DR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New solar	-	-	-	-	230	461	691	921	1,152	1,382	1,621	1,860	2,099	2,338	2,577	2,816	3,055	3,294	3,533	3,772
New solar (D)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New EWR	-	-	-	13	39	64	89	113	136	150	165	186	192	207	223	225	223	231	238	231
Remaining Existing Portfolio	6,095	5,667	5,533	5,781	5,694	5,694	5,624	5,589	5,589	4,227	4,209	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168
PRMR	7,558	7,600	7,542	7,539	7,396	7,456	7,556	7,554	7,626	7,635	7,783	7,897	7,909	7,880	8,007	8,051	8,084	8,073	8,082	8,161
Capacity position	617	154	449	714	131	456	541	803	1,077	6	93	249	493	775	904	1,100	1,304	1,562	1,799	10

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Aurora Retirement Base Case Optimal Plans, PCA, and Alternate Plan
EP AEO Optimal Plan: Retirement of Campbell 1-3 2025; Karn 3&4 2023

Case No.: U-21090
Exhibit No.: A-14 (STW-11)

Witness: STWalz
Date: June 2021

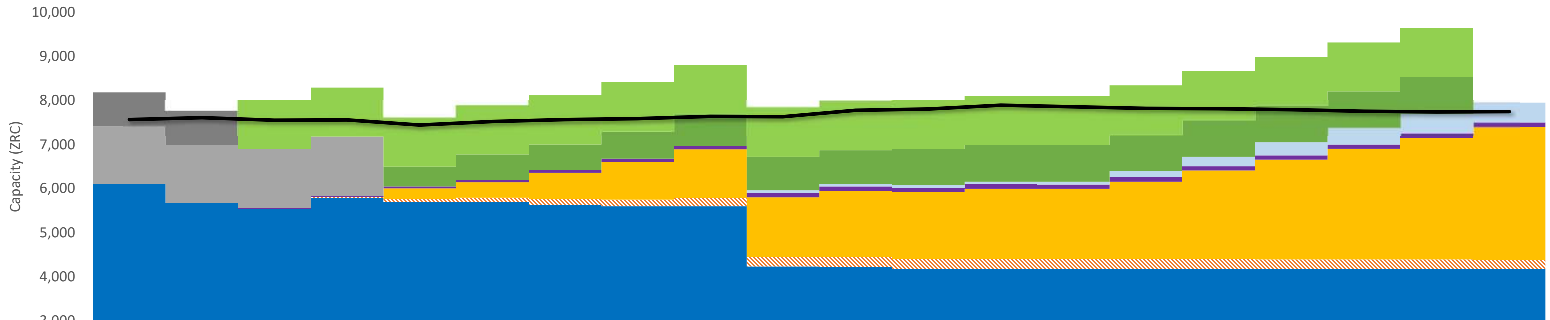


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1100 MW Purchased Gas	-	-	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	
1000 MW Purchased Gas	-	-	-	-	451	579	579	619	711	767	767	817	828	828	828	828	828	828	828	
Karn 3&4	767	769	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,344	1,346	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New storage	-	-	67	112	147	148	149	150	152	208	211	213	216	218	297	376	455	468	546	546
New DR	-	-	12	25	37	49	62	74	87	99	99	99	99	99	99	99	99	99	99	99
New solar	-	-	-	-	500	664	977	1,289	1,601	1,913	2,199	2,354	2,572	2,712	3,020	3,410	3,800	4,190	4,580	4,970
New solar (D)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New EWR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New ZRC purchase	-	33	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Remaining Existing Portfolio	6,095	5,667	5,533	5,781	5,694	5,694	5,624	5,589	5,589	4,227	4,209	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168
PRMR	7,655	7,786	7,869	8,018	7,942	7,915	8,066	8,123	8,255	8,323	8,529	8,754	8,834	8,911	9,119	9,247	9,457	9,483	9,663	9,783
Capacity position	520	1	202	359	1	334	439	713	999	6	70	12	164	229	408	749	1,007	1,385	1,673	1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Aurora Retirement Base Case Optimal Plans, PCA, and Alternate Plan
BAU CE Optimal Plan: Retirement of Campbell 1-3 2025; Karn 3&4 2023

Case No.: U-21090
Exhibit No.: A-14 (STW-11)

Witness: STWalz
Date: June 2021

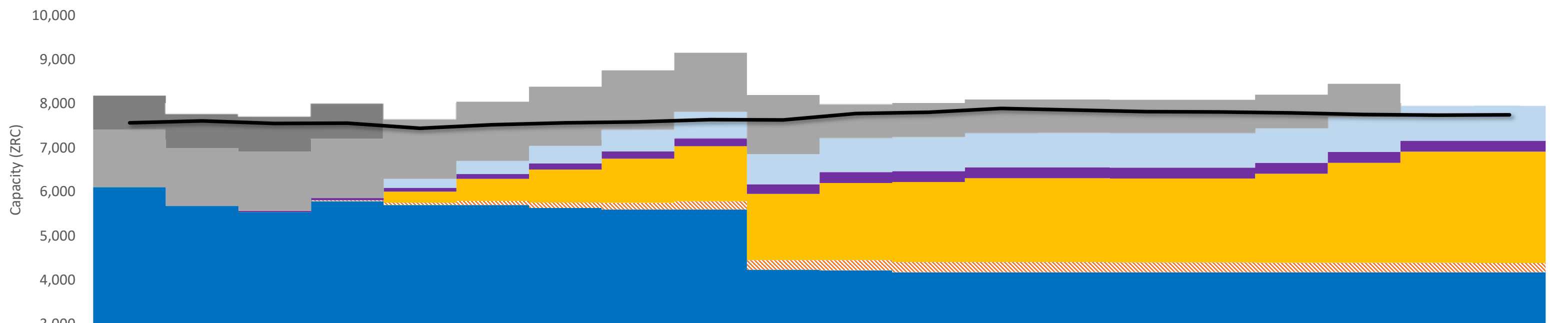


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1100 MW Purchased Gas	-	-	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114	
1000 MW Purchased Gas	-	-	-	-	451	579	579	619	711	767	767	817	828	828	828	828	828	828	828	
Karn 3&4	767	769	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,344	1,346	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New storage	-	-	-	-	-	-	-	-	-	55	57	58	59	60	138	216	293	371	449	450
New DR	-	-	12	25	37	49	62	74	87	99	99	99	99	99	99	99	99	99	99	99
New solar	-	-	-	-	250	352	602	852	1,102	1,352	1,498	1,513	1,591	1,591	1,759	2,009	2,259	2,509	2,759	3,009
New solar (D)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New EWR	-	-	-	20	57	91	123	157	187	216	231	232	229	229	225	222	220	218	215	213
Remaining Existing Portfolio	6,095	5,667	5,533	5,781	5,694	5,694	5,624	5,589	5,589	4,227	4,209	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168
PRMR	7,558	7,600	7,542	7,553	7,435	7,516	7,558	7,575	7,627	7,625	7,770	7,796	7,883	7,844	7,807	7,804	7,785	7,745	7,734	7,739
Capacity position	617	154	462	732	167	363	547	830	1,164	205	205	205	206	246	524	852	1,196	1,562	1,898	200

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Aurora Retirement Base Case Optimal Plans, PCA, and Alternate Plan
236_07_05_BAUCE_PCA_Base

Case No.: U-21090
Exhibit No.: A-14 (STW-11)

Witness: STWalz
Date: June 2021



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1100 MW Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
1000 MW Purchased Gas	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Karn 3&4	767	769	787	785	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,344	1,346	1,345	1,344	1,343	1,343	1,343	1,343	756	756	756	756	756	756	756	756	-	-
New storage	-	-	-	-	206	301	396	492	587	682	777	778	779	781	782	783	785	786	787	789
New DR	-	-	27	55	82	109	137	164	191	219	246	246	246	246	246	246	246	246	246	246
New solar	-	-	-	-	250	500	750	1,000	1,250	1,500	1,750	1,815	1,904	1,904	1,904	1,904	2,017	2,267	2,517	2,523
New solar (D)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
New EWR	-	-	-	20	57	91	123	157	187	216	231	232	229	229	225	222	220	218	215	213
Remaining Existing Portfolio	6,095	5,667	5,533	5,781	5,694	5,694	5,624	5,589	5,589	4,227	4,209	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168	4,168
PRMR	7,558	7,600	7,542	7,553	7,435	7,516	7,558	7,575	7,627	7,625	7,770	7,796	7,883	7,844	7,807	7,804	7,785	7,745	7,734	7,739
Capacity position	617	154	150	433	198	523	816	1,170	1,521	562	200	200	200	241	274	276	407	697	200	200

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Purchased Gas Units Operations
Dearborn Industrial Generation

Case No.: U-21090
Exhibit No.: A-15 (STW-12)

Witness: STWalz
Date: June 2021

Line No.			(a) Unit 1	(b) Unit 2	(c) Unit 3	(d) Unit 4	(e) Total Plant
1	Technology		CT	CC	CC	ST	
2	Commercial Operation Date	(mm/dd/yyyy)	7/1/1999	7/1/2001	7/1/2001	7/1/2001	
3	Maximum Capacity	(MW)	178	197	197	197	770
4	Minimum Capacity	(MW)	39	43	43	43	169
5	Summer Capacity	(MW)	166	185	185	185	720
6	Summer Derate	(%)	6.49%	6.49%	6.49%	6.49%	
7	Zonal Resource Credits	(ZRC)	168.3	186.6	186.6	186.6	728
8	Variable O&M Excl LTSA Component (2021$)	($/MWh)	$2.22	$1.39	$1.39	$1.39	
9	Annual Forced Outage Rate	(%)	1.57%	0.93%	0.76%	0.44%	
10	Annual Maintenance	(days/yr)	14	14	14	14	
11	Operation Cycle (Cycling or Must-run)		Cycling	Cycling	Cycling	Cycling	
12	Heat Rate						
13	Full Load Output	(MW)	166	185	185	185	720
14	Mininmum Output	(MW)	39	43	43	43	
15	Full Load Heat Rate	(Btu/kWh)	9,500	7,200	7,500	14,000	
16	Average Heat Rate at Minimum	(Btu/kWh)	10,925	8,280	8,625	16,100	
17	SO2 Emission Rate	(lb/MMBtu)	0.001	0.0006	0.0006		
18	NOx Emission Rate	(lb/MMBtu)	0.04	0.05	0.05		
19	CO2 Emission Rate	(lb/MMBtu)	118	119	119		

CT = Combustion Turbine
CC = Combined Cycle
ST = Steam Turbine

Line No.			(a) Unit 1
1	Technology		SC
2	Commercial Operation Date	(mm/dd/yyyy)	1/1/1999
3	Maximum Capacity	(MW)	75
4	Minimum Capacity	(MW)	0
5	Summer Capacity	(MW)	70
6	Summer Derate (See note below)	(%)	6.67%
7	Zonal Resource Credits	(ZRC)	70.0
8	Variable O&M (2021$)	($/MWh)	$4.83
9	Annual Forced Outage Rate	(%)	1.48%
10	Annual Maintenance	(days/yr)	5
11	Operation Cycle (Cycling or Must-run)		Cycling
12	Heat Rate		
13	Full Load Output	(MW)	70
14	Mininmum Output	(MW)	0
15	Full Load Heat Rate	(Btu/kWh)	12,500
16	Average Heat Rate at Minimum	(Btu/kWh)	15,100
17	SO2 Emission Rate	(lb/MMBtu)	0.00099
18	NOx Emission Rate	(lb/MMBtu)	0.0462
19	CO2 Emission Rate	(lb/MMBtu)	118

SC = Simple Cycle

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Purchased Gas Units Operations
Livingston Generating Station

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Line No.			(a) Unit 1	(b) Unit 2	(c) Unit 3	(d) Unit 4	(e) Total Plant
1	Technology		SC	SC	SC	SC	
2	Commercial Operation Date	(mm/dd/yyyy)	1/1/1999	1/1/1999	1/1/1999	1/1/1999	
3	Maximum Capacity	(MW)	33	33	33	33	132
4	Minimum Capacity	(MW)	0	0	0	0	0
5	Summer Capacity	(MW)	27	27	27	27	108
6	Summer Derate (See note below)	(%)	18.00%	18.00%	18.00%	18.00%	
7	Zonal Resource Credits	(ZRC)	29	29	29	29	114
8	Variable O&M (2021$)	($/MWh)	$4.83	$4.83	$4.83	$4.83	
9	Annual Forced Outage Rate	(%)	8.29%	5.65%	7.00%	3.03%	
10	Annual Maintenance	(days/yr)	5	5	5	5	
11	Operation Cycle (Cycling or Must-run)		Cycling	Cycling	Cycling	Cycling	
12	Heat Rate						
13	Full Load Output	(MW)	33	33	33	33	132
14	Mininmum Output	(MW)	0	0	0	0	
15	Full Load Heat Rate	(Btu/kWh)	16,000	16,000	16,000	16,000	
16	Average Heat Rate at Minimum	(Btu/kWh)	17,600	17,400	17,300	17,000	
17	SO2 Emission Rate	(lb/MMBtu)	0.0005	0.0005	0.0005	0.0005	
18	NOx Emission Rate	(lb/MMBtu)	0.24	0.24	0.24	0.24	
19	CO2 Emission Rate	(lb/MMBtu)	123	123	123	123	

SC = Simple Cycle

Line No.			(a) Unit 1	(b) Unit 2	(c) Unit 3	(d) Unit 4	(e) Unit 5	(f) Unit 6	(g) Total Plant
1	Technology		ST	ST	ST	CT	CT	CT	CC/DB
2	Commercial Operation Date	(mm/dd/yyyy)	3/1/2004	3/1/2004	3/1/2004	3/1/2004	3/1/2004	3/1/2004	
3	Maximum Capacity	(MW)	372	372	372	20	20	20	1,176
4	Minimum Capacity	(MW)	186	186	186	19.9	19.9	19.9	618
5	Summer Capacity	(MW)	357	357	357	19	19	19	1,128
6	Summer Derate (See note below)	(%)	4.08%	4.08%	4.08%	4.08%	4.08%	4.08%	
7	Zonal Resource Credits	(ZRC)	351.3	351.3	351.3	20.0	20.0	20.0	1,114
8	Variable O&M Excl LTSA Component (2021$)	($/MWh)	$1.39	$1.39	$1.39	$1.39	$1.39	$1.39	
9	Annual Forced Outage Rate	(%)	1.14%	1.74%	0.96%	1.14%	1.74%	0.96%	
10	Annual Maintenance	(days/yr)	19	20	25	19	20	25	
11	Operation Cycle (Cycling or Must-run)		Cycling	Cycling	Cycling	Cycling	Cycling	Cycling	
12	Heat Rate								
13	Full Load Output	(MW)	357	357	357	19	19	19	1,128
14	Mininmum Output	(MW)	186	186	186	19.9	19.9	19.9	
15	Full Load Heat Rate	(Btu/kWh)	6,983	6,983	6,983	10,600	10,600	10,600	
16	Average Heat Rate at Minimum	(Btu/kWh)	8,022	8,022	8,022	10,600	10,600	10,600	
17	SO2 Emission Rate	(lb/MMBtu)	0.06	0.06	0.06	0.06	0.06	0.06	
18	NOx Emission Rate	(lb/MMBtu)	0.007	0.007	0.007	0.007	0.007	0.007	
19	CO2 Emission Rate	(lb/MMBtu)	119	119	119	119	119	119	

ST = Steam Turbine
CT = Combustion Turbine

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

2021 IRP Purchased Gas Units Operations

Projected Operation of Purchased Gas Units

Case No.: U-21090
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Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
No.	**PROJECTED GENERATION (MWH)**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
1	Covert Generating Facility (CC)	-	-	1,737,728	3,101,693	3,211,601	3,211,601	3,170,551	2,913,714	2,919,232	2,758,619	2,679,057	2,573,123	2,604,284	2,601,856	2,700,575	2,600,489	2,448,428	2,511,824	2,567,716	926,983
2	Covert Generating Facility (CC)	-	-	1,727,181	3,082,868	3,192,109	3,192,109	3,151,308	2,896,030	2,901,514	2,741,876	2,624,684	2,484,350	2,772,312	2,846,949	2,706,493	2,782,129	2,433,569	2,496,579	2,552,132	921,007
3	Covert Generating Facility (CC)	-	-	1,625,478	3,001,345	2,954,493	2,938,863	2,938,863	2,765,410	2,766,903	2,763,642	2,681,503	2,568,190	2,887,236	2,746,175	2,866,398	2,624,073	2,556,306	2,549,163	2,813,411	1,001,490
4	Covert Generating Facility (DB)	-	-	81,630	121,064	117,969	90,268	73,615	35,119	44,473	27,619	41,195	19,000	18,990	24,737	25,236	7,446	15,219	13,545	15,388	-
5	Covert Generating Facility (DB)	-	-	81,135	112,716	107,573	94,203	73,168	34,906	44,203	27,452	40,945	18,885	18,875	24,587	25,083	7,400	15,126	13,462	15,294	-
6	Covert Generating Facility (DB)	-	-	81,779	126,154	118,426	90,432	73,749	35,183	40,528	27,670	41,270	19,035	19,025	24,782	25,282	7,459	15,246	13,569	15,247	-
7	Dearborn Industrial Generation (CT)	-	-	-	-	662,703	518,826	376,679	217,710	166,560	162,663	227,808	112,269	126,864	124,743	132,286	39,589	78,104	71,764	82,064	-
8	Dearborn Industrial Generation (CC)	-	-	-	-	925,609	1,222,155	1,238,458	1,015,748	816,434	716,156	701,745	788,794	613,969	744,919	517,629	377,293	613,172	387,531	685,949	84,753
9	Dearborn Industrial Generation (CC)	-	-	-	-	916,988	1,152,597	931,049	884,604	856,255	466,748	728,487	690,641	568,762	684,651	477,855	193,896	544,431	285,216	603,063	69,544
10	Dearborn Industrial Generation (CC)	-	-	-	-	974,682	1,687,481	1,687,481	1,692,320	1,687,481	1,687,481	1,687,481	1,692,320	1,687,481	1,687,481	1,687,481	1,692,320	1,687,481	1,687,481	1,687,481	717,638
11	Livingston Generating Station (001)	-	-	-	-	107	107	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Livingston Generating Station (002)	-	-	-	-	110	110	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Livingston Generating Station (003)	-	-	-	-	43	109	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Livingston Generating Station (004)	-	-	-	-	-	46	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Kalamazoo River Generating Station	-	-	-	-	1,280	1,633	256	-	-	-	-	-	-	-	-	-	-	-	-	-

No.	**PROJECTED HOURS OF OPERATION**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
16	Covert Generating Facility (CC)	-	-	4,817	8,475	8,760	8,760	8,654	7,989	8,003	7,587	7,381	7,107	7,123	7,117	7,437	7,178	6,784	6,948	7,093	2,525
17	Covert Generating Facility (CC)	-	-	4,817	8,475	8,760	8,760	8,654	7,989	8,003	7,587	7,282	6,916	7,666	7,861	7,431	7,692	6,784	6,948	7,093	2,526
18	Covert Generating Facility (CC)	-	-	4,519	8,146	8,016	8,040	8,040	7,592	7,596	7,587	7,375	7,082	7,907	7,542	7,853	7,226	7,051	6,968	7,707	2,714
19	Covert Generating Facility (DB)	-	-	4,254	6,268	6,088	4,691	3,835	1,857	2,352	1,461	2,181	1,005	1,004	1,311	1,337	394	806	717	815	-
20	Covert Generating Facility (DB)	-	-	4,254	5,844	5,573	4,930	3,835	1,857	2,352	1,461	2,181	1,005	1,004	1,311	1,337	394	806	717	815	-
21	Covert Generating Facility (DB)	-	-	4,254	6,503	6,101	4,691	3,835	1,857	2,139	1,461	2,181	1,005	1,004	1,311	1,337	394	806	717	806	-
22	Dearborn Industrial Generation (CT)	-	-	-	-	4,365	3,801	2,833	1,844	1,435	1,453	2,173	988	1,142	1,311	1,417	376	802	704	802	-
23	Dearborn Industrial Generation (CC)	-	-	-	-	4,923	6,706	6,918	5,971	4,813	3,981	3,981	4,622	3,946	4,725	3,359	2,208	3,991	2,721	4,622	839
24	Dearborn Industrial Generation (CC)	-	-	-	-	4,923	6,600	5,136	5,560	5,454	3,000	4,416	4,841	3,946	4,622	3,359	1,145	3,991	1,995	4,622	839
25	Dearborn Industrial Generation (CC)	-	-	-	-	5,136	8,760	8,760	8,784	8,760	8,760	8,760	8,784	8,760	8,760	8,760	8,784	8,760	8,760	8,760	3,648
26	Livingston Generating Station (001)	-	-	-	-	4	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Livingston Generating Station (002)	-	-	-	-	4	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Livingston Generating Station (003)	-	-	-	-	4	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Livingston Generating Station (004)	-	-	-	-	-	4	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Kalamazoo River Generating Station	-	-	-	-	22	31	4	-	-	-	-	-	-	-	-	-	-	-	-	-

No.	**PROJECTED CAPACITY FACTORS**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
31	Covert Generating Facility (CC)	-	-	92.4%	95.1%	98.9%	98.9%	97.6%	89.2%	89.5%	84.5%	82.1%	78.6%	79.9%	79.9%	82.7%	79.5%	74.9%	76.8%	78.6%	67.2%
32	Covert Generating Facility (CC)	-	-	91.8%	94.6%	98.3%	98.3%	97.0%	88.7%	89.0%	84.0%	80.4%	75.8%	84.9%	87.3%	83.1%	85.2%	74.4%	76.3%	78.1%	66.8%
33	Covert Generating Facility (CC)	-	-	86.1%	92.2%	91.1%	90.3%	90.3%	84.4%	84.8%	84.7%	82.1%	78.4%	88.4%	84.3%	87.9%	80.3%	78.2%	78.2%	86.3%	72.6%
34	Covert Generating Facility (DB)	-	-	80.8%	69.0%	67.2%	51.6%	42.0%	19.9%	25.1%	15.5%	23.4%	10.7%	10.7%	13.9%	14.2%	4.2%	8.5%	7.6%	8.6%	0.0%
35	Covert Generating Facility (DB)	-	-	80.3%	64.3%	61.4%	53.8%	41.7%	19.7%	25.0%	15.4%	23.2%	10.6%	10.7%	13.8%	14.1%	4.2%	8.5%	7.6%	8.6%	0.0%
36	Covert Generating Facility (DB)	-	-	80.9%	71.9%	67.5%	51.7%	42.1%	19.9%	22.9%	15.5%	23.4%	10.7%	10.7%	13.9%	14.2%	4.2%	8.6%	7.6%	8.6%	0.0%
37	Dearborn Industrial Generation (CT)	-	-	0.0%	0.0%	75.1%	33.8%	24.5%	14.1%	10.7%	10.4%	14.8%	7.2%	8.2%	8.0%	8.5%	2.5%	5.0%	4.6%	5.3%	0.0%
38	Dearborn Industrial Generation (CC)	-	-	0.0%	0.0%	94.6%	71.8%	72.6%	59.6%	47.9%	42.1%	41.2%	46.2%	35.9%	43.7%	30.2%	22.1%	35.9%	22.7%	40.2%	11.6%
39	Dearborn Industrial Generation (CC)	-	-	0.0%	0.0%	93.7%	67.7%	54.7%	51.8%	50.2%	27.3%	42.6%	40.4%	33.2%	40.1%	27.9%	11.5%	31.9%	16.7%	35.3%	9.5%
40	Dearborn Industrial Generation (CC)	-	-	0.0%	0.0%	99.6%	99.6%	99.6%	99.6%	99.6%	99.6%	99.6%	99.6%	99.6%	99.6%	99.6%	99.6%	99.6%	99.6%	99.6%	99.6%
41	Livingston Generating Station (001)	-	-	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
42	Livingston Generating Station (002)	-	-	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
43	Livingston Generating Station (003)	-	-	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
44	Livingston Generating Station (004)	-	-	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
45	Kalamazoo River Generating Station	-	-	0.0%	0.0%	0.3%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Purchased Gas Units Operations
Average Total Costs of Purchased Gas Units

Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
No.	**PROJECTED ANNUAL AVERAGE COSTS ($/MWH)**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
1	Dearborn Industrial Generation	N/A	N/A	N/A	N/A	$16	$17	$24	$26	$27	$28	$29	$31	$33	$35	$38	$40	$41	$45	$45	$33
2	Kalamazoo River Generating Station	N/A	N/A	N/A	N/A	$1,062	$1,440	$9,102	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	Livingston Generating Station	N/A	N/A	N/A	N/A	$3,529	$4,305	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	Covert Generating Facility	N/A	N/A	$20	$22	$23	$25	$27	$29	$30	$32	$33	$35	$37	$38	$41	$42	$45	$47	$49	$44
No.	**PROJECTED DELIVERED FUEL COSTS ($/MMBtu)**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
5	Dearborn Industrial Generation (Natural Gas)	$0	$0	$0	$0	$2.45	$2.72	$2.92	$3.11	$3.25	$3.34	$3.46	$3.60	$3.80	$3.94	$4.05	$4.16	$4.37	$4.55	$4.70	$4.86
6	Dearborn Industrial Generation (Blast Furnace Gas)	$0	$0	$0	$0	$0.64	$0.66	$0.67	$0.69	$0.70	$0.72	$0.74	$0.75	$0.77	$0.79	$0.81	$0.82	$0.84	$0.86	$0.88	$0.90
7	Kalamazoo River Generating Station	$0	$0	$0	$0	$4.26	$4.72	$4.95	$4.47	$5.13	$5.28	$5.44	$5.64	$6.08	$5.88	$6.25	$6.41	$6.67	$6.91	$7.12	$7.36
8	Livingston Generating Station	$0	$0	$0	$0	$4.26	$4.72	$4.95	$4.47	$5.13	$5.28	$5.44	$5.64	$6.08	$5.88	$6.25	$6.41	$6.67	$6.91	$7.12	$7.36
9	Covert Generating Facility	$0	$0	$2.39	$2.43	$2.45	$2.72	$2.92	$3.11	$3.25	$3.34	$3.46	$3.60	$3.80	$3.94	$4.05	$4.16	$4.37	$4.55	$4.70	$4.86

Total Costs include fuel costs, start-up costs, variable operating and maintenance costs, fixed operating costs and emissions costs
A value of N/A indicates the resource did not produce generation during the period indicated

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

2021 IRP Purchased Gas Units Operations

Projected Start-ups per Year and Projected Heat Rates

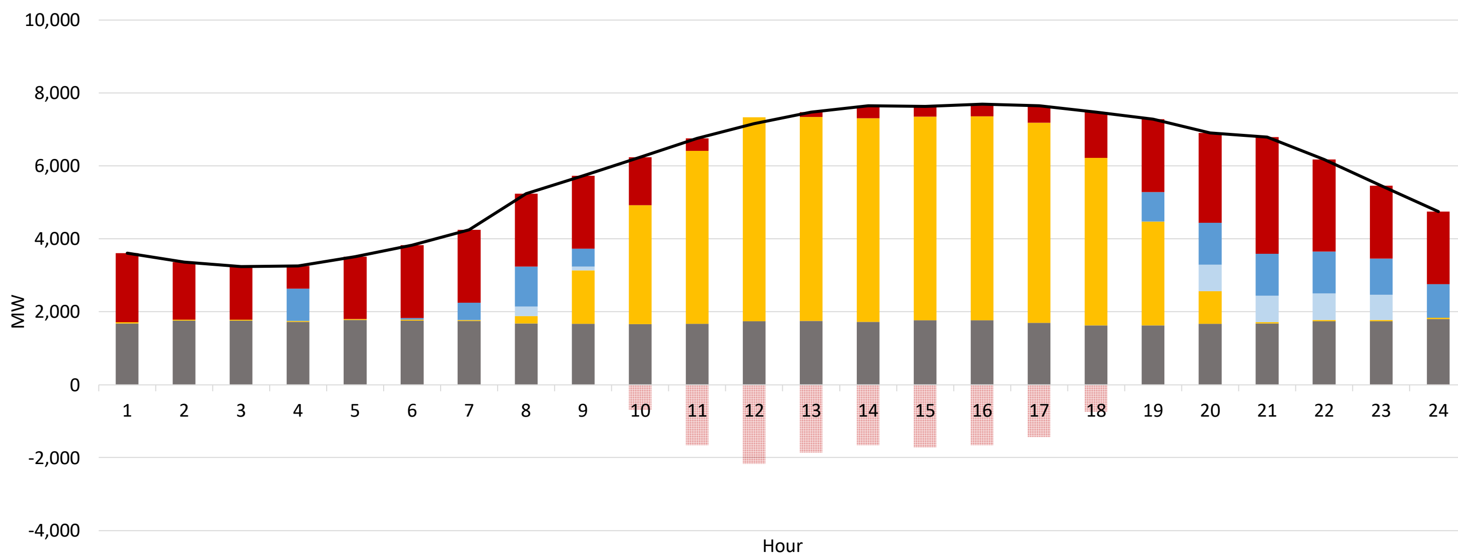
Case No.: U-21090
Exhibit No.: A-15 (STW-12)

Witness: STWalz
Date: June 2021

Line No.		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	PROJECTED STARTUPS PER YEAR	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
1	Covert Generating Facility (CC)	-	-	1	2	-	-	-	2	4	3	3	4	3	3	3	4	3	3	3	2
2	Covert Generating Facility (CC)	-	-	1	2	-	-	-	2	4	3	3	3	3	2	3	4	3	3	3	2
3	Covert Generating Facility (CC)	-	-	2	1	1	1	1	2	3	3	3	4	2	3	4	4	4	3	3	2
4	Covert Generating Facility (DB)	-	-	2	4	3	4	4	1	2	1	1	1	3	1	1	1	2	2	2	-
5	Covert Generating Facility (DB)	-	-	2	4	3	3	4	1	2	1	1	1	3	1	1	1	2	2	2	-
6	Covert Generating Facility (DB)	-	-	2	4	3	4	4	1	2	1	1	1	3	1	1	1	2	2	2	-
7	Dearborn Industrial Generation (CT)	-	-	-	-	1	2	2	1	1	1	1	1	2	1	1	1	2	2	2	-
8	Dearborn Industrial Generation (CC)	-	-	-	-	2	2	1	1	1	1	1	1	1	1	1	1	1	1	1	-
9	Dearborn Industrial Generation (CC)	-	-	-	-	2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	-
10	Dearborn Industrial Generation (CC)	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Livingston Generating Station (001)	-	-	-	-	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Livingston Generating Station (002)	-	-	-	-	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Livingston Generating Station (003)	-	-	-	-	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Livingston Generating Station (004)	-	-	-	-	-	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Kalamazoo River Generating Station	-	-	-	-	2	3	1	-	-	-	-	-	-	-	-	-	-	-	-	-

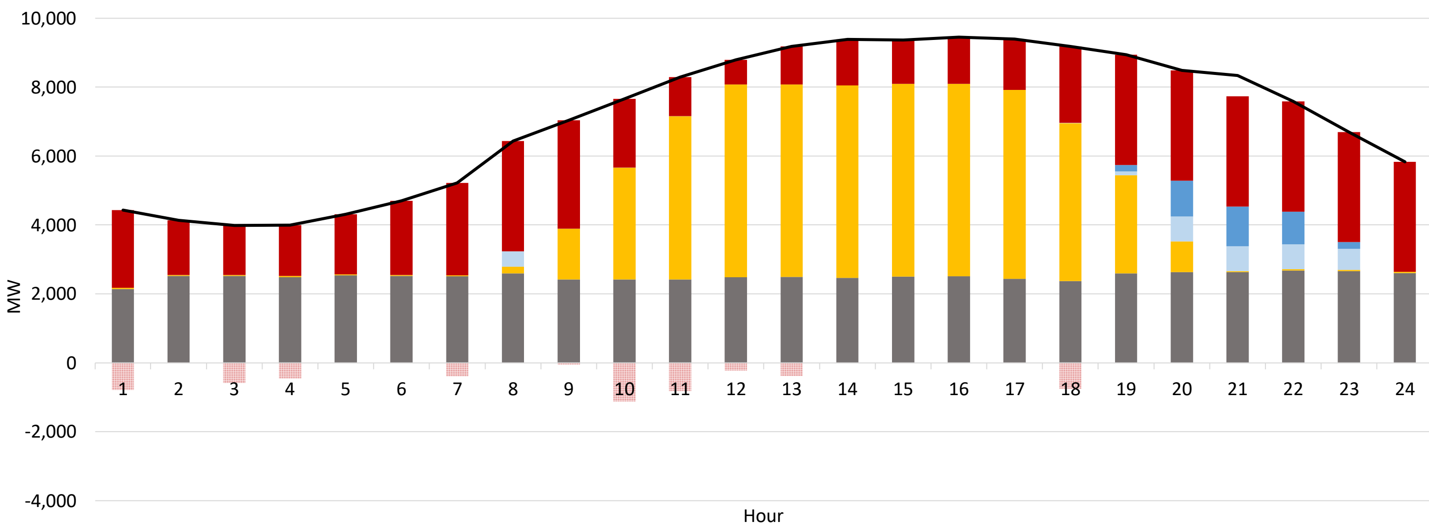
No.	**PROJECTED HEAT RATES**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
16	Covert Generating Facility (CC)	-	-	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983
17	Covert Generating Facility (CC)	-	-	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983
18	Covert Generating Facility (CC)	-	-	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983	6,983
19	Covert Generating Facility (DB)	-	-	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	-
20	Covert Generating Facility (DB)	-	-	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	-
21	Covert Generating Facility (DB)	-	-	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	10,600	-
22	Dearborn Industrial Generation (CT)	-	-	-	-	10,961	11,001	11,012	11,059	11,066	11,084	11,124	11,076	11,088	11,173	11,184	11,116	11,159	11,134	11,131	-
23	Dearborn Industrial Generation (CC)	-	-	-	-	8,280	8,274	8,271	8,263	8,263	8,274	8,271	8,264	8,249	8,251	8,247	8,268	8,246	8,232	8,241	8,139
24	Dearborn Industrial Generation (CC)	-	-	-	-	8,622	8,604	8,615	8,577	8,573	8,573	8,589	8,542	8,550	8,558	8,545	8,600	8,530	8,552	8,516	8,283
25	Dearborn Industrial Generation (CC)	-	-	-	-	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100	16,100
26	Livingston Generating Station (001)	-	-	-	-	16,000	16,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Livingston Generating Station (002)	-	-	-	-	16,000	16,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	Livingston Generating Station (003)	-	-	-	-	16,000	16,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Livingston Generating Station (004)	-	-	-	-	-	16,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Kalamazoo River Generating Station	-	-	-	-	12,609	12,609	12,609	-	-	-	-	-	-	-	-	-	-	-	-	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capacity Sufficiency Analysis Loss of Load Event Examples: High Renewable
Typical Day



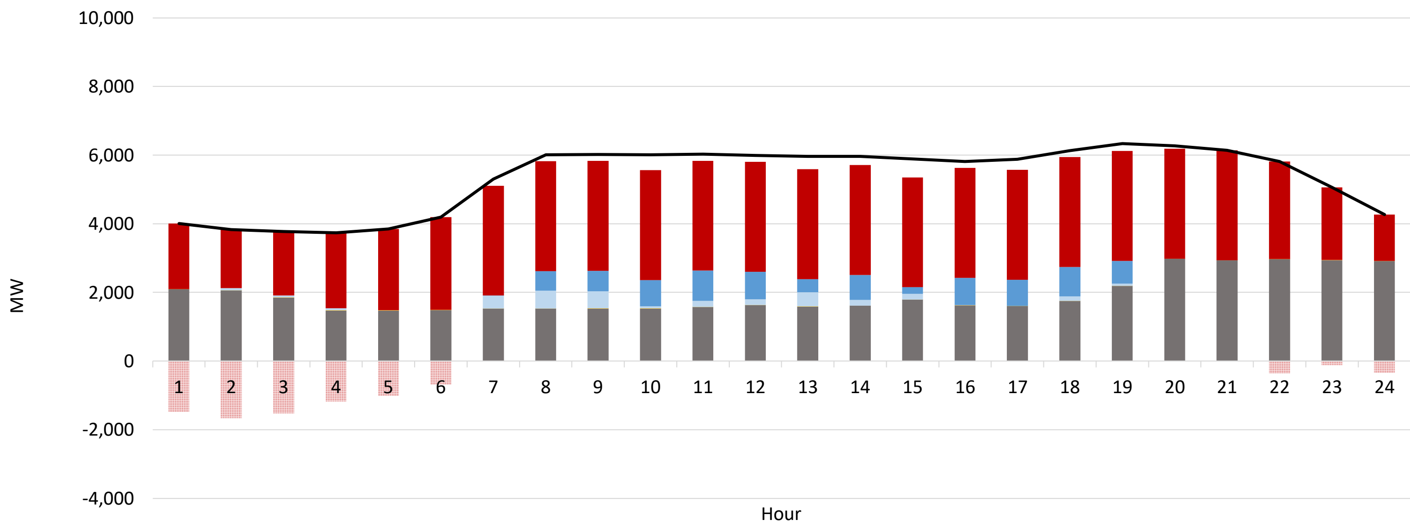
MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capacity Sufficiency Analysis Loss of Load Event Examples: High Renewable
Summer Peak Day

Case No.: U-21090
Exhibit No.: A-16 (STW-13)
Page: 2 of 5
Witness: STWalz
Date: June 2021



MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capacity Sufficiency Analysis Loss of Load Event Examples: High Renewable
Winter Day with No Solar

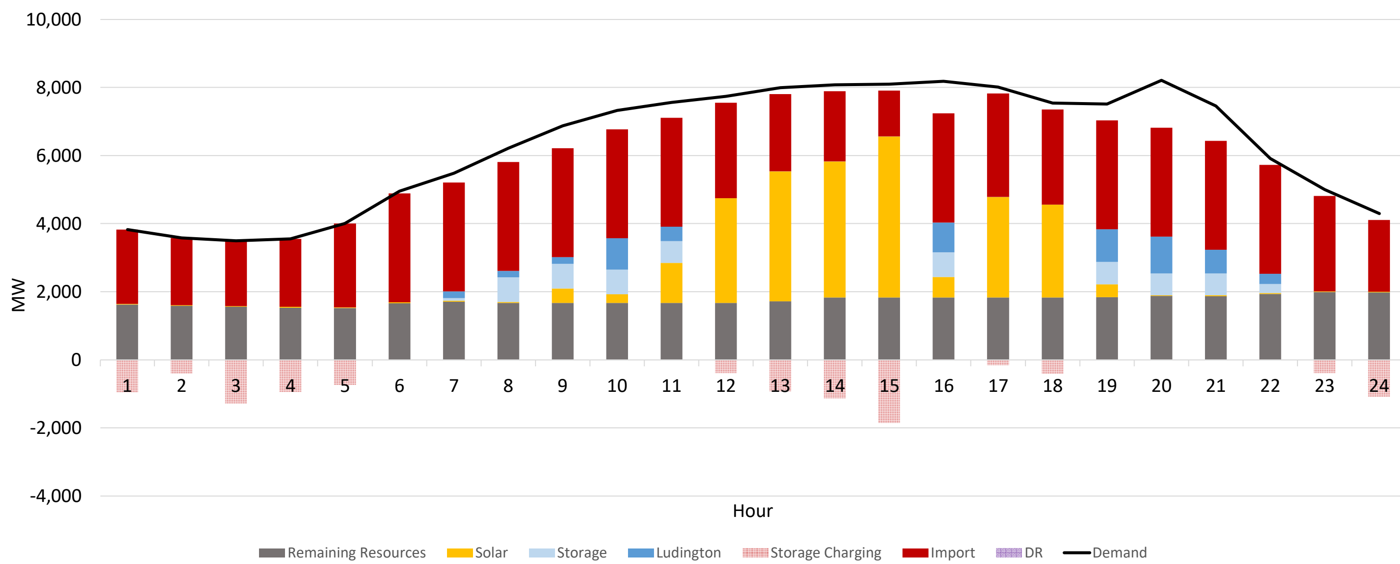
Case No.: U-21090
Exhibit No.: A-16 (STW-13)
Page: 3 of 5
Witness: STWalz
Date: June 2021

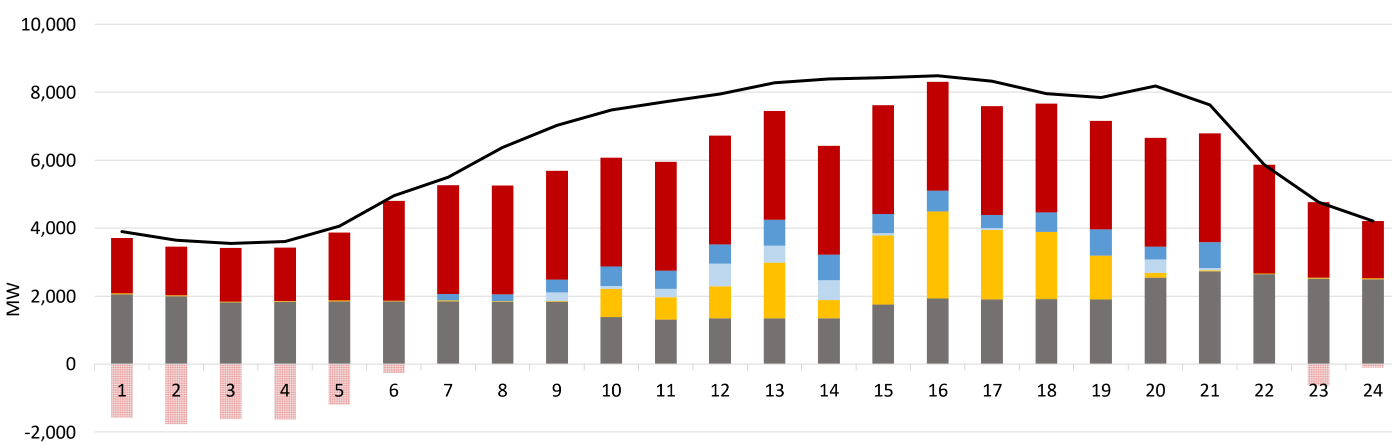


MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capacity Sufficiency Analysis Loss of Load Event Examples: High Renewable Consecutive Days

Case No.: U-21090
Exhibit No.: A-16 (STW-13)
Page: 4 of 5
Witness: STWalz
Date: June 2021

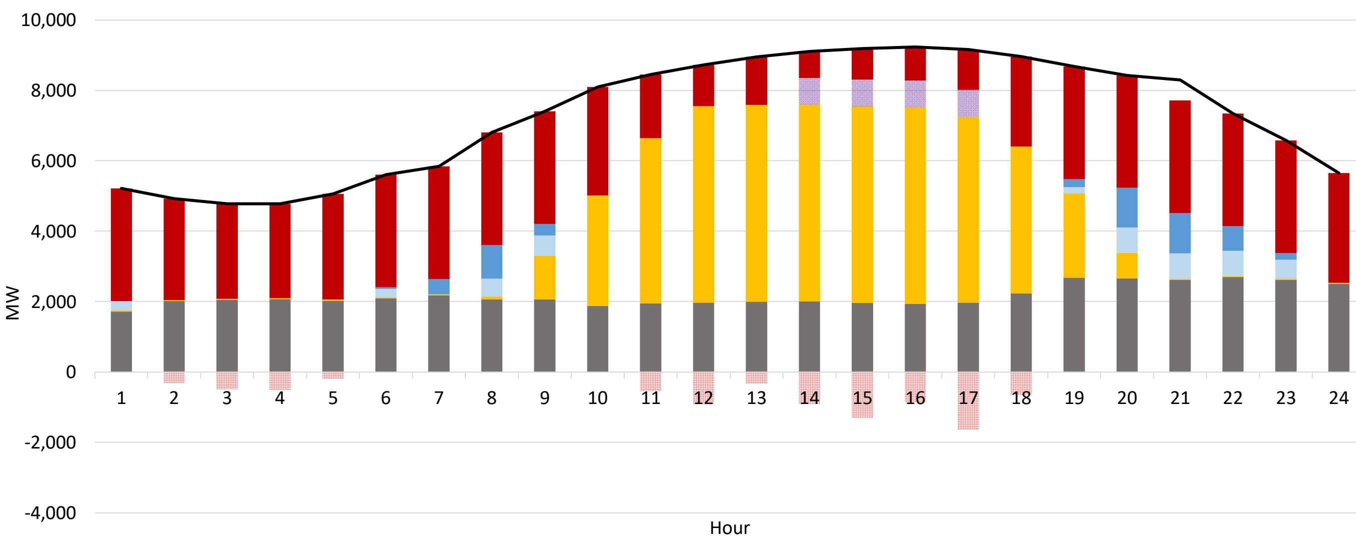
September 7, 2032



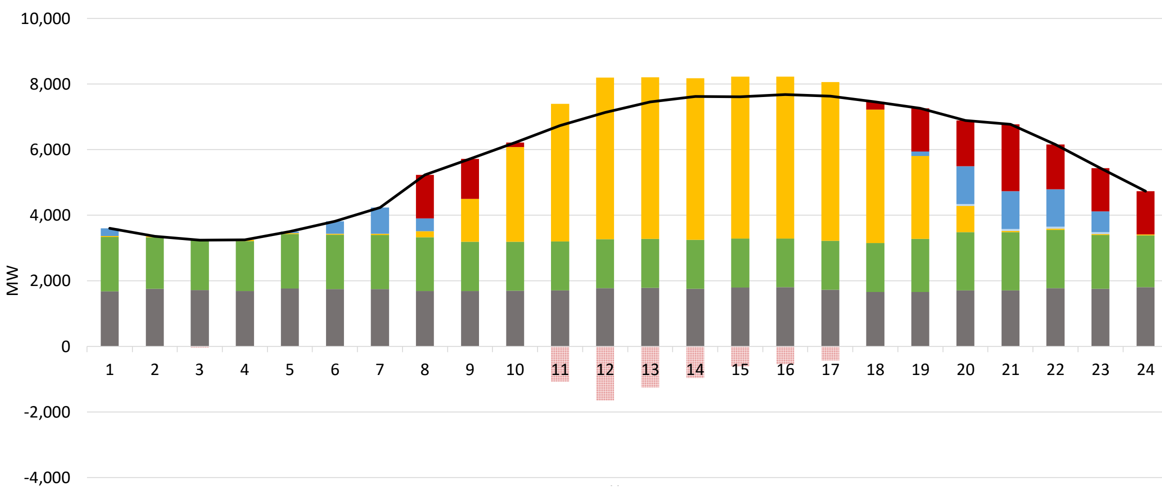


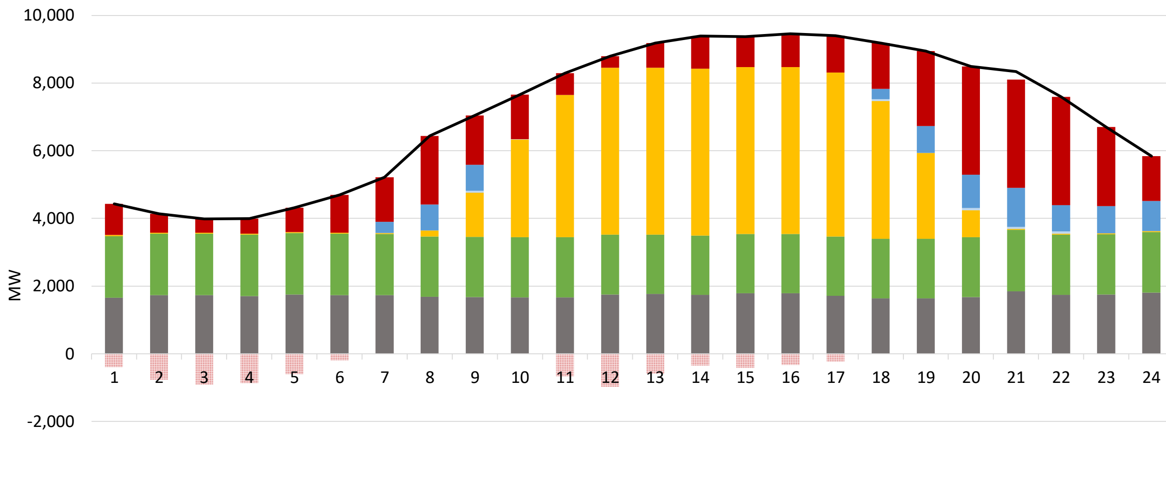
MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capacity Sufficiency Analysis Loss of Load Event Examples: High Renewable
Demand Response

Case No.: U-21090
Exhibit No.: A-16 (STW-13)
Page: 5 of 5
Witness: STWalz
Date: June 2021



Capacity Sufficiency Analysis Loss of Load Event Examples: Controllable Generation
Typical Day




10,000
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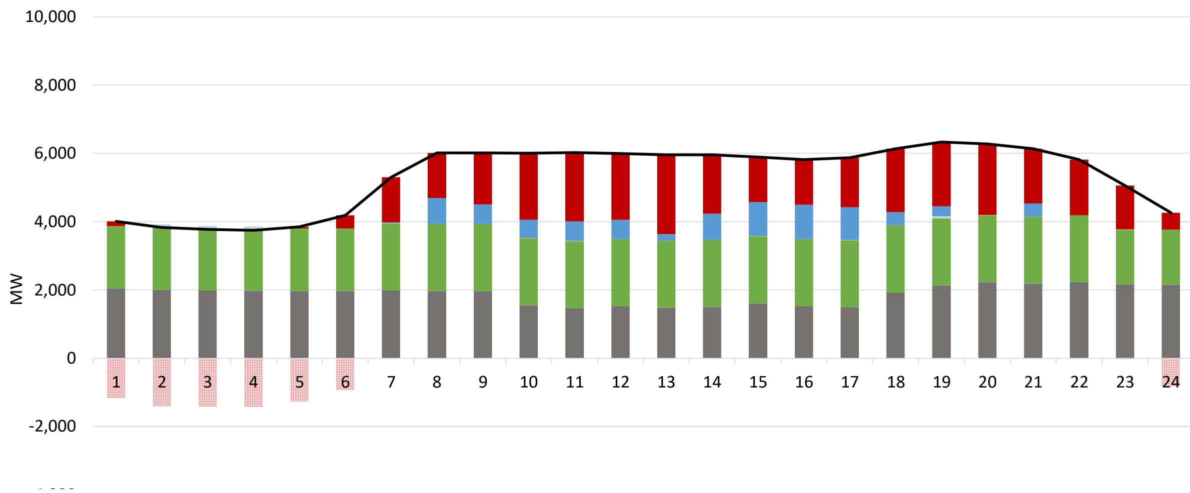
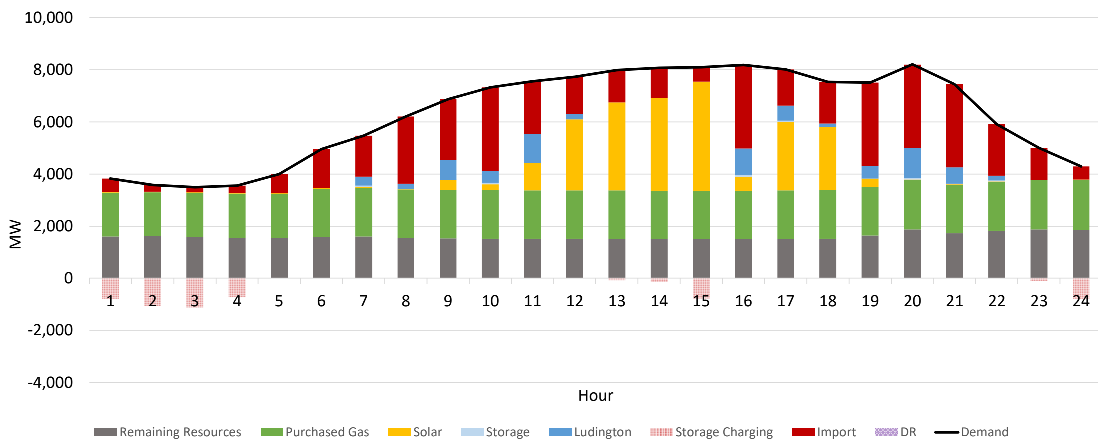
MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capacity Sufficiency Analysis Loss of Load Event Examples: Controllable Generation
Winter Day with No Solar

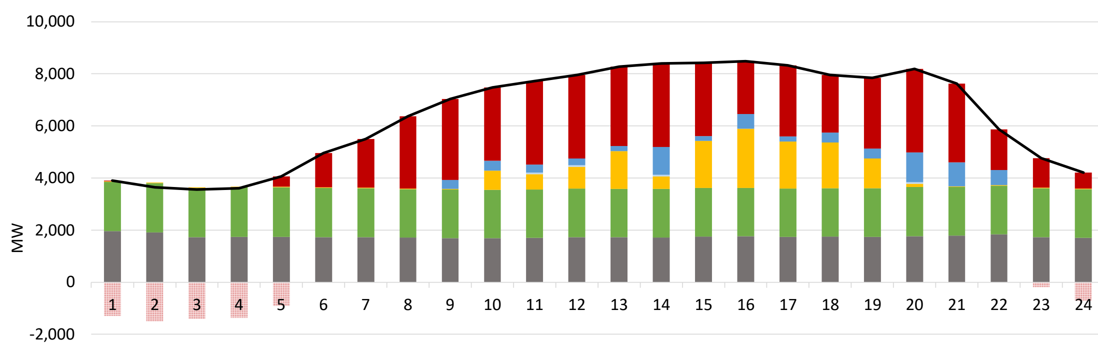


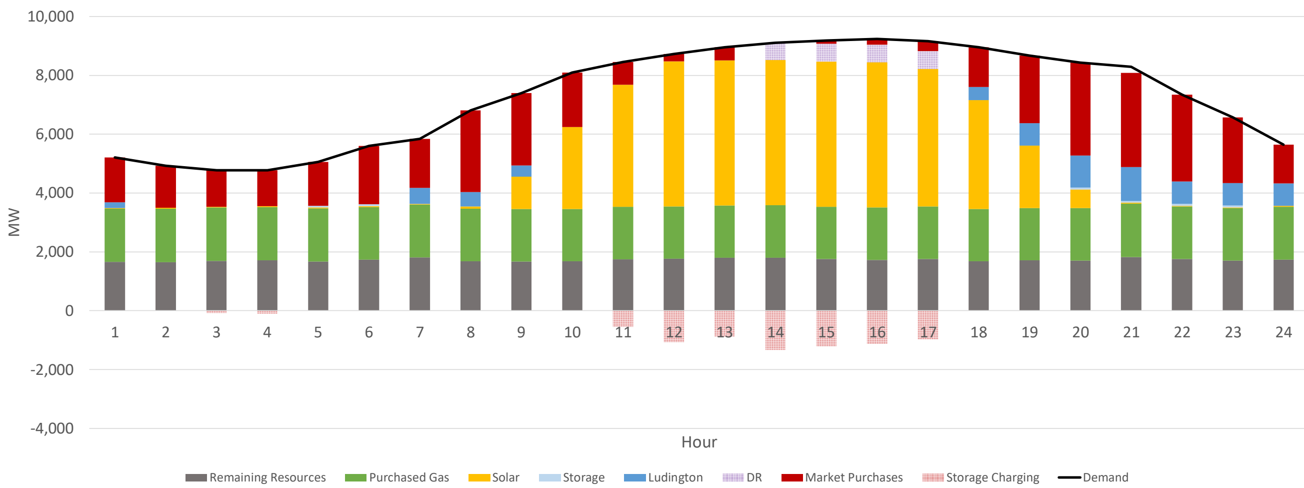
MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Capacity Sufficiency Analysis Loss of Load Event Examples: Controllable Generation
Consecutive Days

September 7, 2032



September 8, 2032

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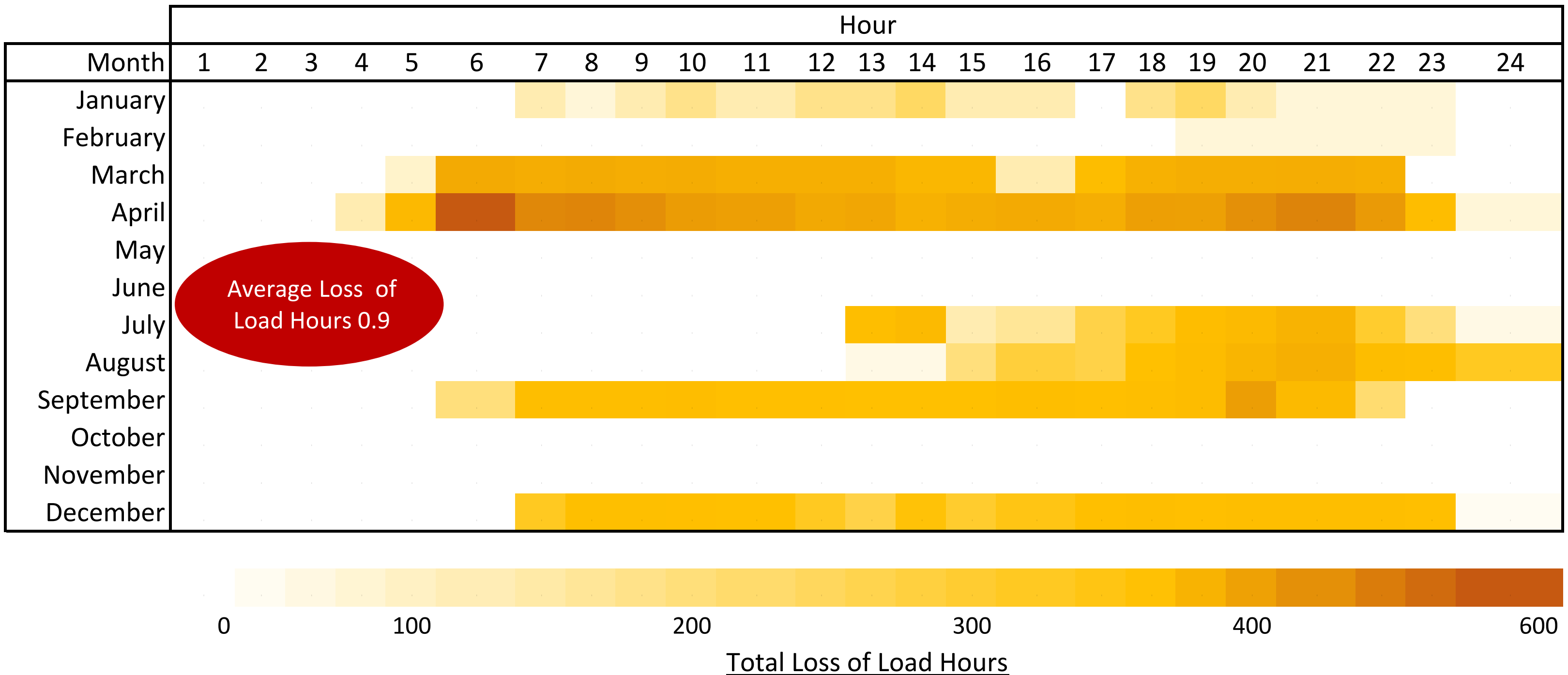
22
23
24
Hour
Remaining Resources
Purchased Gas
Solar
Storage
Ludington
DR
Market Purchases
Storage Charging
Demand

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Capacity Sufficiency Analysis Results: Heat Maps
Alternate Plan

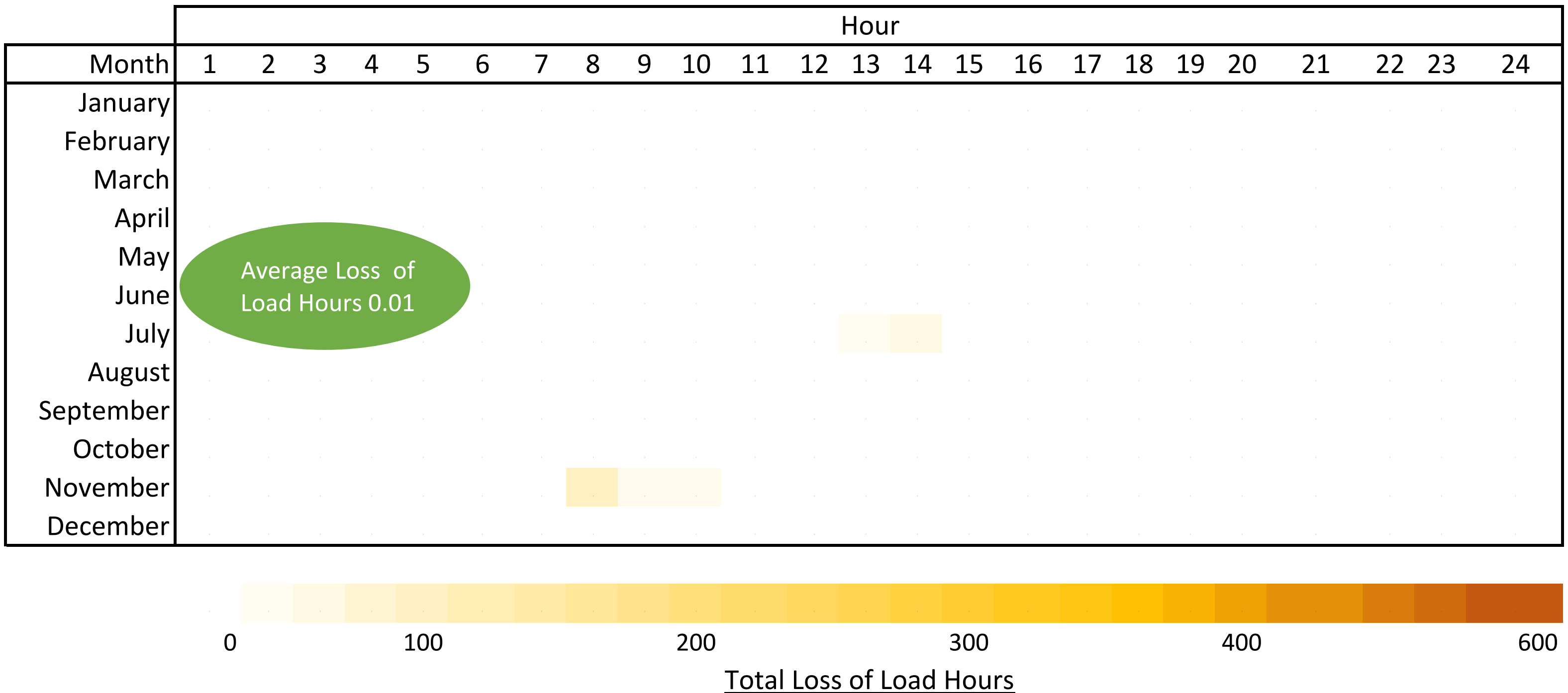
Case No.: U-21090
Exhibit No.: A-18 (STW-15)

Witness: STWalz
Date: June 2021



MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Capacity Sufficiency Analysis Results: Heat Maps
Proposed Course of Action

Case No.: U-21090
Exhibit No.: A-18 (STW-15)
Page: 2 of 2
Witness: STWalz
Date: June 2021



MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Retirement Analysis, PCA and Alternate Plan Cost Summary
PROPOSED COURSE OF ACTION

Case No.: U-21090
Exhibit No.: A-19 (STW-16)

Witness: STWalz
Date: June 2021

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	-1,119	-1,119	-2,515	-2,515	-2,515	-2,515	-2,515	-2,515	-789	-789	-789	-789	-789	-789	-789	-789	0	0
2	Purchased Natural Gas Capacity		0	0	1,176	1,176	2,153	2,153	2,153	2,153	2,153	2,153	2,153	2,153	2,153	2,153	2,153	2,153	2,153	2,153	2,153	0
3	EWR		0	0	0	20	57	91	125	159	190	218	233	233	231	229	227	224	222	220	218	215
4	Solar		0	0	0	0	500	704	1,204	1,704	2,204	2,704	2,996	3,026	3,182	3,182	3,518	4,018	4,518	5,018	5,518	6,018
5	DR		0	0	11	23	34	45	57	68	80	91	91	91	91	91	91	91	91	91	91	91
6	Storage		0	0	0	0	0	0	0	0	0	58	60	61	62	64	145	227	309	391	473	474
7	Combustion Turbine		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**68**	**100**	**229**	**479**	**1,023**	**1,569**	**2,111**	**2,709**	**4,744**	**4,775**	**4,930**	**4,929**	**5,345**	**5,924**	**6,504**	**7,084**	**8,452**	**6,799**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		-$8,047	-$62,992	-$85,305	-$57,106	-$48,396	-$46,673	-$50,408	-$24,074	-$34,470	-$37,946	-$17,741	-$2,750	-$11,750	-$5,400	-$3,650	-$4,650	-$2,400	-$550	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$833,839	$19,284	$553,863	$20,656	$30,698	$25,145	$28,758	$32,772	$34,888	$37,019	$38,976	$39,937	$40,910	$17,526	$18,017	$15,398	$11,540	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$331,082	$133,587	$323,752	$319,743	$315,686	$311,251	$182,607	$18,841	$98,261	$0	$212,650	$317,983	$319,437	$320,801	$322,071	$323,242
15	DR	(Capital = 10% DR costs)	$0	$0	$89	$181	$277	$376	$480	$589	$699	$827	$844	$863	$878	$896	$914	$934	$951	$970	$989	$1,011
16	Storage	(100% CE ownership)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$50,875	$1,120	$1,145	$1,169	$1,194	$73,819	$74,211	$74,584	$74,938	$75,272	$1,342
17	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**-$8,047**	**-$62,992**	**$748,623**	**-$37,641**	**$836,825**	**$107,947**	**$304,522**	**$321,402**	**$310,673**	**$357,779**	**$201,717**	**$55,119**	**$127,534**	**$36,626**	**$324,642**	**$406,003**	**$410,588**	**$411,557**	**$409,873**	**$325,596**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		-$1,327	$200	$1,056	-$10,700	-$10,534	-$81,460	-$83,806	-$84,879	-$89,718	-$86,377	-$63,329	-$48,311	-$37,429	-$35,879	-$37,043	-$37,259	-$40,008	-$38,061	-$19,869	$0
22	Purchased Natural Gas Capacity		$0	$0	$25,379	$44,700	$43,825	$41,299	$72,322	$71,944	$72,775	$72,735	$74,254	$74,695	$76,358	$77,744	$78,467	$78,240	$79,667	$80,285	$82,947	$7,767
23	EWR		$0	$0	$0	$90,736	$105,729	$102,709	$111,129	$115,483	$101,414	$108,688	$18,864	-$26,812	$7,462	$9,298	$11,993	$26,493	$30,953	$32,859	$38,487	$47,831
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$2,165	$3,819	$7,874	$11,899	$15,897	$19,850	$22,522	$23,088	$24,690	$24,998	$28,177	$32,926	$37,791	$42,770	$47,862	$53,066
25	DR	(O&M = 90% DR costs)	$0	$0	$798	$1,632	$2,490	$3,386	$4,317	$5,299	$6,289	$7,447	$7,596	$7,769	$7,903	$8,061	$8,222	$8,410	$8,555	$8,726	$8,900	$9,103
26	Storage	(100% CE ownership)	$0	$0	$0	$0	$0	$0	$0	$0	$0	-$3,380	-$3,545	-$3,712	-$3,906	-$4,104	-$1,837	$459	$2,791	$5,141	$7,536	$7,406
27	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**-$1,327**	**$200**	**$27,233**	**$126,368**	**$143,674**	**$69,753**	**$111,837**	**$119,746**	**$106,656**	**$118,964**	**$56,362**	**$26,717**	**$75,077**	**$80,118**	**$87,980**	**$109,270**	**$119,749**	**$131,719**	**$165,863**	**$125,174**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31		100% CONE	$1,871,539	$1,762,051	$1,637,246	$1,590,039	$1,572,428	$1,600,885	$1,637,045	$1,627,739	$1,572,473	$1,558,366	$1,516,797	$1,486,368	$1,541,702	$1,574,638	$1,580,903	$1,567,553	$1,552,387	$1,543,251	$1,510,482	$1,862,103
32		75% CONE	$1,886,326	$1,765,824	$1,648,757	$1,608,660	$1,576,770	$1,610,493	$1,651,804	$1,650,592	$1,605,153	$1,564,105	$1,522,648	$1,492,327	$1,547,797	$1,582,051	$1,597,303	$1,594,876	$1,591,581	$1,595,518	$1,575,295	$1,869,084
33	PSCR	50% CONE	$1,901,113	$1,769,596	$1,660,268	$1,627,281	$1,581,113	$1,620,100	$1,666,564	$1,673,444	$1,637,833	$1,569,843	$1,528,498	$1,498,285	$1,553,892	$1,589,465	$1,613,702	$1,622,199	$1,630,776	$1,647,785	$1,640,107	$1,876,066
34		25% CONE	$1,915,900	$1,773,369	$1,671,778	$1,645,903	$1,585,456	$1,629,708	$1,681,323	$1,696,297	$1,670,514	$1,575,582	$1,534,349	$1,504,244	$1,559,986	$1,596,878	$1,630,102	$1,649,522	$1,669,970	$1,700,052	$1,704,920	$1,883,048
35		0% CONE	$1,930,687	$1,777,141	$1,683,289	$1,664,524	$1,589,799	$1,639,316	$1,696,082	$1,719,150	$1,703,194	$1,581,321	$1,540,199	$1,510,202	$1,566,081	$1,604,292	$1,646,502	$1,676,845	$1,709,165	$1,752,318	$1,769,732	$1,890,030

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Retirement Analysis, PCA and Alternate Plan Cost Summary
ALTERNATE PLAN

Case No.: U-21090
Exhibit No.: A-19 (STW-16)

Witness: STWalz
Date: June 2021

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	0	0	-1,119	-1,119	-1,119	-1,119	-1,119	-1,119	0	0	0	0	0	0	0	0	0	0
2	Purchased Natural Gas Capacity		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	EWR		0	0	0	20	57	91	125	159	190	218	233	233	231	229	227	224	222	220	218	215
4	Solar		0	0	0	0	500	1,000	1,500	2,000	2,500	3,000	3,500	3,630	3,808	3,808	3,808	3,808	4,034	4,534	5,034	5,046
5	DR		0	0	25	50	75	100	126	151	176	201	226	226	226	226	226	226	226	226	226	226
6	Storage		0	0	0	0	217	317	418	518	618	719	819	820	822	823	824	826	827	828	830	831
7	Combustion Turbine		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**25**	**70**	**-270**	**390**	**1,049**	**1,708**	**2,365**	**3,018**	**4,778**	**4,910**	**5,087**	**5,086**	**5,085**	**5,084**	**5,309**	**5,808**	**6,307**	**6,319**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		$1,173	-$20,250	-$9,512	-$9,275	-$9,934	-$9,900	-$8,950	-$2,000	-$2,000	-$1,000	-$500	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$331,082	$327,419	$323,752	$319,743	$315,686	$311,251	$312,684	$81,645	$112,118	$0	$0	$0	$144,386	$320,801	$322,071	$7,758
15	DR	(Capital = 10% DR costs)	$0	$0	$196	$401	$612	$865	$1,176	$1,506	$1,849	$2,231	$2,627	$2,687	$2,733	$2,788	$2,844	$2,909	$2,959	$3,018	$3,078	$3,148
16	Storage	(100% CE ownership)	$0	$0	$0	$0	$219,303	$98,945	$96,322	$93,530	$90,648	$87,582	$88,242	$1,145	$1,169	$1,194	$1,218	$1,243	$1,268	$1,293	$1,317	$1,342
17	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**$1,173**	**-$20,250**	**-$9,316**	**-$8,874**	**$541,063**	**$417,329**	**$412,300**	**$412,780**	**$406,183**	**$400,063**	**$403,053**	**$85,477**	**$116,021**	**$3,982**	**$4,062**	**$4,151**	**$148,612**	**$325,112**	**$326,467**	**$12,249**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		$624	$491	$1,430	-$501	-$6,290	-$19,292	-$19,524	-$19,771	-$20,018	-$20,110	-$12,716	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	EWR		$0	$0	$0	$90,736	$105,729	$102,709	$111,129	$115,483	$101,414	$108,688	$18,864	-$26,812	$7,462	$9,298	$11,993	$26,493	$30,953	$32,859	$38,487	$47,831
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$2,165	$6,233	$10,283	$14,300	$18,291	$22,234	$26,635	$28,081	$29,926	$30,294	$30,658	$31,105	$33,537	$38,459	$43,495	$44,185
25	DR	(O&M = 90% DR costs)	$0	$0	$1,763	$3,607	$5,504	$7,783	$10,583	$13,557	$16,637	$20,075	$23,645	$24,184	$24,600	$25,092	$25,594	$26,177	$26,628	$27,160	$27,703	$28,335
26	Storage	(100% CE ownership)	$0	$0	$0	$0	$6,913	$5,704	$8,422	$11,023	$13,496	$15,808	$18,755	$18,822	$18,844	$18,862	$18,887	$18,894	$18,891	$18,861	$18,833	$18,799
27	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**$624**	**$491**	**$3,193**	**$93,842**	**$114,020**	**$103,137**	**$120,892**	**$134,592**	**$129,819**	**$146,695**	**$75,182**	**$44,275**	**$80,832**	**$83,546**	**$87,132**	**$102,669**	**$110,009**	**$117,339**	**$128,518**	**$139,150**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31		100% CONE	$1,880,832	$1,772,073	$1,751,432	$1,749,344	$1,686,091	$1,673,855	$1,683,021	$1,650,994	$1,585,833	$1,554,579	$1,561,092	$1,529,879	$1,583,666	$1,627,136	$1,649,985	$1,684,344	$1,704,909	$1,704,001	$1,797,850	$1,935,634
32		75% CONE	$1,895,619	$1,775,846	$1,755,171	$1,760,358	$1,691,231	$1,687,699	$1,705,052	$1,683,198	$1,628,562	$1,570,676	$1,566,936	$1,535,830	$1,589,753	$1,634,542	$1,658,648	$1,693,249	$1,718,297	$1,727,384	$1,804,701	$1,942,612
33	PSCR	50% CONE	$1,910,406	$1,779,618	$1,758,909	$1,771,372	$1,696,371	$1,701,543	$1,727,084	$1,715,403	$1,671,291	$1,586,772	$1,572,780	$1,541,782	$1,595,841	$1,641,949	$1,667,312	$1,702,153	$1,731,685	$1,750,767	$1,811,552	$1,949,589
34		25% CONE	$1,925,193	$1,783,391	$1,762,648	$1,782,387	$1,701,511	$1,715,387	$1,749,115	$1,747,608	$1,714,020	$1,602,868	$1,578,623	$1,547,733	$1,601,928	$1,649,355	$1,675,975	$1,711,057	$1,745,073	$1,774,150	$1,818,403	$1,956,567
35		0% CONE	$1,939,980	$1,787,163	$1,766,387	$1,793,401	$1,706,652	$1,729,231	$1,771,147	$1,779,813	$1,756,749	$1,618,964	$1,584,467	$1,553,685	$1,608,016	$1,656,761	$1,684,639	$1,719,961	$1,758,461	$1,797,533	$1,825,255	$1,963,545

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Retirement Analysis, PCA and Alternate Plan Cost Summary
BASE CASE

Case No.: U-21090
Exhibit No.: A-19 (STW-16)
Page: 3 of 16
Witness: STWalz
Date: June 2021

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Purchased Natural Gas Capacity		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	EWR		0	0	0	20	58	92	126	160	192	205	208	195	180	164	138	120	104	104	104	82
4	Solar		0	0	0	0	500	1,000	1,500	2,000	2,500	3,000	3,500	3,870	4,175	4,513	4,850	5,188	5,526	5,863	6,201	6,201
5	DR		0	0	23	60	107	160	231	295	297	297	297	297	297	297	297	297	297	297	297	297
6	Storage		0	0	0	24	47	71	94	118	141	225	252	254	255	256	257	259	260	262	240	217
7	Combustion Turbine		0	0	0	0	0	0	0	0	0	0	478	478	478	478	478	478	478	478	478	478
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**23**	**104**	**712**	**1,323**	**1,951**	**2,573**	**3,130**	**3,727**	**4,734**	**5,093**	**5,384**	**5,707**	**6,020**	**6,341**	**6,664**	**7,003**	**7,318**	**7,274**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$331,082	$327,419	$323,752	$319,743	$315,686	$311,251	$312,684	$232,348	$192,251	$213,188	$213,656	$214,695	$215,677	$216,599	$217,456	$0
15	DR	(Capital = 10% DR costs)	$0	$0	$157	$416	$794	$1,282	$2,060	$2,878	$2,946	$3,005	$3,065	$3,135	$3,189	$3,253	$3,318	$3,394	$3,452	$3,521	$3,591	$3,673
16	Storage	(100% CE ownership)	$0	$0	$0	$25,434	$23,848	$23,249	$22,634	$21,978	$21,301	$73,199	$23,613	$1,145	$1,169	$1,194	$1,218	$1,243	$1,268	$1,293	$0	$0
17	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$419,246	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**$0**	**$0**	**$157**	**$25,850**	**$355,724**	**$351,950**	**$348,445**	**$344,599**	**$339,934**	**$387,455**	**$758,608**	**$236,628**	**$196,610**	**$217,634**	**$218,192**	**$219,332**	**$220,397**	**$221,412**	**$221,048**	**$3,673**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	EWR		$0	$0	$0	$101,294	$103,225	$98,341	$103,234	$106,295	$94,268	$100,608	$26,008	-$173	$1,136	$3,421	$6,778	$23,033	$29,170	$33,025	$39,923	$50,116
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$4,085	$8,150	$12,196	$16,209	$20,197	$24,135	$28,533	$31,960	$34,890	$38,147	$41,465	$44,959	$48,531	$52,179	$55,901	$56,615
25	DR	(O&M = 90% DR costs)	$0	$0	$1,412	$3,741	$7,149	$11,536	$18,536	$25,904	$26,516	$27,047	$27,588	$28,216	$28,702	$29,276	$29,862	$30,542	$31,068	$31,689	$32,323	$33,060
26	Storage	(100% CE ownership)	$0	$0	$0	$788	$1,503	$2,220	$2,911	$3,573	$4,205	$1,476	$2,109	$2,002	$1,862	$1,720	$1,584	$1,433	$1,273	$1,088	$159	-$786
27	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,077	$13,836	$14,417	$14,989	$15,674	$16,521	$17,283	$18,240	$19,170	$19,983
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**$0**	**$0**	**$1,412**	**$105,823**	**$115,962**	**$120,247**	**$136,877**	**$151,981**	**$145,186**	**$153,266**	**$97,314**	**$75,841**	**$81,007**	**$87,552**	**$95,364**	**$116,488**	**$127,324**	**$136,222**	**$147,477**	**$158,988**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31	PSCR		$1,916,922	$1,763,204	$1,738,360	$1,750,737	$1,684,263	$1,701,073	$1,759,632	$1,778,379	$1,769,117	$1,640,709	$1,613,276	$1,614,079	$1,655,448	$1,712,727	$1,791,212	$1,847,674	$1,906,870	$1,962,569	$2,004,062	$2,172,071

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Retirement Analysis, PCA and Alternate Plan Cost Summary
CAMPBELL 1 RETIREMENT MAY 31, 2024

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	0	-260	-260	-260	-260	-260	-260	-260	0	0	0	0	0	0	0	0	0	0
2	Purchased Natural Gas Capacity		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	EWR		0	0	0	20	58	92	126	160	192	205	208	195	180	164	138	120	104	104	104	82
4	Solar		0	0	0	0	500	1,000	1,500	2,000	2,500	3,000	3,500	3,870	4,175	4,513	4,850	5,188	5,526	5,863	6,201	6,201
5	DR		0	0	23	60	107	160	231	295	297	297	297	297	297	297	297	297	297	297	297	297
6	Storage		0	0	0	24	47	71	94	118	141	225	252	254	255	256	257	259	260	262	240	217
7	Combustion Turbine		0	0	0	0	0	0	0	0	0	0	478	478	478	478	478	478	478	478	478	478
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**23**	**-156**	**452**	**1,063**	**1,691**	**2,313**	**2,870**	**3,467**	**4,734**	**5,093**	**5,384**	**5,707**	**6,020**	**6,341**	**6,664**	**7,003**	**7,318**	**7,274**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		$99	-$13,484	-$26,801	-$9,503	-$2,550	-$3,300	-$4,050	-$3,500	-$3,879	-$2,564	-$250	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$331,082	$327,419	$323,752	$319,743	$315,686	$311,251	$312,684	$232,348	$192,251	$213,188	$213,656	$214,695	$215,677	$216,599	$217,456	$0
15	DR	(Capital = 10% DR costs)	$0	$0	$157	$416	$794	$1,282	$2,060	$2,878	$2,946	$3,005	$3,065	$3,135	$3,189	$3,253	$3,318	$3,394	$3,452	$3,521	$3,591	$3,673
16	Storage	(100% CE ownership)	$0	$0	$0	$25,434	$23,848	$23,249	$22,634	$21,978	$21,301	$73,199	$23,613	$1,145	$1,169	$1,194	$1,218	$1,243	$1,268	$1,293	$0	$0
17	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$419,246	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**$99**	**-$13,484**	**-$26,644**	**$16,347**	**$353,174**	**$348,650**	**$344,395**	**$341,099**	**$336,055**	**$384,891**	**$758,358**	**$236,628**	**$196,610**	**$217,634**	**$218,192**	**$219,332**	**$220,397**	**$221,412**	**$221,048**	**$3,673**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		-$322	-$67	-$255	-$4,233	-$11,067	-$11,402	-$11,920	-$12,364	-$12,172	-$11,744	-$4,418	$1,860	$1,897	$1,935	$1,974	$2,014	$2,054	$2,095	$1,068	$0
22	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	EWR		$0	$0	$0	$101,294	$103,225	$98,341	$103,234	$106,295	$94,268	$100,608	$26,008	-$173	$1,136	$3,421	$6,778	$23,033	$29,170	$33,025	$39,923	$50,116
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$4,085	$8,150	$12,196	$16,209	$20,197	$24,135	$28,533	$31,960	$34,890	$38,147	$41,465	$44,959	$48,531	$52,179	$55,901	$56,615
25	DR	(O&M = 90% DR costs)	$0	$0	$1,412	$3,741	$7,149	$11,536	$18,536	$25,904	$26,516	$27,047	$27,588	$28,216	$28,702	$29,276	$29,862	$30,542	$31,068	$31,689	$32,323	$33,060
26	Storage	(100% CE ownership)	$0	$0	$0	$788	$1,503	$2,220	$2,911	$3,573	$4,205	$1,476	$2,109	$2,002	$1,862	$1,720	$1,584	$1,433	$1,273	$1,088	$159	-$786
27	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,078	$13,836	$14,417	$14,989	$15,674	$16,521	$17,283	$18,240	$19,170	$19,983
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**-$322**	**-$67**	**$1,157**	**$101,590**	**$104,896**	**$108,845**	**$124,956**	**$139,617**	**$133,014**	**$141,522**	**$92,897**	**$77,701**	**$82,904**	**$89,488**	**$97,338**	**$118,502**	**$129,378**	**$138,317**	**$148,545**	**$158,988**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31	PSCR		$1,916,407	$1,762,590	$1,738,309	$1,758,363	$1,695,341	$1,710,841	$1,769,556	$1,785,152	$1,778,809	$1,653,177	$1,618,401	$1,613,891	$1,655,266	$1,712,726	$1,791,361	$1,847,785	$1,906,882	$1,962,537	$2,004,407	$2,171,793

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Retirement Analysis, PCA and Alternate Plan Cost Summary
CAMPBELL 1 RETIREMENT MAY 31, 2025

Case No.: U-21090
Exhibit No.: A-19 (STW-16)

Witness: STWalz
Date: June 2021

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	0	0	-260	-260	-260	-260	-260	-260	0	0	0	0	0	0	0	0	0	0
2	Purchased Natural Gas Capacity		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	EWR		0	0	0	20	58	92	126	160	192	205	208	195	180	164	138	120	104	104	104	82
4	Solar		0	0	0	0	500	1,000	1,500	2,000	2,500	3,000	3,500	3,870	4,175	4,513	4,850	5,188	5,526	5,863	6,201	6,201
5	DR		0	0	23	60	107	160	231	295	297	297	297	297	297	297	297	297	297	297	297	297
6	Storage		0	0	0	24	47	71	94	118	141	225	252	254	255	256	257	259	260	262	240	217
7	Combustion Turbine		0	0	0	0	0	0	0	0	0	0	478	478	478	478	478	478	478	478	478	478
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**23**	**104**	**452**	**1,063**	**1,691**	**2,313**	**2,870**	**3,467**	**4,734**	**5,093**	**5,384**	**5,707**	**6,020**	**6,341**	**6,664**	**7,003**	**7,318**	**7,274**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		-$700	-$15,490	-$32,920	-$8,953	-$2,300	-$3,300	-$4,050	-$3,500	-$3,879	-$2,564	-$250	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$331,082	$327,419	$323,752	$319,743	$315,686	$311,251	$312,684	$232,348	$192,251	$213,188	$213,656	$214,695	$215,677	$216,599	$217,456	$0
15	DR	(Capital = 10% DR costs)	$0	$0	$157	$416	$794	$1,282	$2,060	$2,878	$2,946	$3,005	$3,065	$3,135	$3,189	$3,253	$3,318	$3,394	$3,452	$3,521	$3,591	$3,673
16	Storage	(100% CE ownership)	$0	$0	$0	$25,434	$23,848	$23,249	$22,634	$21,978	$21,301	$73,199	$23,613	$1,145	$1,169	$1,194	$1,218	$1,243	$1,268	$1,293	$0	$0
17	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$419,246	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**-$700**	**-$15,490**	**-$32,763**	**$16,897**	**$353,424**	**$348,650**	**$344,395**	**$341,099**	**$336,055**	**$384,891**	**$758,358**	**$236,628**	**$196,610**	**$217,634**	**$218,192**	**$219,332**	**$220,397**	**$221,412**	**$221,048**	**$3,673**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		-$322	-$67	$0	-$250	-$3,489	-$11,400	-$11,919	-$12,362	-$12,170	-$11,742	-$4,417	$1,861	$1,899	$1,937	$1,975	$2,015	$2,055	$2,096	$1,069	$0
22	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	EWR		$0	$0	$0	$101,294	$103,225	$98,341	$103,234	$106,295	$94,268	$100,608	$26,008	-$173	$1,136	$3,421	$6,778	$23,033	$29,170	$33,025	$39,923	$50,116
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$4,085	$8,150	$12,196	$16,209	$20,197	$24,135	$28,533	$31,960	$34,890	$38,147	$41,465	$44,959	$48,531	$52,179	$55,901	$56,615
25	DR	(O&M = 90% DR costs)	$0	$0	$1,412	$3,741	$7,149	$11,536	$18,536	$25,904	$26,516	$27,047	$27,588	$28,216	$28,702	$29,276	$29,862	$30,542	$31,068	$31,689	$32,323	$33,060
26	Storage	(100% CE ownership)	$0	$0	$0	$788	$1,503	$2,220	$2,911	$3,573	$4,205	$1,476	$2,109	$2,002	$1,862	$1,720	$1,584	$1,433	$1,273	$1,088	$159	-$786
27	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,077	$13,836	$14,417	$14,989	$15,674	$16,521	$17,283	$18,240	$19,170	$19,983
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**-$322**	**-$67**	**$1,412**	**$105,573**	**$112,473**	**$108,847**	**$124,958**	**$139,618**	**$133,016**	**$141,524**	**$92,897**	**$77,702**	**$82,905**	**$89,489**	**$97,339**	**$118,503**	**$129,379**	**$138,318**	**$148,546**	**$158,988**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31	PSCR		$1,916,407	$1,762,590	$1,738,240	$1,750,744	$1,692,344	$1,710,055	$1,769,612	$1,785,219	$1,778,839	$1,652,632	$1,618,406	$1,613,925	$1,655,083	$1,712,810	$1,790,927	$1,847,835	$1,906,819	$1,962,613	$2,003,992	$2,171,642

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Retirement Analysis, PCA and Alternate Plan Cost Summary
CAMPBELL 1 RETIREMENT MAY 31, 2026

Case No.: U-21090
Exhibit No.: A-19 (STW-16)

Witness: STWalz
Date: June 2021

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	0	0	0	-260	-260	-260	-260	-260	0	0	0	0	0	0	0	0	0	0
2	Purchased Natural Gas Capacity		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	EWR		0	0	0	20	58	92	126	160	192	205	208	195	180	164	138	120	104	104	104	82
4	Solar		0	0	0	0	500	1,000	1,500	2,000	2,500	3,000	3,500	3,870	4,175	4,513	4,850	5,188	5,526	5,863	6,201	6,201
5	DR		0	0	23	60	107	160	231	295	297	297	297	297	297	297	297	297	297	297	297	297
6	Storage		0	0	0	24	47	71	94	118	141	225	252	254	255	256	257	259	260	262	240	217
7	Combustion Turbine		0	0	0	0	0	0	0	0	0	0	478	478	478	478	478	478	478	478	478	478
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**23**	**104**	**712**	**1,063**	**1,691**	**2,313**	**2,870**	**3,467**	**4,734**	**5,093**	**5,384**	**5,707**	**6,020**	**6,341**	**6,664**	**7,003**	**7,318**	**7,274**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		-$700	-$15,490	-$32,630	-$8,137	-$1,750	-$3,050	-$4,050	-$3,500	-$3,879	-$2,564	-$250	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$331,082	$327,419	$323,752	$319,743	$315,686	$311,251	$312,684	$232,348	$192,251	$213,188	$213,656	$214,695	$215,677	$216,599	$217,456	$0
15	DR	(Capital = 10% DR costs)	$0	$0	$157	$416	$794	$1,282	$2,060	$2,878	$2,946	$3,005	$3,065	$3,135	$3,189	$3,253	$3,318	$3,394	$3,452	$3,521	$3,591	$3,673
16	Storage	(100% CE ownership)	$0	$0	$0	$25,434	$23,848	$23,249	$22,634	$21,978	$21,301	$73,199	$23,613	$1,145	$1,169	$1,194	$1,218	$1,243	$1,268	$1,293	$0	$0
17	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$419,246	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**-$700**	**-$15,490**	**-$32,473**	**$17,713**	**$353,974**	**$348,900**	**$344,395**	**$341,099**	**$336,055**	**$384,891**	**$758,358**	**$236,628**	**$196,610**	**$217,634**	**$218,192**	**$219,332**	**$220,397**	**$221,412**	**$221,048**	**$3,673**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		-$322	-$67	$0	$0	-$500	-$3,648	-$11,920	-$12,364	-$12,172	-$11,743	-$4,418	$1,860	$1,897	$1,935	$1,974	$2,013	$2,053	$2,095	$1,068	$0
22	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	EWR		$0	$0	$0	$101,294	$103,225	$98,341	$103,234	$106,295	$94,268	$100,608	$26,008	-$173	$1,136	$3,421	$6,778	$23,033	$29,170	$33,025	$39,923	$50,116
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$4,085	$8,150	$12,196	$16,209	$20,197	$24,135	$28,533	$31,960	$34,890	$38,147	$41,465	$44,959	$48,531	$52,179	$55,901	$56,615
25	DR	(O&M = 90% DR costs)	$0	$0	$1,412	$3,741	$7,149	$11,536	$18,536	$25,904	$26,516	$27,047	$27,588	$28,216	$28,702	$29,276	$29,862	$30,542	$31,068	$31,689	$32,323	$33,060
26	Storage	(100% CE ownership)	$0	$0	$0	$788	$1,503	$2,220	$2,911	$3,573	$4,205	$1,476	$2,109	$2,002	$1,862	$1,720	$1,584	$1,433	$1,273	$1,088	$159	-$786
27	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,077	$13,836	$14,417	$14,989	$15,674	$16,521	$17,284	$18,240	$19,170	$19,983
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**-$322**	**-$67**	**$1,412**	**$105,823**	**$115,463**	**$116,600**	**$124,957**	**$139,617**	**$133,015**	**$141,523**	**$92,896**	**$77,701**	**$82,904**	**$89,487**	**$97,337**	**$118,501**	**$129,378**	**$138,316**	**$148,545**	**$158,988**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31	PSCR		$1,916,407	$1,762,522	$1,738,189	$1,750,706	$1,684,192	$1,706,640	$1,769,615	$1,785,179	$1,778,787	$1,653,171	$1,618,514	$1,613,862	$1,655,095	$1,712,644	$1,791,143	$1,847,799	$1,906,665	$1,962,771	$2,004,245	$2,171,694

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Retirement Analysis, PCA and Alternate Plan Cost Summary
CAMPBELL 1 RETIREMENT MAY 31, 2028

Case No.: U-21090
Exhibit No.: A-19 (STW-16)

Witness: STWalz
Date: June 2021

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	0	0	0	0	0	-260	-260	-260	0	0	0	0	0	0	0	0	0	0
2	Purchased Natural Gas Capacity		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	EWR		0	0	0	20	58	92	126	160	192	205	208	195	180	164	138	120	104	104	104	82
4	Solar		0	0	0	0	500	1,000	1,500	2,000	2,500	3,000	3,500	3,870	4,175	4,513	4,850	5,188	5,526	5,863	6,201	6,201
5	DR		0	0	23	60	107	160	231	295	297	297	297	297	297	297	297	297	297	297	297	297
6	Storage		0	0	0	24	47	71	94	118	141	225	252	254	255	256	257	259	260	262	240	217
7	Combustion Turbine		0	0	0	0	0	0	0	0	0	0	478	478	478	478	478	478	478	478	478	478
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**23**	**104**	**712**	**1,323**	**1,951**	**2,313**	**2,870**	**3,467**	**4,734**	**5,093**	**5,384**	**5,707**	**6,020**	**6,341**	**6,664**	**7,003**	**7,318**	**7,274**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		$0	$0	$0	$0	$0	-$1,250	-$3,250	-$3,250	-$3,879	-$2,564	-$250	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$331,082	$327,419	$323,752	$319,743	$315,686	$311,251	$312,684	$232,348	$192,251	$213,188	$213,656	$214,695	$215,677	$216,599	$217,456	$0
15	DR	(Capital = 10% DR costs)	$0	$0	$157	$416	$794	$1,282	$2,060	$2,878	$2,946	$3,005	$3,065	$3,135	$3,189	$3,253	$3,318	$3,394	$3,452	$3,521	$3,591	$3,673
16	Storage	(100% CE ownership)	$0	$0	$0	$25,434	$23,848	$23,249	$22,634	$21,978	$21,301	$73,199	$23,613	$1,145	$1,169	$1,194	$1,218	$1,243	$1,268	$1,293	$0	$0
17	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$419,246	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**$0**	**$0**	**$157**	**$25,850**	**$355,724**	**$350,700**	**$345,195**	**$341,349**	**$336,055**	**$384,891**	**$758,358**	**$236,628**	**$196,610**	**$217,634**	**$218,192**	**$219,332**	**$220,397**	**$221,412**	**$221,048**	**$3,673**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		$0	$0	$0	$0	$0	$0	-$639	-$4,363	-$12,171	-$11,743	-$4,417	$1,861	$1,898	$1,936	$1,975	$2,014	$2,055	$2,096	$1,069	$0
22	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	EWR		$0	$0	$0	$101,294	$103,225	$98,341	$103,234	$106,295	$94,268	$100,608	$26,008	-$173	$1,136	$3,421	$6,778	$23,033	$29,170	$33,025	$39,923	$50,116
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$4,085	$8,150	$12,196	$16,209	$20,197	$24,135	$28,533	$31,960	$34,890	$38,147	$41,465	$44,959	$48,531	$52,179	$55,901	$56,615
25	DR	(O&M = 90% DR costs)	$0	$0	$1,412	$3,741	$7,149	$11,536	$18,536	$25,904	$26,516	$27,047	$27,588	$28,216	$28,702	$29,276	$29,862	$30,542	$31,068	$31,689	$32,323	$33,060
26	Storage	(100% CE ownership)	$0	$0	$0	$788	$1,503	$2,220	$2,911	$3,573	$4,205	$1,476	$2,109	$2,002	$1,862	$1,720	$1,584	$1,433	$1,273	$1,088	$159	-$786
27	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,077	$13,793	$14,417	$14,995	$15,672	$16,554	$17,279	$18,232	$19,152	$19,967
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**$0**	**$0**	**$1,412**	**$105,823**	**$115,963**	**$120,248**	**$136,238**	**$147,618**	**$133,015**	**$141,523**	**$92,897**	**$77,659**	**$82,905**	**$89,494**	**$97,336**	**$118,536**	**$129,375**	**$138,309**	**$148,527**	**$158,971**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31	PSCR		$1,916,894	$1,763,222	$1,738,370	$1,750,656	$1,684,161	$1,701,123	$1,759,746	$1,781,473	$1,779,055	$1,652,155	$1,617,139	$1,612,765	$1,655,157	$1,711,723	$1,791,304	$1,847,945	$1,905,696	$1,962,549	$2,003,773	$2,172,028

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Retirement Analysis, PCA and Alternate Plan Cost Summary
CAMPBELL 2 RETIREMENT MAY 31, 2024

Case No.: U-21090
Exhibit No.: A-19 (STW-16)

Witness: STWalz
Date: June 2021

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	0	-347	-347	-347	-347	-347	-347	-347	0	0	0	0	0	0	0	0	0	0
2	Purchased Natural Gas Capacity		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	EWR		0	0	0	20	58	92	126	160	192	205	208	195	180	164	138	120	104	104	104	82
4	Solar		0	0	0	0	500	1,000	1,500	2,000	2,500	3,000	3,500	3,870	4,175	4,513	4,850	5,188	5,526	5,863	6,201	6,201
5	DR		0	0	23	60	107	160	231	295	297	297	297	297	297	297	297	297	297	297	297	297
6	Storage		0	0	0	24	47	71	94	118	141	225	252	254	255	256	257	259	260	262	240	217
7	Combustion Turbine		0	0	0	0	0	0	0	0	0	0	478	478	478	478	478	478	478	478	478	478
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**23**	**-243**	**365**	**976**	**1,604**	**2,226**	**2,783**	**3,380**	**4,734**	**5,093**	**5,384**	**5,707**	**6,020**	**6,341**	**6,664**	**7,003**	**7,318**	**7,274**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		-$1,256	-$9,891	-$26,575	-$11,002	-$7,800	-$4,420	-$6,845	-$7,394	-$2,500	-$1,050	-$250	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$331,082	$327,419	$323,752	$319,743	$315,686	$311,251	$312,684	$232,348	$192,251	$213,188	$213,656	$214,695	$215,677	$216,599	$217,456	$0
15	DR	(Capital = 10% DR costs)	$0	$0	$157	$416	$794	$1,282	$2,060	$2,878	$2,946	$3,005	$3,065	$3,135	$3,189	$3,253	$3,318	$3,394	$3,452	$3,521	$3,591	$3,673
16	Storage	(100% CE ownership)	$0	$0	$0	$25,434	$23,848	$23,249	$22,634	$21,978	$21,301	$73,199	$23,613	$1,145	$1,169	$1,194	$1,218	$1,243	$1,268	$1,293	$0	$0
17	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$419,246	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**-$1,256**	**-$9,891**	**-$26,418**	**$14,848**	**$347,924**	**$347,530**	**$341,600**	**$337,205**	**$337,434**	**$386,405**	**$758,358**	**$236,628**	**$196,610**	**$217,634**	**$218,192**	**$219,332**	**$220,397**	**$221,412**	**$221,048**	**$3,673**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		-$1,629	-$130	-$250	-$4,109	-$15,776	-$14,948	-$14,959	-$15,374	-$17,417	-$15,637	-$6,217	$2,480	$2,530	$2,580	$2,632	$2,684	$2,738	$2,793	$1,424	$0
22	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	EWR		$0	$0	$0	$101,294	$103,225	$98,341	$103,234	$106,295	$94,268	$100,608	$26,008	-$173	$1,136	$3,421	$6,778	$23,033	$29,170	$33,025	$39,923	$50,116
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$4,085	$8,150	$12,196	$16,209	$20,197	$24,135	$28,533	$31,960	$34,890	$38,147	$41,465	$44,959	$48,531	$52,179	$55,901	$56,615
25	DR	(O&M = 90% DR costs)	$0	$0	$1,412	$3,741	$7,149	$11,536	$18,536	$25,904	$26,516	$27,047	$27,588	$28,216	$28,702	$29,276	$29,862	$30,542	$31,068	$31,689	$32,323	$33,060
26	Storage	(100% CE ownership)	$0	$0	$0	$788	$1,503	$2,220	$2,911	$3,573	$4,205	$1,476	$2,109	$2,002	$1,862	$1,720	$1,584	$1,433	$1,273	$1,088	$159	-$786
27	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,077	$13,836	$14,417	$14,989	$15,674	$16,521	$17,283	$18,240	$19,170	$19,983
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**-$1,629**	**-$130**	**$1,162**	**$101,715**	**$100,187**	**$105,300**	**$121,918**	**$136,607**	**$127,769**	**$137,629**	**$91,097**	**$78,321**	**$83,536**	**$90,133**	**$97,995**	**$119,172**	**$130,062**	**$139,015**	**$148,901**	**$158,988**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31	PSCR		$1,917,438	$1,762,370	$1,738,099	$1,758,914	$1,693,652	$1,707,626	$1,766,631	$1,783,731	$1,777,599	$1,652,375	$1,618,970	$1,613,830	$1,655,289	$1,712,693	$1,791,299	$1,847,601	$1,906,956	$1,962,617	$2,004,186	$2,171,618

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Retirement Analysis, PCA and Alternate Plan Cost Summary
CAMPBELL 2 RETIREMENT MAY 31, 2025

Case No.: U-21090
Exhibit No.: A-19 (STW-16)

Witness: STWalz
Date: June 2021

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	0	0	-347	-347	-347	-347	-347	-347	0	0	0	0	0	0	0	0	0	0
2	Purchased Natural Gas Capacity		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	EWR		0	0	0	20	58	92	126	160	192	205	208	195	180	164	138	120	104	104	104	82
4	Solar		0	0	0	0	500	1,000	1,500	2,000	2,500	3,000	3,500	3,870	4,175	4,513	4,850	5,188	5,526	5,863	6,201	6,201
5	DR		0	0	23	60	107	160	231	295	297	297	297	297	297	297	297	297	297	297	297	297
6	Storage		0	0	0	24	47	71	94	118	141	225	252	254	255	256	257	259	260	262	240	217
7	Combustion Turbine		0	0	0	0	0	0	0	0	0	0	478	478	478	478	478	478	478	478	478	478
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**23**	**104**	**365**	**976**	**1,604**	**2,226**	**2,783**	**3,380**	**4,734**	**5,093**	**5,384**	**5,707**	**6,020**	**6,341**	**6,664**	**7,003**	**7,318**	**7,274**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		-$741	-$12,150	-$35,161	-$10,452	-$7,550	-$4,420	-$6,845	-$7,394	-$2,500	-$1,050	-$250	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$331,082	$327,419	$323,752	$319,743	$315,686	$311,251	$312,684	$232,348	$192,251	$213,188	$213,656	$214,695	$215,677	$216,599	$217,456	$0
15	DR	(Capital = 10% DR costs)	$0	$0	$157	$416	$794	$1,282	$2,060	$2,878	$2,946	$3,005	$3,065	$3,135	$3,189	$3,253	$3,318	$3,394	$3,452	$3,521	$3,591	$3,673
16	Storage	(100% CE ownership)	$0	$0	$0	$25,434	$23,848	$23,249	$22,634	$21,978	$21,301	$73,199	$23,613	$1,145	$1,169	$1,194	$1,218	$1,243	$1,268	$1,293	$0	$0
17	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$419,246	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**-$741**	**-$12,150**	**-$35,004**	**$15,398**	**$348,174**	**$347,530**	**$341,600**	**$337,205**	**$337,434**	**$386,405**	**$758,358**	**$236,628**	**$196,610**	**$217,634**	**$218,192**	**$219,332**	**$220,397**	**$221,412**	**$221,048**	**$3,673**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		-$1,629	-$130	$0	-$19	-$6,069	-$14,947	-$14,958	-$15,373	-$17,417	-$15,637	-$6,217	$2,480	$2,530	$2,581	$2,632	$2,685	$2,739	$2,793	$1,425	$0
22	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	EWR		$0	$0	$0	$101,294	$103,225	$98,341	$103,234	$106,295	$94,268	$100,608	$26,008	-$173	$1,136	$3,421	$6,778	$23,033	$29,170	$33,025	$39,923	$50,116
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$4,085	$8,150	$12,196	$16,209	$20,197	$24,135	$28,533	$31,960	$34,890	$38,147	$41,465	$44,959	$48,531	$52,179	$55,901	$56,615
25	DR	(O&M = 90% DR costs)	$0	$0	$1,412	$3,741	$7,149	$11,536	$18,536	$25,904	$26,516	$27,047	$27,588	$28,216	$28,702	$29,276	$29,862	$30,542	$31,068	$31,689	$32,323	$33,060
26	Storage	(100% CE ownership)	$0	$0	$0	$788	$1,503	$2,220	$2,911	$3,573	$4,205	$1,476	$2,109	$2,002	$1,862	$1,720	$1,584	$1,433	$1,273	$1,088	$159	-$786
27	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,077	$13,836	$14,417	$14,989	$15,674	$16,521	$17,283	$18,240	$19,172	$19,985
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**-$1,629**	**-$130**	**$1,412**	**$105,805**	**$109,893**	**$105,300**	**$121,919**	**$136,607**	**$127,769**	**$137,629**	**$91,097**	**$78,321**	**$83,537**	**$90,133**	**$97,996**	**$119,173**	**$130,063**	**$139,015**	**$148,903**	**$158,990**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31	PSCR		$1,917,438	$1,762,370	$1,738,099	$1,750,942	$1,690,559	$1,707,638	$1,766,648	$1,783,722	$1,777,618	$1,652,362	$1,619,079	$1,613,921	$1,655,342	$1,712,637	$1,791,279	$1,847,753	$1,906,868	$1,962,706	$2,004,013	$2,172,431

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	0	0	0	-347	-347	-347	-347	-347	0	0	0	0	0	0	0	0	0	0
2	Purchased Natural Gas Capacity		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	EWR		0	0	0	20	58	92	126	160	192	205	208	195	180	164	138	120	104	104	104	82
4	Solar		0	0	0	0	500	1,000	1,500	2,000	2,500	3,000	3,500	3,870	4,175	4,513	4,850	5,188	5,526	5,863	6,201	6,201
5	DR		0	0	23	60	107	160	231	295	297	297	297	297	297	297	297	297	297	297	297	297
6	Storage		0	0	0	24	47	71	94	118	141	225	252	254	255	256	257	259	260	262	240	217
7	Combustion Turbine		0	0	0	0	0	0	0	0	0	0	478	478	478	478	478	478	478	478	478	478
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**23**	**104**	**712**	**976**	**1,604**	**2,226**	**2,783**	**3,380**	**4,734**	**5,093**	**5,384**	**5,707**	**6,020**	**6,341**	**6,664**	**7,003**	**7,318**	**7,274**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		-$741	-$12,150	-$35,161	-$9,952	-$7,000	-$4,170	-$6,845	-$7,394	-$2,500	-$1,050	-$250	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$331,082	$327,419	$323,752	$319,743	$315,686	$311,251	$312,684	$232,348	$192,251	$213,188	$213,656	$214,695	$215,677	$216,599	$217,456	$0
15	DR	(Capital = 10% DR costs)	$0	$0	$157	$416	$794	$1,282	$2,060	$2,878	$2,946	$3,005	$3,065	$3,135	$3,189	$3,253	$3,318	$3,394	$3,452	$3,521	$3,591	$3,673
16	Storage	(100% CE ownership)	$0	$0	$0	$25,434	$23,848	$23,249	$22,634	$21,978	$21,301	$73,199	$23,613	$1,145	$1,169	$1,194	$1,218	$1,243	$1,268	$1,293	$0	$0
17	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$419,246	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**-$741**	**-$12,150**	**-$35,004**	**$15,898**	**$348,724**	**$347,780**	**$341,600**	**$337,205**	**$337,434**	**$386,405**	**$758,358**	**$236,628**	**$196,610**	**$217,634**	**$218,192**	**$219,332**	**$220,397**	**$221,412**	**$221,048**	**$3,673**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		-$1,629	-$130	$0	$231	-$1,950	-$4,999	-$14,958	-$15,373	-$17,416	-$15,636	-$6,217	$2,480	$2,530	$2,581	$2,632	$2,685	$2,739	$2,793	$1,425	$0
22	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	EWR		$0	$0	$0	$101,294	$103,225	$98,341	$103,234	$106,295	$94,268	$100,608	$26,008	-$173	$1,136	$3,421	$6,778	$23,033	$29,170	$33,025	$39,923	$50,116
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$4,085	$8,150	$12,196	$16,209	$20,197	$24,135	$28,533	$31,960	$34,890	$38,147	$41,465	$44,959	$48,531	$52,179	$55,901	$56,615
25	DR	(O&M = 90% DR costs)	$0	$0	$1,412	$3,741	$7,149	$11,536	$18,536	$25,904	$26,516	$27,047	$27,588	$28,216	$28,702	$29,276	$29,862	$30,542	$31,068	$31,689	$32,323	$33,060
26	Storage	(100% CE ownership)	$0	$0	$0	$788	$1,503	$2,220	$2,911	$3,573	$4,205	$1,476	$2,109	$2,002	$1,862	$1,720	$1,584	$1,433	$1,273	$1,088	$159	-$786
27	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,077	$13,836	$14,417	$14,989	$15,674	$16,521	$17,283	$18,240	$19,172	$19,983
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**-$1,629**	**-$130**	**$1,412**	**$106,055**	**$114,013**	**$115,248**	**$121,919**	**$136,608**	**$127,770**	**$137,630**	**$91,098**	**$78,321**	**$83,537**	**$90,133**	**$97,996**	**$119,173**	**$130,062**	**$139,015**	**$148,903**	**$158,988**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31	PSCR		$1,917,437	$1,762,352	$1,737,882	$1,750,728	$1,687,037	$1,706,751	$1,767,658	$1,783,722	$1,777,665	$1,652,243	$1,618,871	$1,614,149	$1,655,017	$1,712,663	$1,791,455	$1,847,753	$1,906,990	$1,962,621	$2,004,053	$2,171,898

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	0	0	0	0	0	-347	-347	-347	0	0	0	0	0	0	0	0	0	0
2	Purchased Natural Gas Capacity		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	EWR		0	0	0	20	58	92	126	160	192	205	208	195	180	164	138	120	104	104	104	82
4	Solar		0	0	0	0	500	1,000	1,500	2,000	2,500	3,000	3,500	3,870	4,175	4,513	4,850	5,188	5,526	5,863	6,201	6,201
5	DR		0	0	23	60	107	160	231	295	297	297	297	297	297	297	297	297	297	297	297	297
6	Storage		0	0	0	24	47	71	94	118	141	225	252	254	255	256	257	259	260	262	240	217
7	Combustion Turbine		0	0	0	0	0	0	0	0	0	0	478	478	478	478	478	478	478	478	478	478
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**23**	**104**	**712**	**1,323**	**1,951**	**2,226**	**2,783**	**3,380**	**4,734**	**5,093**	**5,384**	**5,707**	**6,020**	**6,341**	**6,664**	**7,003**	**7,318**	**7,274**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		$0	$0	$0	$0	-$3,000	-$1,250	-$3,139	-$7,144	-$2,500	-$1,050	-$250	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$331,082	$327,419	$323,752	$319,743	$315,686	$311,251	$312,684	$232,348	$192,251	$213,188	$213,656	$214,695	$215,677	$216,599	$217,456	$0
15	DR	(Capital = 10% DR costs)	$0	$0	$157	$416	$794	$1,282	$2,060	$2,878	$2,946	$3,005	$3,065	$3,135	$3,189	$3,253	$3,318	$3,394	$3,452	$3,521	$3,591	$3,673
16	Storage	(100% CE ownership)	$0	$0	$0	$25,434	$23,848	$23,249	$22,634	$21,978	$21,301	$73,199	$23,613	$1,145	$1,169	$1,194	$1,218	$1,243	$1,268	$1,293	$0	$0
17	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$419,246	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**$0**	**$0**	**$157**	**$25,850**	**$352,724**	**$350,700**	**$345,306**	**$337,455**	**$337,434**	**$386,405**	**$758,358**	**$236,628**	**$196,610**	**$217,634**	**$218,192**	**$219,332**	**$220,397**	**$221,412**	**$221,048**	**$3,673**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		-$750	$0	$0	$0	$0	$0	-$250	-$4,852	-$17,416	-$15,636	-$6,216	$2,481	$2,531	$2,581	$2,633	$2,686	$2,739	$2,794	$1,425	$0
22	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	EWR		$0	$0	$0	$101,294	$103,225	$98,341	$103,234	$106,295	$94,268	$100,608	$26,008	-$173	$1,136	$3,421	$6,778	$23,033	$29,170	$33,025	$39,923	$50,116
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$4,085	$8,150	$12,196	$16,209	$20,197	$24,135	$28,533	$31,960	$34,890	$38,147	$41,465	$44,959	$48,531	$52,179	$55,901	$56,615
25	DR	(O&M = 90% DR costs)	$0	$0	$1,412	$3,741	$7,149	$11,536	$18,536	$25,904	$26,516	$27,047	$27,588	$28,216	$28,702	$29,276	$29,862	$30,542	$31,068	$31,689	$32,323	$33,060
26	Storage	(100% CE ownership)	$0	$0	$0	$788	$1,503	$2,220	$2,911	$3,573	$4,205	$1,476	$2,109	$2,002	$1,862	$1,720	$1,584	$1,433	$1,273	$1,088	$159	-$786
27	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,077	$13,836	$14,417	$14,989	$15,674	$16,521	$17,283	$18,240	$19,170	$19,983
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**-$750**	**$0**	**$1,412**	**$105,823**	**$115,963**	**$120,248**	**$136,627**	**$147,128**	**$127,770**	**$137,630**	**$91,098**	**$78,322**	**$83,538**	**$90,133**	**$97,997**	**$119,174**	**$130,063**	**$139,016**	**$148,902**	**$158,988**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31	PSCR		$1,917,437	$1,762,864	$1,738,189	$1,750,737	$1,684,263	$1,701,073	$1,759,632	$1,783,178	$1,778,692	$1,652,450	$1,618,918	$1,613,929	$1,655,678	$1,712,549	$1,790,962	$1,847,682	$1,907,132	$1,962,688	$2,003,839	$2,171,921

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Retirement Analysis, PCA and Alternate Plan Cost Summary
CAMPBELL 1&2 RETIREMENT MAY 31, 2024

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	0	-607	-607	-607	-607	-607	-607	-607	0	0	0	0	0	0	0	0	0	0
2	Purchased Natural Gas Capacity		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	EWR		0	0	0	20	58	92	126	160	192	205	208	195	180	164	138	120	104	104	104	82
4	Solar		0	0	0	0	492	984	1,476	1,969	2,461	2,953	3,445	3,771	4,097	4,423	4,750	5,076	5,402	5,728	6,054	6,380
5	DR		0	0	23	60	107	160	231	237	237	237	237	237	237	237	237	237	237	237	237	237
6	Storage		0	0	0	59	67	74	81	89	96	104	111	113	114	115	117	118	119	121	43	37
7	Combustion Turbine		0	0	0	0	0	0	0	0	0	0	716	716	716	716	716	716	716	716	716	716
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**23**	**-468**	**116**	**704**	**1,307**	**1,847**	**2,379**	**2,891**	**4,717**	**5,032**	**5,344**	**5,656**	**5,957**	**6,267**	**6,578**	**6,906**	**7,155**	**7,453**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		$4,307	-$7,865	-$15,893	-$6,164	-$10,350	-$7,720	-$10,895	-$17,674	-$20,720	-$32,296	-$14,841	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$325,877	$322,272	$318,663	$314,717	$310,724	$306,358	$307,768	$204,821	$205,422	$205,951	$206,403	$207,407	$208,356	$209,246	$210,074	$210,838
15	DR	(Capital = 10% DR costs)	$0	$0	$157	$416	$794	$1,282	$2,060	$2,173	$2,211	$2,255	$2,300	$2,352	$2,393	$2,441	$2,490	$2,546	$2,590	$2,642	$2,695	$2,756
16	Storage	(100% CE ownership)	$0	$0	$0	$63,907	$7,458	$7,288	$7,112	$6,923	$6,727	$6,515	$6,581	$1,145	$1,169	$1,194	$1,218	$1,243	$1,268	$1,293	$0	$0
17	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$628,869	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**$4,307**	**-$7,865**	**-$15,736**	**$58,160**	**$323,779**	**$323,122**	**$316,940**	**$306,139**	**$298,941**	**$282,831**	**$930,676**	**$208,318**	**$208,984**	**$209,585**	**$210,111**	**$211,196**	**$212,214**	**$213,180**	**$212,769**	**$213,594**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		-$1,951	-$197	-$506	-$12,005	-$30,824	-$30,483	-$31,167	-$32,182	-$34,192	-$32,146	-$15,865	$395	$409	$421	$434	$448	$462	$476	$135	$0
22	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	EWR		$0	$0	$0	$101,294	$103,225	$98,341	$103,234	$106,295	$94,268	$100,608	$26,008	-$173	$1,136	$3,421	$6,778	$23,033	$29,170	$33,025	$39,923	$50,116
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$4,021	$8,022	$12,005	$15,954	$19,879	$23,756	$28,084	$31,144	$34,238	$37,391	$40,603	$43,986	$47,443	$50,975	$54,578	$58,253
25	DR	(O&M = 90% DR costs)	$0	$0	$1,412	$3,741	$7,149	$11,536	$18,536	$19,559	$19,895	$20,293	$20,699	$21,171	$21,535	$21,966	$22,406	$22,916	$23,311	$23,777	$24,252	$24,805
26	Storage	(100% CE ownership)	$0	$0	$0	-$1,931	-$1,918	-$1,926	-$1,945	-$1,967	-$2,002	-$2,062	-$2,031	-$2,182	-$2,362	-$2,544	-$2,719	-$2,910	-$3,109	-$3,332	$1,377	$1,191
27	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$19,615	$20,753	$21,625	$22,492	$23,535	$24,826	$25,923	$27,357	$28,761	$29,778
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**-$1,951**	**-$197**	**$906**	**$91,099**	**$81,653**	**$85,491**	**$100,663**	**$107,659**	**$97,848**	**$110,449**	**$76,511**	**$71,109**	**$76,582**	**$83,147**	**$91,037**	**$112,299**	**$123,200**	**$132,279**	**$149,027**	**$164,143**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31	PSCR		$1,916,919	$1,762,251	$1,738,210	$1,764,036	$1,702,648	$1,713,024	$1,771,862	$1,787,225	$1,778,013	$1,661,545	$1,626,348	$1,615,879	$1,657,667	$1,715,741	$1,793,771	$1,850,122	$1,909,600	$1,966,918	$2,011,282	$2,168,288

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP Retirement Analysis, PCA and Alternate Plan Cost Summary
CAMPBELL 1&2 RETIREMENT MAY 31, 2025

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	0	0	-607	-607	-607	-607	-607	-607	0	0	0	0	0	0	0	0	0	0
2	Purchased Natural Gas Capacity		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	EWR		0	0	0	20	58	92	126	160	192	205	208	195	180	164	138	120	104	104	104	82
4	Solar		0	0	0	0	500	1,000	1,500	2,000	2,500	3,000	3,500	3,870	4,175	4,513	4,850	5,188	5,525	5,863	6,200	6,200
5	DR		0	0	23	60	107	160	231	295	297	297	297	297	297	297	297	297	297	297	297	297
6	Storage		0	0	0	23	47	70	148	173	197	224	250	252	253	254	256	257	258	260	238	216
7	Combustion Turbine		0	0	0	0	0	0	0	0	0	0	478	478	478	478	478	478	478	478	478	478
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**23**	**103**	**104**	**715**	**1,398**	**2,021**	**2,579**	**3,118**	**4,732**	**5,091**	**5,382**	**5,705**	**6,018**	**6,339**	**6,662**	**7,001**	**7,316**	**7,272**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		-$941	-$8,860	-$24,250	$9,278	$4,491	-$7,720	-$10,895	-$17,674	-$20,720	-$32,296	-$14,841	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$331,082	$327,419	$323,752	$319,743	$315,686	$311,251	$312,684	$232,342	$192,195	$213,156	$213,624	$214,664	$215,646	$216,567	$217,424	$0
15	DR	(Capital = 10% DR costs)	$0	$0	$157	$416	$794	$1,282	$2,060	$2,878	$2,946	$3,005	$3,065	$3,135	$3,189	$3,253	$3,318	$3,394	$3,452	$3,521	$3,591	$3,673
16	Storage	(100% CE ownership)	$0	$0	$0	$25,186	$23,615	$23,022	$74,807	$22,899	$22,210	$23,219	$23,411	$1,145	$1,169	$1,194	$1,218	$1,243	$1,268	$1,293	$0	$0
17	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$419,246	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**-$941**	**-$8,860**	**-$24,093**	**$34,879**	**$359,983**	**$344,003**	**$389,723**	**$327,846**	**$320,123**	**$305,178**	**$743,564**	**$236,622**	**$196,553**	**$217,603**	**$218,160**	**$219,300**	**$220,365**	**$221,380**	**$221,015**	**$3,673**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		-$1,951	-$197	-$1	-$269	-$13,395	-$30,449	-$31,134	-$32,149	-$34,159	-$32,112	-$15,831	$429	$442	$455	$468	$481	$495	$509	$167	$0
22	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	EWR		$0	$0	$0	$101,294	$103,225	$98,341	$103,234	$106,295	$94,268	$100,608	$26,008	-$173	$1,136	$3,421	$6,778	$23,033	$29,170	$33,025	$39,923	$50,116
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$4,085	$8,150	$12,196	$16,209	$20,197	$24,135	$28,533	$31,960	$34,889	$38,146	$41,463	$44,957	$48,528	$52,176	$55,897	$56,611
25	DR	(O&M = 90% DR costs)	$0	$0	$1,412	$3,741	$7,149	$11,536	$18,536	$25,904	$26,516	$27,047	$27,588	$28,216	$28,702	$29,276	$29,862	$30,542	$31,068	$31,689	$32,323	$33,060
26	Storage	(100% CE ownership)	$0	$0	$0	$781	$1,489	$2,198	$114	$575	$1,001	$1,430	$2,055	$1,947	$1,807	$1,664	$1,528	$1,376	$1,216	$1,031	$108	-$830
27	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,077	$13,836	$14,417	$14,989	$15,674	$16,521	$17,283	$18,240	$19,170	$19,983
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**-$1,951**	**-$197**	**$1,411**	**$105,547**	**$102,552**	**$89,776**	**$102,946**	**$116,834**	**$107,822**	**$121,107**	**$81,429**	**$76,215**	**$81,392**	**$87,950**	**$95,774**	**$116,910**	**$127,759**	**$136,670**	**$147,589**	**$158,940**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31	PSCR		$1,916,898	$1,762,226	$1,738,172	$1,751,046	$1,698,564	$1,713,737	$1,771,925	$1,786,477	$1,776,060	$1,660,401	$1,624,945	$1,613,936	$1,655,241	$1,712,722	$1,791,376	$1,847,673	$1,907,006	$1,962,905	$2,004,115	$2,171,440

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	0	0	0	-607	-607	-607	-607	-607	0	0	0	0	0	0	0	0	0	0
2	Purchased Natural Gas Capacity		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	EWR		0	0	0	20	58	92	126	160	192	205	208	195	180	164	138	120	104	104	104	82
4	Solar		0	0	0	0	500	1,000	1,500	2,000	2,500	3,000	3,500	3,870	4,175	4,513	4,850	5,188	5,526	5,863	6,201	6,201
5	DR		0	0	23	60	107	160	231	295	297	297	297	297	297	297	297	297	297	297	297	297
6	Storage		0	0	0	23	46	69	149	175	200	226	253	254	255	256	258	259	261	262	240	219
7	Combustion Turbine		0	0	0	0	0	0	0	0	0	0	478	478	478	478	478	478	478	478	478	478
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**23**	**103**	**711**	**715**	**1,399**	**2,023**	**2,581**	**3,121**	**4,735**	**5,093**	**5,384**	**5,707**	**6,020**	**6,341**	**6,664**	**7,003**	**7,319**	**7,275**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		-$941	-$15,640	-$31,522	-$3,748	$19,933	$7,121	-$10,895	-$17,674	-$20,720	-$32,296	-$14,841	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$331,082	$327,419	$323,752	$319,743	$315,686	$311,251	$312,684	$232,354	$192,245	$213,188	$213,656	$214,695	$215,677	$216,599	$217,456	$0
15	DR	(Capital = 10% DR costs)	$0	$0	$157	$416	$794	$1,282	$2,060	$2,878	$2,946	$3,005	$3,065	$3,135	$3,189	$3,253	$3,318	$3,394	$3,452	$3,521	$3,591	$3,673
16	Storage	(100% CE ownership)	$0	$0	$0	$24,938	$23,383	$22,795	$76,506	$24,549	$22,002	$23,018	$23,208	$1,145	$1,169	$1,194	$1,218	$1,243	$1,268	$1,293	$0	$0
17	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$419,246	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**-$941**	**-$15,640**	**-$31,365**	**$21,606**	**$375,191**	**$358,618**	**$391,422**	**$329,495**	**$319,915**	**$304,978**	**$743,362**	**$236,634**	**$196,604**	**$217,634**	**$218,192**	**$219,332**	**$220,397**	**$221,412**	**$221,048**	**$3,673**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		-$1,951	-$197	-$1	$231	-$2,449	-$12,600	-$31,102	-$32,117	-$34,128	-$32,081	-$15,800	$460	$472	$486	$499	$512	$526	$539	$198	$0
22	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	EWR		$0	$0	$0	$101,294	$103,225	$98,341	$103,234	$106,295	$94,268	$100,608	$26,008	-$173	$1,136	$3,421	$6,778	$23,033	$29,170	$33,025	$39,923	$50,116
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$4,085	$8,150	$12,196	$16,209	$20,197	$24,135	$28,533	$31,960	$34,890	$38,147	$41,465	$44,959	$48,531	$52,179	$55,901	$56,615
25	DR	(O&M = 90% DR costs)	$0	$0	$1,412	$3,741	$7,149	$11,536	$18,536	$25,904	$26,516	$27,047	$27,588	$28,216	$28,702	$29,276	$29,862	$30,542	$31,068	$31,689	$32,323	$33,060
26	Storage	(100% CE ownership)	$0	$0	$0	$773	$1,474	$2,176	$142	$651	$1,068	$1,488	$2,107	$2,000	$1,860	$1,717	$1,582	$1,431	$1,270	$1,086	$171	-$760
27	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,077	$13,836	$14,417	$14,989	$15,674	$16,521	$17,283	$18,240	$19,170	$19,983
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**-$1,951**	**-$197**	**$1,411**	**$106,039**	**$113,484**	**$107,604**	**$103,007**	**$116,942**	**$107,920**	**$121,197**	**$81,513**	**$76,299**	**$81,477**	**$88,036**	**$95,860**	**$116,998**	**$127,848**	**$136,758**	**$147,686**	**$159,014**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31	PSCR		$1,916,916	$1,762,196	$1,738,113	$1,750,726	$1,685,181	$1,712,845	$1,774,159	$1,786,442	$1,776,156	$1,660,337	$1,624,923	$1,613,967	$1,655,478	$1,712,881	$1,791,605	$1,847,800	$1,906,819	$1,962,396	$2,004,030	$2,171,608

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	0	0	0	0	0	-607	-607	-607	0	0	0	0	0	0	0	0	0	0
2	Purchased Natural Gas Capacity		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	EWR		0	0	0	20	58	92	126	160	192	205	208	195	180	164	138	120	104	104	104	82
4	Solar		0	0	0	0	500	1,000	1,500	2,000	2,500	3,000	3,500	3,870	4,175	4,513	4,850	5,188	5,526	5,863	6,201	6,201
5	DR		0	0	23	60	107	160	231	295	297	297	297	297	297	297	297	297	297	297	297	297
6	Storage		0	0	0	24	47	71	94	118	199	225	252	254	255	256	257	259	260	262	240	217
7	Combustion Turbine		0	0	0	0	0	0	0	0	0	0	478	478	478	478	478	478	478	478	478	478
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**23**	**104**	**712**	**1,323**	**1,951**	**1,966**	**2,580**	**3,120**	**4,734**	**5,093**	**5,384**	**5,707**	**6,020**	**6,341**	**6,664**	**7,003**	**7,318**	**7,274**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		$0	$0	$0	$0	$3,780	$11,841	$22,294	-$2,833	-$20,720	-$32,296	-$14,841	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$331,082	$327,419	$323,752	$319,743	$315,686	$311,251	$312,684	$232,350	$192,249	$213,188	$213,656	$214,695	$215,677	$216,599	$217,456	$0
15	DR	(Capital = 10% DR costs)	$0	$0	$157	$416	$794	$1,282	$2,060	$2,878	$2,946	$3,005	$3,065	$3,135	$3,189	$3,253	$3,318	$3,394	$3,452	$3,521	$3,591	$3,673
16	Storage	(100% CE ownership)	$0	$0	$0	$25,434	$23,848	$23,249	$22,634	$21,978	$72,827	$23,419	$23,613	$1,145	$1,169	$1,194	$1,218	$1,243	$1,268	$1,293	$0	$0
17	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$419,246	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**$0**	**$0**	**$157**	**$25,850**	**$359,504**	**$363,791**	**$370,739**	**$341,766**	**$370,740**	**$305,379**	**$743,766**	**$236,630**	**$196,608**	**$217,634**	**$218,192**	**$219,332**	**$220,397**	**$221,412**	**$221,048**	**$3,673**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		-$751	$1	-$1	-$1	$1	$1	-$890	-$13,411	-$34,063	-$32,017	-$15,736	$524	$537	$550	$562	$577	$590	$604	$261	$0
22	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	EWR		$0	$0	$0	$101,294	$103,225	$98,341	$103,234	$106,295	$94,268	$100,608	$26,008	-$173	$1,136	$3,421	$6,778	$23,033	$29,170	$33,025	$39,923	$50,116
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$4,085	$8,150	$12,196	$16,209	$20,197	$24,135	$28,533	$31,960	$34,890	$38,147	$41,465	$44,959	$48,531	$52,179	$55,901	$56,615
25	DR	(O&M = 90% DR costs)	$0	$0	$1,412	$3,741	$7,149	$11,536	$18,536	$25,904	$26,516	$27,047	$27,588	$28,216	$28,702	$29,276	$29,862	$30,542	$31,068	$31,689	$32,323	$33,060
26	Storage	(100% CE ownership)	$0	$0	$0	$788	$1,503	$2,220	$2,911	$3,573	$1,042	$1,476	$2,109	$2,002	$1,862	$1,720	$1,584	$1,433	$1,273	$1,088	$159	-$786
27	Combustion Turbine		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$13,077	$13,836	$14,417	$14,989	$15,674	$16,521	$17,283	$18,240	$19,170	$19,983
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**-$751**	**$1**	**$1,411**	**$105,823**	**$115,963**	**$120,248**	**$135,987**	**$138,570**	**$107,959**	**$121,249**	**$81,578**	**$76,365**	**$81,544**	**$88,102**	**$95,926**	**$117,065**	**$127,914**	**$136,826**	**$147,737**	**$158,988**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31	PSCR		$1,917,437	$1,762,864	$1,738,189	$1,750,737	$1,684,263	$1,701,073	$1,759,632	$1,789,310	$1,778,737	$1,660,281	$1,624,822	$1,614,082	$1,655,354	$1,712,557	$1,791,498	$1,847,775	$1,906,803	$1,962,702	$2,004,056	$2,171,943

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Cumulative Capacity Changes (MW)																					
1	Retirement Units		0	0	0	0	-1,119	-1,119	-1,119	-1,119	-1,119	-1,119	0	0	0	0	0	0	0	0	0	0
2	Purchased Natural Gas Capacity		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	EWR		0	0	0	20	58	92	126	160	192	205	208	195	180	164	138	120	104	104	104	82
4	Solar		0	0	0	0	500	1,000	1,500	2,000	2,500	3,000	3,500	3,870	4,203	4,554	4,906	5,257	5,608	5,960	6,311	6,311
5	DR		0	0	23	60	107	160	231	295	297	297	297	297	297	297	297	297	297	297	297	297
6	Storage		0	0	0	23	98	124	150	176	200	227	253	254	255	257	258	259	261	262	241	147
7	Combustion Turbine		0	0	0	0	239	239	239	239	239	239	478	478	478	478	478	478	478	478	478	478
8	Wind		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	ZRC Purchase		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	**Total**		**0**	**0**	**23**	**103**	**-118**	**496**	**1,127**	**1,751**	**2,309**	**2,848**	**4,735**	**5,093**	**5,412**	**5,749**	**6,076**	**6,410**	**6,747**	**7,100**	**7,430**	**7,314**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Incremental Capital Investment (K$)																					
11	Retirement Units		$1,173	-$20,250	-$9,512	-$9,275	-$9,934	-$9,900	-$8,950	-$2,000	-$2,000	-$1,000	-$500	$0	$0	$0	$0	$0	$0	$0	$0	$0
12	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
13	EWR		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
14	Solar	(50% CE ownership)	$0	$0	$0	$0	$331,082	$327,419	$323,752	$319,743	$315,686	$311,251	$312,684	$232,342	$209,623	$221,896	$222,383	$223,465	$224,488	$225,446	$226,339	$0
15	DR	(Capital = 10% DR costs)	$0	$0	$157	$416	$794	$1,282	$2,060	$2,878	$2,946	$3,005	$3,065	$3,135	$3,189	$3,253	$3,318	$3,394	$3,452	$3,521	$3,591	$3,673
16	Storage	(100% CE ownership)	$0	$0	$0	$24,690	$75,946	$25,706	$25,043	$24,334	$21,794	$22,817	$23,006	$1,145	$1,169	$1,194	$1,218	$1,243	$1,268	$1,293	$0	$0
17	Combustion Turbine		$0	$0	$0	$0	$188,059	$0	$0	$0	$0	$0	$209,623	$0	$0	$0	$0	$0	$0	$0	$0	$0
18	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
19	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
20	**Total**		**$1,173**	**-$20,250**	**-$9,355**	**$15,830**	**$585,947**	**$344,507**	**$341,904**	**$344,955**	**$338,427**	**$336,073**	**$547,878**	**$236,622**	**$213,982**	**$226,343**	**$226,920**	**$228,102**	**$229,207**	**$230,260**	**$229,930**	**$3,673**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	O&M Expense (K$)																					
21	Retirement Units		$624	$491	$1,430	-$501	-$6,290	-$19,292	-$19,524	-$19,771	-$20,018	-$20,110	-$12,716	$0	$0	$0	$0	$0	$0	$0	$0	$0
22	Purchased Natural Gas Capacity		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
23	EWR		$0	$0	$0	$101,294	$103,225	$98,341	$103,234	$106,295	$94,268	$100,608	$26,008	-$173	$1,136	$3,421	$6,778	$23,033	$29,170	$33,025	$39,923	$50,116
24	Solar	(50% CE ownership)	$0	$0	$0	$0	$4,085	$8,150	$12,196	$16,209	$20,197	$24,135	$28,533	$31,960	$35,120	$38,497	$41,936	$45,557	$49,257	$53,038	$56,895	$57,622
25	DR	(O&M = 90% DR costs)	$0	$0	$1,412	$3,741	$7,149	$11,536	$18,536	$25,904	$26,516	$27,047	$27,588	$28,216	$28,702	$29,276	$29,862	$30,542	$31,068	$31,689	$32,323	$33,060
26	Storage	(100% CE ownership)	$0	$0	$0	$765	-$914	-$356	$170	$671	$1,081	$1,494	$2,107	$1,999	$1,859	$1,716	$1,581	$1,429	$1,269	$1,084	$177	$4,674
27	Combustion Turbine		$0	$0	$0	$0	$4,936	$5,256	$5,569	$5,903	$5,985	$6,250	$13,077	$13,836	$14,417	$14,992	$15,674	$16,554	$17,283	$18,237	$19,172	$19,966
28	Wind		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
29	ZRC Purchase		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
30	**Total**		**$624**	**$491**	**$2,842**	**$105,299**	**$112,192**	**$103,636**	**$120,181**	**$135,210**	**$128,029**	**$139,424**	**$84,595**	**$75,838**	**$81,234**	**$87,902**	**$95,832**	**$117,115**	**$128,047**	**$137,073**	**$148,491**	**$165,437**
			2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	PSCR (K$)																					
31	PSCR		$1,916,906	$1,763,229	$1,738,358	$1,751,071	$1,684,951	$1,702,191	$1,757,624	$1,776,052	$1,765,134	$1,639,469	$1,613,709	$1,613,912	$1,654,787	$1,711,965	$1,790,447	$1,847,167	$1,905,596	$1,962,593	$2,001,586	$2,170,521

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Total Fuel Cost Of Existing Owned Units: Business As Usual, AEO Gas, Retirement Base Case – Optimal Plan

Case No.: U-21090
Exhibit No.: A-20 (STW-17)

Witness: STWalz
Date: June 2021

Line No.	UNIT NAME	TYPE	(a) 2021	(b) 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030	(k) 2031	(l) 2032	(m) 2033	(n) 2034	(o) 2035	(p) 2036	(q) 2037	(r) 2038	(s) 2039	(t) 2040
1	CAMPBELL 1	COAL	$ 38,407	$ 38,845	$ 30,141	$ 37,458	$ 14,701	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,550	$ 40,153	$ 29,958	$ 38,430	$ 15,272	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,565	$ 126,999	$ 26,379	$ 109,159	$ 48,945	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ 28,997	$ 29,493	$ 1,100	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,965	$ 31,518	$ 1,093	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,646	$ 6,177	$ 1,102	$ 264	$ 814	$ 1,753	$ 1,685	$ 1,307	$ -	$ 257	$ -	$ 360	$ 810	$ -	$ -	$ -	$ -	$ 1,867	$ 4,142	$ 1,760
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,414	$ 6,150	$ -	$ 263	$ 816	$ 1,742	$ 1,633	$ 1,328	$ -	$ 255	$ -	$ 389	$ 805	$ -	$ -	$ -	$ -	$ 1,854	$ 4,115	$ 12,999
8	ZEELAND CC	NATURAL GAS	$ 77,735	$ 82,835	$ -	$ 90,618	$ 90,958	$ 100,707	$ 96,664	$ 90,859	$ 89,506	$ 83,049	$ 102,681	$ 71,225	$ 71,351	$ 102,542	$ 104,068	$ 87,393	$ 103,512	$ 99,589	$ 102,435	$ 153,484
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 63,329	$ 65,864	$ 61,761	$ 72,625	$ 68,487	$ 63,583	$ 67,010	$ 53,547	$ 64,760	$ 60,637	$ 61,198	$ 66,838	$ 63,637	$ 61,363	$ 73,697	$ 79,990	$ 87,155	$ 90,173	$ 85,973	$ 90,444
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 30,141	$ 59,741	$ 59,955	$ 65,125	$ 67,274	$ 65,723	$ 70,232	$ 68,021	$ 68,478	$ 68,405	$ 74,129	$ 75,859	$ 77,092	$ 82,372	$ 82,945	$ 88,418	$ 92,588	$ 44,282
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 29,958	$ 59,379	$ 59,642	$ 64,079	$ 66,917	$ 64,607	$ 70,005	$ 67,609	$ 68,063	$ 67,991	$ 80,327	$ 83,771	$ 80,501	$ 87,540	$ 82,442	$ 87,883	$ 92,988	$ 45,980
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 28,270	$ 57,996	$ 55,204	$ 59,133	$ 63,610	$ 64,138	$ 66,760	$ 68,144	$ 68,602	$ 68,530	$ 82,555	$ 80,087	$ 82,949	$ 82,210	$ 83,953	$ 92,650	$ 103,096	$ 48,375
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,100	$ 1,012	$ 492	$ 337	$ 406	$ 458	$ 191	$ 84	$ 198	$ 410	$ 504	$ 432	$ 217	$ 131	$ 360	$ 580	$ 790	$ -
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,093	$ 1,006	$ 489	$ 335	$ 404	$ 456	$ 190	$ 84	$ 197	$ 408	$ 501	$ 429	$ 215	$ 130	$ 358	$ 576	$ 785	$ -
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,102	$ 1,014	$ 481	$ 337	$ 407	$ 459	$ 192	$ 84	$ 198	$ 411	$ 505	$ 433	$ 217	$ 131	$ 361	$ 581	$ 791	$ -
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 2,947	$ 2,657	$ 2,903	$ 2,993	$ 2,210	$ 1,254	$ 1,413	$ 2,675	$ 3,396	$ 3,084	$ 1,148	$ 1,054	$ 2,445	$ 4,184	$ 5,409	$ -
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 10,508	$ 13,162	$ 16,930	$ 14,814	$ 13,824	$ 15,062	$ 14,455	$ 14,204	$ 13,997	$ 17,553	$ 11,228	$ 6,544	$ 18,820	$ 11,478	$ 31,113	$ 5,871
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 10,580	$ 11,865	$ 13,958	$ 13,314	$ 11,916	$ 8,369	$ 9,844	$ 12,261	$ 12,343	$ 13,798	$ 9,684	$ 5,266	$ 15,947	$ 10,948	$ 21,364	$ 3,743
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 10,075	$ 17,850	$ 18,284	$ 18,773	$ 19,154	$ 19,588	$ 20,023	$ 20,544	$ 20,947	$ 21,409	$ 21,871	$ 22,424	$ 22,849	$ 23,365	$ 23,881	$ 10,387
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ 29	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Total Fuel Cost Of Existing Owned Units: Business As Usual, AEO Gas, Retirement Base Case - Proposed Course Of Action

Line No.	UNIT NAME	TYPE	(a) 2021	(b) 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030	(k) 2031	(l) 2032	(m) 2033	(n) 2034	(o) 2035	(p) 2036	(q) 2037	(r) 2038	(s) 2039	(t) 2040
1	CAMPBELL 1	COAL	$ 38,407	$ 38,845	$ 39,976	$ 37,479	$ 14,701	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,550	$ 40,153	$ 41,291	$ 38,436	$ 15,272	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,565	$ 126,999	$ 131,307	$ 109,159	$ 48,945	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ 28,997	$ 29,493	$ 13,350	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,967	$ 31,518	$ 14,432	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,646	$ 6,177	$ -	$ 264	$ 814	$ 1,753	$ 1,643	$ 1,307	$ -	$ 257	$ -	$ 392	$ 1,318	$ 321	$ -	$ -	$ -	$ 1,867	$ 4,693	$ 12,235
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,414	$ 6,150	$ 34	$ 263	$ 816	$ 1,742	$ 1,633	$ 1,328	$ -	$ -	$ -	$ 389	$ 1,485	$ 319	$ -	$ -	$ -	$ 1,892	$ 4,665	$ 12,996
8	ZEELAND CC	NATURAL GAS	$ 77,735	$ 82,835	$ 85,035	$ 90,659	$ 90,987	$ 100,704	$ 96,682	$ 90,684	$ 89,499	$ 83,038	$ 102,723	$ 71,250	$ 71,351	$ 102,104	$ 104,074	$ 82,180	$ 103,512	$ 99,688	$ 127,060	$ 138,570
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 63,329	$ 65,864	$ 61,761	$ 72,625	$ 68,486	$ 63,594	$ 68,284	$ 53,539	$ 64,836	$ 59,043	$ 61,199	$ 61,219	$ 63,549	$ 64,054	$ 74,101	$ 79,918	$ 87,077	$ 90,277	$ 89,905	$ 90,371
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 30,141	$ 59,741	$ 59,955	$ 65,125	$ 67,260	$ 65,586	$ 70,282	$ 67,956	$ 68,478	$ 68,405	$ 74,895	$ 75,920	$ 77,186	$ 82,060	$ 82,945	$ 90,818	$ 93,555	$ 44,282
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 29,958	$ 59,379	$ 59,642	$ 64,079	$ 66,917	$ 64,471	$ 69,983	$ 67,609	$ 68,063	$ 67,991	$ 80,327	$ 83,873	$ 80,573	$ 87,540	$ 82,442	$ 87,883	$ 92,988	$ 45,980
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 28,270	$ 57,996	$ 55,204	$ 59,133	$ 63,610	$ 64,026	$ 66,853	$ 68,144	$ 68,602	$ 68,530	$ 82,555	$ 80,087	$ 82,980	$ 82,210	$ 84,007	$ 92,021	$ 102,767	$ 47,417
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,100	$ 1,012	$ 492	$ 337	$ 406	$ 458	$ 191	$ 84	$ 198	$ 413	$ 504	$ 524	$ 221	$ 131	$ 360	$ 580	$ 791	$ -
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,093	$ 1,006	$ 489	$ 335	$ 404	$ 456	$ 190	$ 84	$ 197	$ 408	$ 501	$ 521	$ 219	$ 130	$ 358	$ 576	$ 786	$ -
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,102	$ 1,014	$ 493	$ 337	$ 407	$ 459	$ 192	$ 84	$ 198	$ 414	$ 505	$ 525	$ 221	$ 131	$ 361	$ 581	$ 792	$ -
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 2,946	$ 2,644	$ 2,903	$ 2,992	$ 2,472	$ 1,257	$ 1,401	$ 2,697	$ 3,468	$ 3,193	$ 1,492	$ 1,396	$ 2,554	$ 4,222	$ 5,622	$ -
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 10,522	$ 14,903	$ 17,024	$ 15,003	$ 13,812	$ 15,072	$ 14,448	$ 14,297	$ 14,106	$ 17,815	$ 11,434	$ 6,596	$ 19,132	$ 11,712	$ 27,501	$ 5,943
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 10,595	$ 11,867	$ 13,971	$ 13,549	$ 11,924	$ 8,407	$ 9,780	$ 12,392	$ 12,459	$ 14,106	$ 9,883	$ 5,363	$ 16,295	$ 10,890	$ 23,722	$ 4,504
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 10,075	$ 17,850	$ 18,284	$ 18,773	$ 19,154	$ 19,588	$ 20,023	$ 20,544	$ 20,947	$ 21,409	$ 21,871	$ 22,424	$ 22,849	$ 23,365	$ 23,881	$ 10,387
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ 29	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Total Fuel Cost Of Existing Owned Units: Business As Usual, AEO Gas - Alternate Plan

Case No.: U-21090
Exhibit No.: A-20 (STW-17)
Page: 3 of 20
Witness: STWalz
Date: June 2021

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
Line No.	UNIT NAME	TYPE	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	CAMPBELL 1	COAL	$ 38,397	$ 39,061	$ 40,218	$ 37,905	$ 41,607	$ 42,595	$ 43,218	$ 40,502	$ 44,456	$ 44,798	$ 20,182	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,550	$ 40,157	$ 41,603	$ 39,000	$ 43,171	$ 43,816	$ 44,386	$ 45,089	$ 45,545	$ 45,770	$ 20,845	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,536	$ 127,021	$ 131,301	$ 109,159	$ 135,783	$ 138,572	$ 141,384	$ 144,631	$ 147,160	$ 150,146	$ 153,179	$ 155,770	$ 158,382	$ 131,816	$ 165,056	$ 167,035	$ 168,136	$ 167,889	$ 184,204	$ -
4	KARN 1	COAL	$ 28,993	$ 29,499	$ 13,347	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,967	$ 31,540	$ 14,415	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,664	$ 6,177	$ -	$ 526	$ 790	$ 1,745	$ 1,643	$ 1,307	$ -	$ 257	$ -	$ 392	$ 2,058	$ 321	$ -	$ -	$ -	$ 1,905	$ 4,693	$ 6,110
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,651	$ 6,150	$ -	$ 544	$ 786	$ 1,742	$ 1,633	$ 1,357	$ -	$ -	$ -	$ 389	$ 2,135	$ 319	$ -	$ -	$ -	$ 1,892	$ 4,665	$ 6,092
8	ZEELAND CC	NATURAL GAS	$ 77,735	$ 82,835	$ 85,035	$ 90,616	$ 89,760	$ 100,561	$ 65,933	$ 86,822	$ 82,990	$ 82,853	$ 95,447	$ 71,310	$ 71,345	$ 102,024	$ 96,790	$ 120,040	$ 103,512	$ 97,581	$ 127,061	$ 126,869
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 63,315	$ 59,738	$ 61,343	$ 69,871	$ 67,070	$ 60,580	$ 69,093	$ 52,544	$ 58,447	$ 55,507	$ 61,198	$ 62,917	$ 62,272	$ 63,807	$ 69,511	$ 80,020	$ 79,177	$ 89,713	$ 89,933	$ 93,198
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Total Fuel Cost Of Existing Owned Units: Business As Usual, CE Gas, Retirement Base Case – Optimal Plan

Case No.: U-21090
Exhibit No.: A-20 (STW-17)
Page: 4 of 20
Witness: STWalz
Date: June 2021

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
Line No.	UNIT NAME	TYPE	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	CAMPBELL 1	COAL	$ 38,236	$ 38,612	$ 39,653	$ 37,338	$ 14,467	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,496	$ 39,829	$ 40,854	$ 38,261	$ 14,921	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,233	$ 126,463	$ 130,798	$ 109,130	$ 48,391	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ 28,861	$ 29,327	$ 13,282	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,786	$ 31,280	$ 14,343	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,765	$ 4,173	$ 7,959	$ 6,360	$ 9,139	$ 2,930	$ 3,374	$ 6,361	$ 1,785	$ 606	$ 848	$ 3,003	$ 1,900	$ 948	$ -	$ -	$ 300	$ 345	$ 1,139	$ -
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,760	$ 4,146	$ 7,921	$ 6,569	$ 9,109	$ 2,910	$ 3,841	$ 7,212	$ 1,783	$ 602	$ 868	$ 2,984	$ 1,897	$ 951	$ -	$ -	$ 1,642	$ 343	$ 2,175	$ 255
8	ZEELAND CC	NATURAL GAS	$ 70,296	$ 73,504	$ 74,274	$ 75,903	$ 76,111	$ 82,195	$ 73,917	$ 94,429	$ 99,520	$ 84,969	$ 98,769	$ 103,387	$ 108,604	$ 112,166	$ 100,081	$ 117,880	$ 124,298	$ 84,651	$ 87,769	$ 133,374
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 52,033	$ 52,098	$ 56,435	$ 61,552	$ 60,292	$ 66,976	$ 72,702	$ 75,145	$ 77,141	$ 81,645	$ 82,130	$ 80,176	$ 82,595	$ 72,492	$ 85,579	$ 74,891	$ 81,549	$ 77,224	$ 87,298	$ 77,728
13	NEW COVERT GENERATING FACILITY (CC	NATURAL GAS	$ -	$ -	$ 25,879	$ 53,160	$ 55,335	$ 61,191	$ 64,964	$ 61,796	$ 65,209	$ 63,848	$ 63,112	$ 59,685	$ 65,662	$ 69,700	$ 75,305	$ 73,547	$ 70,792	$ 76,439	$ 81,525	$ 33,733
14	NEW COVERT GENERATING FACILITY (CC	NATURAL GAS	$ -	$ -	$ 25,723	$ 52,837	$ 54,999	$ 60,820	$ 64,570	$ 61,422	$ 64,814	$ 63,461	$ 61,915	$ 59,324	$ 70,171	$ 75,218	$ 75,801	$ 78,126	$ 70,501	$ 76,671	$ 81,102	$ 33,396
15	NEW COVERT GENERATING FACILITY (CC	NATURAL GAS	$ -	$ -	$ 24,308	$ 51,772	$ 51,900	$ 56,769	$ 61,000	$ 59,255	$ 62,200	$ 63,964	$ 63,652	$ 59,794	$ 70,831	$ 72,524	$ 79,496	$ 73,681	$ 75,311	$ 78,061	$ 88,759	$ 37,072
16	NEW COVERT GENERATING FACILITY (DB	NATURAL GAS	$ -	$ -	$ 1,823	$ 2,785	$ 2,666	$ 2,371	$ 1,988	$ 1,021	$ 1,318	$ 859	$ 1,310	$ 636	$ 685	$ 910	$ 840	$ 338	$ 617	$ 574	$ 617	$ -
17	NEW COVERT GENERATING FACILITY (DB	NATURAL GAS	$ -	$ -	$ 1,811	$ 2,612	$ 2,469	$ 2,354	$ 1,976	$ 1,015	$ 1,310	$ 854	$ 1,302	$ 632	$ 680	$ 905	$ 835	$ 336	$ 614	$ 571	$ 614	$ -
18	NEW COVERT GENERATING FACILITY (DB	NATURAL GAS	$ -	$ -	$ 1,826	$ 2,914	$ 2,677	$ 2,375	$ 1,992	$ 1,023	$ 1,325	$ 861	$ 1,312	$ 639	$ 686	$ 912	$ 842	$ 339	$ 619	$ 575	$ 619	$ -
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 15,145	$ 13,159	$ 10,485	$ 6,578	$ 5,237	$ 5,278	$ 7,610	$ 3,918	$ 4,077	$ 4,839	$ 4,900	$ 1,927	$ 3,298	$ 3,219	$ 3,745	$ -
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 16,199	$ 25,016	$ 27,432	$ 24,020	$ 19,893	$ 17,163	$ 17,387	$ 20,784	$ 17,574	$ 21,376	$ 16,026	$ 11,386	$ 19,314	$ 13,660	$ 23,291	$ 4,201
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 16,699	$ 24,236	$ 20,673	$ 21,462	$ 21,633	$ 12,286	$ 19,009	$ 19,250	$ 16,748	$ 18,892	$ 15,270	$ 7,977	$ 17,712	$ 12,522	$ 21,471	$ 3,507
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 10,075	$ 17,850	$ 18,284	$ 18,773	$ 19,154	$ 19,588	$ 20,023	$ 20,544	$ 20,947	$ 21,409	$ 21,871	$ 22,424	$ 22,849	$ 23,365	$ 23,881	$ 10,387
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 6	$ 6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATIOI	NATURAL GAS	$ -	$ -	$ -	$ -	$ 61	$ 66	$ 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Total Fuel Cost Of Existing Owned Units: Business As Usual, CE Gas, Retirement Base Case - Proposed Course Of Action

Line No.	UNIT NAME	TYPE	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
			2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
1	CAMPBELL 1	COAL	$ 38,236	$ 38,612	$ 39,653	$ 37,338	$ 14,467	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,496	$ 39,829	$ 40,854	$ 38,261	$ 14,921	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,233	$ 126,464	$ 130,798	$ 109,130	$ 48,391	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ 28,861	$ 29,327	$ 13,282	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,786	$ 31,280	$ 14,343	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,765	$ 4,173	$ 7,959	$ 6,360	$ 9,139	$ 2,930	$ 3,374	$ 6,356	$ 1,785	$ 606	$ 855	$ 3,003	$ 1,900	$ 948	$ -	$ -	$ 2,014	$ 345	$ 1,139	$ -
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,760	$ 4,146	$ 7,921	$ 6,569	$ 9,109	$ 2,910	$ 3,841	$ 7,212	$ 1,783	$ 602	$ 875	$ 2,984	$ 1,914	$ 951	$ -	$ -	$ 2,003	$ 343	$ 2,166	$ 255
8	ZEELAND CC	NATURAL GAS	$ 70,296	$ 73,504	$ 74,274	$ 75,903	$ 76,111	$ 82,195	$ 73,917	$ 94,429	$ 99,521	$ 84,969	$ 98,799	$ 103,405	$ 108,594	$ 112,331	$ 100,194	$ 118,022	$ 124,376	$ 84,725	$ 87,796	$ 133,343
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 686	$ -	$ -	$ 78,061	$ 75,311	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 52,033	$ 52,038	$ 56,436	$ 61,552	$ 60,271	$ 66,976	$ 72,701	$ 75,161	$ 76,717	$ 81,648	$ 82,122	$ 81,913	$ 82,605	$ 75,957	$ 85,666	$ 75,039	$ 81,310	$ 77,263	$ 79,725	$ 77,671
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 25,879	$ 53,160	$ 55,335	$ 61,191	$ 64,964	$ 61,744	$ 65,209	$ 63,848	$ 63,493	$ 62,482	$ 67,018	$ 69,700	$ 75,305	$ 73,547	$ 70,931	$ 76,439	$ 81,597	$ 33,733
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 25,723	$ 52,837	$ 54,999	$ 60,820	$ 64,570	$ 61,370	$ 64,814	$ 63,461	$ 61,861	$ 59,324	$ 70,171	$ 75,218	$ 75,801	$ 78,126	$ 70,501	$ 75,976	$ 81,102	$ 33,396
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 24,308	$ 51,772	$ 51,900	$ 56,769	$ 61,000	$ 59,255	$ 62,200	$ 63,964	$ 63,489	$ 62,235	$ 74,139	$ 72,524	$ 79,496	$ 74,390	$ 75,311	$ 78,061	$ 88,759	$ 36,997
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,823	$ 2,785	$ 2,666	$ 2,266	$ 1,988	$ 1,021	$ 1,318	$ 859	$ 1,310	$ 636	$ 685	$ 910	$ 956	$ 284	$ 621	$ 578	$ 682	$ -
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,811	$ 2,612	$ 2,426	$ 2,356	$ 1,976	$ 1,015	$ 1,310	$ 854	$ 1,302	$ 632	$ 680	$ 905	$ 950	$ 283	$ 617	$ 575	$ 678	$ -
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,826	$ 2,914	$ 2,677	$ 2,270	$ 1,992	$ 1,023	$ 1,206	$ 861	$ 1,312	$ 637	$ 686	$ 912	$ 958	$ 285	$ 622	$ 579	$ 676	$ -
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 15,120	$ 13,400	$ 10,485	$ 6,594	$ 5,236	$ 5,278	$ 7,602	$ 3,919	$ 4,760	$ 4,839	$ 5,286	$ 1,586	$ 3,359	$ 3,219	$ 3,819	$ -
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 16,199	$ 24,947	$ 27,430	$ 23,972	$ 19,918	$ 17,140	$ 17,399	$ 20,746	$ 17,567	$ 21,490	$ 16,085	$ 11,326	$ 19,495	$ 13,801	$ 23,619	$ 4,134
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 16,713	$ 24,215	$ 20,670	$ 21,453	$ 21,619	$ 12,285	$ 19,022	$ 19,274	$ 16,784	$ 20,413	$ 15,240	$ 5,932	$ 17,824	$ 9,783	$ 21,455	$ 3,468
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 10,075	$ 17,850	$ 18,284	$ 18,773	$ 19,154	$ 19,588	$ 20,023	$ 20,544	$ 20,947	$ 21,409	$ 21,871	$ 22,424	$ 22,849	$ 23,365	$ 23,881	$ 10,387
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 6	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 7	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 3	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ 3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ 61	$ 84	$ 14	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Total Fuel Cost Of Existing Owned Units: Business As Usual, CE Gas - Alternate Plan

Case No.: U-21090
Exhibit No.: A-20 (STW-17)

Witness: STWalz
Date: June 2021

Line No.	UNIT NAME	TYPE	(a) 2021	(b) 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030
1	CAMPBELL 1	COAL	38,259	38,850	39,957	37,795	40,729	41,666	42,396	39,506	43,735	43,954
2	CAMPBELL 2	COAL	32,519	39,854	41,275	38,866	42,081	42,755	43,544	44,088	44,799	44,988
3	CAMPBELL 3	COAL	124,221	126,494	130,816	109,131	134,376	138,030	141,337	143,998	146,920	149,922
4	KARN 1	COAL	28,876	29,325	13,281	-	-	-	-	-	-	-
5	KARN 2	COAL	30,783	31,286	14,343	-	-	-	-	-	-	-
6	ZEELAND 1A (CT)	NATURAL GAS	3,765	4,173	9,162	6,360	9,090	2,845	3,020	5,804	-	-
7	ZEELAND 1B (CT)	NATURAL GAS	3,760	4,146	9,123	6,917	9,062	2,832	3,009	5,845	-	-
8	ZEELAND CC	NATURAL GAS	70,296	73,504	74,274	75,903	76,111	82,195	73,917	94,347	88,355	83,689
9	KARN 3	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
10	KARN 3	OIL	-	-	-	-	-	-	-	-	-	-
11	KARN 4	OIL	-	-	-	-	-	-	-	-	-	-
12	JACKSON	NATURAL GAS	51,792	52,088	54,723	61,551	57,674	66,991	72,365	74,448	75,464	78,688
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	-	-	-	-	-	-	-	-	-	-

Line No.	UNIT NAME	TYPE	(k) 2031	(l) 2032	(m) 2033	(n) 2034	(o) 2035	(p) 2036	(q) 2037	(r) 2038	(s) 2039	(t) 2040
1	CAMPBELL 1	COAL	19,807	-	-	-	-	-	-	-	-	-
2	CAMPBELL 2	COAL	20,415	-	-	-	-	-	-	-	-	-
3	CAMPBELL 3	COAL	152,939	155,685	158,382	131,820	164,838	167,035	168,136	167,751	184,204	-
4	KARN 1	COAL	-	-	-	-	-	-	-	-	-	-
5	KARN 2	COAL	-	-	-	-	-	-	-	-	-	-
6	ZEELAND 1A (CT)	NATURAL GAS	-	898	949	-	-	-	-	345	1,139	-
7	ZEELAND 1B (CT)	NATURAL GAS	-	892	979	-	-	-	-	343	1,132	720
8	ZEELAND CC	NATURAL GAS	98,747	103,362	108,652	108,045	100,125	117,854	124,378	76,537	81,039	100,579
9	KARN 3	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
10	KARN 3	OIL	-	-	-	-	-	-	-	-	-	-
11	KARN 4	OIL	-	-	-	-	-	-	-	-	-	-
12	JACKSON	NATURAL GAS	81,538	76,795	76,708	71,264	83,051	74,511	74,500	77,432	78,150	78,673
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	-	-	-	-	-	-	-	-	-	-
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	-	-	-	-	-	-	-	-	-	-

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Total Fuel Cost Of Existing Owned Units: Emerging Technology, AEO Gas, Retirement Base Case – Optimal Plan

Case No.: U-21090
Exhibit No.: A-20 (STW-17)

Witness: STWalz
Date: June 2021

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
Line No.	UNIT NAME	TYPE	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	CAMPBELL 1	COAL	$ 38,395	$ 38,839	$ 39,981	$ 37,373	$ 14,685	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,550	$ 40,147	$ 41,291	$ 38,296	$ 15,217	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,509	$ 126,999	$ 131,307	$ 109,077	$ 48,945	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ 28,990	$ 29,495	$ 13,350	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,961	$ 31,519	$ 14,427	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,646	$ 6,177	$ -	$ 222	$ 821	$ 1,675	$ 2,719	$ 2,062	$ 1,432	$ 1,979	$ 1,596	$ 2,619	$ 4,107	$ 5,850	$ 6,675	$ 7,269	$ 8,655	$ 10,857	$ 11,513	$ 5,505
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,414	$ 6,150	$ -	$ 221	$ 816	$ 1,699	$ 2,735	$ 2,051	$ 1,429	$ 1,691	$ 1,591	$ 2,668	$ 4,124	$ 6,308	$ 6,769	$ 7,298	$ 8,681	$ 10,826	$ 11,678	$ 5,497
8	ZEELAND CC	NATURAL GAS	$ 77,735	$ 82,832	$ 83,959	$ 80,480	$ 91,102	$ 100,899	$ 86,957	$ 87,493	$ 93,255	$ 91,001	$ 107,578	$ 115,168	$ 114,740	$ 124,287	$ 128,406	$ 137,148	$ 139,022	$ 139,325	$ 150,916	$ 141,253
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 63,329	$ 65,864	$ 61,289	$ 69,547	$ 68,874	$ 66,376	$ 71,491	$ 70,885	$ 75,358	$ 76,566	$ 73,045	$ 91,005	$ 103,057	$ 101,815	$ 105,544	$ 112,529	$ 120,238	$ 118,283	$ 124,636	$ 101,691
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 30,141	$ 58,607	$ 61,215	$ 66,832	$ 72,233	$ 73,101	$ 75,252	$ 74,515	$ 73,859	$ 78,905	$ 82,323	$ 83,712	$ 86,465	$ 89,529	$ 93,339	$ 100,081	$ 97,638	$ 34,933
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 29,958	$ 57,987	$ 61,593	$ 66,427	$ 74,000	$ 69,724	$ 74,817	$ 72,651	$ 73,412	$ 78,467	$ 87,875	$ 87,667	$ 89,027	$ 94,772	$ 92,925	$ 99,022	$ 94,327	$ 35,813
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 28,270	$ 56,818	$ 56,978	$ 61,515	$ 69,781	$ 70,120	$ 72,731	$ 74,752	$ 74,015	$ 79,853	$ 88,774	$ 86,946	$ 91,576	$ 93,297	$ 95,038	$ 101,326	$ 106,480	$ 42,239
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,100	$ 199	$ 971	$ 378	$ 506	$ 448	$ 532	$ 375	$ 388	$ 508	$ 891	$ 1,051	$ 1,421	$ 1,080	$ 1,308	$ 1,298	$ 1,789	$ 261
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,093	$ 198	$ 911	$ 375	$ 453	$ 446	$ 529	$ 372	$ 386	$ 505	$ 885	$ 1,132	$ 1,412	$ 1,074	$ 1,494	$ 1,286	$ 1,862	$ 259
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,102	$ 199	$ 957	$ 378	$ 507	$ 449	$ 533	$ 375	$ 389	$ 509	$ 826	$ 1,053	$ 1,423	$ 1,082	$ 1,311	$ 1,339	$ 1,877	$ 261
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 4,333	$ 2,497	$ 2,893	$ 4,064	$ 2,886	$ 3,878	$ 5,144	$ 3,380	$ 5,615	$ 7,532	$ 10,605	$ 12,307	$ 14,362	$ 15,244	$ 13,318	$ 2,316
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 15,001	$ 14,253	$ 18,089	$ 15,056	$ 17,235	$ 18,475	$ 17,474	$ 20,759	$ 19,726	$ 25,224	$ 24,426	$ 21,369	$ 32,620	$ 32,004	$ 35,335	$ 6,618
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 14,889	$ 11,921	$ 12,683	$ 12,373	$ 12,030	$ 8,069	$ 15,882	$ 16,689	$ 16,803	$ 20,040	$ 19,225	$ 15,602	$ 29,870	$ 26,080	$ 33,834	$ 6,060
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 10,075	$ 17,850	$ 18,284	$ 18,773	$ 19,154	$ 19,554	$ 20,023	$ 20,544	$ 20,905	$ 21,237	$ 21,613	$ 22,228	$ 22,403	$ 22,938	$ 23,463	$ 9,936
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10	$ 41	$ 63	$ 65	$ 55	$ 56	$ 198	$ 204	$ 62	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10	$ 42	$ 65	$ 67	$ 57	$ 57	$ 204	$ 210	$ 63	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10	$ 41	$ 64	$ 66	$ 56	$ 57	$ 201	$ 207	$ 62	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10	$ 43	$ 66	$ 69	$ 58	$ 59	$ 210	$ 216	$ 65	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ 43	$ 48	$ 101	$ 18	$ -	$ 18	$ 55	$ 208	$ 315	$ 404	$ 369	$ 335	$ 616	$ 742	$ 208	$ -

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Total Fuel Cost Of Existing Owned Units: Emerging Technology, AEO Gas, Retirement Base Case - Proposed Course Of Action

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
Line No.	UNIT NAME	TYPE	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	CAMPBELL 1	COAL	$ 38,393	$ 38,839	$ 39,976	$ 37,372	$ 14,685	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,550	$ 40,147	$ 41,291	$ 38,294	$ 15,217	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,509	$ 126,999	$ 131,307	$ 109,077	$ 48,945	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ 28,990	$ 29,495	$ 13,350	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,963	$ 31,519	$ 14,427	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,646	$ 6,177	$ 5,307	$ 222	$ 821	$ 1,701	$ 2,749	$ 2,035	$ 1,432	$ 1,386	$ 1,534	$ 1,945	$ 3,307	$ 4,662	$ 6,071	$ 6,529	$ 8,239	$ 9,411	$ 9,677	$ 5,505
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,414	$ 6,150	$ 5,286	$ 221	$ 816	$ 1,706	$ 2,735	$ 2,024	$ 1,430	$ 1,392	$ 1,529	$ 1,709	$ 3,293	$ 4,745	$ 6,626	$ 6,547	$ 8,573	$ 10,238	$ 9,844	$ 5,497
8	ZEELAND CC	NATURAL GAS	$ 77,735	$ 82,832	$ 83,959	$ 80,480	$ 91,102	$ 100,888	$ 86,920	$ 87,493	$ 93,243	$ 87,482	$ 107,084	$ 88,625	$ 112,293	$ 122,091	$ 121,478	$ 136,573	$ 138,555	$ 138,571	$ 149,996	$ 118,464
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 63,329	$ 65,864	$ 61,556	$ 69,547	$ 68,871	$ 66,700	$ 71,506	$ 70,311	$ 75,205	$ 75,563	$ 73,029	$ 90,907	$ 102,912	$ 101,607	$ 105,295	$ 112,044	$ 117,337	$ 117,580	$ 124,546	$ 101,510
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 30,141	$ 58,607	$ 61,215	$ 66,832	$ 72,292	$ 73,087	$ 75,254	$ 72,002	$ 73,697	$ 77,889	$ 80,180	$ 80,645	$ 86,247	$ 86,623	$ 92,767	$ 99,533	$ 96,098	$ 31,625
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 29,958	$ 57,987	$ 61,593	$ 66,427	$ 73,975	$ 69,724	$ 74,824	$ 71,566	$ 73,261	$ 78,090	$ 85,497	$ 87,410	$ 88,844	$ 93,146	$ 91,538	$ 98,970	$ 95,763	$ 31,467
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 28,270	$ 56,818	$ 56,978	$ 61,515	$ 69,773	$ 70,120	$ 71,273	$ 73,659	$ 73,848	$ 81,689	$ 88,286	$ 86,530	$ 91,254	$ 91,468	$ 94,936	$ 101,183	$ 104,352	$ 38,564
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,093	$ 199	$ 917	$ 380	$ 506	$ 448	$ 532	$ 244	$ 253	$ 467	$ 714	$ 956	$ 1,258	$ 763	$ 1,174	$ 1,206	$ 1,599	$ 261
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,087	$ 198	$ 912	$ 378	$ 453	$ 446	$ 529	$ 243	$ 252	$ 464	$ 702	$ 954	$ 1,133	$ 759	$ 1,131	$ 1,162	$ 1,674	$ 259
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,095	$ 199	$ 919	$ 381	$ 507	$ 449	$ 533	$ 245	$ 254	$ 468	$ 649	$ 881	$ 1,260	$ 765	$ 1,176	$ 1,208	$ 1,687	$ 261
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 4,333	$ 2,510	$ 2,898	$ 4,078	$ 2,886	$ 2,999	$ 3,430	$ 2,531	$ 5,312	$ 7,360	$ 10,497	$ 11,800	$ 14,203	$ 13,214	$ 13,299	$ 1,838
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 15,013	$ 14,204	$ 18,005	$ 15,077	$ 17,309	$ 18,259	$ 15,660	$ 18,523	$ 19,095	$ 23,125	$ 23,910	$ 21,345	$ 32,344	$ 31,693	$ 35,706	$ 7,481
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 14,878	$ 11,906	$ 12,685	$ 12,375	$ 12,001	$ 7,747	$ 12,781	$ 16,513	$ 16,311	$ 19,799	$ 18,828	$ 15,167	$ 29,173	$ 25,776	$ 32,812	$ 6,085
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 10,075	$ 17,850	$ 18,284	$ 18,773	$ 19,154	$ 19,525	$ 19,999	$ 20,533	$ 20,821	$ 21,125	$ 21,570	$ 22,118	$ 22,262	$ 22,866	$ 23,381	$ 9,846
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10	$ 20	$ 42	$ 54	$ 44	$ 33	$ 174	$ 169	$ 24	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4	$ 21	$ 43	$ 55	$ 45	$ 34	$ 179	$ 172	$ 25	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 21	$ 42	$ 54	$ 45	$ 34	$ 177	$ 170	$ 15	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 21	$ 44	$ 57	$ 47	$ 35	$ 184	$ 177	$ 13	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ 43	$ 48	$ 101	$ 18	$ -	$ -	$ 37	$ 171	$ 275	$ 363	$ 328	$ 288	$ 616	$ 663	$ 231	$ -

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Total Fuel Cost Of Existing Owned Units: Emerging Technology, AEO Gas - Alternate Plan

Case No.: U-21090
Exhibit No.: A-20 (STW-17)

Witness: STWalz
Date: June 2021

Line No.	UNIT NAME	TYPE	(a) 2021	(b) 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030	(k) 2031	(l) 2032	(m) 2033	(n) 2034	(o) 2035	(p) 2036	(q) 2037	(r) 2038	(s) 2039	(t) 2040
1	CAMPBELL 1	COAL	$ 38,392	$ 39,061	$ 40,229	$ 37,807	$ 41,603	$ 42,601	$ 43,218	$ 40,410	$ 44,362	$ 44,675	$ 20,138	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,550	$ 40,157	$ 41,599	$ 38,887	$ 43,126	$ 43,816	$ 44,386	$ 44,996	$ 45,439	$ 45,593	$ 20,813	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,502	$ 127,021	$ 131,301	$ 109,139	$ 135,783	$ 138,572	$ 141,384	$ 144,631	$ 147,062	$ 149,783	$ 153,179	$ 155,770	$ 158,314	$ 131,619	$ 163,775	$ 166,342	$ 166,443	$ 165,899	$ 182,111	$ -
4	KARN 1	COAL	$ 28,988	$ 29,502	$ 13,346	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,960	$ 31,520	$ 14,427	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,664	$ 6,177	$ -	$ 243	$ 797	$ 1,675	$ 2,715	$ 1,849	$ 1,419	$ 1,680	$ 1,596	$ 2,682	$ 4,227	$ 6,327	$ 7,568	$ 7,505	$ 9,225	$ 12,085	$ 12,004	$ 5,571
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,651	$ 6,150	$ -	$ 242	$ 793	$ 1,706	$ 2,730	$ 1,875	$ 1,417	$ 1,392	$ 1,591	$ 2,699	$ 4,279	$ 7,343	$ 7,350	$ 7,559	$ 10,652	$ 11,333	$ 12,292	$ 5,750
8	ZEELAND CC	NATURAL GAS	$ 77,735	$ 82,835	$ 83,959	$ 80,480	$ 89,742	$ 100,880	$ 86,852	$ 87,396	$ 90,572	$ 86,296	$ 107,375	$ 88,876	$ 112,441	$ 130,318	$ 125,097	$ 137,043	$ 142,535	$ 139,880	$ 151,082	$ 141,576
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 63,316	$ 59,895	$ 60,612	$ 69,502	$ 67,956	$ 65,819	$ 69,796	$ 64,320	$ 71,114	$ 75,573	$ 74,093	$ 93,442	$ 102,673	$ 103,661	$ 105,920	$ 113,735	$ 119,108	$ 118,411	$ 125,146	$ 103,321
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

Line			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
No.	**UNIT NAME**	**TYPE**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
1	CAMPBELL 1	COAL	$ 38,245	$ 38,618	$ 39,617	$ 37,336	$ 14,611	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,487	$ 39,820	$ 40,863	$ 38,233	$ 15,094	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,215	$ 126,426	$ 130,813	$ 109,074	$ 48,803	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ 28,861	$ 29,328	$ 13,286	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,783	$ 31,272	$ 14,342	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,765	$ 4,165	$ 11,432	$ 8,980	$ 13,034	$ 5,313	$ 5,614	$ 10,066	$ 6,792	$ 8,097	$ 5,182	$ 5,525	$ 7,671	$ 10,546	$ 10,210	$ 7,366	$ 6,708	$ 10,173	$ 20,146	$ 21,326
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,760	$ 4,146	$ 11,404	$ 8,962	$ 12,906	$ 5,841	$ 6,601	$ 10,065	$ 7,091	$ 8,143	$ 6,079	$ 5,548	$ 7,655	$ 10,933	$ 10,171	$ 8,045	$ 7,113	$ 10,165	$ 20,840	$ 23,688
8	ZEELAND CC	NATURAL GAS	$ 70,294	$ 73,504	$ 74,274	$ 75,903	$ 76,111	$ 84,330	$ 73,917	$ 96,924	$ 101,098	$ 85,122	$ 98,848	$ 110,537	$ 117,851	$ 123,960	$ 127,537	$ 119,652	$ 125,086	$ 124,321	$ 145,798	$ 139,598
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 52,186	$ 52,320	$ 56,431	$ 61,543	$ 60,603	$ 67,150	$ 73,018	$ 76,456	$ 79,993	$ 83,316	$ 84,617	$ 87,762	$ 92,043	$ 94,692	$ 100,109	$ 102,818	$ 106,779	$ 110,642	$ 114,562	$ 117,376
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 25,879	$ 51,785	$ 55,369	$ 61,191	$ 64,964	$ 61,413	$ 67,162	$ 66,673	$ 69,709	$ 75,162	$ 70,858	$ 81,247	$ 81,810	$ 84,837	$ 90,971	$ 92,782	$ 97,942	$ -
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 25,723	$ 49,036	$ 51,057	$ 60,227	$ 63,929	$ 63,034	$ 67,068	$ 66,309	$ 63,720	$ 74,762	$ 80,825	$ 84,240	$ 81,952	$ 89,415	$ 79,244	$ 82,576	$ 97,348	$ -
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 24,308	$ 51,772	$ 47,875	$ 56,769	$ 61,000	$ 63,659	$ 61,344	$ 67,105	$ 66,906	$ 75,407	$ 77,420	$ 78,599	$ 85,949	$ 85,060	$ 91,136	$ 95,732	$ 105,135	$ -
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,822	$ 2,349	$ 2,651	$ 2,513	$ 2,366	$ 1,997	$ 1,788	$ 2,260	$ 2,045	$ 1,598	$ 1,464	$ 1,977	$ 2,155	$ 2,463	$ 2,000	$ 2,665	$ 3,361	$ -
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,811	$ 2,269	$ 2,524	$ 2,498	$ 2,352	$ 2,017	$ 1,777	$ 2,246	$ 2,065	$ 1,588	$ 1,417	$ 1,965	$ 2,142	$ 2,452	$ 1,988	$ 2,649	$ 3,554	$ -
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,825	$ 2,466	$ 2,721	$ 2,517	$ 2,370	$ 1,833	$ 1,677	$ 2,264	$ 1,876	$ 1,335	$ 1,242	$ 1,947	$ 2,159	$ 2,471	$ 1,982	$ 2,670	$ 3,582	$ -
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 17,302	$ 24,957	$ 27,871	$ 22,592	$ 23,369	$ 25,536	$ 21,923	$ 21,497	$ 26,095	$ 25,993	$ 25,166	$ 29,117	$ 26,871	$ 36,254	$ 38,637	$ -
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 14,473	$ 31,961	$ 34,194	$ 34,905	$ 34,032	$ 35,081	$ 37,651	$ 41,240	$ 39,001	$ 43,981	$ 44,585	$ 43,191	$ 50,206	$ 49,834	$ 55,837	$ -
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 14,716	$ 26,076	$ 30,229	$ 31,564	$ 33,412	$ 31,679	$ 33,858	$ 35,241	$ 39,163	$ 39,656	$ 41,318	$ 44,449	$ 47,910	$ 50,876	$ 56,955	$ -
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 8,760	$ 15,521	$ 15,899	$ 16,324	$ 16,655	$ 17,033	$ 17,411	$ 17,864	$ 18,215	$ 18,616	$ 19,018	$ 19,499	$ 19,868	$ 20,317	$ 20,766	$ -
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22	$ 56	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23	$ 58	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ 7	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22	$ 57	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ 8	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 23	$ 59	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ 24	$ 106	$ 98	$ 88	$ -	$ 31	$ 32	$ 150	$ 87	$ 126	$ -	$ 56	$ 118	$ 205	$ 253	$ -

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Total Fuel Cost Of Existing Owned Units: Emerging Technology, CE Gas, Retirement Base Case - Proposed Course Of Action

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
Line No.	**UNIT NAME**	**TYPE**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
1	CAMPBELL 1	COAL	$ 38,245	$ 38,617	$ 39,623	$ 37,336	$ 14,611	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,487	$ 39,824	$ 40,864	$ 38,234	$ 15,094	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,215	$ 126,426	$ 130,813	$ 109,074	$ 48,803	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ 28,861	$ 29,325	$ 13,286	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,783	$ 31,263	$ 14,342	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,794	$ 4,165	$ 11,462	$ 8,980	$ 12,837	$ 5,347	$ 5,614	$ 10,105	$ 6,320	$ 8,102	$ 4,624	$ 5,565	$ 7,760	$ 10,861	$ 10,180	$ 8,071	$ 7,171	$ 10,206	$ 19,624	$ 23,459
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,760	$ 4,146	$ 11,404	$ 8,991	$ 12,906	$ 5,915	$ 6,635	$ 10,107	$ 7,094	$ 8,199	$ 6,034	$ 5,605	$ 7,716	$ 10,965	$ 10,572	$ 8,423	$ 7,176	$ 10,165	$ 20,148	$ 23,408
8	ZEELAND CC	NATURAL GAS	$ 70,293	$ 73,504	$ 74,274	$ 75,903	$ 76,111	$ 84,330	$ 73,917	$ 96,970	$ 101,084	$ 85,122	$ 98,848	$ 110,617	$ 117,851	$ 123,960	$ 127,537	$ 119,652	$ 125,086	$ 124,321	$ 145,798	$ 139,598
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 52,166	$ 52,505	$ 56,421	$ 61,562	$ 60,604	$ 66,792	$ 73,003	$ 76,445	$ 79,519	$ 83,199	$ 84,251	$ 88,625	$ 91,618	$ 94,632	$ 100,039	$ 102,815	$ 106,739	$ 110,944	$ 114,574	$ 117,387
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 25,879	$ 51,785	$ 55,369	$ 61,191	$ 64,964	$ 61,413	$ 67,162	$ 66,714	$ 69,694	$ 75,322	$ 70,858	$ 80,180	$ 81,810	$ 84,837	$ 90,971	$ 92,782	$ 97,942	$ -
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 25,723	$ 49,036	$ 51,057	$ 60,227	$ 63,929	$ 62,462	$ 66,755	$ 66,309	$ 63,674	$ 74,889	$ 80,825	$ 84,240	$ 82,016	$ 89,415	$ 79,244	$ 82,576	$ 97,348	$ -
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 24,308	$ 51,772	$ 51,900	$ 56,769	$ 61,000	$ 63,659	$ 61,344	$ 66,835	$ 66,860	$ 75,524	$ 77,420	$ 78,599	$ 85,949	$ 85,060	$ 91,136	$ 95,732	$ 105,135	$ -
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,822	$ 2,349	$ 2,651	$ 2,513	$ 2,351	$ 1,996	$ 1,743	$ 2,206	$ 1,883	$ 1,792	$ 1,464	$ 1,977	$ 2,161	$ 2,468	$ 2,113	$ 2,543	$ 3,362	$ -
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,811	$ 2,269	$ 2,524	$ 2,495	$ 2,352	$ 2,016	$ 1,732	$ 1,957	$ 1,871	$ 1,808	$ 1,418	$ 1,965	$ 2,148	$ 2,594	$ 2,100	$ 2,496	$ 3,555	$ -
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,825	$ 2,466	$ 2,721	$ 2,549	$ 2,370	$ 1,832	$ 1,632	$ 2,216	$ 1,713	$ 1,710	$ 1,242	$ 1,947	$ 2,165	$ 2,615	$ 2,095	$ 2,548	$ 3,583	$ -
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 17,302	$ 25,146	$ 27,914	$ 22,591	$ 23,333	$ 25,561	$ 21,942	$ 21,507	$ 26,230	$ 26,717	$ 25,199	$ 29,154	$ 27,338	$ 36,193	$ 39,009	$ -
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 14,473	$ 32,005	$ 34,258	$ 34,907	$ 31,719	$ 35,114	$ 37,601	$ 41,356	$ 38,940	$ 44,134	$ 44,542	$ 43,191	$ 49,963	$ 49,983	$ 55,829	$ -
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 14,716	$ 26,076	$ 30,289	$ 31,564	$ 33,468	$ 31,762	$ 33,900	$ 35,256	$ 39,387	$ 39,779	$ 41,493	$ 44,541	$ 48,046	$ 51,198	$ 57,150	$ -
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 8,760	$ 15,521	$ 15,899	$ 16,324	$ 16,655	$ 17,033	$ 17,411	$ 17,864	$ 18,215	$ 18,616	$ 19,018	$ 19,499	$ 19,868	$ 20,317	$ 20,766	$ -
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ 14.29	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10.76	$ 44.75	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ 14.70	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11.07	$ 46.04	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ 14.49	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10.91	$ 45.38	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ 15.11	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11.38	$ 47.31	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ 24.24	$ 105.68	$ 97.90	$ 87.80	$ -	$ 30.88	$ 31.88	$ 150.18	$ 56.27	$ 125.85	$ -	$ 56.33	$ 117.93	$ 163.45	$ 210.25	$ -

Note:

1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Total Fuel Cost Of Existing Owned Units: Emerging Technology - Alternate Plan

Case No.: U-21090
Exhibit No.: A-20 (STW-17)

Witness: STWalz
Date: June 2021

Line No.	UNIT NAME	TYPE	(a) 2021	(b) 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030
1	CAMPBELL 1	COAL	$ 38,250	$ 38,846	$ 40,030	$ 37,916	$ 41,593	$ 42,524	$ 43,096	$ 40,220	$ 44,273	$ 44,662
2	CAMPBELL 2	COAL	$ 32,491	$ 39,824	$ 41,327	$ 38,969	$ 43,049	$ 43,729	$ 44,322	$ 44,764	$ 45,372	$ 45,622
3	CAMPBELL 3	COAL	$ 124,215	$ 126,426	$ 130,841	$ 109,159	$ 135,779	$ 138,572	$ 141,384	$ 144,443	$ 147,013	$ 149,835
4	KARN 1	COAL	$ 28,863	$ 29,324	$ 13,286	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,788	$ 31,262	$ 14,342	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,813	$ 4,165	$ 11,504	$ 2,648	$ 13,000	$ 5,454	$ 6,677	$ 7,835	$ 7,174	$ 8,200
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,760	$ 4,146	$ 11,802	$ 2,663	$ 12,928	$ 5,880	$ 6,607	$ 7,817	$ 8,232	$ 8,197
8	ZEELAND CC	NATURAL GAS	$ 70,294	$ 73,504	$ 74,274	$ 75,903	$ 76,111	$ 84,330	$ 73,917	$ 96,991	$ 101,112	$ 85,122
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ 455	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 52,166	$ 52,435	$ 53,810	$ 61,151	$ 55,995	$ 67,017	$ 72,607	$ 77,283	$ 80,158	$ 83,250
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Line No.	UNIT NAME	TYPE	(k) 2031	(l) 2032	(m) 2033	(n) 2034	(o) 2035	(p) 2036	(q) 2037	(r) 2038	(s) 2039	(t) 2040
1	CAMPBELL 1	COAL	$ 20,073	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 20,748	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 153,179	$ 155,770	$ 158,382	$ 131,852	$ 165,056	$ 167,035	$ 168,136	$ 167,889	$ 184,204	$ -
4	KARN 1	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 6,075	$ 5,730	$ 9,361	$ 13,468	$ 11,323	$ 11,270	$ 10,500	$ 15,702	$ 22,581	$ 23,889
7	ZEELAND 1B (CT)	NATURAL GAS	$ 6,426	$ 5,706	$ 10,073	$ 13,821	$ 11,277	$ 11,264	$ 10,519	$ 16,793	$ 23,873	$ 25,375
8	ZEELAND CC	NATURAL GAS	$ 98,854	$ 110,612	$ 117,851	$ 123,960	$ 127,537	$ 119,652	$ 125,086	$ 124,321	$ 145,798	$ 151,180
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 88,656	$ 89,006	$ 92,634	$ 95,949	$ 100,539	$ 103,048	$ 107,294	$ 111,278	$ 115,390	$ 118,112
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Total Fuel Cost Of Existing Owned Units: Environmental Policy, AEO Gas, Retirement Base Case - Optimal Plan

Line No.	UNIT NAME	TYPE	(a) 2021	(b) 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030
1	CAMPBELL 1	COAL	$ 38,393	$ 38,845	$ 40,080	$ 37,544	$ 14,726	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,550	$ 40,153	$ 41,365	$ 38,500	$ 15,262	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,510	$ 126,999	$ 131,349	$ 109,159	$ 48,945	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ 28,990	$ 29,493	$ 13,409	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,961	$ 31,518	$ 14,492	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,646	$ 6,177	$ 5,369	$ 222	$ 821	$ 1,675	$ 2,201	$ 1,628	$ 493	$ -
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,414	$ 6,150	$ 5,334	$ 242	$ 816	$ 1,673	$ 2,187	$ 1,815	$ 491	$ -
8	ZEELAND CC	NATURAL GAS	$ 77,735	$ 82,835	$ 85,035	$ 80,572	$ 91,116	$ 101,101	$ 86,980	$ 87,736	$ 93,421	$ 89,763
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 63,329	$ 65,864	$ 63,181	$ 69,921	$ 71,102	$ 66,908	$ 71,998	$ 62,675	$ 74,217	$ 72,931
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 30,141	$ 58,387	$ 61,166	$ 66,832	$ 72,350	$ 73,557	$ 75,307	$ 71,743
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 29,958	$ 59,379	$ 60,301	$ 66,427	$ 72,547	$ 70,729	$ 74,851	$ 71,259
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 28,270	$ 57,996	$ 56,927	$ 61,515	$ 69,887	$ 70,171	$ 72,599	$ 71,873
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,094	$ 691	$ 739	$ 380	$ 456	$ 448	$ 450	$ 254
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,087	$ 687	$ 734	$ 378	$ 453	$ 446	$ 448	$ 256
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,096	$ 693	$ 740	$ 381	$ 498	$ 449	$ 451	$ 258
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 3,275	$ 1,979	$ 2,877	$ 3,938	$ 2,653	$ 2,151
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 15,280	$ 14,440	$ 18,565	$ 15,525	$ 17,272	$ 18,338
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 15,230	$ 12,141	$ 12,839	$ 12,579	$ 11,890	$ 8,939
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 10,075	$ 17,850	$ 18,284	$ 18,773	$ 19,154	$ 19,588
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 9	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 9	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 9	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 10	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ 29	$ 23	$ 85	$ 36	$ -	$ -

Line No.	UNIT NAME	TYPE	(k) 2031	(l) 2032	(m) 2033	(n) 2034	(o) 2035	(p) 2036	(q) 2037	(r) 2038	(s) 2039	(t) 2040
1	CAMPBELL 1	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 934	$ 2,799	$ 3,992	$ 2,276	$ 1,303	$ 3,793	$ 4,958	$ 4,558	$ 12,556	$ 15,284
7	ZEELAND 1B (CT)	NATURAL GAS	$ 942	$ 2,813	$ 3,967	$ 2,266	$ 1,660	$ 3,783	$ 4,937	$ 4,537	$ 12,713	$ 15,226
8	ZEELAND CC	NATURAL GAS	$ 121,018	$ 112,935	$ 105,439	$ 99,731	$ 59,083	$ 112,854	$ 129,194	$ 105,798	$ 119,126	$ 131,194
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 69,755	$ 81,425	$ 82,585	$ 75,472	$ 74,685	$ 80,481	$ 89,499	$ 94,071	$ 111,899	$ 122,638
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ 70,829	$ 77,193	$ 79,078	$ 73,037	$ 77,576	$ 83,177	$ 83,331	$ 91,151	$ 91,091	$ 39,416
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ 70,400	$ 77,482	$ 85,164	$ 80,101	$ 79,252	$ 88,708	$ 82,827	$ 90,623	$ 90,539	$ 40,928
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ 74,328	$ 80,626	$ 84,333	$ 77,570	$ 82,733	$ 83,387	$ 83,482	$ 93,133	$ 102,061	$ 42,586
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ 260	$ 485	$ 630	$ 634	$ 328	$ 389	$ 572	$ 802	$ 1,573	$ 772
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ 258	$ 505	$ 626	$ 631	$ 326	$ 387	$ 569	$ 797	$ 1,622	$ 767
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ 260	$ 486	$ 631	$ 636	$ 328	$ 390	$ 573	$ 803	$ 1,630	$ 773
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ 2,024	$ 2,955	$ 4,435	$ 4,210	$ 2,794	$ 2,461	$ 3,792	$ 5,550	$ 12,012	$ 7,008
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ 18,617	$ 16,406	$ 16,291	$ 19,358	$ 15,464	$ 14,133	$ 22,157	$ 17,501	$ 32,742	$ 10,063
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ 18,505	$ 15,228	$ 13,803	$ 14,414	$ 6,808	$ 10,122	$ 16,563	$ 12,728	$ 28,702	$ 9,725
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ 20,023	$ 20,544	$ 20,947	$ 21,323	$ 21,404	$ 22,424	$ 22,849	$ 23,261	$ 23,612	$ 9,873
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12	$ 24	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12	$ 25	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12	$ 25	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13	$ 26	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ 57	$ 60	$ 40	$ 21	$ 21	$ 130	$ 158	$ 255	$ 34

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Total Fuel Cost Of Existing Owned Units: Environmental Policy, AEO Gas, Retirement Base Case - Proposed Course Of Action

Case No.: U-21090
Exhibit No.: A-20 (STW-17)
Page: 14 of 20
Witness: STWalz
Date: June 2021

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
Line No.	UNIT NAME	TYPE	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	CAMPBELL 1	COAL	$ 38,401	$ 38,839	$ 40,080	$ 37,538	$ 14,726	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,550	$ 40,147	$ 41,365	$ 38,499	$ 15,259	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,524	$ 126,999	$ 131,349	$ 109,159	$ 48,945	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ 28,993	$ 29,504	$ 13,409	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,962	$ 31,526	$ 14,492	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,646	$ 2,169	$ 5,369	$ 222	$ 821	$ 1,675	$ 2,201	$ 1,628	$ 493	$ -	$ 944	$ 2,831	$ 3,985	$ 3,359	$ 1,303	$ 3,799	$ 6,264	$ 6,192	$ 12,877	$ 15,400
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,414	$ 2,173	$ 5,334	$ 242	$ 816	$ 1,673	$ 2,476	$ 1,815	$ 491	$ -	$ 938	$ 2,813	$ 4,000	$ 3,810	$ 2,090	$ 3,804	$ 6,279	$ 6,160	$ 13,040	$ 15,843
8	ZEELAND CC	NATURAL GAS	$ 77,735	$ 82,832	$ 85,035	$ 89,260	$ 91,115	$ 101,099	$ 86,980	$ 87,736	$ 93,433	$ 89,368	$ 109,431	$ 113,101	$ 105,439	$ 102,391	$ 89,598	$ 118,361	$ 121,001	$ 118,802	$ 123,251	$ 131,784
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 63,329	$ 65,864	$ 63,181	$ 69,921	$ 71,100	$ 66,918	$ 71,999	$ 62,663	$ 74,217	$ 72,872	$ 69,732	$ 81,456	$ 82,434	$ 76,379	$ 75,287	$ 81,604	$ 89,956	$ 94,137	$ 112,639	$ 122,476
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 30,141	$ 58,387	$ 61,166	$ 66,832	$ 72,350	$ 73,557	$ 75,307	$ 71,743	$ 70,829	$ 77,193	$ 79,078	$ 73,170	$ 77,808	$ 84,293	$ 83,534	$ 91,975	$ 93,551	$ 39,416
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 29,958	$ 59,379	$ 60,301	$ 66,427	$ 72,547	$ 70,729	$ 74,851	$ 71,259	$ 70,400	$ 79,992	$ 85,164	$ 79,948	$ 79,500	$ 88,781	$ 83,105	$ 91,418	$ 90,539	$ 40,273
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 28,270	$ 57,996	$ 57,029	$ 61,515	$ 69,845	$ 70,171	$ 72,599	$ 71,873	$ 74,394	$ 80,626	$ 84,333	$ 80,016	$ 82,898	$ 84,626	$ 84,602	$ 93,504	$ 101,716	$ 42,586
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,094	$ 691	$ 739	$ 380	$ 459	$ 448	$ 450	$ 254	$ 260	$ 485	$ 633	$ 638	$ 448	$ 393	$ 576	$ 847	$ 1,672	$ 871
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,087	$ 687	$ 734	$ 378	$ 457	$ 446	$ 448	$ 253	$ 258	$ 482	$ 630	$ 634	$ 445	$ 391	$ 573	$ 842	$ 1,720	$ 866
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,096	$ 693	$ 740	$ 381	$ 460	$ 449	$ 451	$ 255	$ 260	$ 486	$ 634	$ 639	$ 448	$ 394	$ 577	$ 848	$ 1,734	$ 873
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 3,275	$ 1,988	$ 2,867	$ 3,916	$ 2,653	$ 2,148	$ 2,024	$ 3,077	$ 4,501	$ 4,283	$ 2,826	$ 3,193	$ 3,856	$ 6,442	$ 13,191	$ 7,008
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 15,279	$ 15,026	$ 18,546	$ 15,588	$ 17,359	$ 18,253	$ 18,935	$ 16,631	$ 16,428	$ 19,607	$ 14,269	$ 14,125	$ 23,076	$ 17,424	$ 33,448	$ 9,605
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 15,213	$ 12,184	$ 12,928	$ 12,680	$ 11,967	$ 8,924	$ 18,649	$ 15,459	$ 14,004	$ 14,736	$ 9,006	$ 10,273	$ 17,147	$ 12,767	$ 28,986	$ 9,705
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 10,075	$ 17,850	$ 18,284	$ 18,773	$ 19,154	$ 19,588	$ 20,023	$ 20,544	$ 20,947	$ 21,323	$ 21,476	$ 22,424	$ 22,849	$ 23,261	$ 23,618	$ 9,869
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 13	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12	$ 24	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12	$ 25	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12	$ 25	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 10	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13	$ 26	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ 29	$ 48	$ 104	$ 36	$ -	$ -	$ -	$ 19	$ 79	$ 40	$ 21	$ 21	$ 130	$ 158	$ 232	$ 34

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
Line No.	UNIT NAME	TYPE	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	CAMPBELL 1	COAL	$ 38,394	$ 39,061	$ 40,308	$ 37,994	$ 41,668	$ 42,609	$ 43,218	$ 40,490	$ 44,395	$ 44,778	$ 20,182	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,550	$ 40,157	$ 41,687	$ 39,096	$ 43,146	$ 43,816	$ 44,386	$ 45,089	$ 45,504	$ 45,744	$ 20,845	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,515	$ 127,021	$ 131,349	$ 109,159	$ 135,783	$ 138,572	$ 141,384	$ 144,631	$ 147,160	$ 150,146	$ 153,179	$ 155,770	$ 158,382	$ 131,852	$ 162,461	$ 166,543	$ 167,710	$ 167,085	$ 182,684	$ -
4	KARN 1	COAL	$ 28,990	$ 29,511	$ 13,407	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,960	$ 31,534	$ 14,493	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,664	$ 2,169	$ -	$ 243	$ 797	$ 1,675	$ 2,201	$ 1,628	$ 481	$ -	$ 953	$ 2,831	$ 3,992	$ 3,824	$ 1,734	$ 3,815	$ 6,267	$ 6,230	$ 13,561	$ 17,994
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,651	$ 2,173	$ -	$ 242	$ 793	$ 1,673	$ 2,187	$ 1,618	$ 479	$ -	$ 948	$ 3,471	$ 3,967	$ 3,804	$ 2,090	$ 4,299	$ 6,242	$ 7,037	$ 13,724	$ 17,947
8	ZEELAND CC	NATURAL GAS	$ 77,735	$ 82,835	$ 85,035	$ 80,572	$ 89,928	$ 101,048	$ 86,980	$ 87,729	$ 89,535	$ 85,133	$ 120,851	$ 105,645	$ 105,503	$ 102,017	$ 81,200	$ 111,725	$ 119,883	$ 99,318	$ 123,153	$ 131,682
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 63,316	$ 59,861	$ 61,144	$ 71,079	$ 66,641	$ 66,086	$ 70,440	$ 56,654	$ 70,992	$ 70,790	$ 67,667	$ 78,804	$ 82,380	$ 77,412	$ 74,630	$ 80,017	$ 89,815	$ 94,322	$ 113,093	$ 123,117
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Total Fuel Cost Of Existing Owned Units: Environmental Policy, CE Gas, Retirement Base Case - Optimal Plan

Case No.: U-21090
Exhibit No.: A-20 (STW-17)

Witness: STWalz
Date: June 2021

Line No.	UNIT NAME	TYPE	(a) 2021	(b) 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030	(k) 2031	(l) 2032	(m) 2033	(n) 2034	(o) 2035	(p) 2036	(q) 2037	(r) 2038	(s) 2039	(t) 2040
1	CAMPBELL 1	COAL	$ 38,249	$ 38,613	$ 39,329	$ 36,423	$ 14,355	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,487	$ 39,813	$ 40,444	$ 37,058	$ 14,748	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,215	$ 126,426	$ 130,004	$ 107,878	$ 47,991	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ 28,864	$ 29,325	$ 13,166	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,783	$ 31,273	$ 14,204	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,794	$ 4,165	$ 5,546	$ 2,753	$ 7,076	$ 2,405	$ 3,024	$ 4,878	$ 2,378	$ 1,357	$ 2,453	$ 3,514	$ 3,227	$ 3,297	$ 2,432	$ 2,978	$ 1,043	$ 2,413	$ 3,499	$ 5,222
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,760	$ 4,146	$ 5,879	$ 2,803	$ 8,017	$ 3,334	$ 3,004	$ 5,285	$ 2,410	$ 1,363	$ 2,752	$ 3,491	$ 3,220	$ 4,715	$ 2,423	$ 2,969	$ 1,036	$ 2,185	$ 3,483	$ 5,214
8	ZEELAND CC	NATURAL GAS	$ 70,300	$ 73,504	$ 74,253	$ 75,514	$ 75,835	$ 82,048	$ 73,855	$ 91,436	$ 86,740	$ 84,825	$ 98,809	$ 103,169	$ 108,636	$ 112,817	$ 100,157	$ 104,122	$ 103,972	$ 103,388	$ 75,192	$ 103,468
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 52,177	$ 53,167	$ 56,081	$ 59,788	$ 59,909	$ 66,337	$ 70,592	$ 74,010	$ 75,994	$ 79,631	$ 80,611	$ 83,184	$ 87,415	$ 89,767	$ 90,761	$ 87,795	$ 84,025	$ 87,303	$ 87,445	$ 94,461
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 25,879	$ 48,309	$ 52,044	$ 57,649	$ 58,420	$ 56,435	$ 63,245	$ 62,922	$ 61,394	$ 67,664	$ 59,991	$ 69,989	$ 72,821	$ 71,751	$ 71,535	$ 73,624	$ 74,635	$ -
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 25,723	$ 45,674	$ 47,767	$ 56,763	$ 58,046	$ 57,449	$ 62,965	$ 62,568	$ 55,471	$ 67,254	$ 70,085	$ 75,463	$ 73,692	$ 76,409	$ 67,584	$ 69,696	$ 75,248	$ -
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 24,308	$ 48,355	$ 48,575	$ 53,277	$ 55,080	$ 57,401	$ 58,393	$ 63,646	$ 62,771	$ 67,787	$ 68,736	$ 68,327	$ 77,558	$ 72,024	$ 72,160	$ 79,043	$ 82,874	$ -
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,809	$ 1,848	$ 2,096	$ 1,984	$ 1,941	$ 1,292	$ 1,169	$ 1,183	$ 1,096	$ 887	$ 754	$ 820	$ 914	$ 531	$ 367	$ 534	$ 577	$ -
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,798	$ 1,716	$ 2,041	$ 1,960	$ 1,923	$ 1,287	$ 1,162	$ 1,176	$ 1,090	$ 882	$ 750	$ 815	$ 909	$ 527	$ 365	$ 531	$ 574	$ -
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,812	$ 1,852	$ 2,118	$ 1,989	$ 1,933	$ 1,196	$ 1,171	$ 1,185	$ 1,098	$ 883	$ 639	$ 821	$ 916	$ 579	$ 368	$ 535	$ 578	$ -
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 16,445	$ 20,097	$ 19,068	$ 16,739	$ 16,721	$ 17,773	$ 14,279	$ 15,191	$ 16,848	$ 14,614	$ 15,759	$ 10,207	$ 8,528	$ 7,887	$ 9,939	$ -
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 14,398	$ 24,443	$ 26,801	$ 26,990	$ 29,223	$ 28,868	$ 31,196	$ 33,292	$ 29,352	$ 35,175	$ 32,155	$ 27,707	$ 32,833	$ 34,952	$ 35,979	$ -
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 14,716	$ 25,052	$ 28,290	$ 25,387	$ 27,482	$ 22,232	$ 27,103	$ 32,229	$ 24,555	$ 31,355	$ 25,400	$ 25,622	$ 32,548	$ 30,647	$ 30,791	$ -
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 8,760	$ 15,521	$ 15,899	$ 16,318	$ 16,585	$ 16,975	$ 17,411	$ 17,864	$ 18,215	$ 18,616	$ 18,932	$ 19,382	$ 19,407	$ 20,119	$ 20,207	$ -
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ 24	$ 58	$ 70	$ 30	$ -	$ -	$ 48	$ 117	$ 17	$ -	$ -	$ 38	$ 39	$ 82	$ 50	$ -

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Total Fuel Cost Of Existing Owned Units: Environmental Policy, CE Gas, Retirement Base Case - Proposed Course Of Action

Case No.: U-21090
Exhibit No.: A-20 (STW-17)

Witness: STWalz
Date: June 2021

Line No.	UNIT NAME	TYPE	(a) 2021	(b) 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030
1	CAMPBELL 1	COAL	$ 38,249	$ 38,618	$ 39,324	$ 36,429	$ 14,344	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,487	$ 39,820	$ 40,433	$ 37,058	$ 14,736	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,215	$ 126,426	$ 129,904	$ 107,878	$ 47,905	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ 28,864	$ 29,328	$ 13,166	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,783	$ 31,272	$ 14,210	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,765	$ 4,165	$ 5,546	$ 2,783	$ 7,119	$ 2,299	$ 2,991	$ 4,878	$ 2,378	$ 1,357
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,760	$ 4,146	$ 5,879	$ 2,773	$ 7,018	$ 3,401	$ 3,579	$ 5,285	$ 2,387	$ 1,361
8	ZEELAND CC	NATURAL GAS	$ 70,300	$ 73,504	$ 74,253	$ 75,514	$ 75,847	$ 82,048	$ 73,870	$ 91,325	$ 86,801	$ 84,859
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 52,198	$ 53,176	$ 56,081	$ 60,527	$ 59,554	$ 66,378	$ 70,534	$ 74,011	$ 76,479	$ 79,627
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 25,879	$ 48,309	$ 52,044	$ 57,649	$ 59,043	$ 56,348	$ 63,245	$ 62,835
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 25,723	$ 45,674	$ 47,767	$ 56,763	$ 58,046	$ 57,449	$ 64,282	$ 62,601
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 24,308	$ 48,355	$ 48,575	$ 53,277	$ 55,080	$ 57,316	$ 58,391	$ 63,101
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,809	$ 1,848	$ 2,096	$ 2,009	$ 1,941	$ 1,292	$ 1,166	$ 1,183
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,750	$ 1,743	$ 1,866	$ 1,991	$ 1,929	$ 1,287	$ 1,162	$ 1,176
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,812	$ 1,852	$ 2,100	$ 1,987	$ 1,944	$ 1,196	$ 1,171	$ 1,185
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 16,448	$ 20,153	$ 19,026	$ 16,702	$ 16,587	$ 17,725
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 14,398	$ 24,419	$ 27,453	$ 26,983	$ 29,236	$ 28,733
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 14,716	$ 25,108	$ 28,328	$ 25,961	$ 27,484	$ 22,323
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 8,760	$ 15,521	$ 15,899	$ 16,318	$ 16,572	$ 16,981
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ 24	$ 53	$ 70	$ 30	$ -	$ -

Line No.	UNIT NAME	TYPE	(k) 2031	(l) 2032	(m) 2033	(n) 2034	(o) 2035	(p) 2036	(q) 2037	(r) 2038	(s) 2039	(t) 2040
1	CAMPBELL 1	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 2,423	$ 3,583	$ 3,231	$ 3,986	$ 2,462	$ 3,102	$ 1,011	$ 2,413	$ 2,738	$ 4,917
7	ZEELAND 1B (CT)	NATURAL GAS	$ 2,786	$ 3,517	$ 3,314	$ 4,715	$ 2,453	$ 3,092	$ 1,004	$ 2,348	$ 3,483	$ 5,214
8	ZEELAND CC	NATURAL GAS	$ 98,720	$ 103,180	$ 108,636	$ 112,823	$ 104,637	$ 104,182	$ 104,004	$ 103,395	$ 75,526	$ 103,915
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 80,059	$ 83,156	$ 87,412	$ 89,815	$ 90,835	$ 88,113	$ 84,187	$ 88,346	$ 91,443	$ 93,766
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ 61,394	$ 67,664	$ 60,052	$ 70,006	$ 73,386	$ 72,682	$ 71,741	$ 72,018	$ 74,658	$ -
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ 55,471	$ 67,254	$ 70,085	$ 75,572	$ 73,795	$ 76,472	$ 68,280	$ 70,837	$ 74,450	$ -
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ 62,771	$ 67,802	$ 68,736	$ 68,459	$ 77,702	$ 72,919	$ 75,185	$ 78,414	$ 83,207	$ -
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ 1,096	$ 890	$ 745	$ 823	$ 914	$ 534	$ 367	$ 534	$ 669	$ -
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ 1,090	$ 884	$ 759	$ 818	$ 909	$ 531	$ 365	$ 531	$ 574	$ -
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ 1,098	$ 891	$ 662	$ 824	$ 916	$ 535	$ 368	$ 535	$ 671	$ -
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ 14,255	$ 15,305	$ 17,826	$ 15,906	$ 15,849	$ 10,086	$ 8,745	$ 8,428	$ 9,966	$ -
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ 31,211	$ 33,330	$ 29,393	$ 35,360	$ 32,297	$ 27,886	$ 32,839	$ 34,899	$ 36,006	$ -
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ 27,039	$ 32,267	$ 24,555	$ 31,274	$ 25,402	$ 26,170	$ 32,729	$ 30,849	$ 30,968	$ -
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ 17,411	$ 17,864	$ 18,215	$ 18,616	$ 18,932	$ 19,426	$ 19,451	$ 20,119	$ 20,203	$ -
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 10	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 11	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 11	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 11	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ 48	$ 111	$ 34	$ -	$ -	$ 38	$ 78	$ 82	$ 42	$ -

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Total Fuel Cost Of Existing Owned Units: Environmental Policy - Alternate Plan

Case No.: U-21090
Exhibit No.: A-20 (STW-17)

Witness: STWalz
Date: June 2021

Line No.	UNIT NAME	TYPE	(a) 2021	(b) 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030	(k) 2031	(l) 2032	(m) 2033	(n) 2034	(o) 2035	(p) 2036	(q) 2037	(r) 2038	(s) 2039	(t) 2040
1	CAMPBELL 1	COAL	$ 38,240	$ 38,831	$ 39,634	$ 36,842	$ 40,346	$ 41,280	$ 42,174	$ 39,261	$ 42,993	$ 43,828	$ 19,601	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,487	$ 39,799	$ 40,848	$ 37,580	$ 41,486	$ 42,308	$ 43,238	$ 43,677	$ 43,746	$ 44,595	$ 20,131	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,215	$ 126,371	$ 130,060	$ 107,870	$ 132,884	$ 136,597	$ 140,248	$ 142,523	$ 144,779	$ 148,530	$ 152,705	$ 155,313	$ 158,232	$ 131,852	$ 163,847	$ 165,557	$ 165,472	$ 165,228	$ 177,710	$ -
4	KARN 1	COAL	$ 28,859	$ 29,318	$ 13,155	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,773	$ 31,261	$ 14,203	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,765	$ 4,165	$ 5,159	$ 2,720	$ 4,066	$ 1,907	$ 2,927	$ 3,095	$ 1,290	$ 1,293	$ 1,514	$ 3,490	$ 2,698	$ 3,297	$ 1,656	$ 2,278	$ 1,011	$ 1,364	$ 2,588	$ 2,642
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,760	$ 4,146	$ 5,879	$ 2,803	$ 2,582	$ 1,979	$ 2,928	$ 3,107	$ 1,849	$ 1,300	$ 1,534	$ 3,475	$ 2,709	$ 3,277	$ 2,423	$ 2,969	$ 1,004	$ 1,355	$ 2,578	$ 2,638
8	ZEELAND CC	NATURAL GAS	$ 70,300	$ 73,504	$ 74,240	$ 75,499	$ 73,897	$ 82,012	$ 73,868	$ 77,392	$ 79,232	$ 77,620	$ 98,786	$ 103,309	$ 108,636	$ 112,817	$ 93,532	$ 103,409	$ 103,931	$ 103,360	$ 66,901	$ 72,939
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 51,982	$ 52,900	$ 55,003	$ 60,312	$ 57,619	$ 65,816	$ 69,909	$ 73,791	$ 76,277	$ 74,103	$ 79,496	$ 82,274	$ 87,160	$ 89,213	$ 90,427	$ 82,763	$ 82,255	$ 84,826	$ 77,458	$ 84,320
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Total Fuel Cost Of Existing Owned Units: Advanced Technology, Retirement Base Case - Optimal Plan

Case No.: U-21090
Exhibit No.: A-20 (STW-17)

Witness: STWalz
Date: June 2021

Line No.	UNIT NAME	TYPE	(a) 2021	(b) 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030
1	CAMPBELL 1	COAL	$ 38,399	$ 38,712	$ 39,682	$ 37,354	$ 14,455	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,550	$ 40,005	$ 40,911	$ 38,237	$ 14,942	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,401	$ 126,707	$ 130,930	$ 109,130	$ 48,538	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ 28,986	$ 29,411	$ 13,318	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,978	$ 31,424	$ 14,380	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 4,610	$ 5,658	$ 8,212	$ 2,389	$ 1,540	$ 2,408	$ 3,116	$ 2,184	$ -	$ -
7	ZEELAND 1B (CT)	NATURAL GAS	$ 4,579	$ 5,658	$ 8,187	$ 2,619	$ 1,530	$ 2,411	$ 3,110	$ 2,172	$ 254	$ -
8	ZEELAND CC	NATURAL GAS	$ 74,826	$ 75,272	$ 74,624	$ 77,376	$ 76,978	$ 85,859	$ 81,607	$ 93,965	$ 90,757	$ 82,923
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 83,756	$ 85,643	$ 82,265	$ 91,574	$ 92,571	$ 94,763	$ 103,182	$ 95,289	$ 88,750	$ 87,935
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 26,172	$ 54,097	$ 57,329	$ 63,338	$ 63,699	$ 60,631	$ 65,350	$ 56,903
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 26,014	$ 53,770	$ 56,981	$ 62,953	$ 63,313	$ 59,292	$ 65,525	$ 56,611
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 24,551	$ 52,637	$ 53,822	$ 58,346	$ 60,188	$ 59,133	$ 62,761	$ 57,059
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,845	$ 2,208	$ 805	$ 745	$ 725	$ 928	$ 703	$ 863
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,833	$ 1,908	$ 800	$ 741	$ 720	$ 923	$ 699	$ 858
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,848	$ 2,107	$ 807	$ 747	$ 726	$ 930	$ 704	$ 865
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 4,846	$ 4,579	$ 3,623	$ 4,830	$ 4,148	$ 4,681
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 15,215	$ 17,370	$ 17,487	$ 21,759	$ 17,358	$ 15,327
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 9,452	$ 12,175	$ 16,235	$ 20,350	$ 18,449	$ 11,232
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 10,075	$ 17,850	$ 18,284	$ 18,773	$ 19,154	$ 19,588
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ 14	$ 30	$ -	$ -	$ 47

Line No.	UNIT NAME	TYPE	(k) 2031	(l) 2032	(m) 2033	(n) 2034	(o) 2035	(p) 2036	(q) 2037	(r) 2038	(s) 2039	(t) 2040
1	CAMPBELL 1	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ -	$ 943	$ 974	$ 1,027	$ -	$ 599	$ 3,813	$ -	$ -	$ -
7	ZEELAND 1B (CT)	NATURAL GAS	$ -	$ 937	$ 967	$ 1,647	$ 227	$ 1,377	$ 4,530	$ -	$ -	$ -
8	ZEELAND CC	NATURAL GAS	$ 97,250	$ 102,088	$ 104,982	$ 107,813	$ 109,894	$ 113,285	$ 116,509	$ 62,741	$ 79,918	$ 122,564
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 113,741	$ 104,330	$ 112,693	$ 117,130	$ 127,283	$ 136,359	$ 140,210	$ 82,368	$ 89,766	$ 100,969
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ 56,340	$ 59,108	$ 69,612	$ 66,809	$ 73,136	$ 74,295	$ 81,138	$ 64,836	$ 69,225	$ 30,663
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ 56,109	$ 58,750	$ 73,836	$ 72,041	$ 73,357	$ 81,525	$ 80,646	$ 64,443	$ 68,806	$ 30,478
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ 59,615	$ 59,216	$ 73,209	$ 69,550	$ 77,024	$ 77,797	$ 84,838	$ 67,161	$ 75,679	$ 30,719
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ 1,159	$ 590	$ 552	$ 678	$ 893	$ 1,649	$ 1,316	$ 300	$ 243	$ -
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ 1,152	$ 587	$ 548	$ 671	$ 887	$ 1,639	$ 1,308	$ 298	$ 241	$ -
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ 1,161	$ 591	$ 553	$ 676	$ 894	$ 1,652	$ 1,319	$ 301	$ 277	$ -
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ 5,106	$ 3,427	$ 4,127	$ 4,156	$ 5,798	$ 10,826	$ 8,997	$ -	$ 1,625	$ -
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ 16,080	$ 19,099	$ 18,451	$ 23,658	$ 18,217	$ 11,554	$ 30,775	$ 9,458	$ 21,856	$ 4,099
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ 18,862	$ 19,362	$ 17,757	$ 22,938	$ 16,407	$ 11,599	$ 27,888	$ 9,059	$ 20,052	$ 3,133
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ 20,023	$ 20,544	$ 20,947	$ 21,409	$ 21,871	$ 22,424	$ 22,849	$ 23,365	$ 23,881	$ 10,387
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Total Fuel Cost Of Existing Owned Units: Carbon Reduction Scenario, Retirement Base Case - Optimal Plan

Case No.: U-21090
Exhibit No.: A-20 (STW-17)

Witness: STWalz
Date: June 2021

Line No.	UNIT NAME	TYPE	(a) 2021	(b) 2022	(c) 2023	(d) 2024	(e) 2025	(f) 2026	(g) 2027	(h) 2028	(i) 2029	(j) 2030
1	CAMPBELL 1	COAL	$ 38,406	$ 38,853	$ 40,092	$ 37,559	$ 14,728	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ 32,550	$ 40,179	$ 41,401	$ 38,511	$ 15,266	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ 124,533	$ 127,036	$ 131,349	$ 109,159	$ 48,945	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ 28,996	$ 29,521	$ 13,413	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ 30,973	$ 31,538	$ 14,493	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 3,664	$ 6,183	$ 5,369	$ 243	$ 821	$ 1,709	$ 3,048	$ 2,341	$ 1,432	$ 257
7	ZEELAND 1B (CT)	NATURAL GAS	$ 3,651	$ 6,155	$ 5,339	$ 242	$ 819	$ 1,699	$ 3,047	$ 2,989	$ 1,429	$ 255
8	ZEELAND CC	NATURAL GAS	$ 77,739	$ 82,835	$ 85,035	$ 89,347	$ 91,142	$ 101,169	$ 97,383	$ 95,770	$ 93,433	$ 90,047
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 63,323	$ 59,146	$ 63,770	$ 72,395	$ 71,069	$ 68,943	$ 72,346	$ 72,607	$ 75,674	$ 77,066
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 30,141	$ 59,741	$ 61,215	$ 66,888	$ 72,989	$ 73,557	$ 75,307	$ 75,068
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 29,958	$ 59,379	$ 61,353	$ 67,093	$ 74,734	$ 70,729	$ 76,251	$ 74,614
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ -	$ -	$ 28,270	$ 57,996	$ 57,527	$ 64,715	$ 70,541	$ 70,171	$ 74,189	$ 76,001
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,094	$ 691	$ 1,009	$ 381	$ 519	$ 449	$ 532	$ 258
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,087	$ 687	$ 1,003	$ 378	$ 515	$ 446	$ 529	$ 330
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ -	$ -	$ 1,096	$ 693	$ 1,011	$ 381	$ 520	$ 449	$ 533	$ 258
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 4,383	$ 2,283	$ 2,958	$ 4,063	$ 2,915	$ 1,953
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 15,429	$ 15,433	$ 18,692	$ 17,069	$ 18,393	$ 20,672
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 15,378	$ 12,525	$ 14,489	$ 14,431	$ 12,501	$ 9,580
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ 10,075	$ 17,850	$ 18,284	$ 18,773	$ 19,154	$ 19,588
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 9	$ -	$ -	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 9	$ -	$ -	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 9	$ -	$ -	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ 10	$ -	$ -	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ -	$ -	$ -	$ 29	$ 48	$ 113	$ 18	$ -	$ -

Line No.	UNIT NAME	TYPE	(k) 2031	(l) 2032	(m) 2033	(n) 2034	(o) 2035	(p) 2036	(q) 2037	(r) 2038	(s) 2039	(t) 2040
1	CAMPBELL 1	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	CAMPBELL 2	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	CAMPBELL 3	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	KARN 1	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	KARN 2	COAL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	ZEELAND 1A (CT)	NATURAL GAS	$ 1,976	$ 4,092	$ 4,308	$ 4,312	$ 2,093	$ 4,406	$ 6,271	$ 7,387	$ 13,606	$ 18,030
7	ZEELAND 1B (CT)	NATURAL GAS	$ 1,975	$ 4,073	$ 4,317	$ 4,289	$ 2,485	$ 4,393	$ 6,246	$ 7,353	$ 13,881	$ 19,642
8	ZEELAND CC	NATURAL GAS	$ 121,089	$ 112,944	$ 107,604	$ 111,616	$ 99,856	$ 119,381	$ 130,341	$ 124,345	$ 138,593	$ 152,589
9	KARN 3	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	KARN 3	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	KARN 4	OIL	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	JACKSON	NATURAL GAS	$ 74,456	$ 81,552	$ 85,444	$ 80,295	$ 82,830	$ 81,799	$ 100,501	$ 103,731	$ 122,170	$ 124,796
13	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ 74,259	$ 80,480	$ 79,765	$ 77,753	$ 79,068	$ 84,506	$ 84,958	$ 93,052	$ 93,976	$ 43,539
14	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ 73,809	$ 80,711	$ 86,125	$ 84,704	$ 80,976	$ 88,863	$ 84,500	$ 92,674	$ 95,949	$ 43,380
15	NEW COVERT GENERATING FACILITY (CC)	NATURAL GAS	$ 74,983	$ 82,845	$ 86,498	$ 83,962	$ 84,527	$ 84,708	$ 88,639	$ 94,370	$ 104,698	$ 45,357
16	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ 468	$ 485	$ 696	$ 642	$ 455	$ 389	$ 913	$ 886	$ 1,783	$ 1,200
17	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ 465	$ 482	$ 692	$ 638	$ 452	$ 387	$ 908	$ 881	$ 1,857	$ 1,193
18	NEW COVERT GENERATING FACILITY (DB)	NATURAL GAS	$ 469	$ 486	$ 698	$ 643	$ 456	$ 386	$ 915	$ 887	$ 1,872	$ 1,202
19	DEARBORN INDUSTRIAL GENERATION (1)	NATURAL GAS	$ 3,378	$ 3,040	$ 4,850	$ 5,044	$ 3,350	$ 2,554	$ 4,750	$ 7,047	$ 14,929	$ 7,743
20	DEARBORN INDUSTRIAL GENERATION (2)	NATURAL GAS	$ 19,412	$ 20,897	$ 20,731	$ 20,549	$ 16,321	$ 17,125	$ 26,956	$ 20,876	$ 36,280	$ 10,744
21	DEARBORN INDUSTRIAL GENERATION (3)	NATURAL GAS	$ 19,296	$ 17,237	$ 16,576	$ 17,070	$ 13,580	$ 14,373	$ 20,097	$ 13,263	$ 33,232	$ 10,610
22	DEARBORN INDUSTRIAL GENERATION (4)	NATURAL GAS	$ 20,023	$ 20,544	$ 20,947	$ 21,323	$ 21,614	$ 22,424	$ 22,849	$ 23,261	$ 23,621	$ 9,899
23	LIVINGSTON GENERATION STATION (1)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24	$ 24	$ -
24	LIVINGSTON GENERATION STATION (2)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25	$ 25	$ -
25	LIVINGSTON GENERATION STATION (3)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24	$ 25	$ -
26	LIVINGSTON GENERATION STATION (4)	NATURAL GAS	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 26	$ 26	$ -
27	KALAMAZOO RIVER GENERATING STATION	NATURAL GAS	$ -	$ 57	$ 133	$ 40	$ 21	$ 126	$ 217	$ 158	$ 288	$ 67

Note:
1. Costs are in Thousand Dollars.
2. The costs presented exclude auxiliary and fixed transportation expenses.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

EXHIBIT

OF

ANNA K. MUNIE

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Electric Demand - Risk Assessment Results

Case No.: U-21090
Exhibit No.: A-21 (AKM-1)
Page: 1 of 5
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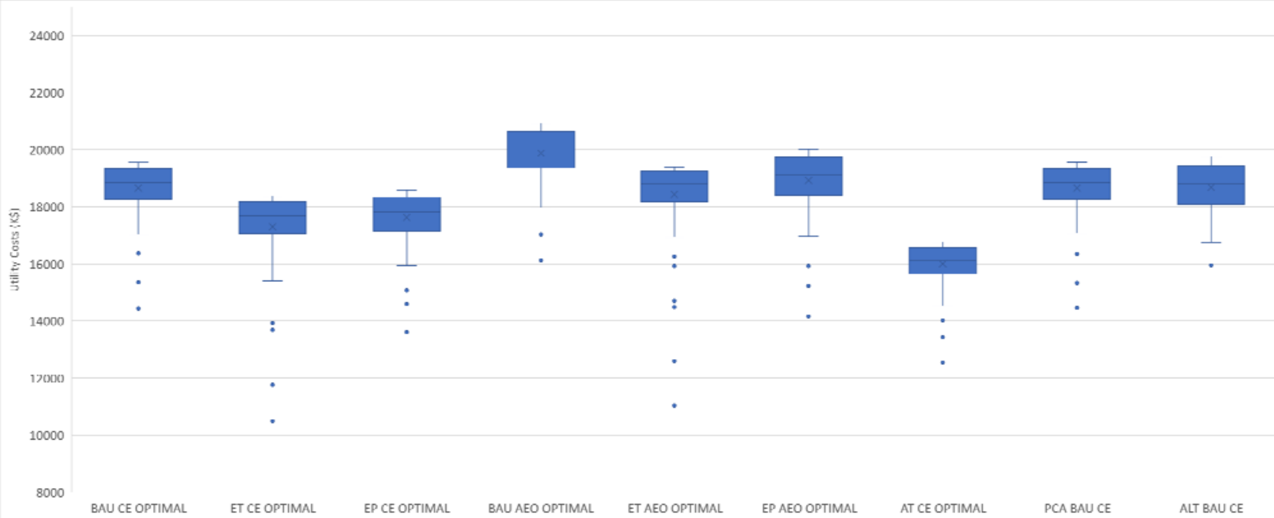
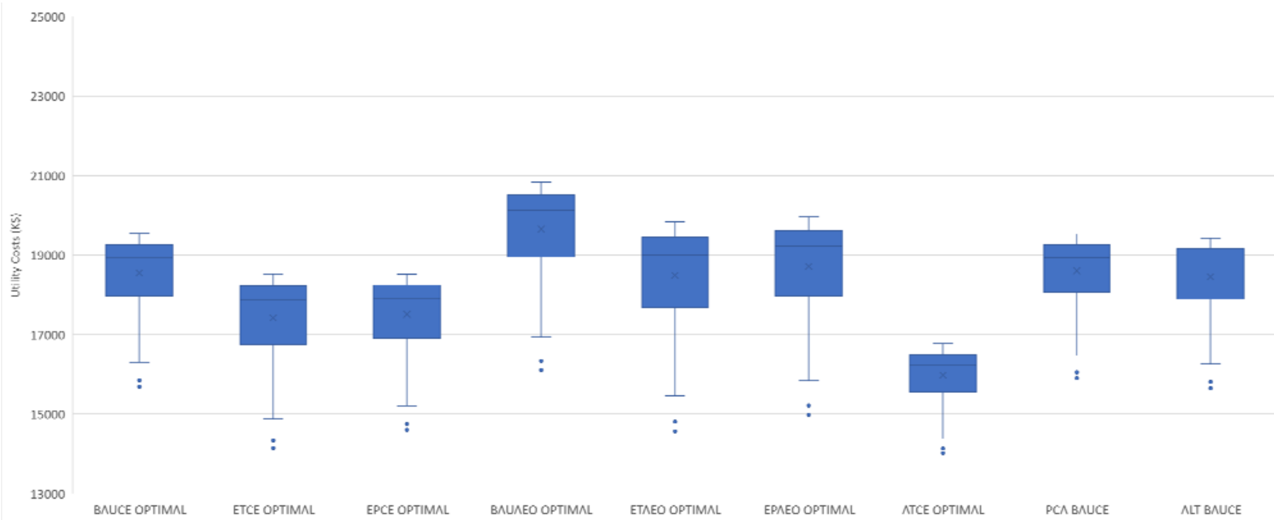
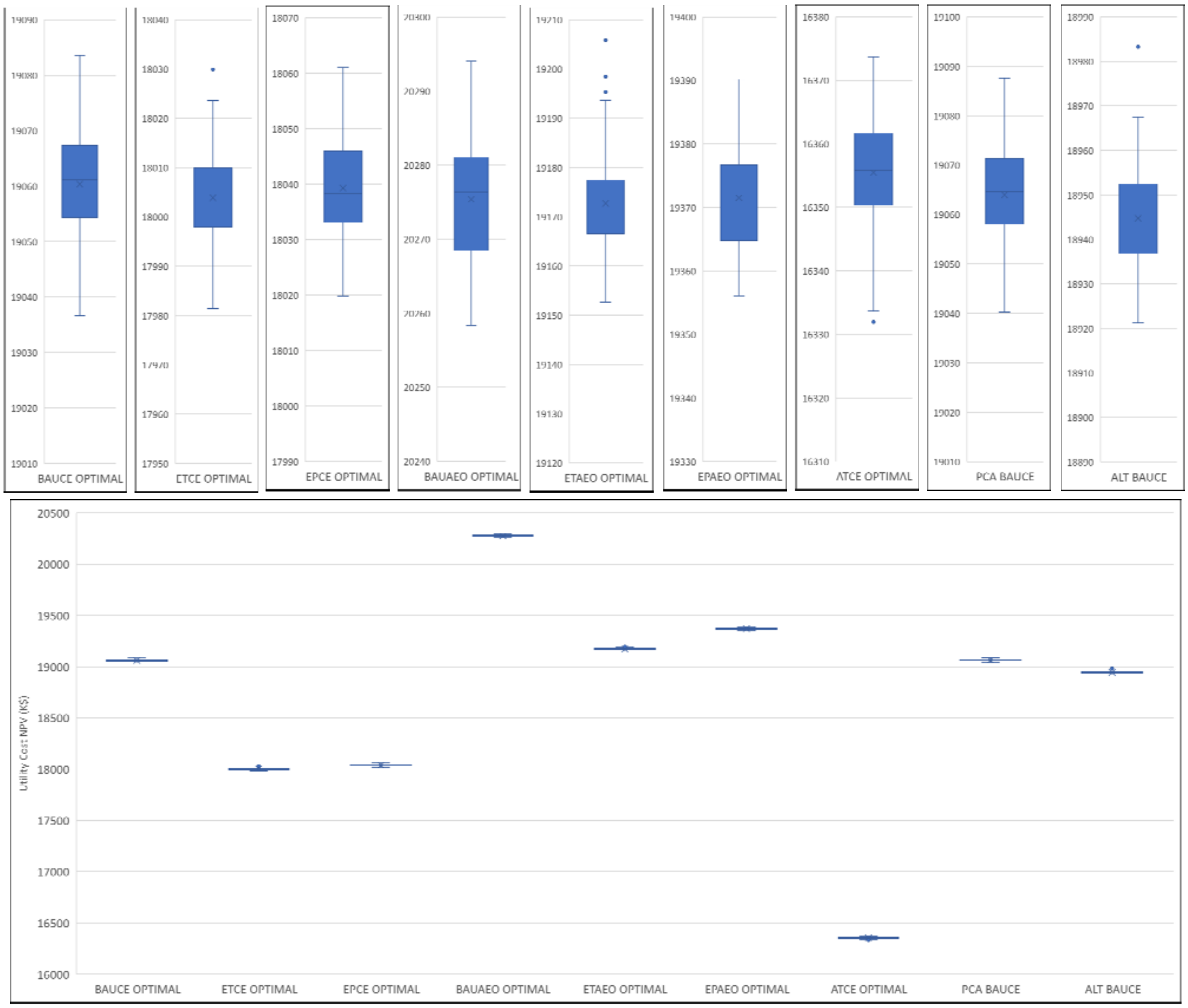
Date: June 2021

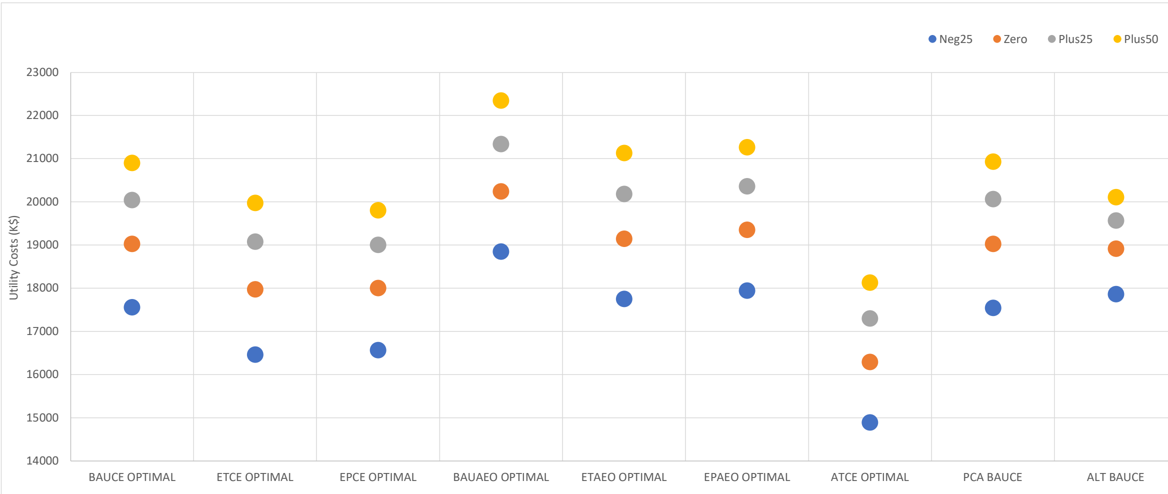




25000
23000
21000
19000
17000
15000
13000
Utility Costs (K$)
BAUCE OPTIMAL
ETCE OPTIMAL
EPCE OPTIMAL
BAUAEO OPTIMAL
ETAEO OPTIMAL
EPAEO OPTIMAL
ATCE OPTIMAL
PCA BAUCE
ALT BAUCE

Utility Cost NPV (K$)



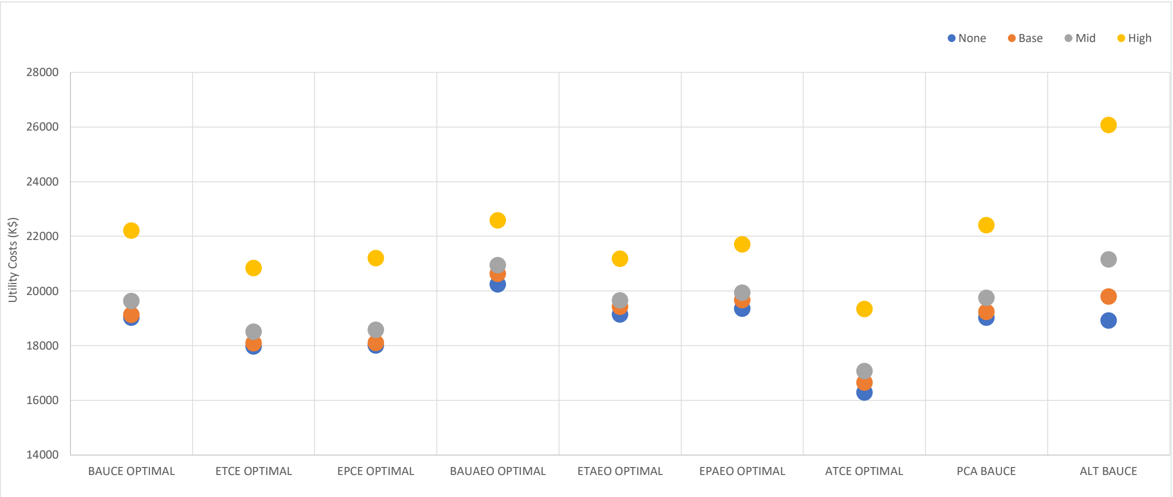

Neg25
Zero
Plus25
Plus50
Utility Costs (K$)
23000
22000
21000
20000
19000
18000
17000
16000
15000
14000
BAUCE OPTIMAL
ETCE OPTIMAL
EPCE OPTIMAL
BAUAEO OPTIMAL
ETAEO OPTIMAL
EPAEO OPTIMAL
ATCE OPTIMAL
PCA BAUCE
ALT BAUCE

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Carbon Prices - Risk Assessment Results

Case No.: U-21090
Exhibit No.: A-21 (AKM-1)
Page: 5 of 5
Witness: AKMunie
Date: June 2021



S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
______________________________________	)	

EXHIBITS

OF

HEATHER A. BREINING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
AQCS Project Summary Table
2020

Case No.: U-21090
Exhibit No.: A-22 (HAB-1)
Page: 1 of 1
Witness: HABreining
Date: June 2021

AQCS Project Summary Table

Line No.	(a.) Unit	(b.) Equipment	(c.) Pollutants Controlled	(d.) Applicable Regulation	(e.) Performance Specifications (lb/mmbtu)	(f.) Actual Performance[a] (lb/mmbtu)	(g.) Actual Date of Operation	(h.) Actual Installed Cost ($M)
(1.)	**JHC 1**	LNB	NOx	NBT, CAIR	0.220[b]	0.191	2001	$11M
(2.)		DSI	SO2, HCl	MATS, CSAPR	0.290	0.259 (SO_2)	2016	$39M
(3.)		PJFF	PM, Hg	MMR, MATS	0.010	< 0.003 (PM)	2016	$140M
(4.)		ACI	Hg	MMR, MATS	1.0 lb/Tbtu	0.827	2016	$10M
(5.)	**JHC2**	LNB	NOx	NBT, CAIR	0.39[b]	NA[c., d.]	2000	$54M
(6.)		SCR	NOx	CSAPR	0.060	0.051	2013	$110M
(7.)		PJFF	PM, Hg	MMR, MATS	0.010	< 0.002 (PM)	2013	$128M
(8.)		DSI	SO2, HCl	MATS, CSAPR	0.320	0.265 (SO_2)	2016	$46M
(9.)		ACI	Hg	MMR, MATS	1.0 lb/Tbtu	0.828	2016	$12KM
(10.)	**JHC3**	LNB	NOx	NBT, CAIR	NA[d.]	NA[d.]	2000	$10M
(11.)		SCR	NOx	NBT, CAIR	0.060	0.053	2007	$159M
(12.)		PJFF	PM, Hg	MMR, MATS	0.010	< 0.001 (PM)	2016	$242M
(13.)		SDA	SO2, HCl	MATS, CSAPR	0.070	0.061 (SO_2)	2016	$314M
(14.)		ACI	Hg	MMR, MATS	1.0 lb/Tbtu	0.792	2016	$7M
(15.)	**DEK1**	SCR	NOx	NBT, CAIR	0.060	0.063	2004	$68M
(16.)		PJFF	PM, Hg	MMR, MATS	0.015	< 0.002 (PM)	2011	$86M
(17.)		SDA	SO2, HCl	MATS, CSAPR	0.070	0.059 (SO_2)	2014	$154M
(18.)		ACI	Hg	MMR, MATS	1.0 lb/Tbtu	0.763	2015	$6M
(19.)	**DEK2**	LNB	NOx	NBT, CAIR	NA[d.]	NA[d.]	1998	$19M
(20.)		SCR	NOx	NBT, CAIR	0.060	0.041	2003	$62M
(21.)		PJFF	PM, Hg	MMR, MATS	0.015	< 0.002 (PM)	2011	$89M
(22.)		SDA	SO2, HCl	MATS, CSAPR	0.070	0.052 (SO_2)	2015	$96M
(23.)		ACI	Hg	MMR, MATS	1.0 lb/Tbtu	0.812	2015	$5M

a. Actual performance is based on the average of all valid hourly average values in the 2020 calendar year.
b. The LNB performance specifications reflect the most recent vendor guarantees. Actual performance as of 2020 (annual average).
c. The LNB capital costs reflect the original installation cost and the amount filed for environmental tax exemptions.
d. Actual performance is assessed via Continuous Emissions Monitoring Systems (CEMS) located downstream of both the LNBs and SCRs. In cases where both LNBs and SCRs are installed, the CEMS measured NOx emission rate is listed as the actual performance value for the SCR, which is responsible for the bulk of the NOx reductions. NOx emission rates specific to the LNBs only are not readily available.

ACI	= Activated Carbon Injection	NOx	= Nitrogen Oxides
PJFF	= Pulse Jet Fabric Filter	PM	= Particulate Matter
SDA	= Spray Dry Absorber	SO2	= Sulfur Dioxide
SCR	= Selective Catalytic Reduction	Hg	= Mercury
LNB	=Low NOx Burner	HCl	=Hydrochloric Acid
DSI	=Dry Sorbent Injection		

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures ($000)

Case No.: U-21090
Exhibit No.: A-23 (HAB-2)
Page: 1 of 3
Witness: HABreining
Date: June 2021

PROJECTED CAPITAL EXPENDITURES
-- BASE PLAN --

		(a.)	(b.)	(c.)	(d.)	(e.)	(f.)	(g.)	(h.)	(i.)	(j.)
		J.H. Campbell Unit 1				**J.H. Campbell Unit 2**				**J.H. Campbell Unit 3**	
		WWT	**CLS**	**Studies**	**Alt Intake***	**WWT**	**CLS**	**Studies**	**Alt Intake***	**WWT**	**CLS**
		SEEG	**SEEG**	**316(b)**	**316(b)**	**SEEG**	**SEEG**	**316(b)**	**316(b)**	**SEEG**	**SEEG**
Line No.		**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**
(1.)	**2021**	$373	$896	$211	$0	$509	$1,223	$289	$0	$1,206	$2,893
(2.)	**2022**	$2,092	$1,993	$0	$5,073	$2,857	$2,721	$0	$6,927	$6,760	$6,439
(3.)	**2023**	$2,408	$2,187	$0	$12,467	$3,288	$2,987	$0	$17,022	$7,780	$7,067
(4.)	**2024**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(5.)	**2025**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(6.)	**2026**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(7.)	**2027**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(8.)	**2028**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(9.)	**2029**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(10.)	**2030**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(11.)	**2031**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(12.)	**2032**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(13.)	**2033**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(14.)	**2034**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(15.)	**2035**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(16.)	**2036**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(17.)	**2037**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(18.)	**2038**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(19.)	**2039**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(20.)	**2040**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(21.)	**Total**	$4,874	$5,076	$211	$17,540	$6,654	$6,930	$289	$23,949	$15,746	$16,399

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures ($000)

Case No.: U-21090
Exhibit No.: A-23 (HAB-2)

Witness: HABreining
Date: June 2021

PROJECTED CAPITAL EXPENDITURES
-- CAPITAL + COR (INITIAL INVESTMENT) (CA 1 AND/OR CA 2 MAY 31, 2024-2026 RET): --

		(a.)	(b.)	(c.)	(d.)	(e.)	(f.)	(g.)	(h.)	(i.)	(j.)
		J.H. Campbell Unit 1				**J.H. Campbell Unit 2**				**J.H. Campbell Unit 3**	
		WWT	**CLS**	**Studies**	**Alt Intake***	**WWT**	**CLS**	**Studies**	**Alt Intake***	**WWT**	**CLS**
		SEEG	**SEEG**	**316(b)**	**316(b)**	**SEEG**	**SEEG**	**316(b)**	**316(b)**	**SEEG**	**SEEG**
Line No.		**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**
(1.)	**2021**	$373	$896	$0	$0	$509	$1,223	$0	$0	$1,206	$2,893
(2.)	**2022**	$2,092	$1,993	$0	$0	$2,857	$2,721	$0	$0	$6,760	$6,439
(3.)	**2023**	$2,408	$2,187	$0	$0	$3,288	$2,987	$0	$0	$7,780	$7,067
(4.)	**2024**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(5.)	**2025**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(6.)	**2026**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(7.)	**2027**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(8.)	**2028**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(9.)	**2029**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(10.)	**2030**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(11.)	**2031**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(12.)	**2032**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(13.)	**2033**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(14.)	**2034**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(15.)	**2035**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(16.)	**2036**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(17.)	**2037**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(18.)	**2038**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(19.)	**2039**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(20.)	**2040**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(21.)	**Total**	$4,874	$5,076	$0	$0	$6,654	$6,930	$0	$0	$15,746	$16,399

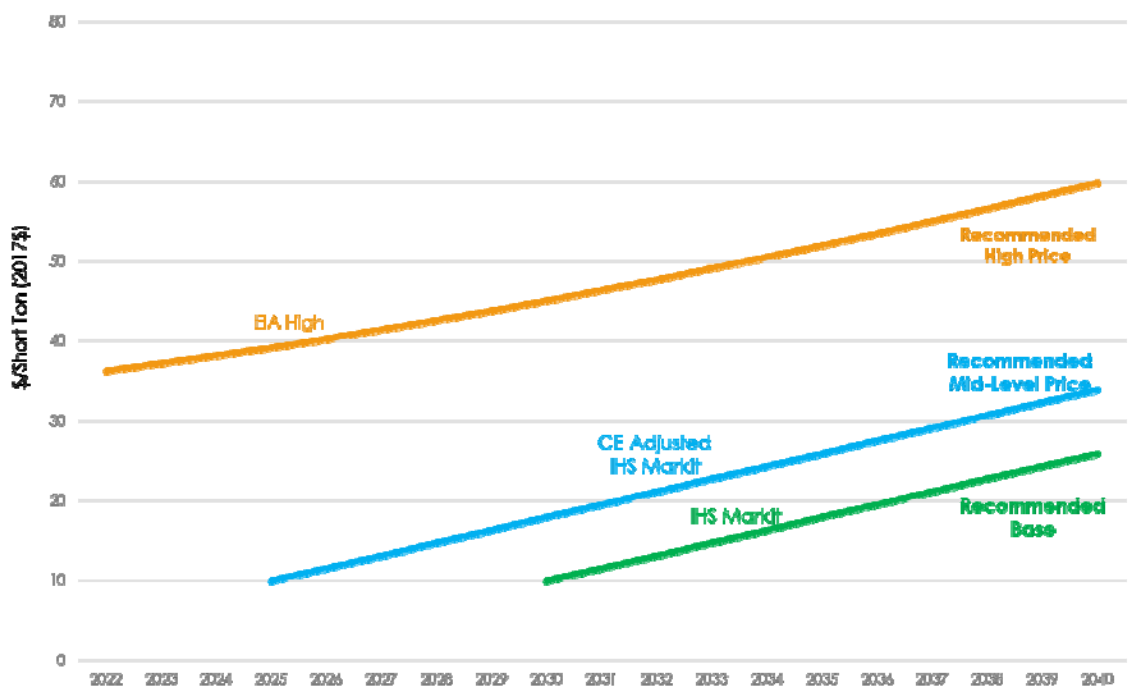
MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Capital Expenditures ($000)

Case No.: U-21090
Exhibit No.: A-23 (HAB-2)
Page: 3 of 3
Witness: HABreining
Date: June 2021

PROJECTED CAPITAL EXPENDITURES
-- CAPITAL + COR (INITIAL INVESTMENT) (CA 1 AND/OR CA 2 MAY 31, 2028 RET): --

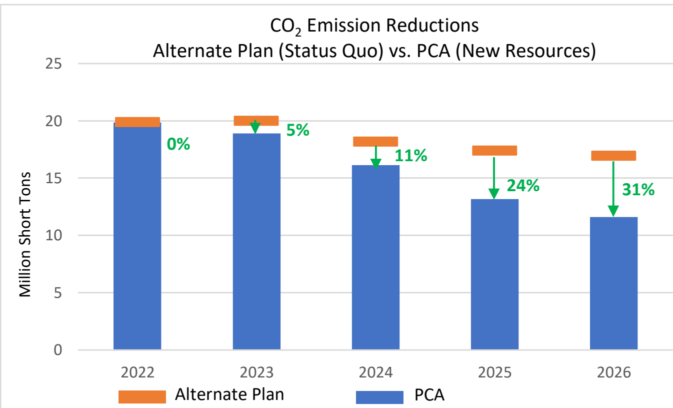
		(a.)	(b.)	(c.)	(d.)	(e.)	(f.)	(g.)	(h.)	(i.)	(j.)
		J.H. Campbell Unit 1				**J.H. Campbell Unit 2**				**J.H. Campbell Unit 3**	
		WWT	**CLS**	**Studies**	**Alt Intake***	**WWT**	**CLS**	**Studies**	**Alt Intake***	**WWT**	**CLS**
		SEEG	**SEEG**	**316(b)**	**316(b)**	**SEEG**	**SEEG**	**316(b)**	**316(b)**	**SEEG**	**SEEG**
Line No.		**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**	**Nominal ($K)**
(1.)	**2021**	$373	$896	$211	$0	$509	$1,223	$289	$0	$1,206	$2,893
(2.)	**2022**	$2,092	$1,993	$0	$5,073	$2,857	$2,721	$0	$6,927	$6,760	$6,439
(3.)	**2023**	$2,408	$2,187	$0	$12,467	$3,288	$2,987	$0	$17,022	$7,780	$7,067
(4.)	**2024**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(5.)	**2025**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(6.)	**2026**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(7.)	**2027**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(8.)	**2028**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(9.)	**2029**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(10.)	**2030**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(11.)	**2031**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(12.)	**2032**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(13.)	**2033**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(14.)	**2034**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(15.)	**2035**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(16.)	**2036**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(17.)	**2037**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(18.)	**2038**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(19.)	**2039**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(20.)	**2040**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
(21.)	**Total**	$4,874	$5,076	$211	$17,540	$6,654	$6,930	$289	$23,949	$15,746	$16,399

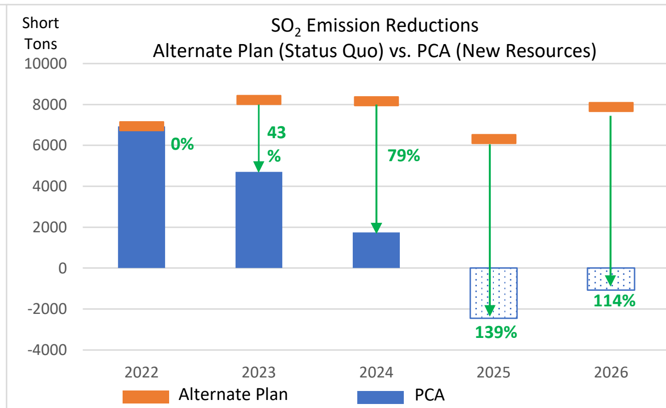
Carbon Price Forecasts Evaluated in IRP Risk Analysis

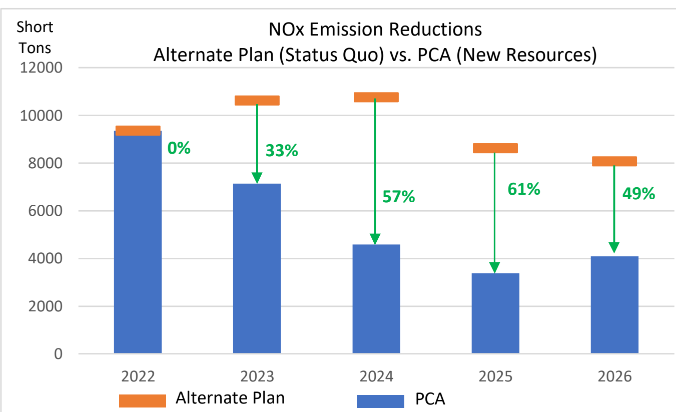


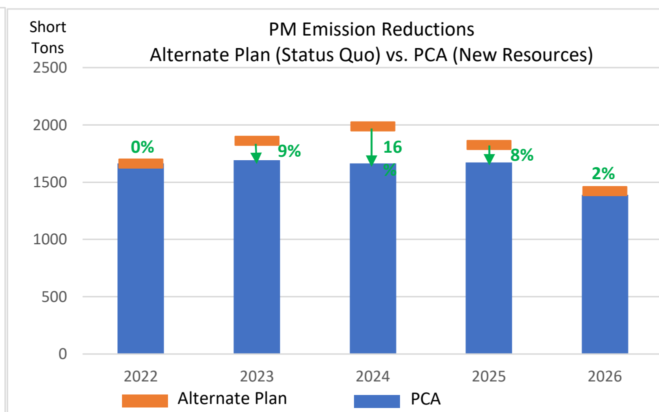
MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
5-Year Annual Emission Projections
2021

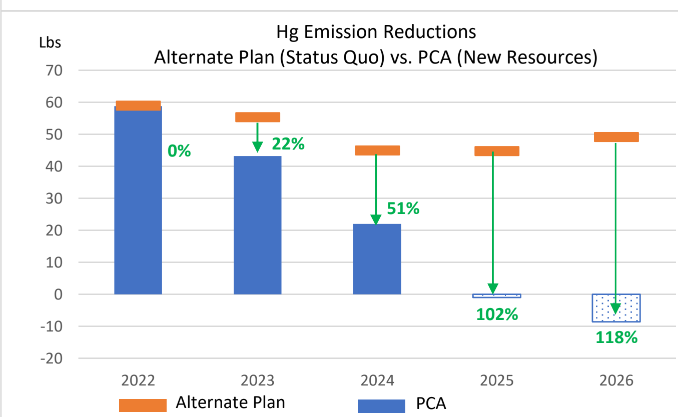
Case No.: U-21090
Exhibit No.: A-25 (HAB-4)
Page: 1 of 1
Witness: HABreining
Date: June 2021











Note: Negative emissions can result when the emissions from the generation that is sold into the MISO exceeds the emissions from the generation that is used to serve CE load.

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

Projected Emissions Comparisons, Company's PCA and MIRPP Scenarios

2021

Case No.: U-21090
Exhibit No.: A-26 (HAB-5)
Page: 1 of 1
Witness: HABreining
Date: June 2021

		Projected CO_2 Emissions (Short Tons)			
		CE-BAU PCA	AEO-BAU PCA	AEO-EP PCA	AEO-ET PCA
		(a.)	(b.)	(c.)	(d.)
(1.)	2022	19,856,152	20,484,749	20,471,112	20,485,625
(2.)	2023	18,891,485	19,243,603	19,324,228	19,287,618
(3.)	2024	16,142,055	16,882,736	17,011,408	17,116,359
(4.)	2025	13,166,225	14,008,804	13,886,735	13,927,466
(5.)	2026	11,602,156	12,401,390	12,233,171	12,237,736
(6.)	2027	11,425,743	12,296,187	12,110,460	12,094,179
(7.)	2028	11,120,042	11,988,288	11,697,752	11,675,216
(8.)	2029	10,681,046	11,533,046	11,261,461	11,294,487
(9.)	2030	10,534,334	11,128,574	10,780,144	10,818,068
(10.)	2031	10,898,354	11,267,244	10,956,281	10,989,548
(11.)	2032	11,142,280	12,061,870	11,438,915	11,460,986
(12.)	2033	11,375,148	11,922,232	11,336,676	11,436,407
(13.)	2034	11,266,899	11,740,487	11,277,301	11,379,901
(14.)	2035	10,757,977	11,783,738	11,159,526	11,507,650
(15.)	2036	9,992,696	11,236,650	10,648,203	11,011,812
(16.)	2037	9,308,626	10,541,216	10,138,065	10,467,106
(17.)	2038	8,756,173	9,912,707	9,549,210	9,846,059
(18.)	2039	8,076,308	9,142,268	9,069,311	9,301,475
(19.)	2040	7,353,349	8,740,278	8,085,467	7,879,761

		Projected SO_2 Emissions (Short Tons)			
		CE-BAU PCA	AEO-BAU PCA	AEO-EP PCA	AEO-ET PCA
		(e.)	(f.)	(g.)	(h.)
(1.)	2022	6,921	9,297	9,516	9,302
(2.)	2023	4,697	7,921	7,805	7,755
(3.)	2024	1,738	6,681	7,498	7,984
(4.)	2025	(2,455)	5,228	4,747	4,779
(5.)	2026	(1,075)	5,326	4,886	4,869
(6.)	2027	(62)	5,482	4,989	4,891
(7.)	2028	320	5,887	5,167	4,904
(8.)	2029	422	5,439	4,351	4,284
(9.)	2030	2,877	6,203	5,019	4,721
(10.)	2031	4,447	6,990	5,806	5,784
(11.)	2032	4,995	8,762	6,156	5,926
(12.)	2033	5,437	8,361	6,223	5,641
(13.)	2034	5,394	7,684	6,698	5,333
(14.)	2035	5,151	7,937	7,220	5,501
(15.)	2036	4,539	7,656	5,748	4,622
(16.)	2037	3,199	5,986	4,793	3,581
(17.)	2038	3,754	5,261	4,068	2,729
(18.)	2039	2,169	3,128	2,321	1,875
(19.)	2040	4,680	6,160	4,759	5,133

		Projected NOx Emissions (Short Tons)			
		CE-BAU PCA	AEO-BAU PCA	AEO-EP PCA	AEO-ET PCA
		(e.)	(f.)	(g.)	(h.)
(1.)	2022	9,347	10,062	10,178	10,063
(2.)	2023	7,140	8,230	8,130	8,143
(3.)	2024	4,587	6,379	6,609	6,963
(4.)	2025	3,373	6,269	6,042	6,069
(5.)	2026	4,083	6,256	5,909	5,919
(6.)	2027	4,339	6,394	6,001	5,969
(7.)	2028	4,130	6,566	5,887	5,846
(8.)	2029	3,818	6,128	5,445	5,475
(9.)	2030	4,567	6,140	5,315	5,229
(10.)	2031	5,433	6,445	5,646	5,647
(11.)	2032	5,862	7,750	5,834	5,837
(12.)	2033	5,960	7,388	5,824	5,655
(13.)	2034	5,948	6,973	6,179	5,582
(14.)	2035	5,612	7,123	6,328	5,750
(15.)	2036	4,882	6,842	5,387	5,151
(16.)	2037	4,159	5,957	5,037	4,625
(17.)	2038	4,306	5,273	4,385	3,947
(18.)	2039	3,187	3,990	3,627	3,363
(19.)	2040	4,993	6,076	5,027	5,084

		Projected PM Emissions (Short Tons)			
		CE-BAU PCA	AEO-BAU PCA	AEO-EP PCA	AEO-ET PCA
		(a.)	(b.)	(c.)	(d.)
(1.)	2022	1,665	1,151	1,168	1,150
(2.)	2023	1,691	1,151	1,092	1,123
(3.)	2024	1,665	835	711	738
(4.)	2025	1,673	793	746	760
(5.)	2026	1,390	840	837	852
(6.)	2027	1,249	841	855	875
(7.)	2028	1,027	872	810	836
(8.)	2029	950	779	792	818
(9.)	2030	530	550	519	544
(10.)	2031	344	458	408	406
(11.)	2032	372	540	430	420
(12.)	2033	391	519	429	405
(13.)	2034	388	492	450	394
(14.)	2035	367	502	467	402
(15.)	2036	333	478	399	357
(16.)	2037	271	401	353	306
(17.)	2038	278	360	311	260
(18.)	2039	204	263	232	219
(19.)	2040	304	388	327	338

		Projected Hg Emissions (Pounds)			
		CE-BAU PCA	AEO-BAU PCA	AEO-EP PCA	AEO-ET PCA
		(e.)	(f.)	(g.)	(h.)
(1.)	2022	59	65	66	65
(2.)	2023	43	51	51	51
(3.)	2024	22	35	38	39
(4.)	2025	(1)	20	18	18
(5.)	2026	(9)	11	10	10
(6.)	2027	(6)	12	11	10
(7.)	2028	(4)	13	12	11
(8.)	2029	(4)	12	9	9
(9.)	2030	2	14	11	10
(10.)	2031	6	16	13	13
(11.)	2032	8	21	14	13
(12.)	2033	8	19	14	12
(13.)	2034	8	17	16	11
(14.)	2035	8	18	18	11
(15.)	2036	6	16	13	8
(16.)	2037	3	12	10	5
(17.)	2038	4	9	7	2
(18.)	2039	1	3	2	0
(19.)	2040	7	11	10	11

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
All Scenarios, Including PCA and Required, Projected CO_2 Emissions
2021

Case No.: U-21090
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Witness: HABreining
Date: June 2021

AEO-BAU SCENARIO: PROJECTED CO2 ANNUAL EMISSIONS (TONS) - ALL GENERATING SOURCES

Line No.		FINAL PCA	MPSC Base - Optimal	Project Marengo 2025 - Optimal	High Load growth rates, 1.5% above BAU growth rates - Optimal	50% ROA Return - Optimal	EE 2.5% over 4 years - Optimal	High Gas, 2x BAU by end of study period - Optimal	Replacement with CT only - Optimal	Project Xavier - Optimal	PX, High Load growth rates, 1.5% above BAU growth rates - Optimal	PX, 50% ROA Return - Optimal	PX, EE 2.5% over 4 years - Optimal	PX, High Gas, 2x BAU by end of study period - Optimal	PX, Replacement with CT only - Optimal
		(a.)	(b.)	(c.)	(d.)	(e.)	(f.)	(g.)	(h.)	(i.)	(j.)	(k.)	(l.)	(m.)	(n.)
(1.)	2022	**20,484,749**	20,355,583	20,351,719	21,416,299	21,669,306	20,349,622	20,858,973	20,354,650	20,484,706	21,409,993	21,800,959	20,484,696	20,850,571	20,484,533
(2.)	2023	**19,243,603**	20,509,083	20,485,518	21,909,791	21,840,514	20,515,065	21,378,685	20,508,620	19,243,064	20,652,358	20,635,426	19,243,863	20,177,919	19,242,835
(3.)	2024	**16,882,736**	18,720,440	18,800,477	20,500,870	20,081,314	18,699,605	19,693,265	18,799,978	16,885,280	18,564,522	18,154,255	16,789,965	18,328,877	16,886,327
(4.)	2025	**14,008,804**	18,069,163	18,070,198	20,176,334	19,281,295	17,790,893	18,820,338	18,717,400	14,062,454	15,957,593	15,247,906	13,828,160	15,402,120	14,691,306
(5.)	2026	**12,401,390**	17,252,090	17,257,914	19,856,670	18,476,686	16,785,712	18,202,031	18,580,348	12,108,186	14,287,502	13,265,052	11,725,207	13,723,975	13,366,851
(6.)	2027	**12,296,187**	17,319,655	17,333,168	20,204,536	18,546,606	16,676,356	18,027,613	19,285,535	12,036,801	14,449,121	13,352,483	11,520,572	13,661,118	14,145,233
(7.)	2028	**11,988,288**	16,666,099	16,687,547	20,183,614	17,886,418	15,826,212	17,321,939	19,331,163	11,801,494	14,422,393	12,874,476	11,157,830	13,144,011	14,350,279
(8.)	2029	**11,533,046**	16,347,206	16,330,829	20,286,786	17,567,935	15,316,731	16,980,849	19,690,607	11,388,066	14,293,488	12,417,637	10,624,876	12,831,395	14,557,904
(9.)	2030	**11,128,574**	15,857,385	15,816,760	14,514,286	17,002,506	14,731,065	16,408,057	19,629,739	11,032,209	14,110,485	12,008,113	10,241,648	12,377,469	14,601,353
(10.)	2031	**11,267,244**	14,792,934	14,773,791	13,969,669	16,000,958	13,658,245	15,437,264	19,023,623	11,019,952	14,360,580	11,942,528	10,154,180	12,407,449	15,014,371
(11.)	2032	**12,061,870**	14,441,204	14,444,651	13,618,233	15,675,219	13,152,792	14,918,622	19,090,465	11,274,140	14,865,609	12,217,430	10,286,631	12,022,107	15,852,010
(12.)	2033	**11,922,232**	14,309,727	14,272,274	13,447,427	15,429,626	13,000,971	14,659,256	18,824,324	10,819,309	14,558,248	11,656,943	9,806,490	11,037,798	15,688,420
(13.)	2034	**11,740,487**	13,339,548	13,251,695	12,532,325	14,347,388	11,952,553	13,658,159	18,145,925	10,134,058	14,126,981	10,916,014	9,043,668	9,922,843	15,489,406
(14.)	2035	**11,783,738**	13,917,968	13,862,628	13,096,164	14,990,738	12,420,611	14,221,821	19,010,004	10,070,935	14,312,501	10,863,531	8,883,028	9,401,380	15,917,844
(15.)	2036	**11,236,650**	13,564,945	13,468,476	12,693,220	14,681,288	12,173,820	13,889,440	19,031,874	9,638,929	13,910,489	10,351,178	8,494,699	8,611,902	15,897,802
(16.)	2037	**10,541,216**	13,296,109	13,182,940	12,426,146	14,228,417	11,796,691	13,382,159	18,879,701	9,115,561	13,696,901	9,738,200	8,006,737	7,634,839	15,825,124
(17.)	2038	**9,912,707**	12,940,819	12,807,203	11,989,495	13,797,745	11,410,265	12,756,958	18,674,704	8,612,800	13,388,959	9,175,663	7,480,005	6,373,043	15,737,558
(18.)	2039	**9,142,268**	12,544,313	12,464,601	11,636,729	13,351,271	11,133,263	12,458,914	17,971,992	8,062,690	12,702,917	8,525,644	6,955,617	5,557,516	15,033,969
(19.)	2040	**8,740,278**	9,135,621	8,977,013	8,432,798	9,810,071	7,764,891	8,921,310	14,414,422	7,707,317	7,666,362	8,088,125	6,687,003	4,891,449	14,355,399

CARBON EMISSION PERCENT REDUCTIONS

	(a.)	(b.)	(c.)	(d.)	(e.)	(f.)	(g.)	(h.)	(i.)	(j.)	(k.)	(l.)	(m.)	(n.)
2005-2025	**50%**	35%	35%	27%	31%	36%	32%	33%	49%	42%	45%	50%	44%	47%
2005-2030	**60%**	43%	43%	48%	39%	47%	41%	29%	60%	49%	57%	63%	55%	47%
2005-2040	**69%**	67%	68%	70%	65%	72%	68%	48%	72%	72%	71%	76%	82%	48%

CE-BAU SCENARIO: PROJECTED CO_2 ANNUAL EMISSIONS (TONS)

Line No.		FINAL PCA	Alternate Base Plan (Marengo 2025)	Base - Optimal	CA1 2024 - Optimal	CA1 2025 - Optimal	CA1 2026 - Optimal	CA1 2028 - Optimal	CA2 2024 - Optimal	CA2 2025 - Optimal	CA2 2026 - Optimal	CA2 2028 - Optimal	CA12 2024 - Optimal	CA12 2025 - Optimal	CA12 2026 - Optimal	CA12 2028 - Optimal	Project Marengo 2025 - Optimal	FINAL PCA (Optimal)
		(a.)	(b.)	(c.)	(d.)	(e.)	(f.)	(g.)	(h.)	(i.)	(j.)	(k.)	(l.)	(m.)	(n.)	(o.)	(p.)	(q.)
(1.)	2022	**19,856,152**	19,863,657	19,544,204	19,539,250	19,539,250	19,544,204	19,544,195	19,544,204	19,544,204	19,544,204	19,544,204	19,539,137	19,539,090	19,544,149	19,544,204	19,544,195	19,857,687
(2.)	2023	**18,891,485**	19,965,071	19,646,006	19,636,198	19,641,257	19,646,006	19,646,122	19,639,960	19,639,960	19,638,112	19,646,006	19,630,381	19,635,250	19,640,234	19,646,006	19,645,998	18,891,627
(3.)	2024	**16,142,055**	18,165,915	17,631,123	17,106,095	17,622,201	17,626,728	17,631,523	17,133,844	17,619,731	17,631,060	17,631,123	16,580,506	17,610,581	17,626,862	17,631,123	17,647,734	16,142,726
(4.)	2025	**13,166,225**	17,367,999	17,017,696	16,139,428	16,478,927	17,012,395	17,013,254	16,166,142	16,470,237	17,032,095	17,017,696	15,329,494	15,934,277	16,999,566	17,017,696	17,049,202	13,291,855
(5.)	2026	**11,602,156**	16,915,470	16,502,619	15,649,831	15,650,234	15,952,465	16,498,186	15,682,174	15,682,499	15,976,223	16,502,619	14,846,809	14,826,273	15,425,544	16,502,619	16,483,071	11,450,104
(6.)	2027	**11,425,743**	16,708,115	16,605,336	15,753,914	15,753,340	15,753,461	16,606,031	15,785,919	15,785,135	15,785,882	16,605,336	14,958,773	14,935,835	14,936,589	16,605,336	16,572,654	11,404,839
(7.)	2028	**11,120,042**	16,167,001	16,192,499	15,418,740	15,418,842	15,418,533	15,639,311	15,380,598	15,380,809	15,380,938	15,684,079	14,626,719	14,595,085	14,595,679	15,136,553	16,161,588	11,226,813
(8.)	2029	**10,681,046**	15,848,853	16,030,821	15,176,125	15,175,776	15,175,867	15,169,894	15,208,912	15,209,273	15,208,964	15,208,907	14,416,215	14,376,946	14,377,408	14,377,386	16,032,275	10,922,575
(9.)	2030	**10,534,334**	15,489,499	15,713,443	14,829,024	14,818,089	14,839,005	14,833,662	14,861,194	14,861,194	14,861,181	14,861,188	14,024,140	13,976,510	13,976,815	13,976,763	15,710,666	10,877,681
(10.)	2031	**10,898,354**	14,554,147	14,748,464	14,354,628	14,354,749	14,354,016	14,346,606	14,362,952	14,363,077	14,363,880	14,363,669	14,036,694	13,980,950	13,981,226	13,982,063	14,760,113	11,104,489
(11.)	2032	**11,142,280**	13,857,909	14,251,763	14,252,161	14,252,060	14,252,052	14,263,393	14,251,953	14,251,744	14,251,688	14,251,943	14,364,903	14,251,351	14,251,999	14,251,606	14,251,951	10,866,484
(12.)	2033	**11,375,148**	14,170,637	14,149,101	14,149,712	14,150,115	14,149,944	14,149,256	14,150,357	14,148,775	14,149,407	14,149,524	14,224,804	14,149,219	14,149,136	14,149,641	14,112,345	10,799,276
(13.)	2034	**11,266,899**	13,567,913	13,283,279	13,283,228	13,283,506	13,283,086	13,284,712	13,284,321	13,283,906	13,283,026	13,282,876	13,379,619	13,283,104	13,283,407	13,283,687	13,228,893	10,174,724
(14.)	2035	**10,757,977**	13,883,264	13,835,964	13,836,542	13,837,176	13,836,756	13,839,309	13,837,094	13,836,404	13,836,418	13,837,811	13,923,275	13,836,805	13,837,079	13,836,539	13,764,556	9,580,020
(15.)	2036	**9,992,696**	13,610,653	13,431,664	13,432,048	13,432,994	13,432,123	13,406,860	13,431,977	13,432,335	13,432,539	13,432,118	13,543,194	13,431,169	13,432,152	13,432,268	13,335,300	8,972,648
(16.)	2037	**9,308,626**	13,105,832	12,978,891	12,979,106	12,979,021	12,978,862	12,985,495	12,978,751	12,979,098	12,978,968	12,978,688	13,110,214	12,979,274	12,979,042	12,979,115	12,878,950	8,409,000
(17.)	2038	**8,756,173**	12,465,771	12,666,221	12,666,264	12,665,890	12,666,271	12,669,180	12,666,430	12,666,449	12,666,490	12,666,295	12,809,246	12,666,699	12,667,952	12,666,270	12,551,197	7,983,647
(18.)	2039	**8,076,308**	11,945,771	12,403,849	12,403,860	12,403,684	12,402,821	12,411,702	12,404,809	12,402,827	12,403,776	12,404,856	12,552,614	12,404,520	12,405,622	12,403,003	12,278,969	7,433,476
(19.)	2040	**7,353,349**	8,432,598	9,131,123	9,130,730	9,132,517	9,130,707	9,133,260	9,131,651	9,130,936	9,130,915	9,130,732	8,921,297	9,132,927	9,131,680	9,131,167	9,004,243	6,871,139

CARBON EMISSION PERCENT REDUCTIONS

	(a.)	(b.)	(c.)	(d.)	(e.)	(f.)	(g.)	(h.)	(i.)	(j.)	(k.)	(l.)	(m.)	(n.)	(o.)	(p.)	(q.)
2005-2025	**53%**	37%	39%	42%	41%	39%	39%	42%	41%	39%	39%	45%	43%	39%	39%	39%	52%
2005-2030	**62%**	44%	43%	47%	47%	47%	47%	46%	46%	46%	46%	49%	50%	50%	50%	43%	61%
2005-2040	**74%**	70%	67%	67%	67%	67%	67%	67%	67%	67%	67%	68%	67%	67%	67%	68%	75%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
All Scenarios, Including PCA and Required, Projected CO_2 Emissions
2021

Case No.: U-21090
Exhibit No.: A-27 (HAB-6)

Witness: HABreining
Date: June 2021

AEO-ET SCENARIO: PROJECTED CO_2 ANNUAL EMISSIONS (TONS)

Line No.		Project Xavier outcome - PCA	MPSC Base - Optimal	Project Marengo 2025 - Optimal	EE 2.5% over 4 years - Optimal	High Gas, 2x BAU by end of study period - Optimal	Project Xavier outcome - Optimal	PX, Renewable Energy 25% by 2030 - Optimal	PX, EE 2.5% over 4 years - Optimal	PX, High Gas, 2x BAU by end of study period - Optimal		High Load growth rates, 1.5% above BAU growth rates - Optimal	PX, High Load growth rates, 1.5% above BAU growth rates - Optimal
		(a.)	(b.)	(c.)	(d.)	(e.)	(f.)	(g.)	(h.)	(i.)		(j.)	(k.)
(1.)	2022	20,485,625	20,354,518	20,325,316	20,355,505	20,356,651	20,485,612	20,485,612	20,485,604	20,852,181		21,410,596	21,410,135
(2.)	2023	19,287,618	20,491,163	20,394,919	20,494,091	20,542,664	19,274,203	19,274,203	19,275,168	20,244,926		21,893,399	20,670,530
(3.)	2024	17,116,359	18,720,968	19,006,480	18,652,800	18,796,128	17,116,607	17,116,607	17,024,336	18,464,582		16,707,350	18,708,293
(4.)	2025	13,927,466	17,968,721	17,956,405	17,695,760	17,946,518	13,980,581	13,980,581	13,752,219	15,163,182		16,236,509	15,841,819
(5.)	2026	12,237,736	17,092,715	17,118,073	16,650,199	17,219,945	11,934,012	11,934,012	11,565,277	13,207,419		15,762,503	14,062,598
(6.)	2027	12,094,179	16,992,083	16,998,617	16,358,379	17,182,492	11,849,003	11,849,003	11,365,509	13,023,466		15,911,691	14,178,112
(7.)	2028	11,675,216	16,452,557	16,447,343	15,630,609	16,557,274	11,482,629	11,482,629	10,872,213	12,553,982		15,641,300	13,985,368
(8.)	2029	11,294,487	16,105,376	16,102,376	15,125,129	16,170,125	11,151,230	11,151,230	10,413,449	12,147,100		15,639,851	13,934,319
(9.)	2030	10,818,068	15,586,712	15,570,938	14,553,004	15,617,398	10,732,171	10,732,171	9,985,116	11,626,821		15,436,867	13,743,938
(10.)	2031	10,989,548	14,506,338	14,586,084	13,416,352	14,480,348	10,687,186	10,687,186	9,870,673	11,856,288		14,649,726	13,853,110
(11.)	2032	11,460,986	14,102,425	14,219,689	12,822,521	14,190,713	10,596,762	10,596,762	9,642,559	12,355,903		14,213,337	14,001,396
(12.)	2033	11,436,407	13,937,927	14,086,476	12,625,002	14,101,717	10,198,885	10,198,885	9,230,167	11,858,541		14,137,799	13,826,347
(13.)	2034	11,379,901	13,051,256	13,219,313	11,667,441	13,225,430	9,629,213	9,629,213	8,604,115	11,262,982		13,256,280	13,406,850
(14.)	2035	11,507,650	13,836,622	13,958,260	12,345,447	14,161,910	9,606,893	9,606,893	8,486,558	11,573,093		14,048,357	13,563,742
(15.)	2036	11,011,812	13,593,959	13,672,667	12,104,182	13,978,371	9,144,598	9,144,598	8,045,654	11,300,584		13,825,222	13,322,699
(16.)	2037	10,467,106	13,231,037	13,377,278	11,823,271	13,547,656	8,744,962	8,744,962	7,714,664	10,778,050		13,516,339	12,983,308
(17.)	2038	9,846,059	12,759,235	12,991,871	11,351,629	13,004,872	8,208,988	8,208,988	7,197,317	10,221,629		12,977,562	12,517,902
(18.)	2039	9,301,475	12,371,528	12,851,092	11,131,508	12,245,953	7,896,806	7,896,806	6,969,150	9,062,939		12,526,997	11,899,438
(19.)	2040	7,879,761	7,966,617	9,427,213	6,955,387	8,191,932	6,669,913	6,669,913	5,854,302	7,828,334		8,246,952	10,483,548

CARBON EMISSION PERCENT REDUCTIONS

	(a.)	(b.)	(c.)	(d.)	(e.)	(f.)	(g.)	(h.)	(i.)	(j.)	(k.)
2005-2025	**50%**	35%	35%	41%	36%	35%	50%	43%	50%	50%	45%
2005-2030	**61%**	44%	44%	44%	48%	44%	61%	50%	61%	64%	58%
2005-2040	**72%**	71%	66%	70%	75%	70%	76%	62%	76%	79%	72%

CE-ET SCENARIO: PROJECTED CO_2 ANNUAL EMISSIONS (TONS)

Line No.		FINAL PCA	Alternate Plan	Base - Optimal	CA1 2024 - Optimal	CA1 2025 - Optimal	CA1 2026 - Optimal	CA1 2028 - Optimal	CA2 2024 - Optimal	CA2 2025 - Optimal	CA2 2026 - Optimal	CA2 2028 - Optimal	CA12 2024 - Optimal	CA12 2025 - Optimal	CA12 2026 - Optimal	CA12 2028 - Optimal	Project Marengo 2025 - Optimal	FINAL PCA - Optimal
		(a.)	(b.)	(c.)	(d.)	(e.)	(f.)	(g.)	(h.)	(i.)	(j.)	(k.)	(l.)	(m.)	(n.)	(o.)	(p.)	(q.)
(1.)	2022	**19,870,885**	19,874,083	19,541,535	19,536,610	19,536,610	19,541,539	19,541,539	19,541,535	19,541,535	19,541,535	19,541,535	19,536,532	19,536,520	19,541,535	19,541,535	19,541,536	19,866,558
(2.)	2023	**18,941,959**	19,959,875	19,684,476	19,647,298	19,652,022	19,684,476	19,684,476	19,678,384	19,678,384	19,678,384	19,684,476	19,668,393	19,645,969	19,678,384	19,684,476	19,684,512	18,943,820
(3.)	2024	**16,515,656**	18,104,185	17,732,576	17,153,569	17,722,652	17,727,053	17,732,477	17,180,728	17,720,868	17,732,046	17,732,114	16,626,801	17,708,902	17,726,790	17,732,576	17,760,163	16,515,366
(4.)	2025	**13,058,067**	17,338,525	17,080,065	16,164,027	16,488,712	17,075,237	17,080,755	16,188,101	16,504,563	17,067,189	17,080,722	15,280,295	15,916,731	17,061,613	17,080,065	17,085,412	13,229,255
(5.)	2026	**11,081,472**	16,795,164	16,515,302	15,621,222	15,621,422	15,934,312	16,515,422	15,652,450	15,652,327	15,957,412	16,515,072	14,761,632	14,761,164	15,376,535	16,515,302	16,528,780	10,950,459
(6.)	2027	**10,891,641**	16,610,075	16,587,100	15,692,761	15,692,602	15,687,661	16,587,267	15,722,593	15,722,999	15,722,377	16,589,268	14,831,742	14,838,989	14,840,131	16,587,100	16,599,015	10,872,925
(7.)	2028	**10,599,607**	16,120,481	16,144,160	15,307,207	15,307,088	15,307,024	15,563,906	15,266,662	15,268,079	15,266,411	15,588,056	14,438,743	14,437,224	14,438,976	15,011,085	16,148,645	10,700,154
(8.)	2029	**10,199,693**	15,776,135	15,956,966	15,065,494	15,065,418	15,068,592	15,065,481	15,101,195	15,101,085	15,101,102	15,101,015	14,161,201	14,172,225	14,169,292	14,169,675	15,984,847	10,422,484
(9.)	2030	**10,048,937**	15,532,205	15,725,586	14,847,617	14,817,703	14,817,729	14,817,734	14,849,497	14,849,498	14,848,889	14,849,438	13,944,148	13,958,348	13,958,137	13,958,016	15,742,207	10,379,675
(10.)	2031	**10,290,361**	14,560,743	14,760,205	14,341,408	14,345,524	14,345,536	14,345,335	14,354,291	14,358,193	14,354,704	14,354,678	13,928,125	13,940,106	13,938,275	13,939,042	14,759,896	10,495,615
(11.)	2032	**10,345,406**	13,703,275	14,082,539	14,077,261	14,082,828	14,082,324	14,082,925	14,084,172	14,081,495	14,082,446	14,082,661	14,065,304	14,082,145	14,083,182	14,084,116	14,081,743	10,068,676
(12.)	2033	**10,670,761**	13,995,715	13,931,958	13,924,836	13,931,895	13,931,500	13,931,321	13,931,256	13,931,837	13,931,681	13,931,911	13,915,697	13,905,597	13,931,382	13,932,075	13,885,814	10,099,818
(13.)	2034	**10,621,342**	13,477,324	13,074,366	13,069,986	13,073,765	13,077,426	13,074,225	13,073,941	13,077,832	13,077,593	13,073,713	13,058,687	13,035,939	13,077,892	13,078,175	13,008,355	9,543,823
(14.)	2035	**10,015,487**	13,759,886	13,656,570	13,643,527	13,656,550	13,656,068	13,656,203	13,656,511	13,656,636	13,654,206	13,654,906	13,638,037	13,605,483	13,655,562	13,656,361	13,570,302	8,851,248
(15.)	2036	**9,428,845**	13,704,572	13,382,949	13,377,460	13,383,713	13,382,780	13,383,154	13,383,023	13,381,741	13,383,343	13,382,286	13,363,334	13,320,782	13,381,916	13,382,971	13,277,693	8,399,905
(16.)	2037	**8,759,558**	13,131,635	12,913,203	12,910,225	12,913,780	12,913,308	12,914,697	12,914,519	12,914,544	12,914,703	12,914,176	12,900,689	12,842,434	12,913,343	12,913,729	12,793,102	7,882,957
(17.)	2038	**8,102,843**	12,421,751	12,509,298	12,503,428	12,507,788	12,508,258	12,508,864	12,509,015	12,509,545	12,507,645	12,507,762	12,495,970	12,424,500	12,509,829	12,508,554	12,366,922	7,339,372
(18.)	2039	**7,637,380**	11,904,464	12,296,835	12,287,795	12,295,628	12,294,859	12,297,317	12,295,974	12,295,773	12,296,254	12,293,987	12,275,385	12,203,893	12,294,641	12,295,201	12,141,999	7,029,301
(19.)	2040	**7,236,305**	8,323,317	8,939,829	8,929,577	8,938,799	8,934,081	8,938,222	8,935,529	8,938,657	8,938,020	8,933,583	8,922,992	8,844,139	8,933,592	8,934,141	8,783,086	6,767,583

CARBON EMISSION PERCENT REDUCTIONS

	(a.)	(b.)	(c.)	(d.)	(e.)	(f.)	(g.)	(h.)	(i.)	(j.)	(k.)	(l.)	(m.)	(n.)	(o.)	(p.)	(q.)
2005-2025	**53%**	38%	38%	42%	41%	38%	38%	42%	41%	38%	38%	45%	43%	39%	38%	38%	52%
2005-2030	**64%**	44%	43%	46%	47%	47%	47%	46%	46%	46%	46%	50%	50%	50%	50%	43%	63%
2005-2040	**74%**	70%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%	76%

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

All Scenarios, Including PCA and Required, Projected CO_2 Emissions

2021

Case No.: U-21090
Exhibit No.: A-27 (HAB-6)

Witness: HABreining
Date: June 2021

AEO-EP SCENARIO: PROJECTED CO_2 ANNUAL EMISSIONS (TONS)

Line No.		Project Xavier outcome - PCA	MPSC Base - Optimal	Project Marengo 2025 - Optimal	High Load growth rates, 1.5% above BAU growth rates - Optimal	50% CO2 reduction by 2030 - Optimal	EE 2.5% over 4 years - Optimal	High Gas, 2x BAU by end of study period - Optimal	Project Xavier outcome - Optimal	PX, High Load growth rates, 1.5% above BAU growth rates - Optimal	PX, EE 2.5% over 4 years - Optimal	PX, High Gas, 2x BAU by end of study period - Optimal	PCA+ with 1.5% load growth, CO2 reduction targets - Optimal
		(a.)	(b.)	(c.)	(d.)	(e.)	(f.)	(g.)	(h.)	(i.)	(j.)	(k.)	(l.)
(1.)	2022	20,471,112	20,354,946	20,342,789	21,417,244	20,608,977	20,356,468	20,861,706	20,485,355	21,411,580	20,485,356	20,854,687	21,411,464
(2.)	2023	19,324,228	20,463,564	20,463,476	18,913,899	20,702,365	20,464,437	21,533,071	19,323,217	20,657,583	19,323,649	20,393,886	20,744,121
(3.)	2024	17,011,408	18,661,774	18,744,585	17,564,225	18,953,622	18,653,723	19,581,918	17,079,060	18,603,479	16,920,056	18,541,008	18,613,580
(4.)	2025	13,886,735	17,943,771	17,952,963	17,134,242	18,015,708	17,669,600	18,665,102	13,941,194	15,812,151	13,713,111	15,222,559	15,137,318
(5.)	2026	12,233,171	17,109,276	17,125,804	16,687,168	17,197,043	16,646,629	17,949,665	11,936,676	14,070,828	11,572,242	13,311,570	13,642,866
(6.)	2027	12,110,460	17,009,684	17,026,122	16,828,432	16,945,278	16,365,743	17,748,002	11,860,462	14,177,889	11,366,498	13,223,072	13,577,480
(7.)	2028	11,697,752	16,482,304	16,491,006	16,551,318	16,381,161	15,658,137	17,051,663	11,509,424	14,028,369	10,889,670	12,745,292	13,265,596
(8.)	2029	11,261,461	16,093,428	16,091,048	16,502,249	16,018,107	15,100,426	16,759,351	11,127,559	13,947,610	10,401,624	12,640,088	13,050,262
(9.)	2030	10,780,144	15,566,895	15,557,766	16,252,038	15,421,847	14,485,075	16,192,808	10,689,203	13,739,420	9,939,235	12,111,568	12,642,694
(10.)	2031	10,956,281	14,456,771	14,462,079	15,507,555	14,651,887	13,358,141	15,104,711	10,572,560	13,865,286	10,042,569	11,976,578	12,659,755
(11.)	2032	11,438,915	14,020,756	14,008,054	14,993,207	14,097,116	12,754,444	14,579,110	10,530,975	14,019,775	10,064,989	11,711,963	13,106,306
(12.)	2033	11,336,676	13,758,144	13,720,004	14,779,441	13,741,029	12,500,639	14,207,451	10,044,970	13,700,205	9,821,143	10,509,135	12,887,218
(13.)	2034	11,277,301	12,730,040	12,677,207	13,748,776	12,811,320	11,478,683	13,034,739	9,507,865	13,139,257	9,437,400	9,249,685	12,637,339
(14.)	2035	11,159,526	13,235,947	13,175,555	14,199,765	13,045,096	11,959,640	13,450,192	9,353,998	13,048,923	9,389,742	8,626,038	12,457,703
(15.)	2036	10,648,203	13,086,004	13,000,695	14,127,121	12,902,397	11,789,069	13,375,192	8,813,114	12,812,353	9,086,966	7,939,111	11,895,904
(16.)	2037	10,138,065	12,751,723	12,654,841	13,823,622	12,572,114	11,528,135	12,975,940	8,354,688	12,488,871	8,877,266	7,051,947	11,304,342
(17.)	2038	9,549,210	12,374,108	12,263,400	13,420,590	12,201,172	11,158,423	12,480,006	7,849,331	12,112,291	8,523,293	6,079,241	10,659,488
(18.)	2039	9,069,311	12,031,060	11,934,684	12,913,686	11,504,082	10,947,876	11,660,749	7,602,117	11,572,686	8,328,547	5,185,048	10,067,516
(19.)	2040	8,085,467	8,138,699	8,033,309	9,191,878	7,971,621	7,143,436	6,653,580	6,749,468	10,753,119	7,610,497	4,093,339	9,075,236

CARBON EMISSION PERCENT REDUCTIONS

	(a.)	(b.)	(c.)	(d.)	(e.)	(f.)	(g.)	(h.)	(i.)	(j.)	(k.)	(l.)
2005-2025	**50%**	35%	35%	38%	35%	36%	33%	50%	43%	51%	45%	45%
2005-2030	**61%**	44%	44%	41%	44%	48%	42%	61%	50%	64%	56%	54%
2005-2040	**71%**	71%	71%	67%	71%	74%	76%	76%	61%	73%	85%	67%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
All Scenarios, Including PCA and Required, Projected CO_2 Emissions
2021

Case No.: U-21090
Exhibit No.: A-27 (HAB-6)

Witness: HABreining
Date: June 2021

CE-EP SCENARIO: PROJECTED CO_2 ANNUAL EMISSIONS (TONS)

Line No.		FINAL PCA	Alternate Plan	Base - Optimal	CA1 2024 - Optimal	CA1 2025 - Optimal	CA1 2026 - Optimal	CA1 2028 - Optimal	CA2 2024 - Optimal	CA2 2025 - Optimal	CA2 2026 - Optimal	CA2 2028 - Optimal	CA12 2024 - Optimal	CA12 2025 - Optimal	CA12 2026 - Optimal	CA12 2028 - Optimal	Project Marengo 2025 - Optimal	FINAL PCA - Optimal
		(a.)	(b.)	(c.)	(d.)	(e.)	(f.)	(g.)	(h.)	(i.)	(j.)	(k.)	(l.)	(m.)	(n.)	(o.)	(p.)	(q.)
(1.)	2022	**19,875,657**	19,880,604	19,541,895	19,536,969	19,536,969	19,541,895	19,541,895	19,541,895	19,541,895	19,541,895	19,541,895	19,536,966	19,536,935	19,541,895	19,541,895	19,541,883	19,875,160
(2.)	2023	**19,057,817**	20,022,221	19,718,940	19,708,638	19,713,880	19,718,940	19,718,940	19,712,763	19,712,763	19,712,763	19,718,940	19,701,857	19,707,603	19,712,490	19,718,474	19,719,318	19,057,933
(3.)	2024	**16,840,244**	18,055,572	17,743,070	17,148,461	17,733,297	17,738,286	17,743,070	17,176,714	17,730,912	17,743,389	17,743,070	16,596,549	17,720,048	17,737,626	17,742,767	17,746,106	16,838,734
(4.)	2025	**13,410,504**	17,403,643	17,161,860	16,256,342	16,575,948	17,155,475	17,161,860	16,275,050	16,601,593	17,148,330	17,161,860	15,339,473	16,009,055	17,142,464	17,162,086	17,192,055	13,501,507
(5.)	2026	**11,476,605**	16,829,096	16,568,256	15,629,194	15,629,013	15,964,196	16,568,256	15,657,833	15,657,515	15,985,017	16,568,256	14,713,166	14,713,275	15,376,628	16,566,602	16,576,787	11,270,753
(6.)	2027	**11,217,456**	16,618,737	16,649,521	15,698,558	15,697,999	15,696,551	16,649,521	15,724,985	15,725,263	15,725,011	16,649,521	14,775,266	14,779,528	14,779,844	16,649,134	16,640,838	11,097,797
(7.)	2028	**10,923,063**	16,138,089	16,208,797	15,333,758	15,333,729	15,333,438	15,598,910	15,286,605	15,286,277	15,286,565	15,626,043	14,412,309	14,422,654	14,422,946	15,019,805	16,213,639	10,876,012
(8.)	2029	**10,496,228**	15,769,379	16,048,593	15,088,952	15,089,019	15,091,106	15,089,565	15,126,505	15,128,869	15,126,613	15,126,421	14,157,490	14,168,620	14,168,606	14,168,754	16,048,569	10,529,345
(9.)	2030	**10,095,190**	15,337,970	15,662,574	14,705,741	14,705,013	14,705,038	14,704,754	14,737,025	14,738,070	14,736,547	14,737,121	13,756,818	13,776,816	13,775,887	13,775,711	15,660,752	10,201,379
(10.)	2031	**10,333,057**	14,209,432	14,562,249	14,135,653	14,135,131	14,135,498	14,133,825	14,144,137	14,144,489	14,144,311	14,144,242	13,703,104	13,713,827	13,713,313	13,713,501	14,561,224	10,322,603
(11.)	2032	**10,417,146**	13,428,141	13,907,880	13,907,152	13,907,805	13,908,500	13,908,699	13,907,976	13,908,229	13,908,039	13,908,468	13,894,107	13,908,366	13,907,676	13,907,631	13,907,730	9,958,750
(12.)	2033	**10,778,433**	13,590,889	13,661,714	13,663,222	13,662,367	13,662,338	13,662,125	13,664,011	13,662,280	13,661,937	13,663,336	13,650,408	13,640,589	13,662,821	13,663,068	13,623,156	10,044,213
(13.)	2034	**10,652,616**	12,985,982	12,763,306	12,764,653	12,765,927	12,764,948	12,764,656	12,764,250	12,763,831	12,763,162	12,763,570	12,755,053	12,728,824	12,763,113	12,764,243	12,704,154	9,453,390
(14.)	2035	**10,099,191**	13,261,766	13,349,427	13,348,900	13,349,490	13,349,282	13,349,072	13,349,290	13,348,128	13,348,927	13,347,817	13,332,177	13,304,027	13,348,943	13,348,990	13,270,862	8,873,569
(15.)	2036	**9,391,962**	12,733,777	12,725,196	12,724,205	12,723,740	12,724,585	12,725,343	12,724,279	12,723,139	12,725,005	12,724,387	12,709,266	12,673,398	12,724,295	12,723,935	12,640,121	8,365,257
(16.)	2037	**8,721,171**	12,000,011	12,054,648	12,047,132	12,058,223	12,042,827	12,052,219	12,038,637	12,038,477	12,043,458	12,041,269	12,030,078	11,996,194	12,048,170	12,044,773	11,945,078	7,882,610
(17.)	2038	**8,189,223**	11,406,560	11,722,381	11,719,607	11,724,175	11,725,439	11,723,313	11,723,737	11,724,447	11,721,049	11,722,999	11,705,383	11,651,316	11,718,743	11,720,863	11,603,855	7,423,251
(18.)	2039	**7,687,314**	10,630,773	11,101,875	11,101,755	11,104,628	11,107,046	11,105,661	11,107,386	11,099,896	11,098,759	11,107,654	11,067,839	11,048,392	11,109,676	11,107,469	11,002,113	7,125,815
(19.)	2040	**5,760,615**	6,316,873	7,014,337	7,009,646	7,005,387	7,004,413	7,009,806	7,015,840	7,006,488	7,013,076	7,010,648	6,989,652	6,941,050	7,012,969	7,015,637	6,896,297	5,350,140

CARBON EMISSION PERCENT REDUCTIONS

	(a.)	(b.)	(c.)	(d.)	(e.)	(f.)	(g.)	(h.)	(i.)	(j.)	(k.)	(l.)	(m.)	(n.)	(o.)	(p.)	(q.)
2005-2025	**52%**	37%	38%	41%	40%	38%	38%	41%	40%	38%	38%	45%	42%	38%	38%	38%	51%
2005-2030	**64%**	45%	44%	47%	47%	47%	47%	47%	47%	47%	47%	50%	50%	50%	50%	44%	63%
2005-2040	**79%**	77%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	81%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
All Scenarios, Including PCA and Required, Projected CO_2 Emissions
2021

Case No.: U-21090
Exhibit No.: A-27 (HAB-6)
Page: 7 of 7
Witness: HABreining
Date: June 2021

CE-ADV SCENARIO: PROJECTED CO_2 ANNUAL EMISSIONS

Line No.		Project Marengo 2025 - Optimal	FINAL PCA - Optimal
		(a.)	(b.)
(1.)	2022	19,676,025	19,616,360
(2.)	2023	19,697,665	18,596,432
(3.)	2024	17,609,732	15,696,007
(4.)	2025	16,972,789	13,276,029
(5.)	2026	16,005,734	11,202,833
(6.)	2027	15,234,445	10,810,703
(7.)	2028	14,469,456	10,436,887
(8.)	2029	13,702,355	9,937,697
(9.)	2030	12,972,939	9,592,233
(10.)	2031	11,585,996	9,554,972
(11.)	2032	10,559,529	9,119,619
(12.)	2033	10,792,236	8,941,419
(13.)	2034	9,924,533	8,365,755
(14.)	2035	9,948,854	7,522,901
(15.)	2036	9,612,653	6,986,134
(16.)	2037	9,288,508	6,367,834
(17.)	2038	9,114,384	6,403,485
(18.)	2039	9,022,973	5,858,518
(19.)	2040	5,473,802	5,297,440

CARBON EMISSION PERCENT REDUCTIONS

	(a.)	(b.)
2005-2025	39%	52%
2005-2030	53%	65%
2005-2040	80%	81%

Emissions Accounting Whitepaper

Consumers Energy
Count on Us®

Heather A. Breining

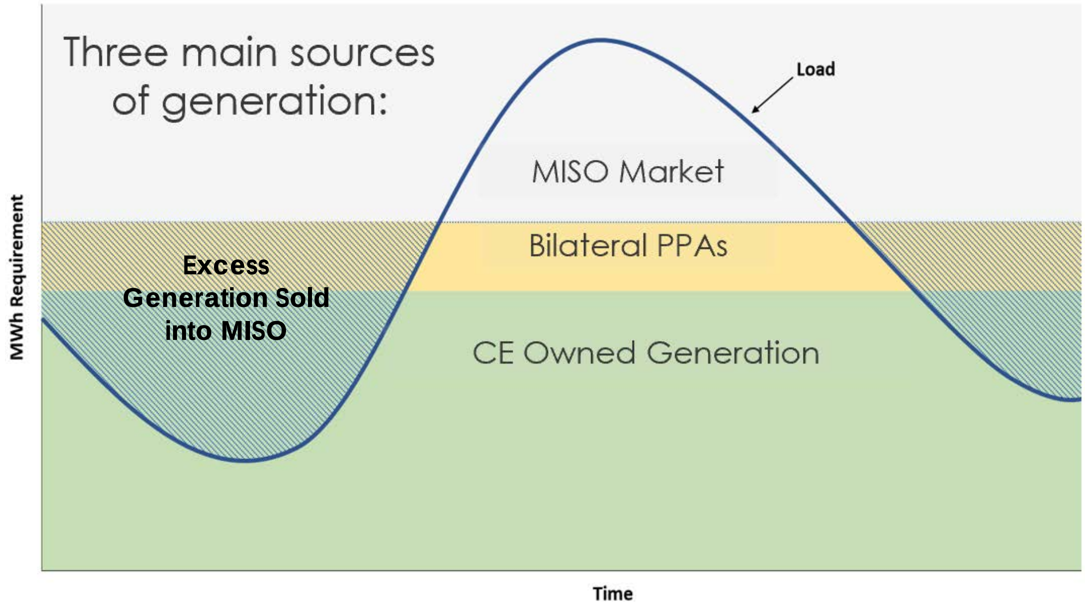
EXECUTIVE SUMMARY

In the past five years, Consumers Energy has created a cleaner, more sustainable energy future for the state by taking a leadership position in reducing air emissions, reducing water usage, saving landfill space, and boosting the amount of renewable energy supplied to customers. Consumers Energy has made a commitment to the planet by committing to the achieve net-zero carbon emissions by 2040 for its electric business. This continued transformation to cleaner fuel sources is part of a long-term strategic commitment to protect the planet.

The purpose of this whitepaper is to provide background information on how Consumers Energy is accounting for carbon and other air emissions in this Integrated Resource Plan.

BACKGROUND

Properly accounting for the carbon associated with electric generation is a crucial component of our Clean Energy Goal. There are three main generation categories from which we serve our load: owned generation, bilateral Power Purchase Agreements (PPAs), and purchases from the Midcontinent Independent System Operator, Inc. ("MISO"). There are times when our energy requirements are low and we are selling the excess generation into the MISO market. Conversely, there are times when our energy requirements are high, and we need to purchase from the MISO market. The graphic below is a simplistic representation of the described interaction.



To properly understand the various accounting options and methodologies we hired a consultant that worked with the Electric Power Research Institute (EPRI) to develop five different carbon accounting approaches. While the context of this whitepaper focuses on carbon accounting, the process for calculating and accounting for other air emissions utilizes the same methodology.

CARBON ACCOUNTING METHODOLOGIES

EPRI identified and described five approaches that can be used by electric companies to address the GHG emissions embedded in wholesale power purchased for resale to end-use customers. These options include:

1. A source-based approach - accounts for GHG emissions of owned and operated facilities, but excludes emissions associated with power purchases.

2. A simplified portfolio approach - accounts for GHG emissions of owned and operated resources as well as emissions associated with net wholesale electricity purchased using a system average emission rate for both bilateral power purchase agreements and purchases from the energy spot market.

3. A specified portfolio approach that accounts for GHG emissions of owned and operated resources, and any specified wholesale electricity procurement, plus emissions associated with bilateral power purchase agreements, and purchases from the energy spot market using a system average emission rate.

4. An annual net-short approach that accounts for the GHG emissions associated with owned and operated non-dispatchable resources, plus emissions associated

with non-dispatchable bilateral power purchase agreements. All remaining energy requirements used to serve load are assigned a residual system emission rate (equivalent of a new natural gas fired unit).

5. An hourly net-short approach that utilizes hourly residual emission rates.

More information about these methodologies can be found on EPRI's webpage here: https://www.epri.com/research/products/3002015044.

The Company evaluated the first four of the five methodologies. The fifth methodology was not evaluated because it is too data intensive and the consultant did not believe it would offer any materially different results.

METHODOLOGY CALCULATIONS

Methodological Equations for Greenhouse Gas Accounting Approaches:

Method	Total Generation	Calculation of Net System Purchases	Calculation of GHG Emissions
Source-based	$\sum_{i=1}^{N} G_{OWN}$	Not applicable	$\sum_{i=1}^{N} G_{OWN}\, ER_{ACT}$
Simple Portfolio	AL	$AL - \sum_{i=1}^{n} G_{OWN}$	$\sum_{i=1}^{n} G_{OWN} ER_{ACT} + NSER_{SYS}$
Specified Portfolio	AL	$AL - \sum_{i=1}^{n} G_{OWN} + \sum_{i=1}^{n} G_{PPAsp}$	$\sum_{i=1}^{n} G_{OWN} ER_{ACT} + \sum_{i=1}^{n} G_{PPA_{sp}}\, ER_{ACT} + NSER_{SYS}$
Annual Net Short	AL	$AL - \sum_{i=1}^{n} G_{OWNnd} + \sum_{i=1}^{n} G_{PPAnd}$	$\sum_{i=1}^{n} G_{OWNnd} ER_{ACT} + \sum_{i=1}^{n} G_{PPA_{nd}}\, ER_{ACT} + NSER_{RES}$

<u>Legend</u>

AL = Total Annual load (including battery charge and discharge)

NS= Net system purchases

G_{OWN} = Generation of owned resource

G_{OWNnd} = Generation of owned non-dispatchable resource

G_{PPA} = Generation of PPA resource

G_{PPAsp} = Generation of PPA specified resource

G_{PPAnd} = Generation of PPA non-dispatchable resource

ER_{ACT} = Actual emission rate of resource, where known

ER_{SYS} = System emission rate, the generation-weighted average emission rate of *all* resource on MISO system (or sub-system)

ER_{RES}= Residual emission rate, the generation-weighted average emission rate of *dispatchable* resources only (i.e. gas) on MISO system (or sub-system)

SELECTED METHODOLOGY

The specified portfolio method was selected to account for all the carbon that is generated from all sources used to serve customer load. The Company felt this methodology was the most accurate and thus provided better information to base emissions-related decisions on. Although the Company's initial Clean Energy goal in 2018 used a source-based approach, the Company concluded that methodology lacked completeness by not accounting for non-CE owned generation sources. The simple portfolio method was eliminated since carbon reductions that occur from renewable bilateral PPAs are not reflected. The annual net short method was also eliminated because it does not accurately reflect a regional/MISO market that achieves a high rate of renewables. The hourly net short methodology was eliminated because it is too data intensive and also would penalize a regional/MISO market that achieved a high rate of renewables.

CALCULATING BASELINE YEAR EMISSIONS

Gathering baseline emissions for calendar year 2005 for all emission types proved challenging. Many assumptions had to be made, such as emission rates per fuel type, and not all the same data sources were available for each pollutant. Each of the subcategories below portrays the baseline data, assumptions and data source(s) used for each pollutant.

Carbon Dioxide (CO_2)

2005 CO_2 Baseline Calculation			
Generation Source	**MWh**	**CO_2 Emissions (Tons)**	**Data Source**
CE-Owned Generation	26,798,769	22,234,110	Generation: 2005 Performance Report CO_2 Emissions: 2005 CEMS Report
Bilateral PPAs	8,999,168	4,051,373	Generation: PSCR-R Case U-14274-R, Exhibit DFR-2 CO_2 Emissions: Calculated based on Fuel Type (Gas Rate: 1,135 lb/MWh; Coal 2,249 lb/MWh)
MISO/Market Purchases	1,771,914	1,463,091	Generation: PSCR-R Case U-14274-R, Exhibit DFR-1 CO_2 Emissions: https://www.michigan.gov/documents/mpsc/regional_notice2005_575954_7.pdf
CE Energy Requirement	37,569,851	27,748,574	

Sulfur Dioxide (SO_2)

2005 SO_2 Baseline Calculation			
Generation Source	**MWh**	**SO_2 Emissions (Tons)**	**Data Source**
CE-Owned Generation	26,798,769	81,499	Generation: 2005 Performance Report SO_2 Emissions: 2005 CEMS Report
Bilateral PPAs	8,999,168	165	Generation: PSCR-R Case U-14274-R, Exhibit DFR-2 SO_2 Emissions: Estimated rate using 2019 EIA data
MISO/Market Purchases	1,771,914	8,611	Generation: PSCR-R Case U-14274-R, Exhibit DFR-1 SO_2 Emissions: 2019 EIA Data, MISO Region (Total Fossil SO_2 (Tons)/Total Fossil Gen (MWh) *76%)
CE Energy Requirement	37,569,851	90,275	

Nitrogen Oxides (NOx)

2005 NOx Baseline Calculation			
Generation Source	**MWh**	**NOx Emissions (Tons)**	**Data Source**
CE-Owned Generation	26,798,769	26,048	Generation: 2005 Performance Report NOx Emissions: 2005 CEMS Report
Bilateral PPAs	8,999,168	4,217	Generation: PSCR-R Case U-14274-R, Exhibit DFR-2 NOx Emissions: Estimated rate using 2019 EIA data
MISO/Market Purchases	1,771,914	3,340	Generation: PSCR-R Case U-14274-R, Exhibit DFR-1 NOx Emissions: 2019 EIA Data, MISO Region (Total Fossil NOx (Tons)/Total Fossil Gen (MWh) *76%)
CE Energy Requirement	37,569,851	33,604	

Particulate Matter (PM)

2005 PM Baseline Calculation			
Generation Source	**MWh**	**PM Emissions (Tons)**	**Data Source**
CE-Owned Generation	26,798,769	4,412	Generation: 2005 Performance Report PM Emissions: 2005 Performance Report
Bilateral PPAs	8,999,168	1,408	Generation: PSCR-R Case U-14274-R, Exhibit DFR-2 PM Emissions: Utilized estimated rates similar to CE-units
MISO/Market Purchases	1,771,914	78	Generation: PSCR-R Case U-14274-R, Exhibit DFR-1 PM Emissions: 2018 eGrid Data, 5-State Region (MI, OH, WI, IN, IL) (Total Fossil PM (Tons)/Total Fossil Gen (MWh) *76%)
CE Energy Requirement	37,569,851	5,899	

Mercury (Hg)

2005 Hg Baseline Calculation			
Generation Source	**MWh**	**Hg Emissions (Lbs)**	**Data Source**
CE-Owned Generation	26,798,769	795	Generation: 2005 Performance Report Hg Emissions: 2005 TRI Report
Bilateral PPAs	8,999,168	0.012	Generation: PSCR-R Case U-14274-R, Exhibit DFR-2 Hg Emissions: Utilized estimated rates similar to CE-units
MISO/Market Purchases	1,771,914	63	Generation: PSCR-R Case U-14274-R, Exhibit DFR-1 Hg Emissions: Utilized estimated rates similar to CE fossil units*76%
CE Energy Requirement	37,569,851	858	

FORWARD LOOKING PROJECTIONS

Emissions from Owned Generation

Air emissions from CE-owned generating sources were calculated using heat input data from the Aurora model and unit-specific emission rates for each pollutant. Below is a table of emission rates used for CE-owned generation in the calculations.

UNIT	NOx (lb/mmBtu)	SO2 (lb/mmBtu)	CO2 (lb/mmBtu)	Hg (lb/TBtu)	PM (lb/mmBtu)
JHC 1	0.200	0.290	209.760	1.000	0.003
JHC 2	0.060	0.300	209.760	1.000	0.003
JHC 3	0.060	0.060	209.760	1.000	0.002
DEK 1	0.060	0.060	209.760	1.000	0.004
DEK 2	0.060	0.060	209.760	1.000	0.003
ZEE 1A	0.039	0.001	118.857	0.000	0.002
ZEE 1B	0.041	0.001	118.857	0.000	0.004
ZEE CC	0.011	0.001	118.857	0.000	0.003
DEK 3	0.017	0.037	123.500	0.000	0.003
DEK 4	0.017	0.037	123.500	0.000	0.003
JAX1	0.064	0.001	118.857	0.000	0.002
New Covert Generating Facility	0.007	0.060	118.857	0.000	0.003
Dearborn Industrial Generation	0.100	0.001	116.889	0.000	0.004
Kalamazoo River Gen. Station	0.100	0.060	118.857	0.000	0.004
Livingston Generating Station	0.100	0.060	118.857	0.000	0.007

Emissions from Power Purchase Agreements (PPAs)

Since the Aurora model does not project heat input data for non-CE owned generation, the air emissions from PPAs were calculated using generation data from the Aurora model and unit-specific emission rates on a pounds per megawatt hour basis, for each pollutant. Below is a table of the assumed emission rates used for fossil fired PPA generation in the calculations.

UNIT	CO2 (lb/MWh)	SO2 (lb/MWh)	NOx (lb/MWh)	PM (lb/MWh)	Hg (lb/MWh)
Midland Co-Generating Venture	962	0.0053	0.8777	0.4585	0
Ada	1,135	0.0063	2.9151	0.0363	0
Michigan Power	1,141	0.0054	0.2721	0.0244	0
TES Filer City	2,249	0.6048	5.1892	0.0766	0.00005

Emissions from MISO Purchases and Sales

The Aurora model is also used to calculate the emission rate, or intensity, of the MISO Market. To calculate the Intensity rate of the MISO market, the fuel mix percentage is then multiplied by an emission rate for each specific fuel rate.

Example, CE-BAU MISO Outlook:

BAUCE	Fuel Mix (%)									
Year	Coal	Gas	Wind	Hydro	Other, Bio, ZZ, WC, WH	Nuclear	Storage	Solar	Oil	Refuse
2021	41%	35%	10%	1%	3%	8%	0%	1%	0%	1%
2022	38%	36%	11%	1%	3%	9%	0%	1%	0%	1%
2023	39%	33%	13%	1%	2%	9%	0%	2%	0%	1%
2024	41%	30%	14%	1%	2%	10%	0%	2%	0%	1%
2025	36%	34%	14%	1%	2%	10%	0%	2%	0%	1%
2026	40%	28%	15%	1%	2%	11%	0%	2%	0%	0%
2027	40%	28%	15%	1%	2%	11%	0%	2%	0%	0%
2028	40%	27%	15%	1%	2%	11%	0%	2%	0%	0%
2029	38%	31%	15%	1%	2%	10%	0%	2%	0%	0%
2030	31%	41%	12%	1%	2%	8%	0%	2%	0%	1%
2031	31%	40%	13%	1%	2%	9%	0%	3%	0%	1%
2032	33%	38%	13%	1%	2%	9%	0%	3%	0%	1%
2033	33%	38%	13%	1%	2%	9%	0%	3%	0%	1%
2034	32%	38%	13%	1%	2%	10%	0%	4%	0%	1%
2035	31%	38%	13%	1%	2%	9%	0%	5%	0%	1%
2036	30%	39%	13%	1%	2%	9%	0%	6%	0%	1%
2037	28%	40%	13%	1%	2%	9%	0%	6%	0%	1%
2038	27%	41%	13%	1%	2%	9%	0%	7%	0%	1%
2039	23%	45%	13%	1%	2%	9%	0%	7%	0%	1%
2040	21%	45%	13%	1%	2%	10%	0%	7%	0%	0%

Carbon by Fuel Type		SO2 by Fuel Type		NOx by Fuel Type		PM by Fuel Type		Hg by Fuel Type	
Coal (Tons)	Gas (Tons)	Coal (Tons)	Gas (Tons)	Coal (Tons)	Gas (Tons)	Coal (Tons)	Gas (Tons)	Coal (Tons)	Gas (Tons)
1.1245	0.5675	3.061	1.697	1.852	1.944	0.167800424	0.07625025	5.76312E-06	0

For example, in the table above, in 2021, ~41% of the MISO generation was from coal and ~35% was from gas. There was no additional generation from sources with air emissions. Utilizing the same fuel specific emission rates as previously discussed, the CO_2 weighted average emission rate of the MISO would then be (45% x 1.1245) + (35% x 0.5675) = 0.657 Lb/MWh. The weighted average was calculated for every year, for every pollutant, for every scenario of the IRP: CE-BAU, AEO-BAU, CE-ET, AEO-ET, CE-EP and AEO-EP. Below is the calculated emission rate tables for the CE-BAU scenario:

MISO Market Emissions Intensities - CE BAU Scenario					
Year	CO_2 Intensity (Tons/MWh)	SO_2 Intensity (Tons/MWh)	NOx Intensity (Tons/MWh)	PM Intensity (Tons/MWh)	Hg Intensity (Lb/MWh)
2021	0.657633	0.000922	0.000720	0.000048	0.000002
2022	0.631023	0.000887	0.000704	0.000046	0.000002
2023	0.630209	0.000883	0.000686	0.000046	0.000002
2024	0.633147	0.000884	0.000671	0.000046	0.000002
2025	0.597731	0.000839	0.000662	0.000043	0.000002
2026	0.612973	0.000856	0.000647	0.000045	0.000002
2027	0.612555	0.000855	0.000648	0.000045	0.000002
2028	0.608787	0.000849	0.000639	0.000044	0.000002
2029	0.606865	0.000849	0.000655	0.000044	0.000002
2030	0.587953	0.000832	0.000693	0.000042	0.000002
2031	0.581974	0.000823	0.000683	0.000042	0.000002
2032	0.590541	0.000833	0.000679	0.000042	0.000002
2033	0.589540	0.000831	0.000678	0.000042	0.000002
2034	0.578212	0.000816	0.000666	0.000042	0.000002
2035	0.571571	0.000807	0.000664	0.000041	0.000002
2036	0.555406	0.000786	0.000654	0.000040	0.000002
2037	0.543199	0.000769	0.000647	0.000039	0.000002
2038	0.536087	0.000760	0.000646	0.000038	0.000002
2039	0.515958	0.000737	0.000652	0.000037	0.000001
2040	0.494908	0.000708	0.000634	0.000035	0.000001

When calculating the emissions associated with MISO purchases and sales, the emission rates above are used.

CONCLUSION

Properly accounting for the carbon associated with electric generation is a crucial component of the emissions projections for our PCA, as well as our Clean Energy Goal. The three main generation categories from which we serve our load must be accounted for. During the times when our energy requirements are low and we are selling the excess generation into the MISO market our overall emissions profile will be reduced and those emissions will, presumably, but accounted for by those purchasing the generation. Conversely, when our energy requirements are high, and we need to purchase from the MISO market, we are including those emissions as part of our carbon footprint. By accurately reflecting the emissions from all sources, we allow the Company to fully understand the emissions impact of the PCA and ultimately help leave Michigan better than we found it.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Environmental Justice Results

Case No.: U-21090
Exhibit No.: A-29 (HAB-8)

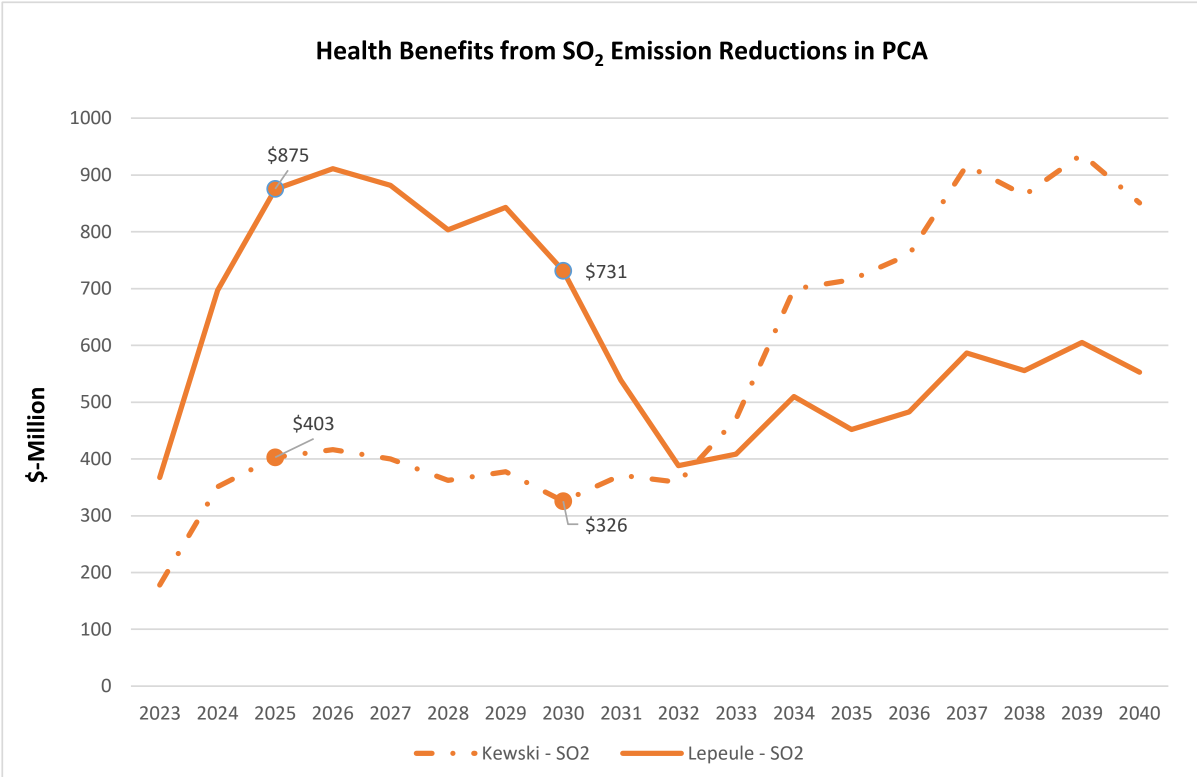
Witness: HABreining
Date: June 2021

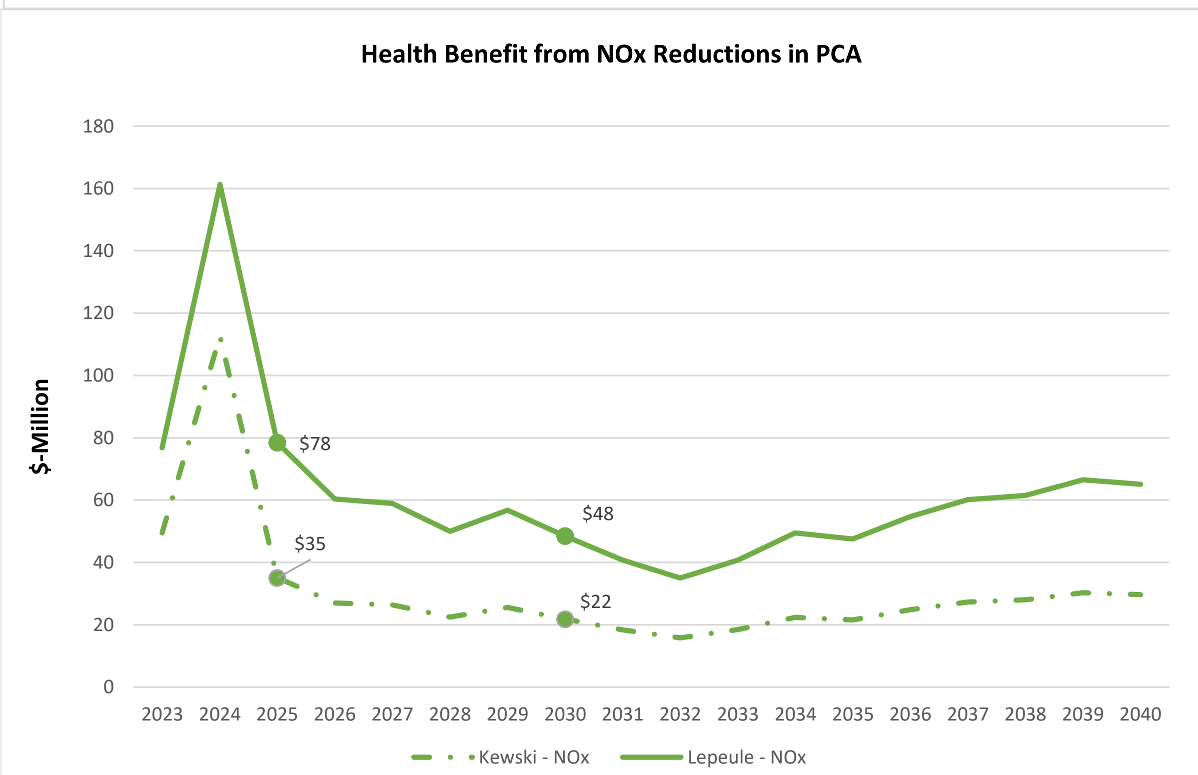
	(a.)	(b.)	(c.)	(d.)
	Facility	**2km Evaluation[1.]: >75 Percentile?**	**10km Evaluation[1.]: >75 Percentile?**	**Additional PM Evaluation?**
(1.)	Campbell	No	No	No
(2.)	Covert	Yes	Yes	Yes
(3.)	DIG	Yes	Yes	Yes
(4.)	Jackson	No	No	No
(5.)	Kalamazoo River	No	Yes	Yes
(6.)	Karn	No	No	No
(7.)	Livingston	No	No	No
(8.)	Zeeland	No	No	No

1. The Company used EPA's EJSCREEN tool (https://www.epa.gov/ejscreen) to provide an initial screen for vulnerable areas. Analysis was performed using an impact area of 2 kilometers and 10 kilometers. The Company considered any facilities that had an environmental or demographic "indicator" examined by the EJSCREEN above the 75th percentile to be a potentially vulnerable community.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Health Benefits
2021

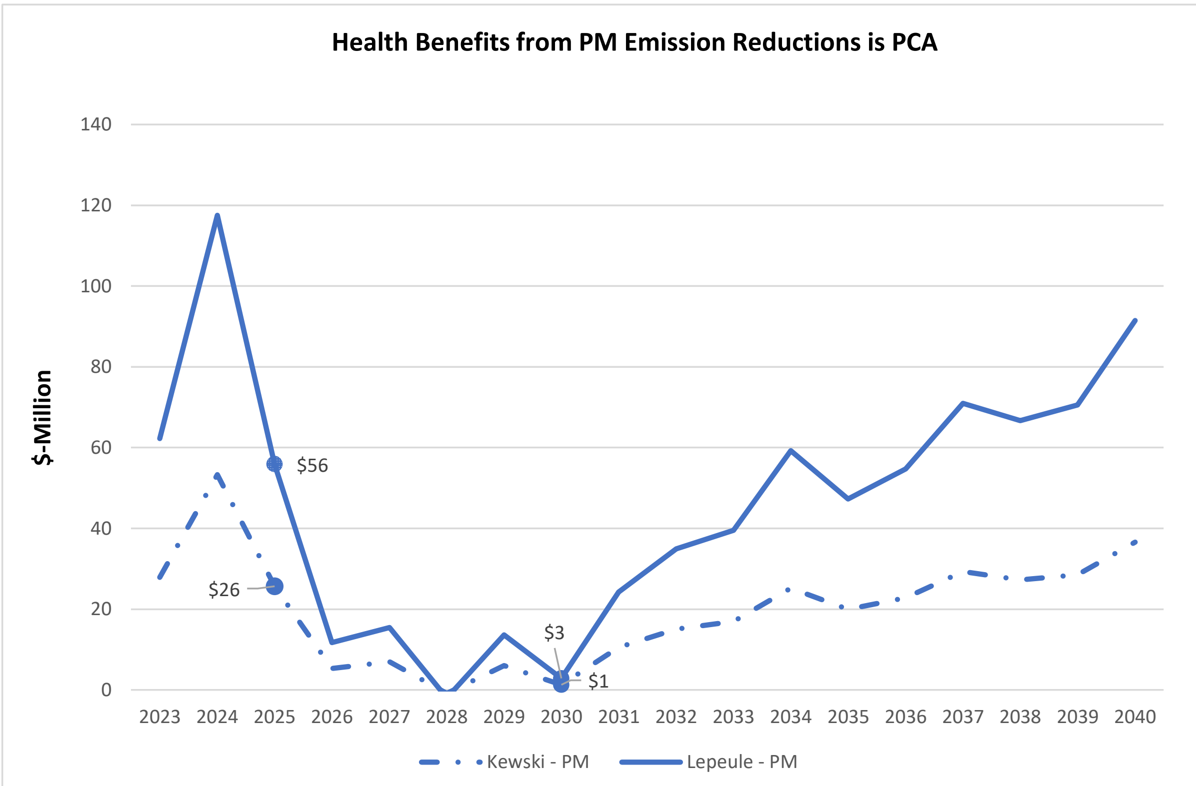
Case No.: U-21090
Exhibit No.: A-30 (HAB-9)
Page: 1 of 2
Witness: HABreining
Date: June 2021





MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Health Benefits
2021

Case No.: U-21090
Exhibit No.: A-30 (HAB-9)
Page: 2 of 2
Witness: HABreining
Date: June 2021

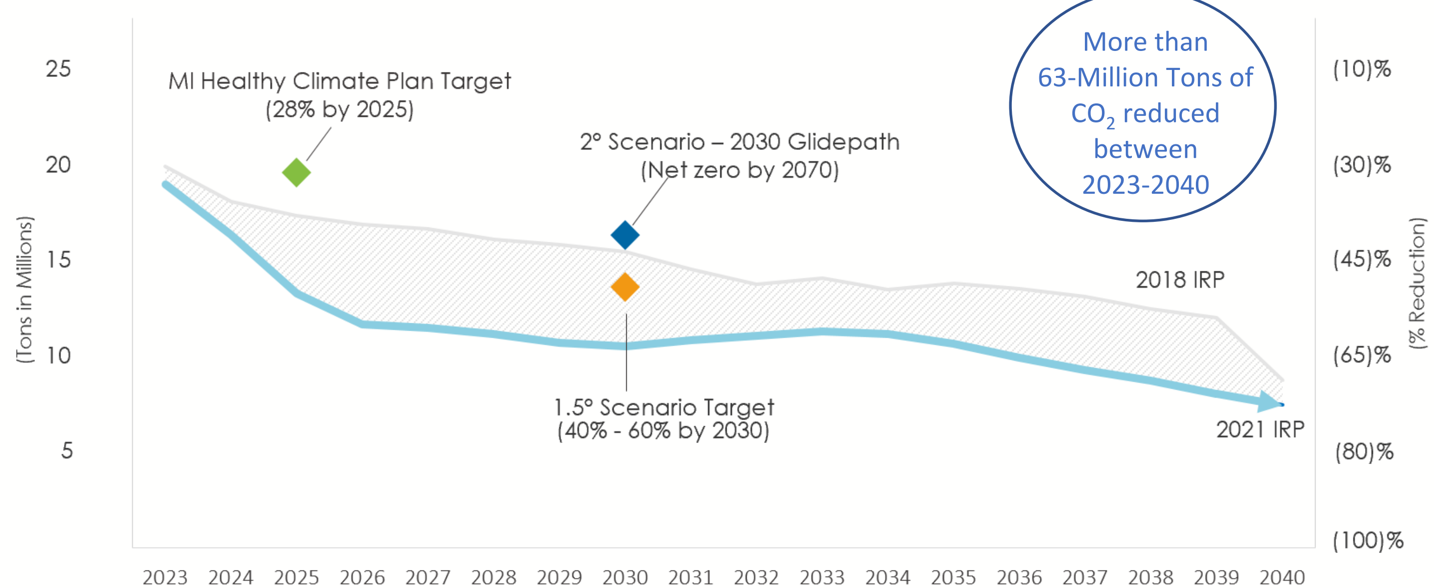


MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Clean Energy Goal Comparison

Case No.: U-21090
Exhibit No.: A-31 (HAB-10)
Page: 1 of 1
Witness: HABreining
Date: June 2021

2021 IRP Accelerates Decarbonization . . .

Carbon Emissions Reductions[a]



[a]All generating sources

. . . and outpaces scientific targets.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

EXHIBITS

OF

KEVIN J. WATKINS

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Unrecovered Balances
$000's

Case No.: U-21090
Exhibit No.: A-32 (KJW-1)
Page: 1 of 1
Witness: KJWatkins
Date: June 2021

DE Karn 3 & 4

Line No.	(A) Year	(B) Begin Plant in Service	(C) Additions	(B + C) (D) Ending Plant in Service	((B + D) / 2) (E) Average Plant in Service	(F) Depreciation Rate	(G) Begin Accumulated Depreciation	(E x F) (H) Depreciation Expense	(G + H) (I) Ending Accumulated Depreciation	(D - I) (J) Ending Unrecovered Balance
1	2020	363,956	6,390	370,346	367,151	4.92%	216,513	18,064	234,577	135,769
2	2021	370,346	11,046	381,392	375,869	4.92%	234,577	18,493	253,070	128,322
3	2022	381,392	2,500	383,892	382,642	4.92%	253,070	18,826	271,896	**111,996**

JH Campbell 1 & 2

Line No.	Year	Begin Plant in Service	Additions	Ending Plant in Service	Average Plant in Service	Depreciation Rate	Begin Accumulated Depreciation	Depreciation Expense	Ending Accumulated Depreciation	Ending Unrecovered Balance
4	2020	1,053,312	19,208	1,072,520	1,062,916	4.94%	424,196	52,508	476,704	595,816
5	2021	1,072,520	16,564	1,089,084	1,080,802	4.94%	476,704	53,392	530,096	558,988
6	2022	1,089,084	8,917	1,098,001	1,093,543	4.94%	530,096	54,021	584,117	**513,884**

JH Campbell 3

Line No.	Year	Begin Plant in Service	Additions	Ending Plant in Service	Average Plant in Service	Depreciation Rate	Begin Accumulated Depreciation	Depreciation Expense	Ending Accumulated Depreciation	Ending Unrecovered Balance
7	2020	1,728,866	12,860	1,741,726	1,735,296	4.90%	591,810	85,030	676,840	1,064,886
8	2021	1,741,726	18,397	1,760,123	1,750,925	4.90%	676,840	85,795	762,635	997,488
9	2022	1,760,123	12,885	1,773,008	1,766,566	4.90%	762,635	86,562	849,197	**923,811**

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected Decommissioning and Ash Disposal Costs
$000's

Case No.: U-21090
Exhibit No.: A-33 (KJW-2)
Page: 1 of 1
Witness: KJWatkins
Date: June 2021

	(A)	**(B)**	**(C)**	**(B + C)** **(D)**
Line No.	Generating Units	Decommissioning Costs (1)	Ash Disposal Costs (2)	Total
1	DE Karn Units 1 & 2	54,361	10,789	65,150
2	DE Karn Units 3 & 4	29,486	n/a	29,486
3	JH Campbell Units 1 & 2	47,289	20,744	68,033
4	JH Campbell Unit 3	50,885	26,068	76,953
5	BC Cobb 1-5, JC Weadock 7 & 8, JR Whiting 1-3	n/a	140,885	140,885
6	**Total**	**182,021**	**198,486**	**380,507**

Notes:
(1) Decommissioning costs from U-20849, adjusted for change in retirement dates.
(2) Ash disposal costs from U-20849.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

EXHIBITS

OF

SRIKANTH MADDIPATI

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Illustration of PPA Financial Incentive

Case No.: U-21090
Exhibit No.: A-34 (SM-1)
Page: 1 of 1
Witness: SMaddipati
Date: June 2021

	(a)	(b)	(c)	(d)	(e) = c x d	(f)	(g)
		Capital Structure			Weighted Cost		
Line No.	Description	Amount ($000,000)	Percent Permanent Capital	Cost Rate %	Permanent Capital %	Conversion Factor	Pre-Tax Return (9)
1							
2	Long-Term Debt	$ 8,178	48.67%	3.81%	1.85%	1.0000	1.85%
3							
4	Preferred Stock	37	0.22%	4.50%	0.01%	1.3391	0.01%
5							
6	Common Shareholder's Equity	8,587	51.11%	9.90%	5.06%	1.3391	6.78%
7							
8	Total Permanent Capital	$ 16,803	100.00%				8.64%
9							
10							
11	**Illustrative PPA Incentive**						
12	PPA Payment	$ 100					
13	Pre-Tax Return	8.64%					
14	PPA Incentive	$8.64					

All data based on order from MPSC Case No. U-20697

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Impact of Securitization on Capital Structure

Case No.: U-21090
Exhibit No.: A-35 (SM-2)
Page: 1 of 1
Witness: SMaddipati
Date: June 2021

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Current (U-20697)					**Adjusted Capital Structure**		**Rebalanced Capital Structure**	
Line No.	**Description**	**Amount ($000,000)**	**Percent Permanent Capital**	**Classic 7 Securitization**	**Karn 1&2 Securitization**	**Karn 3&4 Campbell 1, 2, & 3 Unrecovered Book**	**Amount ($000,000)**	**Percent Permanent Capital**	**Amount ($000,000)**	**Percent Permanent Capital**
1										
2	Long-Term Debt	$ 8,178	48.7%	$225	$678	$1,550	$ 10,631	55.2%	$ 9,590	49.8%
3										
4	Preferred Stock	37	0.2%				37	0.2%	37	0.2%
5										
6	Common Shareholder's Equity	8,587	51.1%				8,587	44.6%	9,628	50.0%
7										
8	Total Permanent Capital	$ 16,803	100.0%				$ 19,256	100.0%	$ 19,256	100.0%

Sources
Column (f): Sum of ending unrecovered balace as of 12/31/2022 in Exhibit KJW-1.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
	)	

EXHIBITS

OF

JASON R. COKER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Incremental Revenue Requirement - Proposed Course of Action
(000)

Case No.: U-21090
Exhibit No.: A-36 (JRC-1)

Witness: JRCoker
Date: June 2021

Line No.	Proposed[1]	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	Incremental Revenue Requirement	(123)	(11,825)	(14,031)	(42,253)	(35,682)	7,179	(29,117)	(12,460)	(15,320)	(30,548)	(29,329)	(74,671)	(86,718)	(72,189)	(75,550)	(55,456)	(39,486)	(22,369)	(194)	(63,305)	63,229
2	Percentage Change in RR	0.00%	-0.27%	-0.32%	-0.96%	-0.81%	0.16%	-0.66%	-0.28%	-0.35%	-0.69%	-0.66%	-1.69%	-1.96%	-1.63%	-1.71%	-1.25%	-0.89%	-0.51%	0.00%	-1.43%	1.43%
3	Percentage Change over Prior Year	0.00%	-0.26%	-0.05%	-0.64%	0.15%	0.97%	-0.82%	0.38%	-0.06%	-0.34%	0.03%	-1.03%	-0.27%	0.33%	-0.08%	0.45%	0.36%	0.39%	0.50%	-1.43%	2.86%
4	Cents/kWh Incremental Revenue Requirement	0.00	-0.04	-0.04	-0.13	-0.11	0.02	-0.09	-0.04	-0.05	-0.09	-0.09	-0.22	-0.26	-0.21	-0.22	-0.16	-0.12	-0.07	0.00	-0.19	0.19
5	Cents/kWh Change Over Prior Year	0.00	-0.03	-0.01	-0.08	0.02	0.13	-0.11	0.05	-0.01	-0.05	0.00	-0.13	-0.04	0.04	-0.01	0.06	0.05	0.05	0.07	-0.19	0.38

Net Present Value Incremental Revenue Requirement
6 **Proposed Course of Action** **(290,015)**

[1] Source: WP-JRC-1

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Karn 3 & 4 and Campbell 1, 2, & 3 Net Book Value Recovery
(000)

Case No.: U-21090
Exhibit No.: A-37 (JRC-2)
Page: 1 of 1
Witness: JRCoker
Date: June 2021

Line	Revenue Requirement [1]	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	Karn 3&4	24,475	24,323	24,170	22,926	21,682	20,438	19,194	17,950	7,263	-	-	-	-	-	-	-	-	-
2	Campbell 1&2	104,608	99,492	94,375	91,776	89,177	84,061	78,945	73,829	29,874	-	-	-	-	-	-	-	-	-
3	Campbell 3	123,696	119,444	115,192	113,787	112,382	108,130	103,878	99,626	95,374	91,122	86,870	82,618	78,366	74,114	69,862	65,610	61,358	24,828
4	Total	252,780	243,258	233,737	228,489	223,242	212,629	202,017	191,405	132,511	91,122	86,870	82,618	78,366	74,114	69,862	65,610	61,358	24,828

Line	Revenue Requirement Increase/(Decrease) From 2019	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
5	Karn 3&4	(6,898)	(7,051)	(7,203)	(8,447)	(9,691)	(10,935)	(12,179)	(13,423)	(24,110)	(31,373)	(31,373)	(31,373)	(31,373)	(31,373)	(31,373)	(31,373)	(31,373)	(31,373)
6	Campbell 1&2	(3,811)	(8,927)	(14,043)	(16,642)	(19,242)	(24,358)	(29,474)	(34,590)	(78,545)	(108,419)	(108,419)	(108,419)	(108,419)	(108,419)	(108,419)	(108,419)	(108,419)	(108,419)
7	Campbell 3	(2,145)	(6,397)	(10,649)	(12,054)	(13,458)	(17,710)	(21,962)	(26,214)	(30,467)	(34,719)	(38,971)	(43,223)	(47,475)	(51,727)	(55,979)	(60,231)	(64,483)	(101,013)
8	Total	(12,853)	(22,374)	(31,896)	(37,143)	(42,391)	(53,003)	(63,616)	(74,228)	(133,122)	(174,511)	(178,763)	(183,015)	(187,267)	(191,519)	(195,771)	(200,023)	(204,275)	(240,805)

[1] Source: WP-JRC-3 to WP-JRC-5 (NBV Workpapers)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Incremental Revenue Requirement - Campbell 1 2024
(000)

Campbell 1 2024	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Capital Spending	-381	99	-13,484	-26,801	-9,503	-2,550	-3,300	-4,050	-3,500	-3,879	-2,564	-250	0	0	0	0	0	0	0	0	0
Average Rate Base	(186)	(314)	(6,825)	(26,127)	(42,495)	(46,144)	(46,471)	(47,385)	(48,217)	(48,778)	(48,702)	(46,698)	(43,374)	(39,922)	(36,470)	(33,018)	(29,566)	(26,114)	(22,662)	(19,210)	(15,758)
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	(14)	(23)	(505)	(1,933)	(3,144)	(3,414)	(3,439)	(3,506)	(3,568)	(3,609)	(3,604)	(3,455)	(3,209)	(2,954)	(2,699)	(2,443)	(2,188)	(1,932)	(1,677)	(1,421)	(1,166)
Depreciation Expense	(9)	(16)	(346)	(1,337)	(2,230)	(2,526)	(2,670)	(2,851)	(3,037)	(3,218)	(3,377)	(3,446)	(3,452)	(3,452)	(3,452)	(3,452)	(3,452)	(3,452)	(3,452)	(3,452)	(3,452)
O&M and Property Tax Expense	(585)	(322)	(67)	(255)	(4,233)	(11,067)	(11,402)	(11,920)	(12,364)	(12,172)	(11,744)	(4,417)	1,860	1,897	1,936	1,974	2,014	2,054	2,095	1,068	-
PSCR	-	(515)	(614)	(50)	7,626	11,079	9,768	9,924	6,772	9,691	12,468	5,125	(188)	(182)	(1)	149	111	11	(31)	345	(278)
Incremental Revenue Requirement	(608)	(876)	(1,531)	(3,575)	(1,981)	(5,928)	(7,743)	(8,354)	(12,196)	(9,308)	(6,256)	(6,193)	(4,989)	(4,691)	(4,216)	(3,772)	(3,515)	(3,319)	(3,065)	(3,460)	(4,896)
Percentage Increase in RR	-0.01%	-0.02%	-0.03%	-0.08%	-0.04%	-0.13%	-0.18%	-0.19%	-0.28%	-0.21%	-0.14%	-0.14%	-0.11%	-0.11%	-0.10%	-0.09%	-0.08%	-0.08%	-0.07%	-0.08%	-0.11%
Percentage Increase over Prior Year	-0.01%	-0.01%	-0.01%	-0.05%	0.04%	-0.09%	-0.04%	-0.01%	-0.09%	0.07%	0.07%	0.00%	0.03%	0.01%	0.01%	0.01%	0.01%	0.00%	0.01%	-0.01%	-0.03%
Cents/kWh Incremental Revenue Requirement	-0.0018	-0.0026	-0.0046	-0.0106	-0.0059	-0.0176	-0.0230	-0.0248	-0.0363	-0.0277	-0.0186	-0.0184	-0.0148	-0.0139	-0.0125	-0.0112	-0.0105	-0.0099	-0.0091	-0.0103	-0.0146
Cents/kWh Increase Over Prior Year	-0.0018	-0.0008	-0.0019	-0.0061	0.0047	-0.0117	-0.0054	-0.0018	-0.0114	0.0086	0.0091	0.0002	0.0036	0.0009	0.0014	0.0013	0.0008	0.0006	0.0008	-0.0012	-0.0043
U-18322 MWh Full Service	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639

Revenue Requirement (Current Rates)	4,419,264
U-20134 MWh Full Service [(1)]	33,633,639

[(1)] U-20134 Exhibit A-16 (JCA-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Incremental Revenue Requirement - Campbell 1 2025
(000)

Case No.: U-21090
Exhibit No.: A-38 (JRC-3)

Witness: JRCoker
Date: June 2021

Campbell 1 2025	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Capital Spending	-36	-700	-15,490	-32,920	-8,953	-2,300	-3,300	-4,050	-3,500	-3,879	-2,564	-250	0	0	0	0	0	0	0	0	0
Average Rate Base	(17)	(375)	(8,252)	(31,444)	(50,257)	(53,107)	(52,923)	(53,455)	(53,904)	(54,083)	(53,624)	(51,237)	(47,530)	(43,696)	(39,861)	(36,026)	(32,192)	(28,357)	(24,522)	(20,688)	(16,853)
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	(1)	(28)	(611)	(2,327)	(3,719)	(3,930)	(3,916)	(3,955)	(3,989)	(4,002)	(3,968)	(3,791)	(3,517)	(3,233)	(2,950)	(2,666)	(2,382)	(2,098)	(1,815)	(1,531)	(1,247)
Depreciation Expense	(1)	(19)	(417)	(1,608)	(2,638)	(2,915)	(3,053)	(3,234)	(3,419)	(3,601)	(3,759)	(3,829)	(3,835)	(3,835)	(3,835)	(3,835)	(3,835)	(3,835)	(3,835)	(3,835)	(3,835)
O&M and Property Tax Expense	(585)	(322)	(67)	(0)	(250)	(3,489)	(11,400)	(11,919)	(12,362)	(12,170)	(11,742)	(4,417)	1,861	1,899	1,937	1,975	2,015	2,055	2,096	1,069	-
PSCR	-	(515)	(614)	(120)	8	8,082	8,982	9,980	6,840	9,722	11,923	5,130	(155)	(365)	84	(284)	161	(52)	44	(70)	(429)
Incremental Revenue Requirement	(587)	(883)	(1,709)	(4,055)	(6,600)	(2,252)	(9,388)	(9,127)	(12,930)	(10,051)	(7,546)	(6,906)	(5,645)	(5,535)	(4,763)	(4,810)	(4,041)	(3,930)	(3,509)	(4,366)	(5,511)
Percentage Increase in RR	-0.01%	-0.02%	-0.04%	-0.09%	-0.15%	-0.05%	-0.21%	-0.21%	-0.29%	-0.23%	-0.17%	-0.16%	-0.13%	-0.13%	-0.11%	-0.11%	-0.09%	-0.09%	-0.08%	-0.10%	-0.12%
Percentage Increase over Prior Year	-0.01%	-0.01%	-0.02%	-0.05%	-0.06%	0.10%	-0.16%	0.01%	-0.09%	0.07%	0.06%	0.01%	0.03%	0.00%	0.02%	0.00%	0.02%	0.00%	0.01%	-0.02%	-0.03%
Cents/kWh Incremental Revenue Requirement	-0.0017	-0.0026	-0.0051	-0.0121	-0.0196	-0.0067	-0.0279	-0.0271	-0.0384	-0.0299	-0.0224	-0.0205	-0.0168	-0.0165	-0.0142	-0.0143	-0.0120	-0.0117	-0.0104	-0.0130	-0.0164
Cents/kWh Increase Over Prior Year	-0.0017	-0.0009	-0.0025	-0.0070	-0.0076	0.0129	-0.0212	0.0008	-0.0113	0.0086	0.0074	0.0019	0.0038	0.0003	0.0023	-0.0001	0.0023	0.0003	0.0012	-0.0025	-0.0034
U-18322 MWh Full Service	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639

Revenue Requirement (Current Rates)	4,419,264
U-20134 MWh Full Service [1]	33,633,639

[1] U-20134 Exhibit A-16 (JCA-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Incremental Revenue Requirement - Campbell 1 2026
(000)

Campbell 1 2026	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Capital Spending	-36	-700	-15,490	-32,630	-8,137	-1,750	-3,050	-4,050	-3,500	-3,879	-2,564	-250	0	0	0	0	0	0	0	0	0
Average Rate Base	(17)	(375)	(8,252)	(31,303)	(49,585)	(51,803)	(51,296)	(51,794)	(52,336)	(52,609)	(52,244)	(49,950)	(46,338)	(42,597)	(38,856)	(35,115)	(31,374)	(27,633)	(23,892)	(20,151)	(16,410)
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	(1)	(28)	(611)	(2,316)	(3,669)	(3,833)	(3,796)	(3,833)	(3,873)	(3,893)	(3,866)	(3,696)	(3,429)	(3,152)	(2,875)	(2,598)	(2,322)	(2,045)	(1,768)	(1,491)	(1,214)
Depreciation Expense	(1)	(19)	(417)	(1,601)	(2,604)	(2,847)	(2,965)	(3,140)	(3,326)	(3,507)	(3,666)	(3,735)	(3,741)	(3,741)	(3,741)	(3,741)	(3,741)	(3,741)	(3,741)	(3,741)	(3,741)
O&M and Property Tax Expense	(585)	(322)	(67)	(0)	(0)	(500)	(3,648)	(11,920)	(12,364)	(12,172)	(11,743)	(4,418)	1,860	1,897	1,935	1,974	2,013	2,054	2,095	1,068	-
PSCR	-	(515)	(682)	(170)	(31)	(70)	5,566	9,984	6,800	9,670	12,462	5,238	(217)	(353)	(82)	(68)	125	(205)	202	183	(377)
Incremental Revenue Requirement	(587)	(883)	(1,777)	(4,088)	(6,304)	(7,250)	(4,842)	(8,909)	(12,762)	(9,901)	(6,813)	(6,611)	(5,527)	(5,349)	(4,763)	(4,434)	(3,924)	(3,937)	(3,212)	(3,980)	(5,332)
Percentage Increase in RR	-0.01%	-0.02%	-0.04%	-0.09%	-0.14%	-0.16%	-0.11%	-0.20%	-0.29%	-0.22%	-0.15%	-0.15%	-0.13%	-0.12%	-0.11%	-0.10%	-0.09%	-0.09%	-0.07%	-0.09%	-0.12%
Percentage Increase over Prior Year	-0.01%	-0.01%	-0.02%	-0.05%	-0.05%	-0.02%	0.05%	-0.09%	-0.09%	0.06%	0.07%	0.00%	0.02%	0.00%	0.01%	0.01%	0.01%	0.00%	0.02%	-0.02%	-0.03%
Cents/kWh Incremental Revenue Requirement	-0.0017	-0.0026	-0.0053	-0.0122	-0.0187	-0.0216	-0.0144	-0.0265	-0.0379	-0.0294	-0.0203	-0.0197	-0.0164	-0.0159	-0.0142	-0.0132	-0.0117	-0.0117	-0.0095	-0.0118	-0.0159
Cents/kWh Increase Over Prior Year	-0.0017	-0.0009	-0.0027	-0.0069	-0.0066	-0.0028	0.0072	-0.0121	-0.0115	0.0085	0.0092	0.0006	0.0032	0.0005	0.0017	0.0010	0.0015	0.0000	0.0022	-0.0023	-0.0040
U-18322 MWh Full Service	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639

Revenue Requirement (Current Rates)	4,419,264
U-20134 MWh Full Service [1]	33,633,639

[1] U-20134 Exhibit A-16 (JCA-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Incremental Revenue Requirement - Campbell 1 2028
(000)

Case No.: U-21090
Exhibit No.: A-38 (JRC-3)

Witness: JRCoker
Date: June 2021

Campbell 1 2028	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Capital Spending	0	0	0	0	0	0	-1,250	-3,250	-3,250	-3,879	-2,564	-250	0	0	0	0	0	0	0	0	0
Average Rate Base	-	-	-	-	-	-	(610)	(2,774)	(5,802)	(8,977)	(11,642)	(12,379)	(11,797)	(11,086)	(10,376)	(9,665)	(8,955)	(8,244)	(7,534)	(6,823)	(6,113)
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	-	-	-	-	-	-	(45)	(205)	(429)	(664)	(861)	(916)	(873)	(820)	(768)	(715)	(663)	(610)	(557)	(505)	(452)
Depreciation Expense	-	-	-	-	-	-	(31)	(141)	(301)	(477)	(635)	(704)	(711)	(711)	(711)	(711)	(711)	(711)	(711)	(711)	(711)
O&M and Property Tax Expense	(0)	(0)	0	(0)	(0)	0	0	(639)	(4,363)	(12,171)	(11,743)	(4,417)	1,818	1,898	1,943	1,972	2,048	2,051	2,088	1,051	(16)
PSCR	2	(27)	18	10	(80)	(102)	50	115	3,094	9,938	11,446	3,863	(1,314)	(291)	(1,004)	92	271	(1,174)	(20)	(289)	(43)
Incremental Revenue Requirement	1	(27)	18	10	(81)	(101)	(26)	(871)	(2,000)	(3,374)	(1,794)	(2,175)	(1,079)	76	(540)	639	946	(444)	800	(454)	(1,222)
Percentage Increase in RR	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-0.02%	-0.05%	-0.08%	-0.04%	-0.05%	-0.02%	0.00%	-0.01%	0.01%	0.02%	-0.01%	0.02%	-0.01%	-0.03%
Percentage Increase over Prior Year	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-0.02%	-0.03%	-0.03%	0.04%	-0.01%	0.02%	0.03%	-0.01%	0.03%	0.01%	-0.03%	0.03%	-0.03%	-0.02%
Cents/kWh Incremental Revenue Requirement	0.0000	-0.0001	0.0001	0.0000	-0.0002	-0.0003	-0.0001	-0.0026	-0.0059	-0.0100	-0.0053	-0.0065	-0.0032	0.0002	-0.0016	0.0019	0.0028	-0.0013	0.0024	-0.0013	-0.0036
Cents/kWh Increase Over Prior Year	0.0000	-0.0001	0.0001	0.0000	-0.0003	-0.0001	0.0002	-0.0025	-0.0034	-0.0041	0.0047	-0.0011	0.0033	0.0034	-0.0018	0.0035	0.0009	-0.0041	0.0037	-0.0037	-0.0023
U-18322 MWh Full Service	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639

Revenue Requirement (Current Rates)	4,419,264
U-20134 MWh Full Service [1]	33,633,639

[1] U-20134 Exhibit A-16 (JCA-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Incremental Revenue Requirement - Campbell 2 2024
(000)

Campbell 2 2024	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Capital Spending	-407	-1,256	-9,891	-26,575	-11,002	-7,800	-4,420	-6,845	-7,394	-2,500	-1,050	-250	0	0	0	0	0	0	0	0	0
Average Rate Base	(199)	(1,000)	(6,385)	(23,844)	(40,948)	(47,971)	(51,322)	(53,906)	(57,664)	(58,952)	(56,903)	(53,669)	(49,891)	(45,985)	(42,079)	(38,173)	(34,267)	(30,361)	(26,455)	(22,549)	(18,643)
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	(15)	(74)	(472)	(1,764)	(3,030)	(3,550)	(3,798)	(3,989)	(4,267)	(4,362)	(4,211)	(3,971)	(3,692)	(3,403)	(3,114)	(2,825)	(2,536)	(2,247)	(1,958)	(1,669)	(1,380)
Depreciation Expense	(10)	(51)	(325)	(1,222)	(2,147)	(2,609)	(2,910)	(3,187)	(3,537)	(3,781)	(3,868)	(3,900)	(3,906)	(3,906)	(3,906)	(3,906)	(3,906)	(3,906)	(3,906)	(3,906)	(3,906)
O&M and Property Tax Expense	702	(1,629)	(130)	(250)	(4,109)	(15,776)	(14,948)	(14,959)	(15,374)	(17,417)	(15,637)	(6,217)	2,480	2,530	2,581	2,632	2,684	2,738	2,793	1,424	-
PSCR	8	517	(834)	(260)	8,178	9,390	6,553	6,999	5,352	8,482	11,665	5,694	(249)	(159)	(34)	87	(73)	86	49	124	(452)
Incremental Revenue Requirement	685	(1,237)	(1,762)	(3,497)	(1,108)	(12,545)	(15,102)	(15,135)	(17,826)	(17,078)	(12,050)	(8,394)	(5,367)	(4,938)	(4,473)	(4,012)	(3,830)	(3,329)	(3,022)	(4,026)	(5,738)
Percentage Increase in RR	0.02%	-0.03%	-0.04%	-0.08%	-0.03%	-0.28%	-0.34%	-0.34%	-0.40%	-0.39%	-0.27%	-0.19%	-0.12%	-0.11%	-0.10%	-0.09%	-0.09%	-0.08%	-0.07%	-0.09%	-0.13%
Percentage Increase over Prior Year	0.02%	-0.04%	-0.01%	-0.04%	0.05%	-0.26%	-0.06%	0.00%	-0.06%	0.02%	0.11%	0.08%	0.07%	0.01%	0.01%	0.01%	0.00%	0.01%	0.01%	-0.02%	-0.04%
Cents/kWh Incremental Revenue Requirement	0.0020	-0.0037	-0.0052	-0.0104	-0.0033	-0.0373	-0.0449	-0.0450	-0.0530	-0.0508	-0.0358	-0.0250	-0.0160	-0.0147	-0.0133	-0.0119	-0.0114	-0.0099	-0.0090	-0.0120	-0.0171
Cents/kWh Increase Over Prior Year	0.0020	-0.0057	-0.0016	-0.0052	0.0071	-0.0340	-0.0076	-0.0001	-0.0080	0.0022	0.0150	0.0109	0.0090	0.0013	0.0014	0.0014	0.0005	0.0015	0.0009	-0.0030	-0.0051
U-18322 MWh Full Service	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639

Revenue Requirement (Current Rates)	4,419,264
U-20134 MWh Full Service [1]	33,633,639

[1] U-20134 Exhibit A-16 (JCA-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Incremental Revenue Requirement - Campbell 2 2025
(000)

Case No.: U-21090
Exhibit No.: A-38 (JRC-3)
Page: 6 of 13
Witness: JRCoker
Date: June 2021

Campbell 2 2025	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Capital Spending	-49	-741	-12,150	-35,161	-10,452	-7,550	-4,420	-6,845	-7,394	-2,500	-1,050	-250	0	0	0	0	0	0	0	0	0
Average Rate Base	(24)	(408)	(6,675)	(29,410)	(50,154)	(56,310)	(59,081)	(61,214)	(64,520)	(65,357)	(62,857)	(59,172)	(54,943)	(50,585)	(46,228)	(41,871)	(37,513)	(33,156)	(28,799)	(24,442)	(20,084)
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	(2)	(30)	(494)	(2,176)	(3,711)	(4,167)	(4,372)	(4,530)	(4,774)	(4,836)	(4,651)	(4,378)	(4,065)	(3,743)	(3,421)	(3,098)	(2,776)	(2,453)	(2,131)	(1,809)	(1,486)
Depreciation Expense	(1)	(21)	(338)	(1,502)	(2,624)	(3,067)	(3,361)	(3,638)	(3,988)	(4,232)	(4,319)	(4,351)	(4,357)	(4,357)	(4,357)	(4,357)	(4,357)	(4,357)	(4,357)	(4,357)	(4,357)
O&M and Property Tax Expense	702	(1,629)	(130)	(0)	(19)	(6,069)	(14,947)	(14,958)	(15,373)	(17,417)	(15,637)	(6,217)	2,480	2,530	2,581	2,632	2,685	2,739	2,793	1,426	3
PSCR	8	517	(834)	(260)	206	6,296	6,564	7,016	5,343	8,501	11,653	5,803	(159)	(106)	(90)	67	79	(3)	137	(50)	360
Incremental Revenue Requirement	707	(1,163)	(1,796)	(3,939)	(6,148)	(7,006)	(16,115)	(16,110)	(18,793)	(17,984)	(12,954)	(9,143)	(6,101)	(5,676)	(5,287)	(4,756)	(4,369)	(4,075)	(3,558)	(4,789)	(5,481)
Percentage Increase in RR	0.02%	-0.03%	-0.04%	-0.09%	-0.14%	-0.16%	-0.36%	-0.36%	-0.43%	-0.41%	-0.29%	-0.21%	-0.14%	-0.13%	-0.12%	-0.11%	-0.10%	-0.09%	-0.08%	-0.11%	-0.12%
Percentage Increase over Prior Year	0.02%	-0.04%	-0.01%	-0.05%	-0.05%	-0.02%	-0.21%	0.00%	-0.06%	0.02%	0.11%	0.09%	0.07%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	-0.03%	-0.02%
Cents/kWh Incremental Revenue Requirement	0.0021	-0.0035	-0.0053	-0.0117	-0.0183	-0.0208	-0.0479	-0.0479	-0.0559	-0.0535	-0.0385	-0.0272	-0.0181	-0.0169	-0.0157	-0.0141	-0.0130	-0.0121	-0.0106	-0.0142	-0.0163
Cents/kWh Increase Over Prior Year	0.0021	-0.0056	-0.0019	-0.0064	-0.0066	-0.0026	-0.0271	0.0000	-0.0080	0.0024	0.0150	0.0113	0.0090	0.0013	0.0012	0.0016	0.0012	0.0009	0.0015	-0.0037	-0.0021
U-18322 MWh Full Service	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639

Revenue Requirement (Current Rates)	4,419,264
U-20134 MWh Full Service [1]	33,633,639

[1] U-20134 Exhibit A-16 (JCA-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Incremental Revenue Requirement - Campbell 2 2026
(000)

Campbell 2 2026	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Capital Spending	-49	-741	-12,150	-35,161	-9,952	-7,000	-4,170	-6,845	-7,394	-2,500	-1,050	-250	0	0	0	0	0	0	0	0	0
Average Rate Base	(24)	(408)	(6,675)	(29,410)	(49,910)	(55,566)	(57,986)	(60,054)	(63,425)	(64,325)	(61,889)	(58,268)	(54,103)	(49,809)	(45,516)	(41,223)	(36,929)	(32,636)	(28,343)	(24,049)	(19,756)
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	(2)	(30)	(494)	(2,176)	(3,693)	(4,112)	(4,291)	(4,444)	(4,693)	(4,760)	(4,580)	(4,312)	(4,003)	(3,686)	(3,368)	(3,050)	(2,733)	(2,415)	(2,097)	(1,780)	(1,462)
Depreciation Expense	(1)	(21)	(338)	(1,502)	(2,611)	(3,028)	(3,303)	(3,574)	(3,924)	(4,168)	(4,255)	(4,287)	(4,293)	(4,293)	(4,293)	(4,293)	(4,293)	(4,293)	(4,293)	(4,293)	(4,293)
O&M and Property Tax Expense	702	(1,629)	(130)	(0)	231	(1,950)	(4,999)	(14,958)	(15,373)	(17,416)	(15,636)	(6,217)	2,480	2,530	2,581	2,632	2,685	2,739	2,793	1,426	-
PSCR	-	515	(852)	(478)	(9)	2,775	5,678	8,026	5,343	8,548	11,534	5,595	70	(431)	(64)	243	79	120	52	(9)	(173)
Incremental Revenue Requirement	699	(1,164)	(1,814)	(4,156)	(6,082)	(6,315)	(6,915)	(14,949)	(18,647)	(17,796)	(12,937)	(9,220)	(5,746)	(5,880)	(5,144)	(4,468)	(4,262)	(3,850)	(3,545)	(4,655)	(5,928)
Percentage Increase in RR	0.02%	-0.03%	-0.04%	-0.09%	-0.14%	-0.14%	-0.16%	-0.34%	-0.42%	-0.40%	-0.29%	-0.21%	-0.13%	-0.13%	-0.12%	-0.10%	-0.10%	-0.09%	-0.08%	-0.11%	-0.13%
Percentage Increase over Prior Year	0.02%	-0.04%	-0.01%	-0.05%	-0.04%	-0.01%	-0.01%	-0.18%	-0.08%	0.02%	0.11%	0.08%	0.08%	0.00%	0.02%	0.02%	0.00%	0.01%	0.01%	-0.03%	-0.03%
Cents/kWh Incremental Revenue Requirement	0.0021	-0.0035	-0.0054	-0.0124	-0.0181	-0.0188	-0.0206	-0.0444	-0.0554	-0.0529	-0.0385	-0.0274	-0.0171	-0.0175	-0.0153	-0.0133	-0.0127	-0.0114	-0.0105	-0.0138	-0.0176
Cents/kWh Increase Over Prior Year	0.0021	-0.0055	-0.0019	-0.0070	-0.0057	-0.0007	-0.0018	-0.0239	-0.0110	0.0025	0.0144	0.0111	0.0103	-0.0004	0.0022	0.0020	0.0006	0.0012	0.0009	-0.0033	-0.0038
U-18322 MWh Full Service	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639

Revenue Requirement (Current Rates)	4,419,264
U-20134 MWh Full Service [(1)]	33,633,639

[(1)] U-20134 Exhibit A-16 (JCA-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Incremental Revenue Requirement - Campbell 2 2028
(000)

Case No.: U-21090
Exhibit No.: A-38 (JRC-3)
Page: 8 of 13
Witness: JRCoker
Date: June 2021

Campbell 2 2028	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Capital Spending	0	0	0	0	0	-3,000	-1,250	-3,139	-7,144	-2,500	-1,050
Average Rate Base	-	-	-	-	-	(1,463)	(3,462)	(5,424)	(10,153)	(14,317)	(15,272)
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	-	-	-	-	-	(108)	(256)	(401)	(751)	(1,059)	(1,130)
Depreciation Expense	-	-	-	-	-	(74)	(178)	(286)	(539)	(777)	(864)
O&M and Property Tax Expense	750	(750)	0	(0)	(0)	0	0	(250)	(4,852)	(17,416)	(15,636)
PSCR	-	515	(341)	(170)	-	-	-	-	4,799	9,575	11,741
Incremental Revenue Requirement	750	(235)	(340)	(171)	(0)	(182)	(434)	(938)	(1,344)	(9,677)	(5,889)
Percentage Increase in RR	0.02%	-0.01%	-0.01%	0.00%	0.00%	0.00%	-0.01%	-0.02%	-0.03%	-0.22%	-0.13%
Percentage Increase over Prior Year	0.02%	-0.02%	0.00%	0.00%	0.00%	0.00%	-0.01%	-0.01%	-0.01%	-0.19%	0.09%
Cents/kWh Incremental Revenue Requirement	0.0022	-0.0007	-0.0010	-0.0005	0.0000	-0.0005	-0.0013	-0.0028	-0.0040	-0.0288	-0.0175
Cents/kWh Increase Over Prior Year	0.0022	-0.0029	-0.0003	0.0005	0.0005	-0.0005	-0.0008	-0.0015	-0.0012	-0.0248	0.0113
U-18322 MWh Full Service	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639

Campbell 2 2028	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Capital Spending	-250	0	0	0	0	0	0	0	0	0
Average Rate Base	(15,042)	(14,268)	(13,366)	(12,464)	(11,562)	(10,660)	(9,758)	(8,856)	(7,954)	(7,052)
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	(1,113)	(1,056)	(989)	(922)	(856)	(789)	(722)	(655)	(589)	(522)
Depreciation Expense	(896)	(902)	(902)	(902)	(902)	(902)	(902)	(902)	(902)	(902)
O&M and Property Tax Expense	(6,216)	2,481	2,531	2,581	2,633	2,686	2,739	2,794	1,425	-
PSCR	5,642	(151)	229	(177)	(250)	8	262	119	(223)	(150)
Incremental Revenue Requirement	(2,583)	373	869	580	626	1,002	1,377	1,356	(289)	(1,573)
Percentage Increase in RR	-0.06%	0.01%	0.02%	0.01%	0.01%	0.02%	0.03%	0.03%	-0.01%	-0.04%
Percentage Increase over Prior Year	0.07%	0.07%	0.01%	-0.01%	0.00%	0.01%	0.01%	0.00%	-0.04%	-0.03%
Cents/kWh Incremental Revenue Requirement	-0.0077	0.0011	0.0026	0.0017	0.0019	0.0030	0.0041	0.0040	-0.0009	-0.0047
Cents/kWh Increase Over Prior Year	0.0098	0.0088	0.0015	-0.0009	0.0001	0.0011	0.0011	-0.0001	-0.0049	-0.0038
U-18322 MWh Full Service	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639

Revenue Requirement (Current Rates)	4,419,264
U-20134 MWh Full Service [1]	33,633,639

[1] U-20134 Exhibit A-16 (JCA-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Incremental Revenue Requirement - Campbell 1&2 2024
(000)

Campbell 1&2 2024	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital Spending	-788	4,307	-7,865	-15,893	32,310	-31,944	-28,828	-31,506	-38,460	-40,993
Average Rate Base	(384)	1,351	(451)	(12,017)	(3,895)	(4,780)	(35,384)	(63,497)	(94,067)	(126,811)
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	(28)	100	(33)	(889)	(288)	(354)	(2,618)	(4,698)	(6,961)	(9,383)
Depreciation Expense	(19)	67	(20)	(605)	776	1,361	(926)	(3,181)	(5,646)	(8,317)
O&M and Property Tax Expense	117	(1,951)	(197)	(506)	(14,724)	(34,310)	(34,757)	(36,214)	(44,322)	(47,338)
PSCR	7	(2)	(953)	(150)	13,299	18,385	11,950	12,230	8,846	8,895
Incremental Revenue Requirement	76	(1,786)	(1,204)	(2,149)	(937)	(14,917)	(26,351)	(31,864)	(48,082)	(56,143)
Percentage Increase in RR	0.00%	-0.04%	-0.03%	-0.05%	-0.02%	-0.34%	-0.60%	-0.72%	-1.09%	-1.27%
Percentage Increase over Prior Year	0.00%	-0.04%	0.01%	-0.02%	0.03%	-0.32%	-0.26%	-0.12%	-0.37%	-0.18%
Cents/kWh Incremental Revenue Requirement	0.0002	-0.0053	-0.0036	-0.0064	-0.0028	-0.0444	-0.0783	-0.0947	-0.1430	-0.1669
Cents/kWh Increase Over Prior Year	0.0002	-0.0055	0.0017	-0.0028	0.0036	-0.0416	-0.0340	-0.0164	-0.0482	-0.0240
U-18322 MWh Full Service	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639

Campbell 1&2 2024	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Capital Spending	-104,624	172,069	-28,310	12,374	-8,049	-8,081	-8,136	-8,183	-8,232	-8,279	209,920
Average Rate Base	(188,497)	(140,578)	(55,784)	(52,215)	(38,394)	(34,675)	(30,652)	(26,329)	(21,703)	(16,770)	95,222
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	(13,948)	(10,402)	(4,128)	(3,864)	(2,841)	(2,566)	(2,268)	(1,948)	(1,606)	(1,241)	7,046
Depreciation Expense	(13,928)	(14,464)	(11,365)	(11,708)	(11,610)	(11,957)	(12,306)	(12,657)	(13,011)	(13,366)	(8,976)
O&M and Property Tax Expense	(42,817)	(20,803)	(4,732)	(4,425)	(4,405)	(4,327)	(4,189)	(4,124)	(3,943)	1,550	5,156
PSCR	20,836	13,072	1,799	2,219	3,015	2,559	2,448	2,729	4,349	7,220	(3,783)
Incremental Revenue Requirement	(49,857)	(32,598)	(18,426)	(17,778)	(15,842)	(16,290)	(16,315)	(16,000)	(14,210)	(5,836)	(557)
Percentage Increase in RR	-1.13%	-0.74%	-0.42%	-0.40%	-0.36%	-0.37%	-0.37%	-0.36%	-0.32%	-0.13%	-0.01%
Percentage Increase over Prior Year	0.14%	0.39%	0.32%	0.01%	0.04%	-0.01%	0.00%	0.01%	0.04%	0.19%	0.12%
Cents/kWh Incremental Revenue Requirement	-0.1482	-0.0969	-0.0548	-0.0529	-0.0471	-0.0484	-0.0485	-0.0476	-0.0422	-0.0174	-0.0017
Cents/kWh Increase Over Prior Year	0.0187	0.0513	0.0421	0.0019	0.0058	-0.0013	-0.0001	0.0009	0.0053	0.0249	0.0157
U-18322 MWh Full Service	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639

Revenue Requirement (Current Rates)	4,419,264
U-20134 MWh Full Service [1]	33,633,639

[1] U-20134 Exhibit A-16 (JCA-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Incremental Revenue Requirement - Campbell 1&2 2025
(000)

Campbell 1&2 2025	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Capital Spending	-85	-941	-8,860	-24,250	9,030	4,259	-7,947	41,278	-16,754	-19,811	-82,277	-15,044	-6	-57	-32	-32	-32	-32	-32	-32	0
Average Rate Base	(41)	(540)	(5,292)	(21,171)	(27,508)	(19,558)	(20,202)	(3,354)	7,044	(13,651)	(64,803)	(109,858)	(111,756)	(105,972)	(100,199)	(94,411)	(88,623)	(82,833)	(77,042)	(71,250)	(65,441)
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	(3)	(40)	(392)	(1,567)	(2,035)	(1,447)	(1,495)	(248)	521	(1,010)	(4,795)	(8,129)	(8,269)	(7,841)	(7,414)	(6,986)	(6,558)	(6,129)	(5,701)	(5,272)	(4,842)
Depreciation Expense	(2)	(27)	(268)	(1,083)	(1,464)	(1,149)	(1,251)	888	2,840	1,987	(1,771)	(5,440)	(5,815)	(5,816)	(5,818)	(5,820)	(5,821)	(5,822)	(5,824)	(5,825)	(5,826)
O&M and Property Tax Expense	117	(1,951)	(197)	(1)	(277)	(13,410)	(30,471)	(33,930)	(35,147)	(37,364)	(32,159)	(15,885)	374	385	398	410	422	435	448	113	(48)
PSCR	(3)	(24)	(978)	(188)	309	14,301	12,664	12,293	8,098	6,942	19,692	11,669	(143)	(207)	(5)	164	(1)	136	336	53	(630)
Incremental Revenue Requirement	109	(2,042)	(1,836)	(2,838)	(3,466)	(1,705)	(20,554)	(20,997)	(23,687)	(29,445)	(19,033)	(17,785)	(13,853)	(13,479)	(12,839)	(12,232)	(11,957)	(11,381)	(10,741)	(10,932)	(11,346)
Percentage Increase in RR	0.00%	-0.05%	-0.04%	-0.06%	-0.08%	-0.04%	-0.47%	-0.48%	-0.54%	-0.67%	-0.43%	-0.40%	-0.31%	-0.31%	-0.29%	-0.28%	-0.27%	-0.26%	-0.24%	-0.25%	-0.26%
Percentage Increase over Prior Year	0.00%	-0.05%	0.00%	-0.02%	-0.01%	0.04%	-0.43%	-0.01%	-0.06%	-0.13%	0.24%	0.03%	0.09%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.00%	-0.01%
Cents/kWh Incremental Revenue Requirement	0.0003	-0.0061	-0.0055	-0.0084	-0.0103	-0.0051	-0.0611	-0.0624	-0.0704	-0.0875	-0.0566	-0.0529	-0.0412	-0.0401	-0.0382	-0.0364	-0.0356	-0.0338	-0.0319	-0.0325	-0.0337
Cents/kWh Increase Over Prior Year	0.0003	-0.0064	0.0006	-0.0030	-0.0019	0.0052	-0.0560	-0.0013	-0.0080	-0.0171	0.0310	0.0037	0.0117	0.0011	0.0019	0.0018	0.0008	0.0017	0.0019	-0.0006	-0.0012
U-18322 MWh Full Service	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639

Revenue Requirement (Current Rates)	4,419,264
U-20134 MWh Full Service [1]	33,633,639

[1] U-20134 Exhibit A-16 (JCA-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Incremental Revenue Requirement - Campbell 1&2 2026
(000)

Case No.: U-21090
Exhibit No.: A-38 (JRC-3)
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Witness: JRCoker
Date: June 2021

Campbell 1&2 2026	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Capital Spending	-85	-941	-15,640	-31,522	-4,244	19,468	6,668	42,977	-15,104	-20,019	-82,477	-15,246	6	-6	0	0	0	0	0	0	0
Average Rate Base	(41)	(540)	(8,599)	(31,165)	(47,006)	(37,081)	(22,186)	2,866	14,683	(5,667)	(57,424)	(103,061)	(105,420)	(99,966)	(94,515)	(89,061)	(83,607)	(78,153)	(72,699)	(67,245)	(61,791)
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	(3)	(40)	(636)	(2,306)	(3,478)	(2,744)	(1,642)	212	1,086	(419)	(4,249)	(7,626)	(7,801)	(7,397)	(6,994)	(6,590)	(6,187)	(5,783)	(5,379)	(4,976)	(4,572)
Depreciation Expense	(2)	(27)	(435)	(1,595)	(2,488)	(2,138)	(1,518)	1,060	3,179	2,398	(1,380)	(5,069)	(5,454)	(5,454)	(5,454)	(5,454)	(5,454)	(5,454)	(5,454)	(5,454)	(5,454)
O&M and Property Tax Expense	117	(1,951)	(197)	(1)	216	(2,478)	(12,644)	(33,870)	(35,039)	(37,266)	(32,069)	(15,802)	458	470	484	497	510	524	537	209	26
PSCR	(5)	(6)	(1,008)	(247)	(11)	919	11,771	14,527	8,063	7,039	19,628	11,647	(112)	30	154	393	126	(52)	(172)	(32)	(463)
Incremental Revenue Requirement	107	(2,024)	(2,277)	(4,149)	(5,761)	(6,441)	(4,032)	(18,071)	(22,710)	(28,248)	(18,070)	(16,849)	(12,908)	(12,351)	(11,809)	(11,154)	(11,005)	(10,765)	(10,469)	(10,252)	(10,462)
Percentage Increase in RR	0.00%	-0.05%	-0.05%	-0.09%	-0.13%	-0.15%	-0.09%	-0.41%	-0.51%	-0.64%	-0.41%	-0.38%	-0.29%	-0.28%	-0.27%	-0.25%	-0.25%	-0.24%	-0.24%	-0.23%	-0.24%
Percentage Increase over Prior Year	0.00%	-0.05%	-0.01%	-0.04%	-0.04%	-0.02%	0.05%	-0.32%	-0.10%	-0.13%	0.23%	0.03%	0.09%	0.01%	0.01%	0.01%	0.00%	0.01%	0.01%	0.00%	0.00%
Cents/kWh Incremental Revenue Requirement	0.0003	-0.0060	-0.0068	-0.0123	-0.0171	-0.0192	-0.0120	-0.0537	-0.0675	-0.0840	-0.0537	-0.0501	-0.0384	-0.0367	-0.0351	-0.0332	-0.0327	-0.0320	-0.0311	-0.0305	-0.0311
Cents/kWh Increase Over Prior Year	0.0003	-0.0063	-0.0008	-0.0056	-0.0048	-0.0020	0.0072	-0.0417	-0.0138	-0.0165	0.0303	0.0036	0.0117	0.0017	0.0016	0.0019	0.0004	0.0007	0.0009	0.0006	-0.0006
U-18322 MWh Full Service	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639

Revenue Requirement (Current Rates)	4,419,264
U-20134 MWh Full Service [1]	33,633,639

[1] U-20134 Exhibit A-16 (JCA-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Incremental Revenue Requirement - Campbell 1&2 2028
(000)

Case No.: U-21090
Exhibit No.: A-38 (JRC-3)
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Witness: JRCoker
Date: June 2021

Campbell 1&2 2028	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Capital Spending	0	0	0	0	0	3,780	11,841	22,294	-2,833	30,806	-82,076	-14,841	2	-2	0	0	0	0	0	0	0
Average Rate Base	-	-	-	-	-	1,844	9,369	25,540	33,714	44,906	16,088	(33,123)	(39,287)	(37,849)	(36,412)	(34,975)	(33,537)	(32,099)	(30,661)	(29,223)	(27,785)
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	-	-	-	-	-	136	693	1,890	2,495	3,323	1,190	(2,451)	(2,907)	(2,801)	(2,694)	(2,588)	(2,482)	(2,375)	(2,269)	(2,162)	(2,056)
Depreciation Expense	-	-	-	-	-	93	477	1,317	1,796	3,793	2,576	(1,073)	(1,438)	(1,438)	(1,438)	(1,438)	(1,438)	(1,438)	(1,438)	(1,438)	(1,438)
O&M and Property Tax Expense	750	(751)	1	(1)	(1)	1	1	(890)	(13,411)	(37,227)	(32,017)	(15,736)	524	537	550	562	577	590	604	261	-
PSCR	-	515	(341)	(170)	-	-	-	-	10,931	9,620	19,572	11,546	2	(94)	(170)	286	101	(67)	133	(6)	(128)
Incremental Revenue Requirement	750	(235)	(340)	(171)	(1)	230	1,171	2,317	1,810	(20,491)	(8,679)	(7,714)	(3,819)	(3,796)	(3,752)	(3,177)	(3,242)	(3,291)	(2,970)	(3,346)	(3,622)
Percentage Increase in RR	0.02%	-0.01%	-0.01%	0.00%	0.00%	0.01%	0.03%	0.05%	0.04%	-0.46%	-0.20%	-0.17%	-0.09%	-0.09%	-0.08%	-0.07%	-0.07%	-0.07%	-0.07%	-0.08%	-0.08%
Percentage Increase over Prior Year	0.02%	-0.02%	0.00%	0.00%	0.00%	0.01%	0.02%	0.03%	-0.01%	-0.50%	0.27%	0.02%	0.09%	0.00%	0.00%	0.01%	0.00%	0.00%	0.01%	-0.01%	-0.01%
Cents/kWh Incremental Revenue Requirement	0.0022	-0.0007	-0.0010	-0.0005	0.0000	0.0007	0.0035	0.0069	0.0054	-0.0609	-0.0258	-0.0229	-0.0114	-0.0113	-0.0112	-0.0094	-0.0096	-0.0098	-0.0088	-0.0099	-0.0108
Cents/kWh Increase Over Prior Year	0.0022	-0.0029	-0.0003	0.0005	0.0005	0.0007	0.0028	0.0034	-0.0015	-0.0663	0.0351	0.0029	0.0116	0.0001	0.0001	0.0017	-0.0002	-0.0001	0.0010	-0.0011	-0.0008
U-18322 MWh Full Service	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639

Revenue Requirement (Current Rates)	4,419,264
U-20134 MWh Full Service [1]	33,633,639

[1] U-20134 Exhibit A-16 (JCA-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Incremental Revenue Requirement - Karn 3&4 2025
(000)

Case No.: U-21090
Exhibit No.: A-38 (JRC-3)
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Witness: JRCoker
Date: June 2021

Karn 3&4 2025	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Capital Spending	0	1,173	-20,250	-9,512	-10,019	230,223	-7,443	-6,541	356	-1,506	-51,382	-210,730	-6	17,372	8,708	8,727	8,770	8,810	8,848	8,883	0
Average Rate Base	-	572	(8,761)	(22,835)	(31,178)	77,282	180,331	161,721	147,137	135,064	98,384	(37,804)	(141,938)	(129,663)	(113,503)	(102,139)	(91,124)	(80,449)	(70,118)	(60,136)	(54,867)
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	-	42	(648)	(1,690)	(2,307)	5,719	13,344	11,967	10,887	9,994	7,280	(2,797)	(10,503)	(9,595)	(8,399)	(7,558)	(6,743)	(5,953)	(5,188)	(4,450)	(4,060)
Depreciation Expense	-	29	(440)	(1,173)	(1,672)	4,955	11,728	11,507	11,476	11,520	8,952	1,314	(3,781)	(3,403)	(2,836)	(2,457)	(2,076)	(1,694)	(1,310)	(924)	(731)
O&M and Property Tax Expense	999	624	491	1,430	(524)	(3,771)	(16,612)	(16,696)	(16,770)	(17,157)	(13,842)	(12,719)	(3)	227	350	468	627	723	851	1,015	6,450
PSCR	(171)	(15)	25	(1)	334	689	1,118	(2,007)	(2,327)	(3,983)	(1,240)	433	(168)	(661)	(762)	(765)	(507)	(1,274)	24	(2,477)	(1,550)
Incremental Revenue Requirement	828	680	(573)	(1,434)	(4,169)	7,592	9,577	4,771	3,267	374	1,150	(13,769)	(14,454)	(13,431)	(11,647)	(10,312)	(8,698)	(8,198)	(5,623)	(6,836)	109
Percentage Increase in RR	0.02%	0.02%	-0.01%	-0.03%	-0.09%	0.17%	0.22%	0.11%	0.07%	0.01%	0.03%	-0.31%	-0.33%	-0.30%	-0.26%	-0.23%	-0.20%	-0.19%	-0.13%	-0.15%	0.00%
Percentage Increase over Prior Year	0.02%	0.00%	-0.03%	-0.02%	-0.06%	0.27%	0.04%	-0.11%	-0.03%	-0.07%	0.02%	-0.34%	-0.02%	0.02%	0.04%	0.03%	0.04%	0.01%	0.06%	-0.03%	0.16%
Cents/kWh Incremental Revenue Requirement	0.0025	0.0020	-0.0017	-0.0043	-0.0124	0.0226	0.0285	0.0142	0.0097	0.0011	0.0034	-0.0409	-0.0430	-0.0399	-0.0346	-0.0307	-0.0259	-0.0244	-0.0167	-0.0203	0.0003
Cents/kWh Increase Over Prior Year	0.0025	-0.0004	-0.0037	-0.0026	-0.0081	0.0350	0.0059	-0.0143	-0.0045	-0.0086	0.0023	-0.0444	-0.0020	0.0030	0.0053	0.0040	0.0048	0.0015	0.0077	-0.0036	0.0206
U-18322 MWh Full Service	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639	33,633,639

Revenue Requirement (Current Rates)	4,419,264
U-20134 MWh Full Service [1]	33,633,639

[1] U-20134 Exhibit A-16 (JCA-1)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Revenue Requirement - Covert
(000)

Case No.: U-21090
Exhibit No.: A-39 (JRC-4)
Page: 1 of 1
Witness: JRCoker
Date: June 2021

	Covert - Revenue Requirement Calculation	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	Capital Spending	0	0	0	825,991	19,287	19,732	20,192	27,731	21,166	21,664	22,162	22,661	23,168	23,690	24,213	24,744	11,717	11,978	10,356	8,461	0
2	Average Rate Base	-	-	-	402,671	794,094	771,334	748,039	727,647	706,531	681,235	655,354	628,863	601,742	573,976	545,549	516,438	480,011	436,449	391,632	344,541	291,932
3	Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
4	Return	-	-	-	29,798	58,763	57,079	55,355	53,846	52,283	50,411	48,496	46,536	44,529	42,474	40,371	38,216	35,521	32,297	28,981	25,496	21,603
5	Depreciation Expense	-	-	-	20,650	41,782	42,757	43,755	44,953	46,176	47,247	48,342	49,463	50,609	51,780	52,978	54,201	55,113	55,705	56,264	56,734	56,946
6	O&M and Property Tax Expense	-	-	-	26,366	46,573	47,602	48,315	49,002	48,766	49,727	50,102	50,670	50,968	52,820	53,690	54,767	55,279	55,491	56,692	58,311	24,041
7	Revenue Requirement	-	-	-	76,814	147,117	147,438	147,426	147,801	147,225	147,385	146,940	146,669	146,105	147,074	147,038	147,185	145,912	143,493	141,937	140,541	102,590

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Revenue Requirement - DIG, Kalamazoo, and Livingston Plants
(000)

Case No.: U-21090
Exhibit No.: A-40 (JRC-4)

Witness: JRCoker
Date: June 2021

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Capital Spending	0	0	0	0	0	531,354	3,851	6,567	9,533	12,784	16,364	20,332	24,766	29,781	35,539	42,297	46,775	52,410	59,599	69,836	0
Average Rate Base	-	-	-	-	-	259,035	506,663	485,078	466,003	449,555	435,880	425,155	417,610	413,543	413,365	417,655	425,476	436,002	450,298	470,290	457,992
Times Pre-tax Cost of Capital	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%	7.40%
Return	-	-	-	-	-	19,169	37,493	35,896	34,484	33,267	32,255	31,462	30,903	30,602	30,589	30,906	31,485	32,264	33,322	34,801	33,891
Depreciation Expense	-	-	-	-	-	13,284	26,664	26,924	27,327	27,885	28,614	29,531	30,658	32,022	33,655	35,601	37,828	40,307	43,108	46,343	48,089
O&M and Property Tax Expense	-	-	-	-	-	25,112	41,415	41,632	41,750	42,191	42,365	43,724	44,411	44,927	46,204	46,501	46,606	48,532	48,817	50,762	20,953
Revenue Requirement	-	-	-	-	-	57,565	105,573	104,452	103,562	103,343	103,233	104,717	105,972	107,552	110,448	113,008	115,919	121,103	125,247	131,907	102,934

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
____	)	

EXHIBITS

OF

JEFFREY E. BATTAGLIA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP New Gas-Fueled Technologies Capital and Operations Cost Assumptions

Case No.: U-21090
Exhibit No.: A-41 (JEB-1)
Page: 1 of 2
Witness: JEBattaglia
Date: June 2021

Line No.	(a) New Gas-Fueled Technologies - Schedules and Operating Parameters	(b)	(c) Dry Cooled Combined Cycle (2x1 H) Unfired	(d) 2x1 H-Class Dry Cooled Combined Cycle (2x1 H) Fired	(e) Dry Cooled Duct Burner Incr. (2x1 H)	(f) Dry Cooled Combined Cycle (1x1 H) Unfired	(g) 1x1 H-Class Dry Cooled Combined Cycle (1x1 H) Fired	(h) Dry Cooled Duct Burner Incr. (1x1 H)	(i) Dry Cooled Combined Cycle (1x1 F) Unfired	(j) 1x1 F-Class Dry Cooled Combined Cycle (1x1 F) Fired	(k) Dry Cooled Duct Burner Incr. (1x1 F)	(l) 1x0 F-Class Simple Cycle (1x0 F)	(m) 5x0 Reciprocating Engine RICE (5x0)
1	First Year Available [1]	(1/1/20xx)	2025	2025	2025	2025	2025	2025	2025	2025	2025	2023	2023
2	Maximum Capacity	(MW)	1,107	1,252	145	553	634	81	349	394	46	239	85
3	Minimum Capacity	(MW)	382	N/A	N/A	191	N/A	N/A	131	N/A	N/A	69	12
4	Summer Capacity	(MW)	1,055	1,181	126	528	591	64	340	380	40	231	85
5	Summer Derate	(%)	4.7%	5.7%	N/A	4.5%	6.7%	N/A	2.5%	3.6%	N/A	3.4%	0%
6	Operating Life	(Yrs)	30	30	30	30	30	30	30	30	30	30	30
7	Fixed O&M Non-LTSA Component	($/kW-yr)	9.86	9.86	N/A	9.90	9.90	N/A	10.89	10.89	N/A	6.43	6.52
8	Fixed O&M LTSA Component	($/kW-yr)	0.23	0.23	N/A	0.23	0.23	N/A	0.25	0.25	N/A	0.43	0.43
9	Variable O&M Non-LTSA Component	($/MWh)	0.72	0.72	N/A	0.70	0.70	N/A	1.23	1.23	N/A	2.39	1.31
10	Variable O&M LTSA Component	($/MWh)	1.33	1.33	N/A	1.30	1.30	N/A	2.28	2.28	N/A	8.60	4.70
11	Annual EFOR	(%)	2.00%	2.00%	N/A	2.00%	2.00%	N/A	2.00%	2.00%	N/A	2.00%	2.00%
12	Annual Maintenance	(%)	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
13	Annual Maintenance	(Wks/yr)											
14	Summer Performance (New Condition)		-	-	-	-	-	-		-	-	-	-
15	Full Load Output	(MW)	1,055	1,181	126	528	591	64	340	380	40	231	85
16	75% Output	(MW)	791	N/A	N/A	396	N/A	N/A	255	N/A	N/A	173	64
17	50% Output	(MW)	527	N/A	N/A	264	N/A	N/A	170	N/A	N/A	115	42
18	Minimum Output[5]	(MW)	382	N/A	N/A	191	N/A	N/A	131	N/A	N/A	69	12
19	Full Load Heat Rate	(Btu/kWh)	6,411	6,672	8,862	6,405	6,659	8,763	6,697	6,910	8,713	9,616	8,102
20	Avg HR at 75% Output	(Btu/kWh)	6,541	N/A	N/A	6,536	N/A	N/A	6,827	N/A	N/A	9,964	8,371
21	Avg HR at 50% Output	(Btu/kWh)	7,061		N/A	7,057	N/A	N/A	7,592	N/A	N/A	11,645	8,844
22	Avg HR at Minimum Output[5]	(Btu/kWh)	7,637	N/A	N/A	7,633	N/A	N/A	8,126	N/A	N/A	16,610	14,728
23	Winter Performance (New Condition)												
24	Full Load Output	(MW)	1,107	1,252	145	553	634	81	349	394	46	239	85
25	75% Output	(MW)	830	N/A	N/A	415	N/A	N/A	261	N/A	N/A	179	64
26	50% Output	(MW)	553	N/A	N/A	276	N/A	N/A	174	N/A	N/A	119	42
27	Minimum Output[5]	(MW)	419	N/A	N/A	213	N/A	N/A	143	N/A	N/A	72	12
28	Full Load Heat Rate	(Btu/kWh)	6,282	6,538	8,484	6,289	6,549	8,326	6,552	6,760	8,340	9,402	8,090
29	Avg HR at 75% Output	(Btu/kWh)	6,430	N/A	N/A	6,431	N/A	N/A	6,666	N/A	N/A	9,881	8,359
30	Avg HR at 50% Output	(Btu/kWh)	6,923	N/A	N/A	6,924	N/A	N/A	7,446	N/A	N/A	11,649	8,832
31	Avg HR at Minimum Output[5]	(Btu/kWh)	7,364	N/A	N/A	7,365	N/A	N/A	7,832	N/A	N/A	15,199	14,708
32	SO_2 Emission Rate	(lb/MMBtu)	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010	0.0010
33	NOx Emission Rate	(lb/MMBtu)	0.0074	0.0074	0.0074	0.0075	0.0075	0.0075	0.0075	0.0075	0.0075	0.0332	0.0184
34	CO2 Emission Rate	(lb/MMBtu)	117	117	117	117	117	117	117	117	117	117	117
35	Cold Start Heat Input[10]	(MMBtu/MW/S	5.15	N/A	N/A	5.32	N/A	N/A	6.04	N/A	N/A	0.68	0.15
36	Cold Start Time	(Min.)	240	N/A	N/A	240	N/A	N/A	240	N/A	N/A	11	5
			See note #6.	See note #6.	See note #6.	See note #6.	See note #6.	See note #6.	See note #6.	See note #6.	See note #6.		

Notes:
1. Decision to construct is made nominally 3-years in advance of COD.
2. Generation technologies based on EIA defined plants; the 1x1 F-Class option is a modified 2x1 F-Class plant
3. All plant performance data developed using EBSILON software; baseline model heat rates and net outputs benchmarked against EIA ISO performance data
4. Plant performance assumes new and clean; models include evaporative coolers; models include fuel heaters - fuel heated to 550 F in combined cycle cases and 600 F for simple cycle models
5. The turndown for the Minimum Output and Avg. HR at Minimum Output is provided in a Note, in each of the respective cells for both summer and winter conditions
6. Supplemental duct firing 12-13% of the net capacity (PJM 2018 CONE); same rate of duct firing used for summer and winter cases
7. Fired combined cycle parameters not directly input into Aurora model; unfired combined cycle modeled with seperate duct burner unit
8. Fixed and variable O&M costs from EIA data; fixed O&M escalated to using TBD
9. All generation technologies assumed to be equipped with Air Quality Control Technology to meet EPA air quality requirements
10. Start-up heat input computed from zero load point on the Input-Output (IO) curve and OEM published startup times; IO curve generated from EBSILON heat rate curve data at ISO conditions
11. CT options have no emissions control
12. CC options include emissions control for NOx and CO
13. RICE option includes emissions control for NOx and CO
14. 1x1 F-Class emissions assumed to be the same as 2x1 F-Class
15. Fixed and Variable O&M Costs are in 2017$ (Real Escalation flat for all future years - NREL 2019 ATB data)
16. LTSA and Non-LTSA component breakouts for FOM and VOM costs based on AESO 2018 CONE data

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
2021 IRP New Gas-Fueled Technologies Real and Nominal Overnight Cost Projections

Case No.: U-21090
Exhibit No.: A-41 (JEB-1)

Witness: JEBattaglia
Date: June 2021

Overnight Cost ($/kW) - Real Costs 2017$

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Year	2x1 H-Class	1x1 H-Class	1x1 F-Class	1x0 F-Class	5x0 RICE
1	2017	$887	$1,186	$1,284	$692	$1,337
2	2018	$881	$1,177	$1,275	$691	$1,335
3	2019	$874	$1,169	$1,266	$690	$1,333
4	2020	$868	$1,160	$1,257	$695	$1,343
5	2021	$862	$1,152	$1,247	$686	$1,327
6	2022	$856	$1,144	$1,238	$681	$1,317
7	2023	$843	$1,126	$1,220	$668	$1,291
8	2024	$836	$1,118	$1,210	$662	$1,279
9	2025	$833	$1,113	$1,205	$658	$1,272
10	2026	$829	$1,109	$1,201	$654	$1,265
11	2027	$826	$1,104	$1,195	$650	$1,257
12	2028	$823	$1,100	$1,191	$648	$1,252
13	2029	$818	$1,094	$1,184	$644	$1,244
14	2030	$816	$1,090	$1,181	$641	$1,240
15	2031	$813	$1,087	$1,177	$639	$1,235
16	2032	$810	$1,083	$1,172	$636	$1,230
17	2033	$807	$1,079	$1,168	$634	$1,226
18	2034	$805	$1,076	$1,165	$632	$1,222
19	2035	$802	$1,072	$1,161	$629	$1,217
20	2036	$799	$1,068	$1,157	$627	$1,212
21	2037	$797	$1,065	$1,153	$625	$1,208
22	2038	$795	$1,063	$1,151	$624	$1,206
23	2039	$793	$1,060	$1,148	$622	$1,203
24	2040	$791	$1,057	$1,145	$621	$1,200

Overnight Cost ($/kW) - Nominal $

Line No.	Year	2x1 H-Class	1x1 H-Class	1x1 F-Class	1x0 F-Class	5x0 RICE
1	2017	$887	$1,186	$1,284	$692	$1,337
2	2018	$900	$1,203	$1,303	$706	$1,365
3	2019	$910	$1,216	$1,317	$718	$1,387
4	2020	$924	$1,235	$1,337	$739	$1,429
5	2021	$940	$1,257	$1,361	$749	$1,447
6	2022	$957	$1,279	$1,385	$762	$1,472
7	2023	$965	$1,290	$1,396	$765	$1,478
8	2024	$979	$1,309	$1,417	$775	$1,498
9	2025	$997	$1,333	$1,443	$788	$1,522
10	2026	$1,015	$1,357	$1,469	$800	$1,547
11	2027	$1,034	$1,382	$1,496	$814	$1,574
12	2028	$1,054	$1,409	$1,525	$829	$1,603
13	2029	$1,073	$1,434	$1,553	$844	$1,631
14	2030	$1,095	$1,464	$1,585	$861	$1,664
15	2031	$1,117	$1,493	$1,617	$878	$1,697
16	2032	$1,138	$1,521	$1,647	$894	$1,728
17	2033	$1,159	$1,549	$1,678	$910	$1,760
18	2034	$1,181	$1,579	$1,710	$927	$1,793
19	2035	$1,203	$1,608	$1,741	$944	$1,825
20	2036	$1,225	$1,638	$1,773	$961	$1,858
21	2037	$1,248	$1,668	$1,806	$979	$1,893
22	2038	$1,273	$1,701	$1,842	$999	$1,930
23	2039	$1,297	$1,734	$1,878	$1,018	$1,968
24	2040	$1,323	$1,768	$1,914	$1,038	$2,006

Notes
1. EIA data used to establish base year Overnight Costs
2. All Overnight Cost indexed to 2017$; 2017 base year Nominal Cost, future years Real Cost (NREL ATB approach)
3. NREL 2019 ATB data used to develop Real Escalation factors based in 2017$ to project overnight cost
4. CT Real Escalation factor applied to RICE option
5. 36 month construction for CC plant
6. 20 month construction for CT plant
8. Technology definitions and costs from EIA 2016 and 2019 Update Report
9. All costs scaled to summer performance data; CC plants include duct firing
10. CC Plant cost adjusted for ACC (dry cooling)
11. Export steam revenue is $1.68/1,000 lb steam based on LMP of $30/MWh in 2017 dollars

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
CONFIDENTIAL - 2021 IRP Capital Costs of Renewable Generation and Battery Storage Technologies

Case No.: U-21090
Exhibit No.: A-42 (JEB-2)
Page: 1 of 1
Witness: JEBattaglia
Date: June 2021

(a) Line No.	(b) Scenario/Sensitivity	(c) 2021 [1]	(d) 2022	(e) 2023	(f) 2024	(g) 2025	(h) 2026	(i) 2027	(j) 2028	(k) 2029	(l) 2030	(m) 2031	(n) 2032	(o) 2033	(p) 2034	(q) 2035	(r) 2036	(s) 2037	(t) 2038	(u) 2039	(v) 2040
1	Business-as-Usual																				
2	Wind-In State	N/A [2]	$1,572	$1,585	$1,599	$1,612	$1,625	$1,638	$1,651	$1,664	$1,677	$1,710	$1,743	$1,777	$1,810	$1,843	$1,876	$1,909	$1,942	$1,975	$2,008
3	Wind-Out of State	N/A [2]	$1,735	$1,750	$1,764	$1,779	$1,793	$1,806	$1,820	$1,833	$1,846	$1,876	$1,906	$1,937	$1,968	$1,999	$2,031	$2,063	$2,096	$2,128	$2,161
4	Solar, Utlity-Scale, Transmission Connected	$1,363	$1,357	$1,349	$1,338	$1,324	$1,310	$1,295	$1,279	$1,263	$1,245	$1,251	$1,256	$1,260	$1,263	$1,266	$1,272	$1,278	$1,283	$1,288	$1,293
5	Solar, Distribution Connected (46kV and lower)	$1,736	$1,731	$1,722	$1,710	$1,695	$1,678	$1,662	$1,644	$1,625	$1,605	$1,614	$1,622	$1,628	$1,634	$1,639	$1,649	$1,658	$1,666	$1,675	$1,682
6	Battery Storage, Primary Service - Ancillary Services	$1,253	$1,200	$1,141	$1,079	$1,011	$986	$960	$932	$903	$873	$879	$886	$891	$896	$901	$906	$911	$915	$919	$923
7	Battery Storage, Primary Service - Distribution Asset Deferral	$1,253	$1,200	$1,141	$1,079	$1,011	$986	$960	$932	$903	$873	$879	$886	$891	$896	$901	$906	$911	$915	$919	$923
8	Battery Storage, Primary Service - Energy and Capacity	$1,253	$1,200	$1,141	$1,079	$1,011	$986	$960	$932	$903	$873	$879	$886	$891	$896	$901	$906	$911	$915	$919	$923
9	Battery Storage, Primary Service - Solar + Storage [new1]	$2,181	$2,132	$2,077	$2,016	$1,949	$1,915	$1,881	$1,845	$1,808	$1,767	$1,778	$1,787	$1,795	$1,802	$1,808	$1,818	$1,826	$1,834	$1,842	$1,849
10	Emerging Technology																				
11	Wind-In State [3]	N/A [2]	$1,336	$1,348	$1,359	$1,370	$1,381	$1,392	$1,403	$1,414	$1,426	$1,454	$1,482	$1,510	$1,538	$1,566	$1,595	$1,623	$1,651	$1,679	$1,707
12	Wind-Out of State [3]	N/A [2]	$1,475	$1,487	$1,500	$1,512	$1,524	$1,535	$1,547	$1,558	$1,569	$1,595	$1,620	$1,646	$1,673	$1,700	$1,726	$1,754	$1,781	$1,809	$1,837
13	Solar, Utlity-Scale, Transmission Connected [5]	$886	$882	$877	$870	$861	$851	$842	$831	$821	$809	$813	$816	$819	$821	$823	$827	$831	$834	$837	$840
14	Solar, Distribution Connected (46kV and lower) [5]	$1,129	$1,125	$1,119	$1,111	$1,102	$1,091	$1,080	$1,068	$1,056	$1,043	$1,049	$1,054	$1,058	$1,062	$1,066	$1,072	$1,078	$1,083	$1,088	$1,093
15	Battery Storage, Primary Service - Ancillary Services [6]	$815	$780	$742	$701	$657	$641	$624	$606	$587	$567	$572	$576	$579	$583	$586	$589	$592	$595	$597	$600
16	Battery Storage, Primary Service - Distribution Asset Deferral [6]	$815	$780	$742	$701	$657	$641	$624	$606	$587	$567	$572	$576	$579	$583	$586	$589	$592	$595	$597	$600
17	Battery Storage, Primary Service - Energy and Capacity [6]	$815	$780	$742	$701	$657	$641	$624	$606	$587	$567	$572	$576	$579	$583	$586	$589	$592	$595	$597	$600
18	Battery Storage, Primary Service - Solar + Storage [5]	$1,418	$1,386	$1,350	$1,310	$1,267	$1,245	$1,223	$1,199	$1,175	$1,149	$1,155	$1,162	$1,167	$1,171	$1,175	$1,181	$1,187	$1,192	$1,197	$1,202
19	Environmental Policy																				
20	Wind-In State [4]	N/A [2]	$1,022	$1,031	$1,039	$1,048	$1,056	$1,065	$1,073	$1,082	$1,090	$1,112	$1,133	$1,155	$1,176	$1,198	$1,219	$1,241	$1,262	$1,284	$1,305
21	Wind-Out of State [4]	N/A [2]	$1,128	$1,137	$1,147	$1,156	$1,165	$1,174	$1,183	$1,192	$1,200	$1,219	$1,239	$1,259	$1,279	$1,300	$1,320	$1,341	$1,362	$1,383	$1,405
22	Solar, Utlity-Scale, Transmission Connected [5]	$886	$882	$877	$870	$861	$851	$842	$831	$821	$809	$813	$816	$819	$821	$823	$827	$831	$834	$837	$840
23	Solar, Distribution Connected (46kV and lower) [5]	$1,129	$1,125	$1,119	$1,111	$1,102	$1,091	$1,080	$1,068	$1,056	$1,043	$1,049	$1,054	$1,058	$1,062	$1,066	$1,072	$1,078	$1,083	$1,088	$1,093
24	Battery Storage, Primary Service - Ancillary Services [6]	$815	$780	$742	$701	$657	$641	$624	$606	$587	$567	$572	$576	$579	$583	$586	$589	$592	$595	$597	$600
25	Battery Storage, Primary Service - Distribution Asset Deferral [6]	$815	$780	$742	$701	$657	$641	$624	$606	$587	$567	$572	$576	$579	$583	$586	$589	$592	$595	$597	$600
26	Battery Storage, Primary Service - Energy and Capacity [6]	$815	$780	$742	$701	$657	$641	$624	$606	$587	$567	$572	$576	$579	$583	$586	$589	$592	$595	$597	$600
27	Battery Storage, Primary Service - Solar + Storage [5]	$1,418	$1,386	$1,350	$1,310	$1,267	$1,245	$1,223	$1,199	$1,175	$1,149	$1,155	$1,162	$1,167	$1,171	$1,175	$1,181	$1,187	$1,192	$1,197	$1,202
28	Advanced Technologies																				
29	Wind-In State [7]	N/A [2]	$1,572	$1,585	$1,599	$1,612	$1,625	$1,638	$1,651	$1,664	$1,677	$1,710	$1,743	$1,777	$1,810	$1,843	$1,876	$1,909	$1,942	$1,975	$2,008
30	Wind-Out of State [7]	N/A [2]	$1,735	$1,750	$1,764	$1,779	$1,793	$1,806	$1,820	$1,833	$1,846	$1,876	$1,906	$1,937	$1,968	$1,999	$2,031	$2,063	$2,096	$2,128	$2,161
31	Solar, Utlity-Scale, Transmission Connected [8]	$886	$882	$877	$870	$861	$851	$842	$831	$821	$809	$813	$816	$819	$821	$823	$827	$831	$834	$837	$840
32	Solar, Distribution Connected (46kV and lower) [9]	$868	$865	$861	$855	$847	$839	$831	$822	$813	$803	$807	$811	$814	$817	$820	$824	$829	$833	$837	$841
33	Battery Storage, Primary Service - Ancillary Services [10]	$1,222	$1,140	$1,056	$971	$885	$838	$792	$746	$700	$655	$638	$620	$602	$583	$563	$544	$524	$503	$482	$461
34	Battery Storage, Primary Service - Distribution Asset Deferral [10]	$1,222	$1,140	$1,056	$971	$885	$838	$792	$746	$700	$655	$638	$620	$602	$583	$563	$544	$524	$503	$482	$461
35	Battery Storage, Primary Service - Energy and Capacity [10]	$1,222	$1,140	$1,056	$971	$885	$838	$792	$746	$700	$655	$638	$620	$602	$583	$563	$544	$524	$503	$482	$461
36	Battery Storage, Primary Service - Solar + Storage [8]	$1,418	$1,386	$1,350	$1,310	$1,267	$1,245	$1,223	$1,199	$1,175	$1,149	$1,155	$1,162	$1,167	$1,171	$1,175	$1,181	$1,187	$1,192	$1,197	$1,202

Notes:
[1] Costs are shown starting in 2021 as dependent on the scenario this is the first year where there is a capacity shortfall.
[2] With 550 MW of wind being built as part of RFPs to meet A 15% RPS standard, additional not being considered in 2021.
[3] Emerging Technology wind is 15% below BAU.
[4] Environmental Policy wind is 35% below BAU.
[5] Emerging Technology and Environmental Policy solar is 35% below BAU.
[6] Emerging Technology and Environmental Policy battery is 35% below BAU.
[7] Advanced Technologies Wind is 100% of BAU
[8] Advanced Technologies Solar (transmission connected) is 35% below BAU
[9] Advanced Technologies Solar (distribution connected) is 50% below BAU
[10] Advanced Technologies Storage is on a linear decline to 50% below BAU by 2040

Execution Version

PURCHASE AND SALE AGREEMENT

by and between

New Covert Generating Company, LLC

as Seller,

and

Consumers Energy Company

as Buyer

dated as of June 21, 2021

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EXHIBITS

SCHEDULES

PURCHASE AND SALE AGREEMENT

This Purchase and Sale Agreement, dated as of June 21, 2021 (this ***"Agreement"***), is made and entered into by and between New Covert Generating Company, LLC, a Delaware limited liability company (***"Seller"***) and Consumers Energy Company, a Michigan corporation (***"Buyer"***).

W I T N E S S E T H :

WHEREAS, Seller desires to sell to Buyer, and Buyer desires to purchase from Seller, the Purchased Assets (as defined below) on the Closing Date (as defined below) on the terms and subject to the conditions set forth in this Agreement.

NOW, THEREFORE, in consideration of the premises and the mutual representations, warranties, covenants and agreements in this Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereby agree as follows:

ARTICLE I.

DEFINITIONS AND CONSTRUCTION

Section 1.1. Definitions.

As used in this Agreement, the following capitalized terms have the meanings set forth below:

"Acquisition Proposal" has the meaning given to it in Section 5.21.

"Additional Material Contract" has the meaning given to it in Section 10.4(b).

"Adjustment Estimate" has the meaning given to it in Section 2.7(a).

"Affiliate" means, with respect to any Person, any other Person that directly or indirectly through one or more intermediaries, controls, is controlled by or is under common control with such Person. For purposes of this definition, "control" of a Person means the power, direct or indirect, to direct or cause the direction of the management and policies of such Person whether through ownership of voting securities or ownership interests, by Contract or otherwise, and specifically with respect to a corporation, partnership or limited liability company, means direct or indirect ownership of more than 50% of the voting securities in such corporation or of the voting interest in a partnership or limited liability company.

"Agreement" has the meaning given to it in the introduction to this Agreement.

"Ancillary Agreements" means the Assignment and Assumption Agreement, Bill of Sale, the Deed, the Closing Certificates and the other documents and agreements required to be delivered pursuant to this Agreement (excluding the Transition Services Agreement).

"Asset Management Agreement" means that certain Asset Management Agreement between Seller, Eastern Covert, LLC and USPG dated as of June 29, 2018.

"Assets" of any Person means all assets and properties of every kind, nature, character and description (whether real, personal or mixed, whether tangible or intangible and wherever situated), including the related goodwill, which assets and properties are operated, owned or leased by such Person.

"Assigned Contracts" means all Contracts set forth on Schedule 1.1-AC, which schedule may be updated or amended from time to time prior to the Closing in accordance with Section 10.4.

"Assignment and Assumption Agreement" has the meaning given to it in Section 2.6(f).

"Assumed Liabilities" has the meaning given to it in Section 2.2.

"Base Purchase Price" has the meaning given to it in Section 2.4.

"Benefit Plan" means all written and unwritten "employee benefit plans" within the meaning of Section 3(3) of ERISA, and any other written and unwritten profit sharing, pension, savings, deferred compensation, fringe benefit, insurance, medical, medical reimbursement, life, disability, accident, post-retirement health or welfare benefit, stock option, stock purchase, sick pay, vacation, employment, severance, termination or other plan, agreement, contract, policy, trust fund or arrangement.

"Bill of Sale" has the meaning given to it in Section 2.6(c).

"Books and Records" means originals, or where not available, copies of all books and records (in each case, in such format in which the same is reasonably and practically available, including paper and electronic versions (but without requirement of unnecessary duplication)), including books of account, ledgers and general, financial and accounting records, machinery and equipment maintenance files, operational logs and records, production data, quality control records and procedures, records and data (including all correspondence with any Governmental Authority), environmental studies and reports, construction reports and records, as-built documents, access or security codes, safety reports, incident and injury reports, test reports, hazardous waste disposal records, and internal financial statements, that primarily relate to the Business or the Purchased Assets and that are in the possession or control of Seller or its Affiliates. For the avoidance of doubt, "Books and Records" shall not include the corporate seals, Organizational Documents, minute books, Tax Returns, books of account or other records having to do with the corporate organization of Seller and any other books and records which Seller is prohibited from disclosing or transferring to Buyer under applicable Law or the disclosure of which would result in the loss of any attorney-client privilege held by Seller (unless the books or records in question relate to an actual or threatened Claim that will become an Assumed Liability at the Closing).

"Budget" means (a) the major maintenance and capital expenditures budget estimates for Seller for the period from the date hereof until December 31, 2021, as set forth in Schedule 1.1-B and (b) each Subsequent Budget.

"Burdensome Condition" has the meaning given to it in Section 5.1(e).

"Business" means the ownership of the Purchased Assets and operation and maintenance of the Project as currently conducted by Seller.

"Business Day" means a day other than Saturday, Sunday or any day on which banks located in the State of Michigan are authorized or obligated to close.

"Buyer" has the meaning given to it in the introduction to this Agreement.

"Buyer Approvals" means the filings, waivers, approvals, consents, authorizations and notices set forth in Schedule 1.1-BA, in each case in a form not subject to further appeal.

"Buyer Deductible Amount" has the meaning given to it in Section 9.2(c).

"Buyer De Minimis Claim" has the meaning given to it in Section 9.2(c).

"Buyer Indemnified Parties" has the meaning given to it in Section 9.1(a).

"Buyer's Determination" has the meaning given to it in Section 2.8(a).

"Casualty Insurance Proceeds" has the meaning given to it in Section 5.12.

"Casualty Loss" has the meaning given to it in Section 5.12.

"Claim" means any demand, claim, action, investigation, legal proceeding (whether at law or in equity) or arbitration.

"Claiming Party" has the meaning given to it in Section 9.6(a).

"Closing" means the closing of the transactions contemplated by this Agreement, as provided for in Section 2.5.

"Closing Certificates" means the officer's certificates referenced in Section 6.3 and Section 7.3.

"Closing Date" means the date on which the Closing occurs.

"Closing Date Net Working Capital" means the aggregate Net Working Capital of Seller as of the Closing.

"Code" means the Internal Revenue Code of 1986, as amended.

"Condemnation" has the meaning given to it in Section 5.13.

"Condemnation Value" has the meaning given to it in Section 5.13.

"Confidentiality Agreement" means the Confidentiality Agreement between Buyer and Segreto Power Holdings, LLC, a Delaware limited liability company and an Affiliate of Seller, dated January 20, 2021.

"Contract" means any legally binding contract, lease, license, evidence of Indebtedness, mortgage, indenture, purchase order, binding bid, letter of credit, security agreement or other legally binding arrangement, but shall exclude Permits.

"Controlled Group Liability" means any and all liabilities under (i) Title IV of ERISA, (ii) Section 302 of ERISA, (iii) Sections 412 and 4971 of the Code, or (iv) the continuation coverage requirements of Section 601 et seq. of ERISA and Section 4980B of the Code.

"Deed" has the meaning given to it in Section 2.6(d).

"DOE" means the United States Department of Energy.

"Environmental Claim" means any Claim arising out of or related to any violation of, or any Liability or obligation under, any Environmental Law.

"Environmental Law" means the Comprehensive Environmental Response, Compensation and Liability Act, 42 U.S.C. § 9601 et seq.; the Resource Conservation and Recovery Act, 42 U.S.C. § 6901 et seq.; the Federal Water Pollution Control Act, 33 U.S.C. § 1251 et seq.; the Clean Air Act, 42 U.S.C. § 7401 et seq.; the Toxic Substances Control Act, 15 U.S.C. §§ 2601 through 2629; the Oil Pollution Act, 33 U.S.C. § 2701 et seq.; the Emergency Planning and Community Right-to-Know Act, 42 U.S.C. § 11001 et seq.; the Safe Drinking Water Act, 42 U.S.C. §§ 300f through 300j; and all similar Laws (including implementing regulations) of any Governmental Authority having jurisdiction over the assets in question addressing pollution control or protection of the environment.

"ERISA" means the Employee Retirement Income Security Act of 1974.

"ERISA Affiliate" means any entity, trade or business that is a member of a group described in Section 414(b) or (c) of the Code or Section 4001(b)(1) of ERISA that includes Seller, or that is a member of the same "controlled group" as Seller pursuant to Section 4001(a)(14) of ERISA.

"Excluded Assets" has the meaning given to it in Section 2.1.

"Excluded Liabilities" means all Liabilities of Seller or its Affiliates of every kind or nature whatsoever other than Assumed Liabilities.

"Existing Monetary Liens" means title exception Nos. 16 (First Lien Mortgage), 18 (UCC Financing Statement for First Lien Mortgage), 19 (Second Lien Mortgage), and 20 (UCC Financing Statement for Second Lien Mortgage) listed on Schedule B of the Existing Title Insurance Policy.

"Existing Survey" means that certain ALTA Land Title Survey of the Property dated as of June 8, 2016 and prepared by Mitchell & Morse Land Surveying.

"Existing Title Insurance Policy" means that certain Owner's Policy of Title Insurance issued by Title Company for the benefit of Seller dated July 2, 2018.

"External Resource Transaction" means an arrangement that provides Buyer with full credit for and all other benefits of the Project's commercial attributes (including capacity, energy, reactive power and those ancillary services or other attributes, in each case that the Project is currently capable of providing) that can be transferred to Buyer, and in connection with such attributes Buyer can be qualified to participate in MISO, while the Project remains connected to the PJM market.

"Facility Employees" has the meaning given to it in Section 3.18(b).

"FERC" means the Federal Energy Regulatory Commission or its successor Governmental Authority.

"Financial Statements'' means, in relation to any Person, such Person's balance sheet (including any notes thereto) and the related statements of income, shareholder's equity and cash flows for the period then ended.

"Final Adjustment'' has the meaning given to it in Section 2.8(c).

"FPA" means the Federal Power Act, as amended, and FERC's implementing regulations promulgated thereunder.

"FTC" means the Federal Trade Commission or its successor Governmental Authority.

"GAAP" means generally accepted accounting principles in the United States of America.

"Governmental Authority" means the United States and any state, county, city or other political, subdivision or similar governing entity, and any court, tribunal, arbitrator, authority, agency, commission, official or other instrumentality of the United States or any state, county, city or other political subdivision or similar governing entity having legal jurisdiction or effective control over the matter or Person in question, and including any governmental, quasi-governmental or non-governmental body administering, regulating or having general oversight over natural gas, electricity, power or other markets, including NERC.

"Hazardous Material" means any substance designated as a hazardous waste, hazardous substance, extremely hazardous substance, hazardous material, hazardous chemical, pollutant, contaminant or toxic chemical under any Environmental Law, any petroleum or petroleum products, any radioactive material, any asbestos or any materials containing asbestos, and any urea formaldehyde or polychlorinated biphenyls.

"HSR Act" means the Hart-Scott-Rodino Antitrust Improvements Act of 1976.

"Indebtedness" means any of the following: (a) any indebtedness for borrowed money; (b) any obligations evidenced by bonds, debentures, notes or other similar instruments; (c) any obligations to pay the deferred purchase price of property or services, except trade accounts payable and other current liabilities arising in the ordinary course of business consistent with past practices; (d) any obligations as lessee under capitalized leases; (e) any obligations, contingent or otherwise, under acceptance, letters of credit or similar facilities; and (f) any guaranty of any of the foregoing.

"Indemnified Parties" has the meaning given to it in Section 9.1(b).

"Indemnifying Party" means a Person required to indemnify a Seller Indemnified Party or a Buyer Indemnified Party, as the case may be, pursuant to the terms of this Agreement.

"Indemnity Reduction Amounts" has the meaning given to it in Section 9.3(a).

"Independent Accountants" has the meaning given to it in Section 2.8(b).

"Independent Engineer" has the meaning given to it in Section 10.5.

"Initial Cure Period" has the meaning in Section 5.23(a).

"Initial Objection Notice" has the meaning in Section 5.23(a).

"Initial Objection Response" has the meaning in Section 5.23(a).

"Intellectual Property" means the following intellectual property rights, both statutory and common law rights, if applicable: (a) copyrights, registrations and applications for registration thereof, (b) trademarks, service marks, trade names, slogans, domain names, logos, trade dress, and registrations and applications for registrations thereof, (c) patents, as well as any reissued and reexamined patents and extensions corresponding to the patents, and any patent applications, as well as any related continuation, continuation in part and divisional applications and patents issuing therefrom and (d) trade secrets and confidential information, including ideas, designs, concepts, compilations of information, methods, techniques, procedures, processes and other know-how, whether or not patentable.

"Intentional Fraud" means, with respect to either Party, as applicable, any intentional or willful misrepresentation of facts that constitutes common law actual fraud under the Laws of Michigan.

"Interconnection and Capacity Requirement" has the meaning set forth in Section 5.4.

"Interconnection Cap" means an amount equal to two million dollars ($2,000,000).

"Interim Period" has the meaning given to it in Section 5.1.

"Knowledge" when used in a particular representation in this Agreement with respect to Seller, means the actual knowledge of the individuals listed on Schedule 1.1-K, after reasonable inquiry of their direct reports.

"Land Contracts'' means any easements, rights-of-way, and other agreements in favor of Seller necessary for the use and operation of the Project.

"Laws" means (i) all laws, statutes, rules, regulations, ordinances, orders, decrees and court decisions of any Governmental Authority; (ii) other pronouncements of any Governmental Authority having the effect of law; and (iii) for the avoidance of any doubt, and whether or not falling within either or both of the preceding clauses (i) and (ii), all FERC-, NERC-, DOE- MISO- and/or PJM-related requirements.

"Liabilities" means liabilities or obligations of any nature whatsoever, asserted or unasserted, known or unknown, absolute or contingent, accrued or unaccrued, matured or unmatured or otherwise.

"Lien" means any mortgage, pledge, deed of trust, security interest, equitable interest, charge, claim, levy, lien, pledge, assessment, encroachment, title imperfection, conditional sale, option, restriction, easement, lease, covenant, right of first refusal or other encumbrance.

"Loss" means any and all judgments, losses, liabilities, amounts paid in settlement, damages, fines, penalties, deficiencies, costs, charges, Taxes, obligations, demands, fees, interest, losses and expenses (including court costs and reasonable fees of attorneys, accountants and other experts in connection with any Claim). For all purposes in this Agreement the term "Losses" does not include any Non-Reimbursable Damages.

"Material Adverse Effect" or ***"MAE"*** means any change, effect or occurrence, individually or in the aggregate, that has, or could reasonably be expected to have, a material adverse effect on the Business or the Purchased Assets; provided, that, in each case, in no event shall any change, effect or occurrence resulting from or arising out of the following, either alone or in combination, constitute or be taken into account in determining whether a Material Adverse Effect has occurred or is likely or expected to occur: (i) any change in international, national, regional, state or local wholesale or retail markets for electric power, capacity, ancillary services or related products; (ii) any change in international, national, regional, state or local economic conditions or financial, banking or securities markets generally; (iii) any change in costs of commodities or supplies, including electric power, natural gas, emissions, fuel or water; (iv) any change in national, regional, state or local electric or natural gas interconnection, transmission, transportation or distribution markets or procedures; (v) strikes, work stoppages or other labor disputes of a general nature; (vi) any change in general regulatory or political conditions, acts of war, whether or not declared, armed hostilities, sabotage or terrorism (and any escalation or worsening thereof); (vii) any changes or proposed changes in Laws, acts of Governmental Authorities or regulatory policies or interpretations, in accounting standards, principles or interpretations (including with respect to Property Taxes) or in industry standards; (viii) any change (regardless of the applicability of any other subpart hereof) arising out of, in response to, or resulting from any pandemic (including COVID-19), epidemic or other disease outbreak or any domestic protests, including any changes in habits of people or markets, or any Law or any directive, pronouncement or guideline issued by a Governmental Authority or industry group, including providing for business closures, "sheltering-in-place," curfews or other restrictions that relate to, or arise out of any of the foregoing; (ix) earthquakes, hurricanes, floods, acts of God or other natural disasters; (x) the announcement or the pendency of this Agreement or actions taken or not taken at the written request of, or with the written consent of, Buyer, or the failure of Seller to take any action that is prohibited by this Agreement; (xi) the failure by Seller to meet any projections, forecasts or budgets for any period (it being understood and agreed that the exception in this clause (xi) shall not preclude the underlying facts, circumstances, changes, events, occurrences or developments giving rise to such failure from being taken into account in determining whether there has been an MAE if not otherwise excluded by another clause in this definition); (xii) any change in the amount of Property Tax payable with respect to the Purchased Assets; or (xiii) any Casualty Loss or Condemnation; provided, further, that the exceptions stated in clauses (i) through (vii) above shall not apply to the extent the changes, effects or occurrences described therein disproportionately affect the Business or the Purchased Assets compared to other similarly situated businesses or assets in the natural gas-fired power generating industry in the MISO region; and provided, further, that a matter as described in a Schedule hereto will not in and of itself constitute an MAE (but it may be possible that a change, effect or occurrence resulting from or arising out of such a matter could constitute an MAE).

"Material Contracts" has the meaning given to it in Section 3.12(a).

"Mitsubishi LTSA" means the Amended and Restated Long Term Service Agreement between Seller and Mitsubishi Hitachi Power Systems Americas, Inc., dated June 30, 2017, as amended by the Amendment dated February 28, 2019.

"MISO" means Midcontinent Independent System Operator, Inc. or any successor independent system operator.

"MISO GIA" has the meaning given to it in Section 5.4.

"MISO Interconnection Queue Position" means a Queue Position and/or Definitive Planning Phase Queue Position in MISO's queue of valid Interconnection Requests, as such capitalized terms are defined in Attachment X of the MISO tariff and other related MISO rules.

"Moody's" means Moody's Investors Service, Inc., or any successor thereto.

"MPSC" means the Michigan Public Service Commission or its successor Governmental Authority.

"NERC" means the North American Electric Reliability Corporation or its successor Governmental Authority, and includes any applicable regional entity (such as Reliability*First* Corporation) having authority over Seller or the Project.

"Net Working Capital" means, as of the applicable date and without duplication, the amount (expressed as a positive or negative number) determined by subtracting (a) the aggregate value of the current liabilities of the Business that are included in the Assumed Liabilities from (b) the aggregate value of the current assets of the Business that are included in the Purchased Assets, as calculated in accordance with the formula and methodology (including adjustments) as described in, and used in the preparation of, and only applying values to the categories of listed assets and liabilities as set forth in, Schedule 1.1-A. Schedule 1.1A, which is a sample calculation of Net Working Capital as of December 31, 2020, is solely for illustrative purposes.

"Non-Reimbursable Damages" has the meaning given to it in Section 9.5(b).

"O&M Agreement" means that certain Operation and Maintenance Agreement between USPG and Consolidated Asset Management Services (Michigan), LLC, dated June 29, 2018.

"Objections" has the meaning given to it in Section 5.23(a).

"Organizational Documents" means, with respect to any Person, the articles or certificate of incorporation or organization and by-laws, the limited partnership agreement, the partnership agreement or the limited liability company agreement, or such other organizational documents of such Person, including those that are required to be registered or kept in the place of incorporation, organization or formation of such Person and which establish the legal personality of such Person.

"Outside Date" has the meaning given to it in Section 8.1(c).

"Parties" means collectively, Buyer and Seller.

"Permits" means all licenses, permits, certificates of authority, authorizations, approvals, registrations, franchises and similar consents and orders issued or granted by a Governmental Authority.

"Permitted Lien" means

(a) any Lien for Taxes not yet due or delinquent or being contested in good faith by appropriate proceedings and for which adequate reserves have been established in accordance with GAAP;

(b) Liens imposed or promulgated by Law or any Governmental Authority with respect to real property, including zoning, building, environmental and other similar limitations and restrictions of any Governmental Authority regulating the Purchased Assets, but only to the extent not violated by the current use of the real property;

(c) Liens, other than monetary Liens (except as and to the extent provided under Section 5.23 but in no event shall Indebtedness of Seller or Liens to secure such Indebtedness become a Permitted Lien), set forth on (1) the Signing Survey, (2) the Updated Survey, (3) Schedule B of the Signing Title Commitment or (4) Schedule B of the Updated Title Commitment, in each case, which are not objected to or are waived by Buyer pursuant to Section 5.23 or which are cured by Seller pursuant to Section 5.23;

(d) workmen's, repairmen's, warehousemen's, mechanics', materialmen's and carriers' or other like Liens arising or incurred in the ordinary course of business that in each case are for amounts not yet due and payable or which are being contested in good faith by appropriate proceedings and for which adequate reserves have been established in Seller's Financial Statements in accordance with GAAP;

(e) solely prior to the Closing Date, those Liens identified on Schedule 1.1-PL, which will be released at or prior to the Closing;

(f) other non-monetary Liens, which, individually or in the aggregate, (i) do not, and would not be reasonably expected to materially detract from the value of the assets to which they attach or the Project, and (ii) do not, and would not reasonably be expected to materially and adversely affect the use or operation of the subject asset or the Project;

(g) such state of facts as disclosed by the Existing Survey and those matters set forth on Schedule B to the Existing Title Insurance Policy except for Existing Monetary Liens;

(h) any Liens expressly granted by Seller under the Assigned Contracts; and

(i) any other Liens created or permitted with the written consent of Buyer.

"Person" means any natural person, corporation, general partnership, limited partnership, limited liability company, proprietorship, other business organization, trust, union, association or Governmental Authority.

"Post-Closing Gas Agreement" has the meaning set forth in Section 10.4(c)(ii).

"Post-Closing Water Services Agreement" has the meaning set forth in Section 10.4(c)(i).

"PJM" means PJM Interconnection, L.L.C. or any successor independent system operator.

"PJM TSA Services" has the meaning set forth in Section 5.24.

"Pre-Closing Taxable Period'' means any taxable period ending on or before the Closing Date.

"Project" means the 1,176 megawatts nameplate capacity natural gas-fired, combined-cycle facility located in Covert, Michigan in Van Buren County and all equipment, machinery, facilities, improvements and infrastructure used in connection therewith located at the Property and included in the Purchased Assets.

"Property" has the meaning given to it in Section 2.1.

"Property Tax Lien Date" means, with respect to any calendar year, July 1 and December 1 of that calendar year, and the applicable taxable period for any Property Taxes will be the calendar year in which the Property Tax Lien Date occurs for such Property Taxes.

"Property Taxes" means real and personal property taxes, special assessments and any payments in lieu of property taxes.

"Prudent Engineering and Operating Practices" means the standards, practices, methods, procedures and acts which (a) conform with such degree of skill, diligence, prudence and foresight as would reasonably be expected from a significant portion of skillful and experienced independent power producers operating a power station of similar type to the Project during the relevant time period, and (b) would reasonably be expected to be applied by such Person exercising reasonable judgment in light of the facts known at the time a decision was made to accomplish the desired result in an efficient and workman-like manner consistent with good business practices and applicable Laws and at a commercially reasonable cost. "Prudent Engineering and Operating Practices" is not intended to be limited to the optimum practice, but is instead intended to encompass a broad range of acceptable practices, methods, procedures and acts.

"Purchased Assets" has the meaning given to it in Section 2.1.

"Purchase Price" has the meaning given to it in Section 2.4.

"Purchase Price Allocation Schedule" has the meaning given to it in Section 2.9.

"Reactive Tariff" means the FERC Reactive Supply Tariff Acceptance of Filing issued June 20, 2016 and effective June 1, 2016.

"Release" means any release, spill, emission, migration, leaking, pumping, injection, deposit, disposal or discharge of any Hazardous Materials.

"Representatives" means, as to any Person, its officers, directors, partners, members, and employees.

"Responding Party" has the meaning given to it in Section 9.6(a).

"Restoration Cost" has the meaning given to it in Section 5.12.

"S&P" means Standard and Poor's Rating Services, a Standard & Poor's Financial Services LLC business, or any successor thereto.

"Schedules" means the disclosure schedules prepared by Buyer and Seller, as applicable, and attached to this Agreement.

"Secondary Cure Period'' has the meaning given to it in Section 5.23(b).

"Seller'' has the meaning given to it in the introduction to this Agreement.

"Seller Approvals" means the filings, waivers, approvals, consents, authorizations and notices set forth in Schedule 1.1-SA.

"Seller Audited Financial Statements" has the meaning given to it in Section 3.8(b).

"Seller Consents" means the consents set forth in Schedule 3.3(b).

"Seller Deductible Amount" has the meaning given to it in Section 9.2(d).

"***Seller De Minimis Claim***" has the meaning given to it in Section 9.2(d).

"Seller Fundamental Representations" has the meaning given to it in Section 9.2(a).

"Seller Indemnified Parties" has the meaning given to it in Section 9.1(b).

"Seller Parent" means Eastern Generation Holdings, LLC, a Delaware limited liability company.

"Seller Parent Audited Financial Statements" has the meaning given to it in Section 3.8(a).

"Seller Parent Guaranty Agreement" has the meaning given to it in Section 5.18.

"Seller's Response" has the meaning given to it in Section 5.23(b).

"Seller's Response Period" has the meaning given to it in Section 5.23(b).

"Signing Survey" means an ALTA survey signed by the surveyor and certified to the Title Company and Buyer in form and substance reasonably satisfactory to Buyer.

"Signing Title Commitment" means an owner's title commitment with respect to the Property issued by the Title Company.

"Subsequent Budget" means the major maintenance and capital expenditures budget for Seller for the periods from January 1, 2022 to December 31, 2022 and January 1, 2023 to December 31, 2023, in each case adopted by Seller in accordance with Seller's annual budgeting processes.

"Suez" means SUEZ WTS Services USA, Inc. (f/k/a GE Mobile Water, Inc.).

"Straddle Taxable Period" means any taxable period that includes (but does not end on) the Closing Date.

"Tax" or ***"Taxes"*** means (a) any federal, state, local or foreign income, gross receipts, ad valorem, sales and use, employment, social security, disability, occupation, industrial facilities, property, severance, value added, transfer, capital stock, excise, withholding, premium, occupation or other taxes, levies or other like assessments, customs, duties or imposts imposed by or on behalf of any Governmental Authority, including any interest, penalty or addition thereto and (b) any liability for amounts described in clause (a) as a result of transferee liability.

"Tax Clearance Certificate" has the meaning given to it in Section 2.6(b).

"Tax Return" means any return, declaration, report, form, claim for refund, statement or other information (including any amendments) required to be supplied to any Governmental Authority with respect to Taxes, including information returns, any amendments thereof or schedule or attachment thereto, including any such document prepared on a consolidated, combined or unitary basis and also including any schedule or attachment thereto, and including any amendment thereof.

"Taxing Authority" means, with respect to any Tax, the governmental entity or political subdivision thereof that imposes such Tax and the agency (if any) charged with the collection of such Tax for such entity or subdivision.

"Tax Status Letter" has the meaning given to it in Section 2.6(b).

"Title Company" means Fidelity National Title Insurance Company.

"Title Endorsements" means title endorsements set forth on Exhibit 1.1(a).

"Title Policy" means either (i) an American Land Title Association (ALTA) 2006 Owner's Title Insurance Policy (deleting the arbitration clause) with extended coverage (i.e., with all ALTA General Exceptions deleted) for the Property issued by the Title Company; provided, however, that if the Title Policy described in clause (i) above has not been executed and delivered to the Parties at or prior to the time scheduled for the Closing, then Title Policy shall mean (ii) an unconditional written commitment by the Title Company in the form of an instruction letter in form and substance reasonably acceptable to Buyer and executed by the Title Company agreeing to issue such Owner's Title Insurance Policy (deleting the arbitration clause) with extended coverage (i.e., with all ALTA General Exceptions deleted) in the form of the Updated Title Commitment attached thereto upon the Closing without additional title exceptions and without additional conditions for issuance thereof, subject only to the occurrence of the Closing and the receipt of the applicable title insurance premiums and any fees and other charges owed to the Title Company for the issuance thereof, in each case of clauses (i) and (ii), which policy (A) shall be issued to be effective as of the Closing Date in an amount of insured title coverage equal to the Purchase Price or such lesser amount in Buyer's sole discretion, (B) shall insure Buyer is vested with fee simple title to, or with a leasehold or easement interest in, as applicable, the Property, subject only to Permitted Liens, (C) shall not include any exception for any lien or right to a lien, for services, labor, or material, and (D) shall include the Title Endorsements; provided, that if any of the Title Endorsements are not available in Michigan or are no longer issued by the Title Company at the time of the Closing, Buyer shall accept the Title Policy without such Title Endorsements.

"Transfer Tax Affidavit" has the meaning given to it in Section 2.6(e).

"Transfer Taxes" means any and all transaction, transfer, sales, use, goods and services, recording, transaction privilege, real property transfer, stock transfer, value added, documentary, stamp duty, gross receipts, excise, transfer and conveyance Taxes and other similar Taxes, duties, fees or charges, including any related penalties, interest and additions thereto, to any Taxing Authority as a result of the transfer of the Purchased Assets from Seller to Buyer.

"Transition Services Agreement" has the meaning set forth in Section 5.24.

"Updated Objection Notice" has the meaning given to it in Section 5.23(b).

"Updated Objection Response" has the meaning in Section 5.23(b).

"Updated Seller Financial Statements" has the meaning given to it in Section 5.19.

"Updated Seller Parent Financial Statements" has the meaning given to it in Section 5.19.

"Updated Survey" means an ALTA survey signed by the surveyor and certified to the Title Company and Buyer in form and substance reasonably satisfactory to Buyer, which survey shall be sufficient for the Title Company to remove its standard survey exception and to issue the Title Endorsements in any Title Policy issued, showing and including (a) the locations of all Project facilities, (b) the location of all existing roads, buildings or other structures and (c) access affirmatively to at least one public street or road.

"Updated Title Commitment" has the meaning given to it in Section 5.23(b).

"USPG" means USPG Power Services, LLC, a wholly-owned subsidiary of Seller Parent.

"Water Services Agreement" means that certain Master Services Agreement by and between Seller and Suez dated November 1, 2016.

Section 1.2. Rules of Construction.

(a) All article, section, subsection, schedule and exhibit references used in this Agreement are to articles, sections, subsections, schedules and exhibits to this Agreement unless otherwise specified. The exhibits and schedules attached to this Agreement constitute a part of this Agreement and are incorporated in this Agreement for all purposes.

(b) If a term is defined as one part of speech (such as a noun), it shall have a corresponding meaning when used as another part of speech (such as a verb). Unless the context of this Agreement clearly requires otherwise words importing the masculine gender shall include the feminine and neutral genders and vice versa. The words "includes" or "including" shall mean "including without limitation." The words "hereof," "hereby," "herein," "hereunder" and similar terms in this Agreement shall refer to this Agreement as a whole and not any particular section or article in which such words appear. Any reference to a Law shall include any amendment thereof or any successor thereto and any rules and regulations promulgated thereunder. References to any Contract shall mean a reference to such Contract as the same may be amended, modified, supplemented or replaced from time to time, in accordance with its terms and this Agreement. Currency amounts referenced in this Agreement are in U.S. Dollars.

(c) Whenever this Agreement refers to a number of days, such number shall refer to calendar days unless Business Days are specified. Whenever any action must be taken hereunder on or by a day that is not a Business Day, then such action may be validly taken on or by the next day that is a Business Day.

(d) Each Party acknowledges that it and its attorneys have been given an equal opportunity to negotiate the terms and conditions of this Agreement and that any rule of construction to the effect that ambiguities are to be resolved against the drafting Party or any similar rule operating against the drafter of an agreement shall not be applicable to the construction or interpretation of this Agreement.

(e) All accounting terms used herein and not expressly defined herein shall have the respective meanings given such terms under GAAP.

ARTICLE II.

PURCHASE AND SALE AND CLOSING

Section 2.1. Purchase and Sale. On the terms and subject to the conditions set forth in this Agreement, at the Closing Buyer shall purchase and acquire from Seller, and Seller shall sell, convey, assign, transfer and deliver to Buyer, all of Seller's right, title and interest, in and to (i) the real property on which the Project is located, together with all improvements, buildings, structures, fixtures, easements, rights-of-way, division rights, hereditaments and appurtenances associated with that real property, which real property is described in Schedule 3.13(c) (the ***"Property"***), and (ii) the personal property and other properties, assets, and rights of any kind (including Permits), whether tangible or intangible, and with regard to each of (i) and (ii), whether now existing or hereafter acquired, and wherever located, owned, licensed, leased or otherwise held by Seller that are in each case primarily used or held for use in connection with the ownership, leasing, licensing, operation, interconnection, or maintenance of the Business or the Project and are described in Exhibit 2.1(a) (the property described in clauses (i) and (ii), collectively, the ***"Purchased Assets"***), together with exclusive possession thereof. Notwithstanding the previous sentence, the Purchased Assets will not include the Assets listed on Exhibit 2.1(b) (the ***"Excluded Assets"***).

The Purchased Assets will be transferred to Buyer free and clear of all Liens, except for Permitted Liens.

Section 2.2. Assumed Liabilities. As additional consideration for the purchase of the Purchased Assets, and subject to the terms and conditions set forth herein, and without prejudice to Buyer's rights under ARTICLE IX, at the Closing, Buyer shall assume and agree to pay, perform and discharge the following Liabilities of Seller (collectively, the ***"Assumed Liabilities"***), and no other Liabilities:

(a) all trade accounts payable of Seller to third parties in connection with the Business that remain unpaid, are not delinquent as of the Closing Date, and are reflected in the Closing Date Net Working Capital;

(b) all amounts payable under the Assigned Contracts for goods or services received thereunder prior to the Closing that remain unpaid, are not delinquent as of the Closing Date, and are reflected in the Closing Date Net Working Capital;

(c) all Liabilities of Seller under the Assigned Contracts assigned to Buyer (excluding any such Liabilities covered under Section 2.2(a) or Section 2.2(b) and excluding any Excluded Liabilities);

(d) all Liabilities in respect of Permits and under the Land Contracts assigned to Buyer;

(e) all Transfer Taxes and Property Taxes payable by Buyer pursuant to Section 5.9 or Section 5.22(a); and

(f) all other Liabilities arising out of or related to the ownership, leasing, licensing, operation or maintenance of the Purchased Assets prior to, on or after the Closing (other than, for the avoidance of doubt, any Excluded Liabilities).

Section 2.3. Excluded Liabilities. Notwithstanding the provisions of Section 2.2 or any other provision in this Agreement to the contrary, Buyer shall not assume and shall not be responsible to pay, perform or discharge any Excluded Liabilities. Seller shall, and shall cause each of its Affiliates to, pay and satisfy in due course all Excluded Liabilities which they are obligated to pay and satisfy. For the avoidance of doubt, Excluded Liabilities include:

(a) all Liabilities of Seller or its Affiliates that do not relate to the Purchased Assets or the Business;

(b) all Liabilities relating to any Excluded Asset;

(c) all Liabilities (other than Transfer Taxes payable by Buyer pursuant to Section 5.9 or Section 5.22(a)) arising out of or relating to the execution and delivery by Seller or its Affiliates of this Agreement and the Ancillary Agreements and the consummation by Seller and such Affiliates of the transactions contemplated hereby and thereby;

(d) all Indebtedness of Seller or any of its Affiliates and all Liens, Claims or Losses arising in connection with the same (to the extent not included in Closing Date Working Capital);

(e) all Liabilities with respect to any claims of third parties (including any current or former direct or indirect equity holders of Seller), relating to the ownership of any equity interests, participation rights or any other agreements of any nature to purchase or acquire any equity interests or participation rights, or any other interest or participation that confers the right to receive a share of the profits and losses of, or distribution of assets of, Seller, whether arising before, on or after the Closing Date;

(f) (i) all Transfer Taxes and Property Taxes payable by Seller pursuant to Section 5.9 or Section 5.22(a), (ii) all Taxes relating to the ownership, leasing, licensing, operation or maintenance of any of the Purchased Assets attributable to a Pre-Closing Taxable Period and (iii) any Liability imposed on Buyer attributable to any failure of the Parties to comply with any bulk sales or bulk transfer or similar Laws in connection with the transactions contemplated by this Agreement;

(g) all amounts payable under the Assigned Contracts for goods or services received thereunder prior to or on the Closing Date that remain unpaid and are delinquent as of the Closing Date and any Liens arising therefrom;

(h) all Liabilities that relate to, or arise out of, directly or indirectly, (i) any Benefit Plans maintained by Seller or any of its Affiliates with respect to the Facility Employees, including under the Consolidated Omnibus Budget Reconciliation Act, (ii) any collective bargaining agreements or other agreements to which Seller or any of its Affiliates is a party in respect of Facility Employees, or (iii) any Claims by any previous employees of Seller; and

(i) all Liabilities arising out of Section 4.4 of the Asset Management Agreement or Section 4.4 of the O&M Agreement.

Section 2.4. Purchase Price. The purchase price (the ***"Purchase Price"***) for the purchase and sale described in Section 2.1 is equal to the sum of (i) Eight Hundred Ten Million and 00/100 Dollars ($810,000,000.00) (the ***"Base Purchase Price"***), plus (ii) the Closing Date Net Working Capital.

Section 2.5. Closing. The Closing shall take place at the offices of Consumers Energy Company, One Energy Plaza, Jackson, MI 49201 at 10:00 A.M. local time, on (a) the fifth (5^{th}) Business Day after the conditions to the Closing set forth in ARTICLE VI and ARTICLE VII (other than actions that by their nature are to be taken at the Closing, but subject to the satisfaction or waiver of those conditions at the Closing) have been satisfied or waived or (b) such other date and at such other time as Buyer and Seller mutually agree in writing. All actions listed in Section 2.6 or Section 2.7 that occur on the Closing Date shall be deemed to occur simultaneously at the Closing. For purposes of this Agreement and the transactions contemplated hereby, the Closing will be deemed to occur and be effective, and title to and risk of loss associated with the Business or Purchased Assets shall be deemed to occur, at 12:01 A.M. local time on the Closing Date; provided, that the certificates referenced in Sections 2.6(k) and 2.7(e) shall be deemed delivered (and the representations, warranties and conditions affirmed and certified thereby shall be deemed made and given) upon the mutual release of signatures by the Parties on the Closing Date.

Section 2.6. Closing Deliveries by Seller to Buyer. At the Closing, Seller shall deliver, or shall cause to be delivered, to Buyer:

(a) a certification of non-foreign status in the form prescribed by Treasury Regulation Section 1.1445-2(b) with respect to Seller or with respect to the regarded owner of Seller if Seller is treated as a disregarded entity for federal income tax purposes. If, on or before the Closing Date, Buyer shall not have received the non-foreign status affidavit(s), Buyer may withhold from the Purchase Price payable at the Closing to Seller pursuant hereto such sums as are required to be withheld therefrom under Code Section 1445;

(b) Utilizing the application in the form attached as Exhibit 2.6(b)-1 (or such updated application as becomes statutorily mandated after the date of this Agreement), Seller shall order a Tax Clearance Certificate from the Taxing Authority where the Purchased Assets or Business are located substantially in the form attached as Exhibit 2.6(b)-2 or such updated form as becomes statutorily mandated after the date of this Agreement (***"Tax Clearance Certificate"***) and obtain and deliver to Buyer a letter from such Taxing Authority indicating whether there are any amounts owed to such Taxing Authority as of the Closing by Seller with respect to the Purchased Assets or the Business (***"Tax Status Letter"***). If any amounts are owed, Seller represents and warrants, covenants and agrees that it shall make timely payments of such amounts and such amounts paid or to be paid are solely at Seller's cost and expense;

(c) a bill of sale substantially in the form of Exhibit 2.6(c) (the ***"Bill of Sale"***) and duly executed by Seller, conveying to Buyer good and valid title to all of such Seller's owned tangible personal property included in the Purchased Assets or Business, subject only to Permitted Liens;

(d) a covenant deed substantially in the form of Exhibit 2.6(d) (the ***"Deed"***) and duly executed and acknowledged by Seller, conveying good and marketable title to the Property listed on Schedule 3.13(c) to Buyer, subject only to the Permitted Liens;

(e) a real estate transfer tax valuation affidavit (the ***"Transfer Tax Affidavit"***) in a form and substance reasonably acceptable to Buyer;

(f) an assignment and assumption agreement substantially in the form of Exhibit 2.6(f) (the ***"Assignment and Assumption Agreement"***), duly executed by Seller, effecting the assignment to and assumption by Buyer of the Purchased Assets and the Assumed Liabilities;

(g) an owner's affidavit substantially in the form of Exhibit 2.6(g) and duly executed by Seller;

(h) resolutions of the sole member of Seller authorizing the transactions contemplated by this Agreement;

(i) as per Section 6.6, evidence reasonably satisfactory to Buyer of Seller's compliance with Section 5.7;

(j) the Seller Parent Guaranty Agreement, duly executed by Seller Parent;

(k) the certificate referenced in Section 6.3;

(l) if the Purchased Assets include any bank account, a power of attorney in form reasonably acceptable to Buyer, giving Buyer the power to control such bank account until the applicable bank transfers the account to be in the name of Buyer;

(m) the Transition Services Agreement, duly executed by USPG; and

(n) such other customary instruments of sale, assignment, transfer, and assumption, in form and substance reasonably satisfactory to Buyer, as may be required to give effect to this Agreement.

Section 2.7. Closing Deliveries by Buyer to Seller. At the Closing, Buyer shall deliver to Seller the following:

(a) a wire transfer of immediately available funds (to such account or accounts as Seller shall have notified Buyer of at least two (2) Business Days prior to the Closing Date) in an amount equal to (i) the Base Purchase Price plus (ii) Seller's good faith estimate of the Closing Date Net Working Capital (the ***"Adjustment Estimate"***);

(b) the Assignment and Assumption Agreement duly executed by Buyer;

(c) the Bill of Sale duly executed by Buyer;

(d) a countersigned copy of the Seller Parent Guaranty Agreement, duly executed by Buyer;

(e) the certificate referenced in Section 7.3;

(f) the Transition Services Agreement, duly executed by Buyer; and

(g) such other customary instruments of sale, assignment, transfer, and assumption, in form and substance reasonably satisfactory to Seller, as may be required to give effect to this Agreement.

Section 2.8. Post-Closing Adjustment.

(a) After the Closing Date, Seller and Buyer shall cooperate and provide each other access to their respective books, records and employees as are reasonably requested in connection with the matters addressed in this Section 2.8. Within sixty (60) days after the Closing Date, Buyer shall determine the Closing Date Net Working Capital and shall provide Seller with written notice of such determination, along with reasonable supporting information and calculations (the ***"Buyer's Determination"***).

(b) If Seller objects to Buyer's Determination, then it shall provide Buyer written notice thereof within thirty (30) days after receiving Buyer's Determination; provided, that Seller and Buyer shall be deemed to have agreed upon all items and amounts that are not disputed by Seller in such written notice. If the Parties are unable to agree on the Closing Date Net Working Capital within thirty (30) days following Buyer's receipt of Seller's objection notice, the Parties shall refer such dispute to a firm of nationally recognized independent public accountants mutually acceptable to Buyer and Seller (the ***"Independent Accountants"***), which firm shall make a final and binding determination as to only those matters in dispute with respect to this Section 2.8(b) on a timely basis and promptly shall notify the Parties in writing of its resolution. The Independent Accountants shall not have the power to modify or amend any term or provision of this Agreement. Each Party shall bear and pay one-half of the fees and other costs charged by the Independent Accountants with respect to its activities under this Section 2.8(b). If Seller does not object to Buyer's Determination within the time period and in the manner set forth in the first sentence of this Section 2.8(b) or if Seller accepts Buyer's Determination, the Closing Date Net Working Capital as set forth in Buyer's Determination shall become final and binding upon the Parties for all purposes hereunder.

(c) If the Closing Date Net Working Capital (as agreed between the Parties or as determined by the Independent Accountants) (the ***"Final Adjustment"***) is greater than the Adjustment Estimate, then Buyer shall pay Seller, within five (5) Business Days after all amounts are agreed or determined pursuant to Section 2.8(b), by wire transfer of immediately available funds to an account designated by Seller, the difference between the Final Adjustment and the Adjustment Estimate, and if the Final Adjustment is less in the Adjustment Estimate, then Seller shall pay Buyer, within five (5) Business Days after all amounts are agreed or determined pursuant to Section 2.8(b), by wire transfer of immediately available funds to an account designated by Buyer, the absolute value of the difference between the Final Adjustment and the Adjustment Estimate.

Section 2.9. Allocation of Purchase Price.

(a) Within sixty (60) days after the Closing Date, Buyer shall deliver to Seller a schedule allocating the Purchase Price (and all other capitalized costs) among the Purchased Assets, grouped by the seven asset classes referred to in Treasury Regulations Section 1.1060-1(c) (the ***"Purchase Price Allocation Schedule"***). Buyer shall permit Seller thirty (30) days to review and comment on Buyer's proposed Purchase Price Allocation Schedule. Buyer shall make such revisions to its proposed Purchase Price Allocation Schedule as are reasonably requested by Seller within such thirty (30)-day period and shall deliver to Seller a final Purchase Price Allocation Schedule within fifteen (15) days of receiving Seller's comments. The Purchase Price Allocation Schedule shall be revised to take into account subsequent adjustments to the Purchase Price, including the Final Adjustment and any indemnification payments (which shall be treated for Tax purposes as adjustments to the Purchase Price), as mutually agreed by the Parties and in accordance with the provisions of Section 1060 of the Code and the Treasury Regulations thereunder.

(b) The Parties shall report the transaction for federal and state income tax purposes on IRS Form 8594 in accordance with the Purchase Price Allocation Schedule described in Section 2.9(a). Neither Party will take a position inconsistent with such allocation except with the written consent of the other Party. Each of Seller and Buyer agrees to provide the other promptly with any other information required to complete Form 8594.

(c) If the Parties are unable to agree on the Purchase Price Allocation Schedule pursuant to Section 2.9(a) or any subsequent adjustment to the Purchase Price Allocation Schedule, the Parties shall refer such dispute to the Independent Accountants, which firm shall make a final and binding determination as to all matters in dispute with respect to this Section 2.9 (and only such matters) on a timely basis and promptly shall notify the Parties in writing of its resolution. The Independent Accountants shall not have the power to modify or amend any term or provision of this Agreement. Each Party shall bear and pay one-half of the fees and other costs charged by the Independent Accountants with respect to its activities under this Section 2.9.

ARTICLE III.

REPRESENTATIONS AND WARRANTIES OF SELLER

Seller hereby represents and warrants to Buyer as of the date hereof and as of the Closing Date (except for representations and warranties that are made as of a specific date, which are made only as of such date) that:

Section 3.1. Organization. Seller is a limited liability company duly formed, validly existing and in good standing under the Laws of its jurisdiction of formation. Seller is duly qualified or licensed to do business in each other jurisdiction where the actions to be performed by it hereunder makes such qualification or licensing necessary, except in those jurisdictions where the failure to be so qualified or licensed would not reasonably be expected to result in a material adverse effect on Seller's ability to perform such actions under this Agreement or the Ancillary Agreements to which Seller is party.

Section 3.2. Authority; Enforceability. Seller has all requisite limited liability company power and authority to execute and deliver this Agreement and the Ancillary Agreements to which Seller is a party, to perform its obligations hereunder and thereunder and to consummate the transactions contemplated hereby and thereby. The execution and delivery by Seller of this Agreement and the Ancillary Agreements to which Seller is a party, and the performance by Seller of its obligations hereunder and thereunder, have been duly and validly authorized by all necessary limited liability company action. This Agreement has been duly and validly executed and delivered by Seller and constitutes (assuming due authorization, execution and delivery by Buyer), and each Ancillary Agreement to which Seller is a party when executed and delivered on the Closing Date will constitute (assuming due authorization, execution and delivery by the other parties thereto), the legal, valid and binding obligation of Seller enforceable against Seller in accordance with its terms, except as the same may be limited by bankruptcy, insolvency, moratorium or other similar Laws relating to or affecting the rights of creditors generally, or by general equitable principles.

Section 3.3. No Conflicts; Consents and Approvals. The execution and delivery by Seller of this Agreement and the Ancillary Agreements to which Seller is a party do not, and the performance by Seller of its obligations hereunder and thereunder do not and will not:

(a) conflict with or result in a violation or breach of any of the terms, conditions or provisions of the Organizational Documents of Seller;

(b) assuming all of the Seller Consents set forth in Schedule 3.3(b) have been obtained, be in violation of or result in a breach of or default (or give rise to any right of termination, cancellation or acceleration), or require the consent of any other Person, under (with or without the giving of notice, the lapse of time, or both) any Contract to which Seller or any of its Affiliates is a party, except for any such violations or defaults (or rights of termination, cancellation or acceleration) which, or such consents which, if not obtained, would not, individually or in the aggregate, reasonably be expected to result in a material adverse effect on Seller's ability to perform its obligations hereunder or a Material Adverse Effect;

(c) assuming all of the Seller Approvals and the Seller Consents have been made, obtained or given, (i) conflict with, violate or breach any term or provision of any Law or Permit applicable to Seller, the Purchased Assets or the Business, except as would not reasonably be expected to result in a material adverse effect on Seller's ability to perform its obligations hereunder or a Material Adverse Effect; or (ii) require any consent or approval of any Governmental Authority, or notice to, or declaration, filing or registration with, any Governmental Authority, under any applicable Law or Permit, other than such consents, approvals, notices, declarations, filings or registrations which, if not made or obtained, would not reasonably be expected to result in a material adverse effect on Seller's ability to perform its obligations hereunder or a Material Adverse Effect; and

(d) result in the imposition or creation of any Lien upon or with respect to the Business or the Purchased Assets (other than Permitted Liens).

Section 3.4. [Intentionally Omitted].

Section 3.5. Brokers. Seller has no liability or obligation to pay fees or commissions to any broker, finder or agent with respect to the transactions contemplated by this Agreement for which Buyer would become liable or obligated based upon arrangements made by Seller or any of its Affiliates.

Section 3.6. Claims and Legal Proceedings. Except as set forth on Schedule 3.6, no Claim is pending against Seller or its Affiliates, neither Seller nor its Affiliates have been served with written notice of any Claim, to Seller's Knowledge no Claim has been threatened against Seller or its Affiliates, and to Seller's Knowledge there are no facts, conditions or circumstances that would reasonably be expected to form the basis of any Claim that, in each case affects or would reasonably be expected to affect Seller, the Purchased Assets or the Business and would, individually or in the aggregate, reasonably be expected to result in a Material Adverse Effect or in a material adverse effect on Seller's ability to perform its obligations hereunder. As of the Closing, no actions or omissions of Seller or its contractors (of any tier) or agents prior to or on the Closing Date will result in any material Claim against Buyer (a) under any indemnity in any Assigned Contract, Land Contract or Permit assigned to Buyer at the Closing, and (b) for personal injury, death sickness or third party property damage. No Claim is pending against Seller, Seller has not been served with written notice of any Claim, and to Seller's Knowledge no Claim has been threatened against Seller, that seeks a writ, judgment, order, injunction or decree restraining, enjoining or otherwise prohibiting or making illegal any of the transactions contemplated by this Agreement.

Section 3.7. Compliance with Laws and Orders. Seller is, in all material respects, in compliance with all Laws applicable to the Business or the Purchased Assets, including the Project. Seller has not received written notice of any alleged material violation of any Laws applicable to the Business or the Purchased Assets, including the Project.

Section 3.8. Financial Statements.

(a) Seller Parent has previously delivered to Buyer true, correct and complete copies of the audited Financial Statements of Seller Parent as of December 31, 2020 (the ***"Seller Parent Audited Financial Statements"***). The Seller Parent Audited Financial Statements have been prepared in accordance with GAAP consistently applied throughout the periods involved (except as may be stated therein or in the notes thereto). The Seller Parent Audited Financial Statements present fairly, in all material respects, the financial position, statements of operations and comprehensive income, members' equity and cash flows of Seller Parent as of the date thereof and for the applicable period covered thereby.

(b) Seller has previously delivered to Buyer audited Financial Statements of Seller as at December 31, 2020 (***"Seller Audited Financial Statements"***). The Seller Audited Financial Statements have been prepared in accordance with GAAP consistently applied throughout the periods involved (except as may be stated therein or in the notes thereto). The Seller Audited Financial Statements present fairly, in all material respects, the financial position, statements of operations and comprehensive income, members' equity and cash flows of Seller as of the date thereof and for the applicable period covered thereby.

(c) As of the Closing Date, Seller has delivered to Buyer the Updated Seller Parent Financial Statements. The Updated Seller Parent Financial Statements have been prepared in accordance with GAAP consistently applied throughout the periods involved (except as may be stated therein or in the notes thereto). The Updated Seller Parent Financial Statements present fairly, in all material respects, the financial position, statements of operations and comprehensive income, members' equity and cash flows of Seller Parent as of the date thereof and for the applicable period covered thereby.

(d) As of the Closing Date, Seller has delivered to Buyer the Updated Seller Financial Statements. The Updated Seller Financial Statements have been prepared in accordance with GAAP consistently applied throughout the periods involved (except as may be stated therein or in the notes thereto). The Updated Seller Financial Statements present fairly, in all material respects, the financial position, statements of operations and comprehensive income, members' equity and cash flows of Seller as of the date thereof and for the applicable period covered thereby.

Section 3.9. Absence of Certain Changes. Since December 31, 2020 and through the date hereof, (a) Seller has operated the Business and the Purchased Assets in the ordinary course of business and in a manner that is materially consistent with Prudent Engineering and Operating Practices, (b) there has not been any Material Adverse Effect with respect to the Business or the Purchased Assets, and (c) there has not been any event or condition that would reasonably be expected to prevent or delay Seller from consummating the transactions contemplated by this Agreement.

Section 3.10. Taxes. Except as set forth in Schedule 3.10, (a) all Tax Returns that are required to be filed on or before the Closing Date by Seller in respect of the Business or the Purchased Assets have been or will be duly and timely filed, taking into account all permitted extensions, and are true, correct and complete in all material respects, (b) all Taxes required to be paid by Seller with respect to the Business or the Purchased Assets (whether or not shown on any

Tax Return) that are due and payable have been timely paid in full, (c) all material Tax withholding requirements imposed on Seller with respect to the Business or the Purchased Assets have been satisfied in all material respects, except for amounts that are being contested in good faith, (d) Seller does not have in force any waiver of any statute of limitations in respect of Taxes or any extension of time with respect to a Tax assessment or deficiency in each case in respect of the Business or the Purchased Assets, (e) there are no pending or active audits, examinations, claims, assessments or legal proceedings involving Tax matters or, to Seller's Knowledge, threatened audits or proposed deficiencies or other claims for unpaid Taxes of Seller in each case in respect of the Business or the Purchased Assets, (f) Seller, with respect to the Business or the Purchased Assets, has no liability for the Taxes of any other Person (i) as a transferee or successor or (ii) by contract (other than any contract the primary purpose of which does not relate to Taxes), (g) Seller, under the federal check-the-box regulations, is classified as an entity disregarded as separate from its owner for federal income tax purposes, (h) there are no deficiencies asserted or assessments made as a result of any examination of Tax Returns of Seller in respect of the Business or the Purchased Assets, (i) there are no Liens for Taxes (other than Permitted Liens) on any of the Purchased Assets or on the Business, and (j) with respect to the Purchased Assets or the Business, there are no outstanding closing agreements or ruling requests pending with any Taxing Authority.

Section 3.11. Condition of Purchased Assets; Sufficiency of Purchased Assets. The Project and the tangible personal property included in the Purchased Assets are in normal operational condition for a similar project and similar assets of a similar age (and taking into account the accumulated run hours of the Project and the number of fired starts at the Project), free of defects about which Seller has Knowledge and that could have a material adverse impact on such operation, and are in good working order, except for ordinary wear and tear and routine maintenance (in each case, consistent with Prudent Engineering and Operating Practices), except where the failure to be in good working order would not reasonably be expected to have material adverse impact on any Purchased Asset. Seller has not operated the gas turbines of the Project in a manner that violates the conditions of the warranty under the Mitsubishi LTSA in any material respect. As of the Closing, the Purchased Assets are sufficient to enable Buyer to own, operate, interconnect and maintain the Project immediately following the Closing in all material respects in the same manner as the Project was in the ordinary course of business previously owned, operated and maintained by Seller.

Section 3.12. Contracts.

(a) Schedule 3.12(a) sets forth a list as of the date of this Agreement of the following Contracts to which Seller is a party or by which the Assets of Seller are bound, in each case, which pertain to the Business or the Purchased Assets (Contracts that meet the descriptions in this Section 3.12 being collectively, the ***"Material Contracts"***):

(i) all Assigned Contracts;

(ii) all Contracts for the purchase, exchange or sale of natural gas;

(iii) all Contracts for the purchase, exchange, transmission or sale of electric power in any form, including energy, capacity or any ancillary services;

(iv) all Contracts for the transportation of natural gas;

(v) all Contracts for the supply, discharge, or services (including filtration services) related to water;

(vi) all interconnection Contracts;

(vii) all Contracts for the purchase or sale of any Asset or that grant a right or option to purchase or sell any Asset, other than Contracts entered into in the ordinary course of business consistent with past practices with an annual cost of less than $200,000 individually or $500,000 in the aggregate;

(viii) all Contracts for the provision or receipt of any work, goods or services or that grant a right or option to provide or receive any work, goods or services, in each case, requiring annual payments in excess of $200,000;

(ix) all Contracts under which a Lien has been imposed on any of the Purchased Assets, tangible or intangible, which security interest secures outstanding Indebtedness;

(x) all collective bargaining Contracts or other employment Contracts;

(xi) all outstanding futures, swap, collar, put, call, floor, cap, option or other Contracts that are intended to benefit from or reduce or eliminate the risk of fluctuations in interest rates or the price of commodities, including electric power, in any form, including energy, capacity or any ancillary services, natural gas or securities;

(xii) all Contracts that purport to limit the Business' freedom to compete in any line of business or in any geographic area in connection with the Project;

(xiii) all Contracts with Governmental Authorities regarding Property Taxes, Property Tax abatements, Property Tax incentive agreements or any payments in lieu of Property Taxes; and

(xiv) all Land Contracts.

(b) Except as set forth in Schedule 3.12(b), Seller has provided Buyer with, or access to, true, complete, and accurate copies of all Material Contracts. As of the Closing Date, Seller has provided Buyer with, or access to, true, complete, and accurate copies of all Additional Material Contracts.

(c) Each of the Material Contracts, and, as of the Closing Date, each of the Additional Material Contracts, is in full force and effect and constitutes a legal, valid and binding obligation of Seller and, to Seller's Knowledge, of the other parties thereto, except as may be limited by bankruptcy, insolvency, moratorium or other similar Laws relating to or affecting the rights of creditors generally, or by general equitable principles.

(d) Seller is not in material breach or default under any Material Contract or Additional Material Contract and, to Seller's Knowledge, no other party to any of the Material Contracts or

Additional Material Contracts is in material breach or default thereunder nor has Seller given or received written notice to or from any Person relating to any alleged or potential default that has not been cured, nor, has any event or circumstance occurred that, with notice or lapse of time or both, would constitute an event of default thereunder.

Section 3.13. Ownership; Liens.

(a) Seller has good and valid title to all of the Purchased Assets consisting of tangible personal property owned by Seller and valid and subsisting leases with respect to all of the Purchased Assets consisting of tangible personal property leased by Seller, and all such Purchased Assets are free and clear of all Liens except for Permitted Liens.

(b) Seller has good and valid title to, or a valid easement interest in, the Property, free and clear of all Liens except for Permitted Liens.

(c) Schedule 3.13(c) sets forth the legal description of all parcels of the Property. Seller's right, title and interest in and to the Property comprises all real property interests necessary for the ownership, operation, and maintenance of the Project.

(d) Seller has delivered to Buyer a copy of (which, to Seller's Knowledge, is a true, complete and accurate copy of):

(i) the Existing Survey;

(ii) the Existing Title Insurance Policy, including all exception documents referenced therein and, if applicable, recorded copies of such exceptions documents; and

(iii) as of each of the Effective Date and the Closing Date, mineral reports for any severed minerals and any records searches (for any governmental records not included in any title reports) with respect to the Property in the possession of Seller or any of its Affiliates.

(e) There are no pending, and to Seller's Knowledge no threatened, appropriation, condemnation or like proceedings, or zoning change or similar proceeding, relating to any Property, the Project or any portion thereof.

(f) Other than those items that are in the public record, Seller has not leased or otherwise granted to any person the right to use or occupy the Property or any portion thereof. Seller has not granted any outstanding options, rights of first refusal, rights of first offer, rights of reverter or similar third party rights in the Property.

Section 3.14. Permits.

(a) The Permits set forth on Schedule 3.14(a) constitute all Permits (other than immaterial local Permits that are not required to operate the Business) that are required for the ownership, operation, interconnection, or maintenance of the Project, the Purchased Assets and the Business by Seller in the manner in which it is currently owned and operated. All Permits set forth on Schedule 3.14(a) are properly in the name of Seller and are in full force and effect. Seller has provided Buyer with a true and correct copy of each such Permit.

(b) Seller is in material compliance with all Permits set forth on Schedule 3.14(a) and Seller has not received any written notification from any Governmental Authority alleging that it is in material violation of any such Permits.

(c) No material action, or written deficiency notice, demand or notice of any challenge is pending or, to Seller's Knowledge, threatened, which challenges the legality, validity or enforceability of any such Permit, or that attempts to modify in any adverse manner the requirements pertaining to any obtained Permit or application for a Permit.

Section 3.15. Environmental Matters.

(a) Seller has made available or disclosed to Buyer copies of all material written environmental assessments, notices of violation(s) or reports produced since December 23, 2015 that are in the possession of Seller and that relate to environmental matters in connection with operation of the Project.

(b) Except as set forth in Schedule 3.15(b), since December 23, 2015, Seller, the Property, the Project, the Business, and the Purchased Assets are and have been in compliance with all applicable Environmental Laws in all material respects and Seller has not received written notice of any alleged material violation of any applicable Environmental Law from any Governmental Authority.

(c) There are no material Environmental Claims, actions or proceedings that are currently outstanding or pending, or, to Seller's Knowledge, threatened, against Seller (with respect to the Purchased Assets or the Business) or otherwise affecting the Purchased Assets or the Business, by any Governmental Authority or third party under any Environmental Laws.

(d) There is no site to which Seller has transported or arranged for the transport of Hazardous Materials associated with the Project which, to Seller's Knowledge, is, or is threatened to become, the subject of any material Environmental Claim.

(e) To Seller's Knowledge, prior to December 23, 2015, there was no Release or threatened Release of any Hazardous Material at or from the Project in connection with operations of the Project that would be reasonably expected to trigger any material obligation of Seller under Environmental Laws to remediate such Release. Since December 23, 2015, there has been no Release or threatened Release of any Hazardous Material at or from the Project in connection with operations of the Project that would be reasonably expected to trigger any material obligation of Seller under Environmental Laws to remediate such Release.

(f) Schedule 3.15(f) sets forth all emission reduction credits and emissions allowances that have been allocated to or are otherwise held by Seller in respect of the Business as of the date of this Agreement.

Section 3.16. Intellectual Property.

(a) Seller owns, or has licenses or rights to use, all Intellectual Property currently used in or reasonably necessary for the Business and otherwise for the operation and maintenance of the Project.

(b) Seller has not received from any third party a claim in writing that the operation of the Business is infringing the Intellectual Property of such third party.

Section 3.17. [Intentionally Omitted.]

Section 3.18. Employees and Labor Matters.

(a) Seller does not have any employees with respect to the Project.

(b) The persons identified on Schedule 3.18(b) provide full-time or recurring and continuous part-time on site services to the Business with respect to the Project and are employed by a third party vendor or Affiliate of Seller pursuant to an agreement with such third-party vendor or Affiliate of Seller (***"Facility Employees"***).

(c) Schedule 3.18(c) lists each Contract between a third-party vendor and Seller or any Affiliate of Seller pursuant to which Facility Employees provide material on site employee services principally dedicated to Seller with respect to the Business.

(d) No labor organization has representation rights with respect to the Facility Employees. Neither Seller nor any of its Affiliates is a party to any collective bargaining agreement relating to the Facility Employees.

(e) There are no presently occurring, nor, to Seller's Knowledge threatened, labor strikes, work stoppages, slowdowns, or lockouts or other labor disputes by or involving any of the Facility Employees with respect to the Business.

(f) Neither Seller nor any of its Affiliates have received any written notice that any petition respecting any Facility Employees who are principally dedicated to the Business, has been filed with the National Labor Relations Board.

(g) Neither Seller nor any of its Affiliates have received any written notice with respect to the Facility Employees who are principally dedicated to the Business, of any charges before any Governmental Authority responsible for the prevention of unlawful employment practices.

(h) Neither Seller nor any of its Affiliates have received any written notice of any investigation related to the Facility Employees who are principally dedicated to the Business by a Governmental Authority responsible for the enforcement of labor or employment Laws and regulations and, to Seller's Knowledge, no such investigation is threatened.

Section 3.19. Employee Benefits.

(a) Seller does not have any Benefit Plans or any liability with respect to any Benefit Plans that would be a liability of Buyer following the Closing.

(b) There does not now exist, nor do any circumstances exist that would result in, any Controlled Group Liability that would be a liability of Buyer following the Closing. Without limiting the generality of the foregoing, neither Seller nor any of its Affiliates are an ERISA Affiliate that has engaged in any transaction described in Section 4069 or Section 4204 of ERISA.

(c) No Benefit Plan of any Affiliate of Seller with respect to the Purchased Assets or the Business contains any term or provision that would prohibit the transactions contemplated by this Agreement.

(d) No Benefit Plans of any Affiliate of Seller with respect to the Purchased Assets or the Business are presently under audit or examination by the Internal Revenue Service, the Department of Labor, or any other governmental agency or entity that would result in liability to Buyer.

Section 3.20. Inventory. All of Seller's inventory (including spare parts) are of a quality usable in the ordinary course of business, except for obsolete items and items of below-standard quality, all of which have been written off or written down to net realizable value.

Section 3.21. Insurance. Seller has in full force and effect policies of insurance with respect to the Business and the Purchased Assets against such casualties and contingencies and in such amounts, types and forms as are customarily appropriate in Seller's industry for the Business and the Purchased Assets. Schedule 3.21 contains a list and description of all material policies of insurance carried by Seller relating to the Business or the Purchased Assets as of the date hereof; including any material outstanding claims or claims notices filed under those policies as of the date hereof. As of the date hereof, Seller is not in material default under any such policy of insurance or bond such that it can be canceled and all premiums due and payable with respect thereto have been paid. Seller has filed claims with, or given notice of claims to its insurers or bonding companies in timely fashion with respect to all known matters and occurrences for which Seller believes it has coverage and that could result in a claim in excess of $250,000 under any policy after the Closing Date.

Section 3.22. FERC/NERC/DOE/MISO/PJM Matters.

(a) Seller has made available to Buyer copies of all material written reports of assessments, investigations, compliance audits, remedial actions, or other investigative or response activities conducted at or with respect to the Project regarding any FERC, NERC-, DOE-, MISO- and/or PJM-related requirements, including cyber security and testing requirements, that are in the possession of Seller.

(b) Seller and the Project have operated in compliance in all material respects with all applicable FERC, NERC-, DOE-, MISO- and/or PJM-related requirements, including cyber security and testing requirements.

(c) (i) Seller has not been served with written notice of any actual or threatened notice of violation of any FERC, NERC-, DOE-, MISO- and/or PJM-related requirements, or other action, proceeding, investigation, or inquiry pursuant to any FERC, NERC-, DOE-, MISO- and/or PJM-related requirements, and (ii) no Claim regarding any FERC, NERC-, DOE-, MISO- and/or

PJM-related requirements is pending or, to Seller's Knowledge, threatened, against Seller, in each case including cyber security and testing requirements.

Section 3.23. Power of Attorney. Except as is contained in any Material Contract, no power of attorney has been granted by Seller or any of its Affiliates with respect to the Purchased Assets or the Business to any Person.

ARTICLE IV.

REPRESENTATIONS AND WARRANTIES OF BUYER

Buyer hereby represents and warrants to Seller as of the date hereof and as of the Closing Date (except for representations and warranties that are made as of a specific date, which are made only as of such date) that:

Section 4.1. Organization. Buyer is a corporation duly formed, validly existing and in good standing under the Laws of the State of Michigan. Buyer is duly qualified or licensed to do business in each other jurisdiction where the actions to be performed by it hereunder makes such qualification or licensing necessary, except in those jurisdictions where the failure to be so qualified or licensed would not reasonably be expected to result in a material adverse effect on Buyer's ability to perform such actions under this Agreement or the Ancillary Agreements to which Buyer is party.

Section 4.2. Authority; Enforceability. Buyer has all requisite corporate power and authority to enter into this Agreement and the Ancillary Agreements to which Buyer is a party, to perform its obligations hereunder and thereunder and to consummate the transactions contemplated hereby and thereby. The execution and delivery by Buyer of this Agreement and the Ancillary Agreements to which Buyer is a party and the performance by Buyer of its obligations hereunder or thereunder have been duly and validly authorized by all necessary corporate action. This Agreement has been duly and validly executed and delivered by Buyer and constitutes (assuming due authorization, execution and delivery by Seller), and each Ancillary Agreement to which Buyer is a party when executed and delivered on the Closing Date will constitute (assuming the due authorization, execution and delivery by the other parties thereto), the legal, valid and binding obligation of Buyer enforceable against Buyer in accordance with its terms except as the same may be limited by bankruptcy, insolvency, moratorium or other similar Laws relating to or affecting the rights of creditors generally or by general equitable principles.

Section 4.3. No Conflicts. The execution and delivery by Buyer of this Agreement and the Ancillary Agreements to which Buyer is a party do not, and the performance by Buyer of its obligations hereunder and thereunder and the consummation of the transactions contemplated hereby and thereby will not:

(a) conflict with or result in a violation or breach of any of the terms, conditions or provisions of Buyer's Organizational Documents;

(b) assuming all Buyer Approvals have been made, obtained or given, (i) conflict with, violate or breach any term or provision of any Contract or Law applicable to Buyer or any of its Assets, except as would not reasonably be expected to result in a material adverse effect on Buyer's ability to perform its obligations hereunder or (ii) require any material consent or approval of any Governmental Authority or notice to, or declaration, filing or registration with, any Governmental Authority, under any applicable Law, other than such consents, approvals, notices, declarations, filings or registrations which, if not made or obtained, would not reasonably be expected to result in a material adverse effect on Buyer's ability to perform its obligations hereunder.

Section 4.4. Legal Proceedings. No Claim is pending against Buyer, Buyer has not been served with notice of any Claim, and to Buyer's knowledge no Claim has been threatened against Buyer that seeks a writ, judgment, order or decree restraining, enjoining or otherwise prohibiting or making illegal the transactions contemplated by this Agreement.

Section 4.5. Brokers. Buyer has no liability or obligation to pay fees or commissions to any broker, finder or agent with respect to the transactions contemplated by this Agreement for which Seller would become liable or obligated based upon arrangements made by Buyer or any of its Affiliates.

Section 4.6. Financial Capability. Buyer has, or at the Closing will have, sufficient cash on hand or other sources of immediately available funds to enable it to make payment of the Purchase Price and to consummate the transactions contemplated by this Agreement.

ARTICLE V.

COVENANTS

The Parties hereby covenant and agree as follows:

Section 5.1. Regulatory and Other Approvals. From the date of this Agreement until the earlier of the Closing and any termination of this Agreement pursuant to Section 8.1 (the ***"Interim Period"***):

(a) The Parties will (at each Party's own expense), in order to consummate the transactions contemplated hereby, take all commercially reasonable efforts necessary, proper or advisable, and proceed diligently and in good faith and use all commercially reasonable efforts, as promptly as practicable to (i) obtain the Seller Approvals, the Seller Consents (provided that Seller shall be responsible for coordinating initial contact and leading discussions with counterparties unless otherwise agreed between the Parties), and the Buyer Approvals, (ii) obtain all other necessary or appropriate filings, registrations, consents, approvals, certifications, determinations, authorizations or waivers (including the transfer or re-issuance of Permits and the assignment of the Assigned Contracts to Buyer) required in order to consummate the transactions contemplated hereby and to take or cause to be taken all actions necessary to comply with the terms upon which any of the same are granted, and (iii) give all required notices to, Governmental Authorities, and provide such other information and communications to such Governmental Authorities or other Persons as such Governmental Authorities or other Persons may reasonably request in connection therewith; provided, that neither Party shall have any obligation to pay any third Person a fee to obtain any consent, authorization or approval of such Person not already provided for by the applicable agreement or applicable Law. Additionally, Seller will reasonably cooperate with Buyer in making Buyer the "Asset Owner" (as defined in the rules of MISO) with respect to the Project as soon as permitted following the Closing.

(b) Each Party shall consult and reasonably cooperate with the other Party in the regulatory review process. The Parties will provide prompt notification to each other when any such approval referred to in Section 5.1(a) is obtained, taken, made, given or denied, as applicable, and will advise each other of any material communications with any Governmental Authority or other Person regarding any of the transactions contemplated by this Agreement.

(c) In furtherance of the foregoing covenants:

(i) Each Party shall prepare, all necessary filings in connection with the transactions contemplated by this Agreement that may be required to be filed by such Party with the FERC or under the HSR Act in order to obtain the applicable Seller Approvals or the Buyer Approvals, as applicable and shall submit such filings (i) no later than 450 days (subject to extension of such period upon consent of the other Party, which consent shall not be unreasonably withheld, conditioned or delayed) after the execution hereof for filings with the FERC, and (ii) no later than 450 days after the execution hereof for filings under the HSR Act or any FTC filings. Buyer shall as soon as practical following the execution of this Agreement prepare and file its integrated resource plan with the MPSC. Each Party shall otherwise prepare as soon as practical following the execution of this Agreement all other necessary filings in connection with the transactions contemplated by this Agreement that may be required to be filed by such Party with any other Governmental Authority in order to obtain the applicable Seller Approvals or the Buyer Approvals, as applicable. The Parties shall (to the extent permitted by applicable Law) promptly furnish each other with copies of any notices, correspondence or other written communication from the relevant Governmental Authority, shall promptly make any appropriate or necessary subsequent or supplemental filings, and shall cooperate in the preparation of such filings as is reasonably necessary and appropriate. Each Party shall have the right to review, and in the case of all filings except for Buyer's integrated resource plan, approve (which approval shall not be unreasonably withheld, conditioned or delayed) in advance all information related to Seller or Buyer, as applicable, and the transactions contemplated by this Agreement with respect to any filing made by the other Party in connection with the transactions contemplated by this Agreement. Buyer shall afford Seller a reasonable opportunity before filing to review and comment upon the portions of Buyer's proposed integrated resource plan and any application for approval of such plan, and testimony, pleadings, briefs and any other documents Buyer proposes to file in connection with MPSC approval of Buyer's integrated resource plan under MCL 460.6t, in each case, that refer to the transactions contemplated by this Agreement. Notwithstanding the foregoing, neither Party shall extend any waiting period under the HSR Act without the prior consent of the other Party. Buyer and Seller agree that all telephonic calls and meetings with the FTC or FERC regarding the transactions contemplated by this Agreement shall be conducted by Buyer and Seller jointly (subject to exceptions upon consent of both Parties, which consent shall not be unreasonably withheld, conditioned or delayed). All filing fees payable in connection with this Section 5.1(c)(i) shall be paid by Buyer.

(ii) The Parties shall not, and shall cause their respective Affiliates not to, take any action that is intended to adversely affect the approval of any Governmental Authority of any of the filings referenced in Section 5.1(c)(i).

(iii) Seller shall file with the appropriate Governmental Authority an application and shall use commercially reasonable efforts to take such other actions as are necessary for the transfer of all Permits set forth on Schedule 3.14(a) to Buyer or the reissuance of such Permits in Buyer's name.

(iv) Buyer shall use commercially reasonable efforts to support Seller in its efforts to cause, effective as of the Closing, the cancellation or return to Seller of the securities described in Schedule 5.1(c), including by Buyer's delivery as of the Closing of a replacement security to the relevant counterparty in a form and amount reasonably acceptable to Buyer and the applicable counterparties listed in Schedule 5.1(c). If Seller is unable to obtain the cancellation or return to Seller of any such security prior to or at the Closing, then the foregoing covenant shall survive the Closing, and Buyer shall promptly reimburse Seller in full for any amounts drawn by the beneficiary of such security following the Closing.

(d) During the Interim Period, Seller shall use commercially reasonable efforts to timely and properly make all submittals and reports, shall pay all fees, and otherwise do all things necessary to maintain in full force and effect and comply in all material respects with, each Permit required for the ownership and operation of the Project as it is currently operated. In the event of any actual or, if Seller has Knowledge thereof, threatened cancellation, revocation, termination, suspension, nonrenewal, or adverse modification of any such Permit, Seller shall promptly notify Buyer in writing (to the extent not prohibited by applicable Law) and shall use commercially reasonable efforts to pursue all available legal and equitable remedies for the purpose of preserving such Permit and the currently prevailing terms thereof.

(e) Notwithstanding the foregoing, nothing in this Section 5.1 shall require, or be construed to require, Buyer, Seller or any of their respective Affiliates to agree to (i) sell, hold, divest, discontinue or limit, before or after the Closing Date, any assets, businesses or interests of Buyer, Seller or any of their respective Affiliates; (ii) any conditions relating to, or changes or restrictions in, the operations of any such assets, businesses or interests which, in either case, could reasonably be expected to result in a Material Adverse Effect or materially and adversely impact the economic or business benefits to Buyer or Seller of the transactions contemplated by this Agreement or materially and adversely impact other assets or businesses of Buyer or Seller; (iii) any material modification or waiver of the terms and conditions of this Agreement, or (iv) in Buyer's case, result in less than all of the Purchased Assets or less than all of the Purchase Price being eligible for inclusion in Buyer's rate base or prohibits Buyer from recovering the transaction costs relating to the transactions contemplated by this Agreement or prohibits Buyer from deferring the incremental net costs and benefits associated with the transactions contemplated by this Agreement between the Closing and Buyer's next rate case proceeding (any of the foregoing, a ***"Burdensome Condition"***).

Section 5.2. Access of Buyer and Seller.

(a) During the Interim Period, Seller will, and will cause its Representatives to (at Buyer's sole cost and expense) provide Buyer and its Representatives with reasonable access, upon reasonable prior notice to Seller and during normal business hours, to the Property and to the officers and employees of Seller and its Affiliates who have significant responsibility in respect of the Business or the Purchased Assets, but only to the extent that such access is under the supervision of Seller's Representatives and does not disrupt or interfere with the business of Seller or the Business and that such access is reasonably related to the requesting Party's obligations and rights hereunder, and subject to compliance with applicable Laws, COVID-related restrictions and protocols and any Contracts or Permits to which Seller or any of its Affiliates is a party; provided, however, that Seller shall have the right to (x) have a Representative present for any communication with employees or officers of Seller or its Affiliates, and (y) impose reasonable restrictions and requirements for safety purposes. During the Interim Period, Seller will use commercially reasonable efforts to provide Buyer with information as may be reasonably requested by Buyer, relating to any occurrence or failure of an event or circumstance to occur, which occurrence or failure would reasonably be likely to cause any representation or warranty of Seller contained in this Agreement to be untrue or inaccurate. In all events, Seller shall have the right to restrict access to any information to the extent the disclosure of such information would, as reasonably determined by Seller, (1) jeopardize attorney-client privilege relating to any pending or threatened Claim or (2) conflict with any confidentiality obligations by which Seller or any of its Affiliates is bound that Seller is unable to overcome after using commercially reasonable efforts to seek the consent to disclosure from the owner of the confidential information or otherwise having used commercially reasonable efforts to enable the confidential information to be disclosed to Buyer in a manner consistent with such confidentiality obligations. Prior to the Closing Date, Buyer shall not have the right to examine and/or inspect the Property more than one time per week (recognizing that due to the reason for the examination and/or inspection, it may extend beyond one day). From and after the date that is three (3) months prior to the anticipated Closing Date, Seller shall use commercially reasonable efforts to facilitate Buyer's access to the Facility Employees for the purpose of communicating with such Facility Employees regarding bona fide employment opportunities following the Closing with Buyer in accordance with an employee communication plan. The Parties will in good faith work together to develop and complete such plan by no later than the date that is three (3) months prior to the anticipated Closing Date. Within a reasonable time prior to the anticipated Closing Date, Seller shall use commercially reasonable efforts to provide or caused to be provided to Buyer such pertinent data or information as Buyer shall reasonably require to determine the amount of service, compensation or any other information related to benefits with respect to each Facility Employee that Buyer elects to hire as of the Closing Date.

(b) Buyer shall indemnify, defend and hold harmless Seller from any and all third party Claims and Losses arising therefrom as a result of personal injuries, death, or property damage to the extent proximately caused by Buyer's or any of its Representatives' negligence or willful misconduct during their investigations or environmental reviews at the Property pursuant to Section 5.2(a) or Section 5.2(d); provided, that no such indemnity claim may be brought by Seller after one (1) year after the Closing or termination of this Agreement. Buyer will also be liable to Seller for any damage to Seller's tangible property at the Property to the extent proximately caused by Buyer's or any of its Representatives' negligence or willful misconduct during their investigations at the Property pursuant to Section 5.2(a); provided, that to the extent that any such property damage is covered under any policy of insurance held by Seller or its Affiliates that insures against the risk of such property damage Buyer's responsibility for such property damage shall be limited to the amount of the deductible under such policy of insurance; and provided further that no claim for any such damage may be brought by Seller after one (1) year after the Closing or termination of this Agreement.

(c) From and after the Closing, Buyer agrees to preserve and keep the Books and Records for a period of seven (7) years from the Closing. From and after the Closing until the expiration of such seven (7)-year period, Buyer agrees, upon reasonable prior written notice from Seller, to provide to Seller and its Representatives access to or copies (at Seller's expense) of said Books and Records to the extent reasonably requested by Seller or needed by Seller for a legitimate business purpose (including in respect of any post-Closing adjustment under Section 2.8).

(d) Subject to compliance with the requirements set forth in Section 5.2(a), Buyer and its Representatives shall be entitled to conduct reasonable environmental reviews and investigations of the Property or Purchased Assets; provided, that without the prior written consent of Seller, neither Buyer nor its Representatives shall be entitled to conduct any invasive surface or subsurface testing, sampling or investigation of the Property or Purchased Assets. Buyer shall, and shall cause its Representatives to, in connection with the conduct of the diligence activities conducted in connection with the transactions contemplated by this Agreement, comply with all applicable Laws, including Environmental Laws, and rules, policies and instructions reasonably issued by Seller and provided to Buyer regarding such diligence activities.

Section 5.3. Operations During Interim Period.

(a) Except as otherwise expressly contemplated under this Agreement in connection with the transactions contemplated hereby (including obtaining the Seller Approvals and the Seller Consents and satisfying the Interconnection and Capacity Requirement) or expressly consented to in writing by Buyer (such consent not to be unreasonably withheld, conditioned or delayed), during the Interim Period, Seller will (i) operate the Business in the ordinary course and in a manner that is materially consistent with Prudent Engineering and Operating Practices (including maintaining a quantity and type of materials, supplies and spare parts materially consistent with Prudent Engineering and Operating Practices), (ii) make expenditures substantially in accordance with the Budget (subject to any deviations that Seller reasonably determines are consistent with Prudent Engineering and Operating Practices) and (iii) use commercially reasonable efforts to maintain the Project in a manner that is materially consistent with Prudent Engineering and Operating Practices so as to preserve and maintain the Project in the same condition (after giving effect to the accumulated run hours of the Project and the number of fired starts at the Project) as it exists on the date hereof, ordinary wear and tear excepted. Prior to the Closing, Seller will, and Seller will cause USPG and Eastern Covert LLC to, amend the Asset Management Agreement to (A) cause its term to be extended through May 31, 2024, and (B) enable Seller (or Buyer as its assignee) to terminate the same for convenience upon five (5) days' written notice without termination payment, liquidated damage or other penalty. Prior to the Closing, and after the Closing at all times during which the Asset Management Agreement remains in force between Buyer and USPG, Seller will cause USPG not to allow the O&M Agreement to expire or otherwise terminate the O&M Agreement.

(b) Without limiting the foregoing, except as expressly consented to in writing by Buyer (such consent not to be unreasonably withheld, conditioned or delayed), and except as otherwise expressly provided in this Agreement, during the Interim Period, Seller shall not, and shall cause its Affiliates not to, with respect to the Purchased Assets:

(i) (A) create any Lien (other than a Permitted Lien) against any of the Purchased Assets, or (B) permit any Lien (other than a Permitted Lien) against any of the Purchased Assets;

(ii) except in the ordinary course of business (including with respect to incurrence of capital expenditures and major maintenance expenditure in connection with the Project), enter into, modify or renew any Contract with respect to the Purchased Assets that cannot be terminated by Seller (or Buyer, as assignee) on ninety (90) days' or less notice without termination payment, liquidated damages, or penalty and involving total consideration throughout its term in excess of $500,000 individually or $3,000,000 in the aggregate for all such Contracts;

(iii) sell, transfer, remove, assign, convey, distribute or otherwise dispose of any Purchased Asset, or use any Purchased Asset other than in the ordinary course of business;

(iv) sell, transfer, assign or convey the emissions allowances or emission reduction credits set forth on Schedule 3.15(f) or any emissions allowances or emission reduction credits allocated to Seller in respect of the Project after the date hereof; provided, that nothing in this clause (iv) shall restrict the use after the date hereof by Seller of any emissions allowances or emission reduction credits in the ordinary course of business as necessary for compliance for the Project;

(v) liquidate, dissolve, recapitalize, reorganize or otherwise wind up its business or operations;

(vi) make any new, or change any existing, election with respect to Taxes, or settle any Tax liability, in each case, to the extent it would reasonably be expected to materially and adversely affect Buyer after the Closing;

(vii) fail to discharge any material liability of Seller in respect of the Purchased Assets or the Business or fail to make any material payment of Seller in respect of the Purchased Assets or the Business as it comes due, except in connection with a reasonable good faith dispute and for which adequate reserves have been established in accordance with GAAP;

(viii) amend, modify, terminate (excluding any expiration in accordance with its terms) or grant any waiver with respect to any Assigned Contract, except for amendments, modifications or waivers that (A) extend the terms of the applicable Assigned Contracts beyond the Closing Date as specified in Section 5.3(a) and Section 10.4(c), (B) are not material, (C) may be necessary to separate the Excluded Assets from the Purchased Assets, or (D) are needed in order to operate the Business in accordance with Prudent Engineering and Operating Practices;

(ix) amend, modify, terminate (excluding any expiration in accordance with its terms), grant any waiver, or waive any right with respect to any Permit;

(x) compromise or settle any material Claim that is reasonably likely to adversely affect any Purchased Assets or Assumed Liabilities on or after the Closing Date; or

(xi) agree or commit to do any of the foregoing.

Notwithstanding the foregoing or anything in this Agreement to the contrary, (x) Seller may take (or not take, as the case may be) any of the actions described in this Section 5.3 if reasonably necessary to address emergency circumstances or as required pursuant to applicable Law; provided, that Seller shall provide notice to Buyer of such actions as promptly as practicable thereafter and (y) Seller shall take all actions reasonably necessary to cancel or otherwise terminate the Reactive Tariff at or prior to the Closing.

Section 5.4. MISO Interconnection and Capacity.

(a) The covenant described in this Section 5.4(a) is the ***"Interconnection and Capacity Requirement"*** and shall be completed at Seller's sole cost and expense; provided, that in no event shall Seller be required to incur any out-of-pocket fees, costs and/or expenses in connection with satisfying the Interconnection and Capacity Requirement that (when combined with out-of-pocket fees, costs and/or expenses borne by USPG in connection with the PJM TSA Services under Section 5.24) exceed the Interconnection Cap. During the Interim Period Seller shall establish a MISO Interconnection Queue Position and use commercially reasonable efforts to pursue entry into MISO's standard form of generator interconnection agreement (with relevant technical changes to reflect the Purchased Assets) for the Project to be interconnected into MISO within Local Resource Zone 7 and claim all credits or other benefits related to capacity, energy, reactive power, ancillary services or other attributes recognized by MISO that the Project is currently capable of providing (the ***"MISO GIA"***). As part of meeting the Interconnection and Capacity Requirement, during the Interim Period, Seller shall (i) keep Buyer reasonably informed as to the process, (ii) provide Buyer with an opportunity to participate in calls with MISO and/or PJM (to the extent reasonably practicable and permitted by MISO and/or PJM), and (iii) provide Buyer with a reasonable opportunity to review and comment on any material documentation to be submitted by Seller to MISO and/or PJM. In the event that the Closing will occur prior to execution of the MISO GIA, the Parties shall, in coordination with each other, cause the MISO Interconnection Queue Position to be transferred into Buyer's name.

(b) The Parties shall reasonably coordinate and undertake all commercially reasonable efforts necessary, proper or advisable, and proceed diligently and in good faith, as promptly as practicable, to timely complete the MISO GIA or enter into a reasonably acceptable External Resource Transaction with respect to the entire Project by the deadline stated in Section 6.8.

(c) If the out-of-pocket fees, costs and/or expenses incurred by or on behalf of Seller in connection with satisfying the Interconnection and Capacity Requirement, when combined with out-of-pocket fees, costs and/or expenses borne by USPG in connection with providing the PJM TSA Services under Section 5.24, are projected to reach or actually reach the Interconnection Cap, then Buyer and Seller will diligently and in good faith negotiate to seek a mutually-agreeable equitable sharing of such excess fees, costs and/or expenses. If such excess fees, costs and/or expenses exceed twelve million dollars ($12,000,000), Buyer may terminate this Agreement on ten (10) Business Days' written notice to Seller.

Section 5.5. [Intentionally Omitted.]

Section 5.6. [Intentionally Omitted.]

Section 5.7. Liens. Notwithstanding anything in this Agreement to the contrary, prior to or at the Closing, Seller shall (a) cause any and all (x) Liens upon or in respect of the Purchased Assets that secure any Indebtedness of Seller and (y) any and all monetary Liens (other than Permitted Liens) in respect of the Purchased Assets (excluding the Property) that are otherwise in the public record, in each case to be released such that Buyer shall acquire the Purchased Assets free of any such Liens, and (b) as with respect to Liens (other than Permitted Liens) upon or in respect of the Purchased Assets that secure any Indebtedness of Seller, obtain a payoff letter whereby, among other standard provisions, all lenders with respect to the Indebtedness (i) acknowledge and confirm that the Indebtedness has been paid in full and that such Liens have been released, (ii) authorize the filing of necessary termination statements and recording of releases, and (iii) are required to take further actions as are reasonably requested by Seller to evidence the payoff and release of such Liens. For purposes of this Section 5.7, references to "Permitted Liens" shall be deemed not to include Liens described in clause (e) of the definition of Permitted Liens.

Section 5.8. Insurance. During the Interim Period, Seller shall maintain or cause to be maintained in full force and effect the material insurance policies covering the Purchased Assets or shall replace them with reasonably comparable policies to the extent available on commercially reasonable terms. During the Interim Period, Seller shall timely make all claims under such insurance policies for any Losses incurred by Seller or affecting the Project or the other Purchased Assets. All such insurance coverage shall be terminated as of the Closing and following such termination, such insurance policies will exclude coverage of the Purchased Assets. Any and all returned premiums in respect of any replaced or substitute insurance coverage shall be for Seller's account and, if any such premium is received by Buyer or its Affiliates, shall be paid by wire transfer of immediately available funds to such account as Seller shall specify in writing to Buyer. Without limiting the rights of Buyer set forth elsewhere in this Agreement, for a period of one (1) year after the Closing Date, if any Claims may reasonably be made that relate to the Purchased Assets and such Claims arise out of or relate to an event occurring prior to the replacement or substitution of such insurance policy pursuant to this Section 5.8 (to the extent it would be clear to a reasonable person that the event occurred prior to such time), and such Claims may be made against third-party insurance policies retained by Seller or its Affiliates, then Seller (on behalf of itself and its Affiliates) shall, at Buyer's request, use its commercially reasonable efforts to (after the Closing Date) file and otherwise continue to pursue such Claims and recover proceeds under the terms of such policies (but only to the extent the terms and conditions of such policies reasonably would provide coverage for such Claims), and, subject to all of the foregoing, Seller (on behalf of itself and its Affiliates) agrees to otherwise reasonably cooperate with Buyer or its Affiliates to make the benefits of any such third-party insurance policies available to Buyer or its Affiliates in accordance with and subject to the terms hereof; provided, that (a) all reasonable, out-of-pocket costs and expenses of Seller and its Affiliates incurred in connection with assisting in filing or pursuing a Claim shall be paid by Buyer and (b) Seller and its Affiliates will not bear any liability for the failure of an insurance carrier to pay any Claim under any such insurance policy.

Section 5.9. Transfer Taxes; Property Taxes.

(a) *Transfer Taxes.* Notwithstanding anything in this Agreement to the contrary, each of Seller and Buyer shall pay 50% of any Transfer Taxes imposed on Buyer or Seller by Law as a result of the transactions hereunder. Seller shall prepare and file all Tax returns required to be filed to report such Transfer Taxes.

(b) *Property Taxes.*

(i) The following items shall be apportioned between Seller and Buyer on the basis that Buyer owns the Property at 12:01 a.m. on the Closing Date:

a. Ad valorem Property Taxes shall be prorated as follows: the Parties will calculate the prorated Property Taxes for any Straddle Taxable Period based upon both the "due date" method and the "calendar year" method, pursuant to the methodologies stated in Exhibit 5.9(b). The tax proration between Buyer and Seller at the Closing will be the sum of the following: (1) 66.67% of the amount of taxes determined to be due or owing between Buyer and Seller applying the "due date" method and (2) 33.33% of the amount of taxes determined to be due or owing between Buyer and Seller applying the "calendar year" method. In the event of a conflict between Exhibit 5.9(b) and this Section 5.9(b)(i)a., Exhibit 5.9(b) shall control.

b. Any special assessments (or installments thereof) with respect to the Purchased Assets which become due and payable before the Closing Date shall be paid by Seller. Any special assessments (or installments thereof) with respect to the Purchased Assets which become due and payable on or after the Closing Date shall be paid by Buyer.

(ii) After the Closing Date, with respect to Property Taxes on the Purchased Assets for a Straddle Taxable Period, Buyer shall have the right to participate (at its own expense) in the appeal, settlement or compromise of any proceeding to determine the value of the Project for purposes of Property Taxes. Seller shall take such action in connection with any such proceeding as Buyer shall reasonably request from time to time to implement the preceding sentence.

(iii) During the Interim Period, Seller shall take appropriate action to ensure the continuation of existing Project Property Tax incentives, exemptions and abatements, including air and water pollution control tax exemption certificates, industrial facility tax abatements, payment in lieu of taxes or renaissance zones. Further, after the Closing Date Seller shall participate and take appropriate actions to transfer ownership or registration of such incentives, abatements or exemptions to Buyer.

Section 5.10. Books and Records. Seller shall deliver the Books and Records to Buyer as promptly as practicable following the Closing Date if such Books and Records are not provided to Buyer on the Closing Date or are not otherwise located at the Property (it being agreed that Seller may retain a copy thereof).

Section 5.11. Tax Matters.

(a) After the Closing Date, with respect to any Tax for which Seller is responsible pursuant to Section 5.9(b), Seller shall have the right, at its sole cost and expense, to control (in the case of a Pre-Closing Taxable Period) or participate in (in the case of a Straddle Taxable Period) the prosecution, settlement or compromise of any proceeding involving such Tax. Buyer shall take such action in connection with any such proceeding as Seller shall reasonably request from time to time to implement the preceding sentence, including the selection of counsel and experts and the execution of powers of attorney. Notwithstanding the foregoing, Buyer shall be entitled to participate (at its own expense) in any such proceeding involving a Pre-Closing Taxable Period, and Seller shall not settle any such proceeding with respect to any issue that could materially and adversely affect Buyer in a taxable period (or portion thereof) beginning after the Closing Date without Buyer's prior written consent, which consent shall not be unreasonably withheld, conditioned or delayed. Buyer shall not settle any such proceeding involving a Straddle Taxable Period without Seller's prior written consent, which consent shall not be unreasonably withheld, conditioned or delayed. Buyer shall give written notice to Seller of its receipt of any notice of any audit, examination, claim or assessment for any Tax for which Seller is responsible pursuant to Section 5.9(b) within twenty (20) days after its receipt of such notice; failure to give any such written notice within such twenty (20)-day period shall limit Seller's indemnification obligation pursuant to this Agreement to the extent Seller is actually prejudiced by such failure.

(b) Seller shall grant to Buyer (or its designees) access at all reasonable times to all of the information, books and records relating to the Purchased Assets within the possession or control of Seller (including workpapers and correspondence with Taxing Authorities), and shall afford Buyer (or its designees) the right (at Buyer's expense) to take extracts therefrom and to make copies thereof, to the extent reasonably necessary to permit Buyer (or its designees) to prepare Tax Returns, respond to Tax audits and investigations, prosecute Tax protests, appeals and refund claims and to conduct negotiations with Taxing Authorities. Buyer shall grant to Seller (or its designees) access at all reasonable times to all of the information, books and records relating to the Purchased Assets for Pre-Closing Taxable Periods or Straddle Taxable Periods within the possession of Buyer (including workpapers and correspondence with Taxing Authorities) and to any employees of Buyer, and shall afford Seller (or its designees) the right (at Seller's expense) to take extracts therefrom and to make copies thereof, in each case to the extent reasonably necessary to permit Seller (or its designees) to prepare Tax Returns, respond to Tax audits and investigations, prosecute Tax protests, appeals and refund claims and to conduct negotiations with Taxing Authorities. After the Closing Date, Seller and Buyer will preserve all information, records or documents in their respective possessions relating to liabilities for Taxes in respect of the Purchased Assets for Pre-Closing Taxable Periods or Straddle Taxable Periods until the later of (i) seven (7) years or (ii) six (6) months after the expiration of any applicable statute of limitations (including extensions thereof) with respect to the assessment of such Taxes; provided, that neither Party shall dispose of any of the foregoing items without first offering such items to the other Party.

(c) If after the Closing Buyer receives a refund or utilizes a credit of any Property Tax in respect of the Purchased Assets attributable to a Pre-Closing Taxable Period or that portion of a Straddle Taxable Period ending on the Closing Date, Buyer shall pay to Seller within twenty (20) Business Days after such receipt or utilization an amount equal to such refund received or credit utilized, together with any interest received or credited thereon net of any out-of-pocket costs associated therewith.

(d) To the extent that the provisions of Section 9.6 are inconsistent with or conflict with the provisions of Section 5.9(b) and this Section 5.11, the provisions of Section 5.9(b) and this Section 5.11 shall control.

Section 5.12. Casualty. If any Purchased Asset is damaged or destroyed by fire, storm, explosion or other casualty loss during the Interim Period (such loss, a ***"Casualty Loss"***), Seller will promptly notify Buyer of the same, and the sum of (a) the cost of restoring such damaged or destroyed Purchased Asset to a condition reasonably comparable to its prior condition plus (b) the amount of any lost profits reasonably expected to accrue after the Closing as a result of such Casualty Loss (net of and after giving effect to any insurance proceeds available to Seller for such restoration and lost profits (***"Casualty Insurance Proceeds"***)) (such costs and lost profits, as estimated by an independent qualified firm selected by Buyer and reasonably acceptable to Seller acting in good faith, the ***"Restoration Cost"***) is greater than 0.875% of the Base Purchase Price but does not exceed 15% of the Base Purchase Price, Seller may elect, by delivery of written notice to Buyer, to (i) restore, repair or replace the damaged Purchased Assets, or (ii) reduce the amount of the Purchase Price by the Restoration Cost, and (A) such Casualty Loss shall not affect the Closing and (B) if Seller elects the option under clause (ii) immediately above, Buyer shall be entitled to receive (and Seller will use commercially reasonable efforts to obtain, and shall pay over to Buyer) all Casualty Insurance Proceeds (net of any out-of-pocket expenses incurred by Seller in pursuing such Insurance Proceeds), such Casualty Insurance Proceeds to be excluded from the calculation of the Closing Date Net Working Capital. If Seller does not make any such election within ninety (90) days after the date of such Casualty Loss, Buyer may elect to terminate this Agreement, provided that Buyer first gives Seller written notice of termination after the end of such ninety (90)-day period and Seller does not make such an election within ten (10) Business Days after its receipt of such notice from Buyer. If Seller elects to restore, repair or replace the damaged Purchased Assets, Seller will complete or cause to be completed, using commercially reasonable efforts, the repair, replacement or restoration of such Purchased Assets in accordance with Prudent Engineering and Operating Practices prior to the Closing, and the Closing Date shall be postponed for the amount of time reasonably necessary to complete the restoration, repair or replacement of such Purchased Assets as reasonably agreed between Buyer and Seller (provided, that such postponement shall not extend beyond the date that is ninety (90) days following the Outside Date unless otherwise consented to by Buyer in writing in advance). If Seller does not complete the restoration, repair or replacement of the damaged Purchased Assets prior to the date that is ninety (90) days following the Outside Date (as such date may be extended with Buyer's consent), Buyer may upon ten (10) Business Days' prior written notice terminate this Agreement. If the Restoration Cost is in excess of 15% of the Base Purchase Price then either Seller or Buyer may, by delivery of written notice to the other Party within ninety (90) days after the date of such Casualty Loss, terminate this Agreement; provided, that if neither Party so terminates this Agreement then all of the provisions above shall apply as if the Restoration Costs were less than 15% (i.e., Seller elects to restore, repair or replace the damage or reduce the Purchase Price, etc.).

If the Restoration Cost does not exceed 0.875% of the Base Purchase Price, (x) there shall be no reduction in the amount of the Purchase Price, (y) Buyer shall not have the right or option to terminate this Agreement pursuant to this Section 5.12, and (z) Buyer shall be entitled to receive (and Seller will use commercially reasonable efforts to obtain, and shall pay over to Buyer) all Casualty Insurance Proceeds (net of any out-of-pocket expenses incurred by Seller in pursuing such proceeds), such Casualty Insurance Proceeds to be excluded from the calculation of the Closing Date Net Working Capital.

Section 5.13. Condemnation. If any Purchased Asset is taken by condemnation (a ***"Condemnation"***) during the Interim Period, Seller will promptly notify Buyer of the same, and the sum of (a) a condemnation value, as determined under applicable Law, plus (b) to the extent not included in the preceding clause (a), the amount of reduction or loss in value to the Project and any lost profits reasonably expected to accrue after the Closing as a result of such condemnation (net of and after giving effect to any condemnation award) (such compensation, plus reduction or loss in value and lost profits (as such value and profits are estimated by an independent qualified firm selected by Buyer and reasonably acceptable to Seller acting in good faith) collectively, the ***"Condemnation Value"***)) is greater than 0.875% of the Base Purchase Price but not in excess of 15% of the Base Purchase Price, Seller may elect, by delivery of written notice to Buyer, to (i) replace each condemned Purchased Asset with Purchased Assets that restore the Project and the value thereof to its pre-Condemnation condition, or (ii) reduce the Purchase Price by such Condemnation Value, and (A) such Condemnation shall not affect the Closing and (B) if Seller elects the option under clause (ii) immediately above, Buyer shall be entitled to receive (and Seller will use commercially reasonable efforts to obtain, and shall pay over to Buyer) the compensation referred to in clause (a) (net of any out-of-pocket expenses incurred by Seller in pursuing such compensation), such compensation to be excluded from the calculation of the Closing Date Net Working Capital. If Seller does not make any election within ninety (90) days after the date of such Condemnation, Buyer may elect to terminate this Agreement, provided that Buyer first gives Seller written notice of termination after the end of such ninety (90)-day period and Seller does not make such election within ten (10) Business Days after its receipt of such termination notice from Buyer. If Seller elects to replace each condemned Purchased Asset, Seller will complete or cause to be completed, using commercially reasonable efforts, the replacement of each such Purchased Asset in accordance with Prudent Engineering and Operating Practices prior to the Closing, and the Closing Date shall be postponed for the amount of time reasonably necessary to complete the replacement of each such Purchased Asset as reasonably agreed between Buyer and Seller (provided, that such postponement shall not extend beyond the date that is ninety (90) days following the Outside Date unless otherwise consented to by Buyer in writing in advance). If Seller does not complete the replacement of each condemned Purchased Asset prior to the date that is ninety (90) days following the Outside Date (as such date may be extended with Buyer's consent), Buyer may upon ten (10) Business Days' prior written notice terminate this Agreement. If the Condemnation Value is in excess of 15% of the Base Purchase Price, then either Buyer or Seller may, by delivery of written notice to the other Party within ninety (90) days after the date of such Condemnation, terminate this Agreement; provided, that if neither Party so terminates this Agreement then all of the provisions above shall apply as if the Condemnation Value was less than 15% (i.e., Seller elects to replace the condemned Purchased Asset or reduce the Purchase Price, etc.). If the Condemnation Value is not in excess of 0.875% of the Base Purchase Price, (x) there shall be no reduction in the amount of the Purchase Price, (y) Buyer shall not have the right or option to terminate this Agreement pursuant to this Section 5.13, and (z) Buyer shall be entitled to receive (and Seller will use commercially reasonable efforts to obtain, and shall pay over to Buyer) the compensation referred to in clause (a) (net of any out-of-pocket expenses incurred by Seller in pursuing such compensation), such compensation to be excluded from the calculation of the Closing Date Net Working Capital.

Section 5.14. Confidentiality.

(a) Any information or materials furnished by Seller to Buyer or Buyer to Seller on and after the date of this Agreement shall be subject to the Confidentiality Agreement; provided, that Buyer shall not have any obligation to maintain the confidentiality of any information with respect to the Purchased Assets, the Project, the Business or any other information transferred to Buyer under this Agreement from and after the Closing. In the event of any conflict between this Agreement and the Confidentiality Agreement, this Agreement shall prevail.

(b) Notwithstanding the above and anything in the Confidentiality Agreement to the contrary, Buyer or Seller may provide confidential information to any Governmental Authority with jurisdiction as necessary to comply with the terms of this Agreement.

Section 5.15. Public Announcements. Unless required by applicable Law, court or regulatory process, or by the rules of a national securities exchange to make such disclosure, neither Party nor any of its Affiliates shall make any public announcement of this Agreement or the transactions contemplated hereby or otherwise communicate with any third parties or news media in respect of this Agreement or the transactions contemplated hereby unless such Party first consults with the non-disclosing Party regarding such announcement or communication. Seller and Buyer shall not (and shall cause each of their respective Affiliates not to) make any public announcement concerning the other Party or its Affiliates, or their respective business, financial condition or results of operations, without the prior written consent of such Party, which consent shall not be unreasonably withheld, conditioned or delayed. Notwithstanding the foregoing, (a) Seller, on the one hand, and Buyer, on the other hand, may confirm information previously made public in compliance with this Agreement; (b) this Section 5.15 shall not apply to prohibit the disclosure of any information and materials to the extent that such disclosure is necessary to support a Party's efforts to obtain or maintain any one or more of the Buyer Approvals or Seller Approvals; and (c) nothing contained in this Agreement restricts or prevents the ability of Seller or Buyer from answering analyst and investor questions relating to this Agreement or the transactions contemplated hereby in connection with analyst, investor or earnings presentations.

Section 5.16. Further Assurances. Subject to the terms and conditions of this Agreement, at any time or from time to time after the Closing, at any Party's request and without further consideration, the other Party shall execute and deliver to such Party such other instruments of sale, transfer, conveyance, assignment and confirmation, provide such materials and information and take such other actions as such Party may reasonably request in order to consummate the transactions contemplated by this Agreement.

Section 5.17. Monthly Operating Report; Subsequent Budget. During the Interim Period, Seller will (a), promptly after its preparation, and in no event later than fifteen (15) Business Days after the end of each calendar month, provide Buyer with the monthly operating report with respect to the Project in the form attached as Exhibit 5.17 and (b) as promptly as practicable after the adoption thereof, provide Buyer with a copy of each Subsequent Budget.

Section 5.18. Guaranty of Seller's Obligations. At the Closing, Seller will cause Seller Parent to execute and deliver to Buyer a guaranty in the form set forth in Exhibit 5.18 (the ***"Seller Parent Guaranty Agreement"***).

Section 5.19. Financial Statements. During the Interim Period, Seller shall deliver to Buyer true and correct copies of (a) audited Financial Statements of Seller, prepared in accordance with GAAP, no later than one hundred twenty (120) days after each year end, and (b) unaudited Financial Statements of Seller, prepared in accordance with GAAP, no later than sixty (60) days after each quarter end (excluding the fourth quarter) (collectively, the ***"Updated Seller Financial Statements"***). During the Interim Period, Seller shall deliver to Buyer true and correct copies of (i) audited Financial Statements of Seller Parent, prepared in accordance with GAAP, no later than one hundred twenty (120) days after each year end, and (ii) unaudited Financial Statements of Seller Parent, prepared in accordance with GAAP, no later than sixty (60) days after each quarter end (excluding the fourth quarter) (collectively, the ***"Updated Seller Parent Financial Statements"***).

Section 5.20. Copy of Precedent Agreement. During the Interim Period, Seller will use commercially reasonable efforts to locate and provide to Buyer a copy of that certain Precedent Agreement, dated October 30, 2000 as referred to in that Interconnection and Operating Agreement between ANR Pipeline Company and Seller (as assignee of Covert Generating Company, LLC), dated October 30, 2000, as amended by the First Amendment to Interconnection and Operating Agreement dated as of February 5, 2002, including contacting ANR Pipeline Company for a copy.

Section 5.21. No Solicitation of Other Bids.

(a) Seller shall not, and shall not authorize or permit any of its Affiliates or any of its or their Representatives (acting on Seller's behalf) to, directly or indirectly, (i) provide any material non-public information to any Person concerning a possible Acquisition Proposal; or (ii) enter into any agreements or other instruments (whether or not binding) regarding an Acquisition Proposal. Seller shall immediately cease and cause to be terminated, and shall cause its Affiliates and all of its and their Representatives to immediately cease and cause to be terminated, all existing discussions or negotiations with any Persons conducted heretofore with respect to, or that could lead to, an Acquisition Proposal. For purposes hereof, ***"Acquisition Proposal"*** means any inquiry, proposal or offer from any Person (other than Buyer or any of its Affiliates) relating to the direct or indirect disposition, whether by sale, merger or otherwise, of all or any material portion of the Business, the Project, the Purchased Assets or the equity interests of Seller, but does not include any inquiry, proposal or offer with respect to the sale of electricity, capacity or ancillary services by Seller.

(b) In addition to the other obligations under this Section 5.21, Seller shall promptly (and in any event within three (3) Business Days after receipt thereof by Seller or its Representatives) advise Buyer orally and in writing of any Acquisition Proposal, the material terms and conditions of such Acquisition Proposal, and the identity of the Person making the same.

(c) Seller agrees that the rights and remedies for noncompliance with this Section 5.21 shall include having such provision specifically enforced by any court having equity jurisdiction, it being acknowledged and agreed that any such breach or threatened breach shall cause irreparable injury to Buyer and that money damages would not provide an adequate remedy to Buyer.

Section 5.22. Consents Not Obtained at Closing.

(a) Notwithstanding anything to the contrary in this Agreement, and subject to the provisions of this Section 5.22, if (i) at the Closing the sale, assignment, transfer, conveyance or delivery to Buyer of any Purchased Asset requires the consent, authorization, approval or waiver of a Person who is not a Party or an Affiliate of a Party (including any Governmental Authority) that has not been obtained, (ii) each Party has complied in all material respects with its obligations under Section 5.1 with respect to such consent, authorization, approval or waiver, and (iii) the Parties have each waived in writing the applicable conditions in ARTICLES VI and VII, as applicable, as with respect to such consent, authorization, approval or waiver, then (A) this Agreement shall not constitute a sale, assignment, transfer, conveyance or delivery, or an attempted sale, assignment, transfer, conveyance or delivery, thereof, and (B) following the Closing, Seller and Buyer shall use commercially reasonable efforts, and shall cooperate with each other, to obtain any such required consent, authorization, approval or waiver; provided, however, that neither Party shall be required to pay any consideration therefor. Once such consent, authorization, approval, or waiver is obtained, Seller shall sell, assign, transfer, convey and deliver to Buyer the relevant Purchased Asset to which such consent, authorization, approval or waiver relates for no additional consideration. Applicable Transfer Taxes imposed by any Governmental Authority in connection with such sale, assignment, transfer, conveyance or license shall be borne equally between the Parties in accordance with Section 5.9.

(b) Notwithstanding anything to the contrary in this Agreement, and subject to the provisions of this Section 5.22, if (i) at the Closing the sale, assignment, transfer, conveyance or delivery to Buyer of any Purchased Asset requires the consent, authorization, approval or waiver of a Person who is not a Party or an Affiliate of a Party (including any Governmental Authority) that has not been obtained, (ii) each Party has complied in all material respects with its obligations under Section 5.1 with respect to such consent, authorization, approval or waiver, and (iii) the Parties have each waived in writing the applicable conditions in ARTICLES VI and VII, as applicable, as with respect to such consent, authorization, approval or waiver, then, pending receipt, if at all, of any consent, authorization, approval or waiver as described in Section 5.22(a), following the Closing, Buyer and Seller shall use commercially reasonable efforts to enter into such mutually-agreeable arrangements (such as subleasing, sublicensing or subcontracting) to provide to the Parties the economic and, to the extent permitted under applicable Law, operational equivalent of the transfer of such Purchased Asset (and applicable Assumed Liability pertaining thereto) to Buyer as of the Closing and the performance by Buyer of its obligations with respect thereto.

(c) Notwithstanding anything herein to the contrary, the provisions of this Section 5.22 shall not apply to any consent or approval required under any antitrust, competition or trade regulation Law.

Section 5.23. Pre-Closing Title Policy.

(a) Initial Title Cure Period. Within six (6) months following the date of this Agreement, Buyer shall obtain the Signing Survey and the Signing Title Commitment and shall provide a written notice (***"Initial Objection Notice"***) to Seller of any matters (other than Permitted Liens) objectionable to Buyer, as determined in its discretion (such matters, ***"Objections"***). Buyer shall be deemed to have accepted all defects and exceptions disclosed by the Signing Survey and Signing Title Commitment, in each case to which Buyer does not object in a timely Initial Objection Notice. Upon receipt of a timely Initial Objection Notice, Seller shall, within three (3) months (or as otherwise extended in Buyer's sole discretion) following the date of receipt of an Initial Objection Notice (the ***"Initial Cure Period"***), send a written notice to Buyer of its election not to cure any Objection which is the subject of an Initial Objection Notice (the ***"Initial Objection Response"***) by the expiry of the Secondary Cure Period (defined below); provided, that Seller shall be obligated to cure any Objection which is the subject of an Initial Objection Notice that (i) is created by, through, or under Seller and is not otherwise permitted by this Agreement or approved by Buyer in writing or (ii) can be removed by the payment of a liquidated sum of money; provided, that in no event shall Seller be obligated under clause (ii) immediately above to pay an amount in excess of one million dollars ($1,000,000) in the aggregate as to all such Objections (including any Objections pursuant to clause (ii) of Section 5.23(b)). Seller may cure any item included in an Initial Objection Notice by delivering to the Title Company such affidavits and certificates as may be required by the Title Company to induce the Title Insurer to omit such lien and/or encumbrance as an exception to title or causing the Title Company to insure against collection of the same out of the Property to Buyer's reasonable satisfaction. Except for Objections that must be cured by Seller under clauses (i) or (ii) immediately above, if Seller provides an Initial Objection Response, then Buyer, as its sole and exclusive remedy for Seller's election not to cure the Objections that are the subject of the Initial Objection Response, shall have the option of terminating this Agreement within sixty (60) days of receipt of the Initial Objection Response or Buyer may waive such Objection(s) and accept such title as such Seller is able to convey without any reduction to the Purchase Price. If no such termination notice is timely received by Seller hereunder, Buyer shall be deemed to have waived all such Objections. Notwithstanding anything in this Agreement to the contrary, Buyer shall have no obligation to provide an Initial Objection Notice with respect to any Liens described in clause (e) of the definition of Permitted Liens, and no such Liens will be deemed to be accepted by Buyer or become Permitted Liens under any circumstance unless expressly agreed to in writing by Buyer in Buyer's sole discretion.

(b) Secondary Title Cure Period. On or prior to four (4) months prior to the anticipated Closing Date (but in any event not more than six (6) months prior to the anticipated Closing Date), Buyer shall obtain the Updated Survey and an updated owner's title commitment or pro forma title policy with respect to the Property (the ***"Updated Title Commitment"***), issued by the Title Company, which Updated Title Commitment shall contain a commitment of the Title Company to issue the Title Policy. To the extent that the Updated Survey or Updated Title Commitment, or any additional updates thereto, shows any change (other than a change that would constitute a Permitted Lien other than under clause (c) of the definition thereof) to the Existing Survey, the Existing Title Insurance Policy, the Signing Title Commitment or the Signing Survey, or previous version of the Updated Survey or Updated Title Commitment, Buyer may identify such change to which it objects as new Objections in an updated notice (***"Updated Objection Notice"***) to Seller within thirty (30) days of Buyer's receipt of the last of the Updated Survey and the Updated Title Commitment (and copies of all documents referenced therein), or any additional updates thereto; provided, that in no event shall such Updated Objection Notice be delivered less than sixty (60) days prior to the anticipated Closing Date. Upon receipt of a timely Updated Objection Notice, Seller shall, within sixty (60) days following the date of receipt of an Updated Objection Notice (the ***"Secondary Cure Period"***), send a written notice to Buyer of its election not to cure any Objection which is the subject of an Updated Objection Notice (the ***"Updated Objection Response"***) by the expiry of the Secondary Cure Period; provided, that, Seller shall be obligated to cure any Objection which is the subject of an Updated Objection Notice that (i) is created by, through, or under Seller and is not otherwise permitted by this Agreement or approved by Buyer in writing or (ii) can be removed by the payment of a liquidated sum of money; provided, that in no event shall Seller be obligated under clause (ii) immediately above to pay an amount in excess of one million dollars ($1,000,000) in the aggregate as to all such Objections (including any Objections pursuant to clause (ii) of Section 5.23(a)). Seller may cure any item included in an Updated Objection Notice by delivering to the Title Company such affidavits and certificates as may be required by the Title Company to induce the Title Insurer to omit such lien and/or encumbrance as an exception to title or causing the Title Company to insure against collection of the same out of the Property to Buyer's reasonable satisfaction. Except for Objections that must be cured by Seller under clauses (i) or (ii) immediately above (or under clauses (i) or (ii) in Section 5.23(a) that were the subject of an Initial Objection Notice and remain uncured), if either (x) Seller provides an Updated Objection Response or (y) Seller fails to cure any such Objection raised in an Initial Objection Notice (if Seller has not provided an Initial Objection Response) or an Updated Objection Notice (if Seller has not provided an Updated Objection Response) by the expiry of the Secondary Cure Period, then in either such case, Buyer, as its sole and exclusive remedy for Seller's failure or election not to cure such Objections set forth in clauses (x) or (y) immediately above, shall have the option of terminating this Agreement within sixty (60) days of the expiry of the Secondary Cure Period or Buyer may waive such Objection and accept such title as such Seller is able to convey without any reduction to the Purchase Price. If no such termination notice is timely received by Seller hereunder, Buyer shall be deemed to have waived all such Objections. Notwithstanding anything in this Agreement to the contrary, Buyer shall have no obligation to provide an Updated Objection Notice with respect to any Liens described in clause (e) of the definition of Permitted Liens, and no such Liens will be deemed to be accepted by Buyer or become Permitted Liens under any circumstance unless expressly agreed to in writing by Buyer in Buyer's sole discretion.

(c) Seller shall use commercially reasonable efforts to cooperate with Buyer in connection with Buyer's efforts to obtain the Signing Survey and any Updated Survey.

(d) The costs and expenses of the Signing Title Commitment, the Signing Survey, any Updated Title Commitment, the Title Policy, and any Updated Survey shall be borne by Buyer, whether or not the transactions contemplated under this Agreement are consummated. All costs and expenses incurred by Seller in response to any Initial Objection Notice or Updated Objection Notice, including any action taken to cure any Objection, if any, shall be borne by Seller.

Section 5.24. Transition Services Agreement. Commencing promptly after the date of this Agreement, the Parties shall in good faith negotiate a transition services agreement between USPG and Buyer (in form and substance reasonably satisfactory to Buyer and Seller) pursuant to which USPG will provide mutually-agreeable transition services (including such services as are necessary to transition operations, maintenance and ongoing activities at the Project) to Buyer following the Closing (the ***"Transition Services Agreement"***). The Parties shall use commercially reasonable efforts to cause the Transition Services Agreement to be finalized by no later than September 30, 2021, and if the same does not occur by such date then all remaining open issues will be submitted to the Parties' respective senior officers to seek prompt resolution thereof. The Parties agree that the Transition Services Agreement will, without limitation, contain provisions whereby if pursuant to Section 6.8 an External Resource Transaction is completed for purposes of the Closing, then the services to be provided to Buyer under the Transition Services Agreement will include (a) reasonable PJM market participant services (the ***"PJM TSA Services"***) at no cost to Buyer; provided, that in no event shall Seller be required to incur any out-of-pocket fees, costs and/or expenses in connection with providing the PJM TSA Services that (when combined with out-of-pocket fees, costs and/or expenses borne by Seller in connection with the satisfying the Interconnection and Capacity Requirement) exceed the Interconnection Cap, and (b) reasonable support services in connection with Buyer's efforts to obtain firm transmission to MISO and completion of the MISO GIA as soon as possible after the Closing (including participating in calls with MISO). The Transition Services Agreement will also contain provisions to address any issues with Buyer not being able to formally add new employees during the months of December or January due to systems updates.

ARTICLE VI.

BUYER'S CONDITIONS TO CLOSING

The obligation of Buyer to consummate the Closing is subject to the fulfillment of each of the following conditions (except to the extent waived in writing by Buyer):

Section 6.1. Representations and Warranties.

(a) (i) Other than the representation and warranty set forth in Section 3.9(b), all representations and warranties made by Seller set forth in ARTICLE III (disregarding, for purposes of this Section 6.1(a)(i) only, any "material", "Material Adverse Effect" or other similar qualifications set forth in any such representations and warranties), as updated pursuant to Section 10.4(b), shall be true and accurate in all material respects on and as of the Closing Date as though made on and as of the Closing Date (except for representations and warranties which are as of a specific date, which shall be true and accurate as of such date); and (ii) the representation and warranty set forth in Section 3.9(b) shall be true and correct in all respects as of the Closing Date.

(b) Between the date hereof and the Closing Date, there shall have been no Material Adverse Effect.

Section 6.2. Performance. Seller shall have performed and complied in all material respects with all agreements, covenants and obligations required by this Agreement to be performed or complied with by Seller at or before the Closing.

Section 6.3. Officer's Certificate. Seller shall have delivered to Buyer at the Closing a certificate of an officer of Seller, dated as of the Closing Date, affirming and certifying the matters set forth in Section 6.1 and Section 6.2.

Section 6.4. Orders and Laws. There shall be no effective injunction, writ or restraining order or any order of any nature issued by a Governmental Authority of competent jurisdiction that prevents the consummation of the transactions contemplated by this Agreement and no proceeding or lawsuit shall have been commenced by any Governmental Authority which may result in any such injunction, writ or restraining order or to otherwise prohibit or make illegal the consummation of the transactions contemplated by this Agreement.

Section 6.5. Consents and Approvals. All Seller Consents shall have been obtained and shall be in full force and effect. The Buyer Approvals and the Seller Approvals shall have been duly obtained, made or given (each on terms that are not reasonably expected, individually or in the aggregate, to impose a Burdensome Condition) and shall be in full force and effect, and all terminations or expirations of waiting periods imposed by any Governmental Authority shall have occurred. In addition, the waiting period (and any extensions thereof) applicable to the consummation of the transactions contemplated hereunder required pursuant to the provisions of the HSR Act shall have expired or been terminated.

Section 6.6. Release of Liens. Seller shall have delivered to Buyer evidence, reasonably satisfactory to Buyer, of Seller's compliance with Section 5.7.

Section 6.7. Title Insurance. Buyer shall have received the Title Policy from the Title Company.

Section 6.8. MISO Interconnection. The MISO interconnection process shall have been completed by the execution by all of the parties thereto of the MISO GIA upon completion of MISO's Definitive Planning Phase process. However, if the MISO GIA is not completed and fully executed by the time all other conditions to the Closing have been satisfied or waived, then in lieu of the foregoing condition, the following condition precedents will apply: (a) completion by no later than May 15, 2023 of an External Resource Transaction with respect to the entire Project that is reasonably acceptable to Buyer and sufficient to provide the MISO-recognized attributes the Project is able to deliver as of June 1, 2023, and (b) transfer of the MISO Interconnection Queue Position into Buyer's name at or before the Closing.

Section 6.9. Closing Deliverables. Seller shall have delivered, or caused to be delivered, the agreements, instruments, and other documents required to be delivered pursuant to Section 2.6.

Section 6.10. Permits. The Permits set forth on Schedule 3.14(a) shall have been transferred or reissued to Buyer in a form reasonably satisfactory to Buyer and shall be in full force and effect, final and non-appealable.

ARTICLE VII.
SELLER'S CONDITIONS TO CLOSING

The obligation of Seller to consummate the Closing is subject to the fulfillment of each of the following conditions (except to the extent waived in writing by Seller):

Section 7.1. Representations and Warranties. The representations and warranties made by Buyer in ARTICLE IV (disregarding, for purposes of this Section 7.1(a) only, any "material", "Material Adverse Effect" or other similar qualifications set forth in any such representations and warranties) shall be true and accurate in all material respects on and as of the Closing Date as though made on and as of the Closing Date, except for representations and warranties which are as of a specific date, in which event they shall be true and accurate as of such date.

Section 7.2. Performance. Buyer shall have performed and complied in all material respects with all agreements, covenants and obligations required by this Agreement to be so performed or complied with by Buyer at or before the Closing.

Section 7.3. Officer's Certificate. Buyer shall have delivered to Seller at the Closing a certificate of an officer of Buyer, dated as of the Closing Date, affirming and certifying the matters set forth in Section 7.1 and Section 7.2.

Section 7.4. Orders and Laws. There shall be no effective injunction, writ or restraining order or any order of any nature issued by a Governmental Authority of competent jurisdiction that prevents the consummation of the transactions contemplated by this Agreement and no proceeding or lawsuit shall have been commenced by any Governmental Authority which may result in any such injunction, writ or restraining order or to otherwise prohibit or make illegal the consummation of the transactions contemplated by this Agreement.

Section 7.5. Consents and Approvals. The Seller Approvals and the Buyer Approvals shall have been duly obtained, made or given and shall be in full force and effect, and all terminations or expirations of waiting periods imposed by any Governmental Authority shall have occurred. In addition, the waiting period (and any extensions thereof) applicable to the consummation of the transactions contemplated hereunder required pursuant to the provisions of the HSR Act shall have expired or been terminated.

Section 7.6. Closing Deliverables. Buyer shall have delivered, or caused to be delivered, the agreements, instruments, and other documents required to be delivered pursuant to Section 2.7.

ARTICLE VIII.

TERMINATION

Section 8.1. Termination. This Agreement may be terminated, and the transactions contemplated hereby may be abandoned, at any time before the Closing as follows:

(a) by Seller, by written notice to Buyer, if Buyer has breached any representation, warranty, covenant, agreement or obligation in this Agreement that would give rise to the failure of any of the conditions set forth in ARTICLE VII and such breach has not been cured within thirty (30) days following written notification thereof; provided, however, that if, at the end of such thirty (30)-day period, Buyer is endeavoring in good faith, and proceeding diligently, to cure such breach, Buyer shall have an additional thirty (30) days in which to effect such cure provided, further, that Seller is not then in material breach of, or material default under, this Agreement;

(b) by Buyer, by written notice to Seller, if Seller has breached any representation, warranty, covenant, agreement or obligation in this Agreement that would give rise to the failure of any of the conditions set forth in ARTICLE VI and such breach has not been cured within thirty (30) days following written notification thereof; provided, however, that if, at the end of such thirty

(30)-day period, Seller is endeavoring in good faith, and proceeding diligently, to cure such breach, Seller shall have an additional thirty (30) days in which to effect such cure; provided, further, that Buyer is not then in material breach of, or material default under, this Agreement;

(c) by Buyer or Seller, by notice to the other, if the Closing has not occurred on or before September 30, 2023 (the ***"Outside Date"***) or such later date as Buyer and Seller may agree in writing; provided, that Buyer cannot terminate under this provision if the failure of the Closing to occur is the result of the material failure or material default on the part of Buyer to perform any of its obligations hereunder or the material breach by Buyer of its representations or warranties hereunder, and Seller cannot terminate this Agreement under this provision if the failure of the Closing to occur is the result of the material failure or material default on the part of Seller to perform any of its obligations hereunder or a material breach by Seller of its representations or warranties hereunder;

(d) by Buyer or Seller, as applicable, in accordance with Section 5.12 or Section 5.13;

(e) by Buyer in accordance with Section 5.23(a) or Section 5.23(b) or Section 5.4(c); and

(f) by mutual written consent of Buyer and Seller.

Section 8.2. Effect of Termination.

(a) If this Agreement is validly terminated pursuant to Section 8.1, there will be no liability or obligation on the part of Seller or Buyer (or any of their respective Representatives or Affiliates), except as provided in this Section 8.2 and Section 8.3.

(b) Regardless of the reason for termination, Section 5.2(b), Section 5.14, Section 5.15, Section 8.2, Section 8.3, Section 9.5(b) and ARTICLE X (and any related definitions contained in any such Sections or Article) will survive any termination of this Agreement, and each Party shall continue to be liable for (i) any Intentional Fraud in relation to the representations and warranties set forth in ARTICLE III and ARTICLE IV, respectively, and (ii) any material breach prior to such termination of any of its obligations set forth in ARTICLE II or ARTICLE V that is the consequence of an act or omission by such Party intentionally taken (or omitted to be taken) with the actual knowledge that the taking of such act or failure to take such action constitutes a material breach of such obligations.

Section 8.3. Specific Performance and Other Remedies. Each Party hereby acknowledges that the rights of each Party to consummate the transactions contemplated hereby are special, unique and of extraordinary character and that, if either Party violates or fails or refuses to perform any covenant or agreement made by it herein, the non-breaching Party will be without an adequate remedy at law. If either Party breaches, violates or fails or refuses to perform any covenant or agreement made by such Party herein, the non-breaching Party or Parties may, subject to the terms hereof and in addition to any remedy at law for damages or other relief, institute and prosecute an action in any court of competent jurisdiction to enforce specific performance of such covenant or agreement or seek any other equitable relief.

ARTICLE IX.
INDEMNIFICATION, LIMITATIONS OF LIABILITY AND WAIVERS

Section 9.1. Indemnification.

(a) Subject to Section 9.2, from and after the Closing, Seller shall indemnify, defend and hold harmless Buyer and its stockholders, partners, members, officers, employees, Affiliates and Representatives (collectively, the ***"Buyer Indemnified Parties"***) from and against all Losses incurred or suffered by any Buyer Indemnified Party resulting from or arising in connection with:

(i) any breach or inaccuracy as of the Closing Date (as though made on and as of the Closing Date except to the extent otherwise provided in this Agreement) of any representation or warranty of Seller contained in this Agreement or any Ancillary Agreement;

(ii) any breach of any covenant or agreement of Seller contained in this Agreement or any Ancillary Agreement; and

(iii) the Excluded Liabilities.

(b) Subject to Section 9.2, from and after the Closing, Buyer shall indemnify, defend and hold Seller and its stockholders, partners, members, officers, employees, Affiliates and Representatives (collectively, the ***"Seller Indemnified Parties"*** and, together with Buyer Indemnified Parties, the ***"Indemnified Parties"***) harmless from and against all Losses incurred or suffered by any Seller Indemnified Party resulting from or arising in connection with:

(i) any breach or inaccuracy as of the Closing Date (as though made on and as of the Closing Date except to the extent otherwise provided in this Agreement) of any representation or warranty of Buyer contained in this Agreement or any Ancillary Agreement;

(ii) any breach of any covenant or agreement of Buyer contained in this Agreement or any Ancillary Agreement; and

(iii) the Assumed Liabilities.

(c) For purposes of this Section 9.1, the amount of any Losses associated with any inaccuracy in or breach of any representation or warranty set forth in this Agreement (but not for purposes of determining the existence of such inaccuracy or breach) shall be determined without regard for any materiality, "Material Adverse Effect" or similar qualification.

Section 9.2. Limitations of Liability. Notwithstanding anything in this Agreement to the contrary:

(a) the representations, warranties, covenants, agreements and obligations in this Agreement or any Closing Certificate shall survive the Closing (other than covenants and agreements of the Parties to be performed or complied with by either or both of the Parties prior to the Closing, which shall expire one hundred twenty (120) days after the Closing); provided, however, that except for Claims arising out of or related to Intentional Fraud, no Party may make or bring a Claim under Section 9.1 for Losses (i) with respect to any representations or warranties contained in ARTICLE III or ARTICLE IV or any Closing Certificate delivered pursuant hereto (other than those representations and warranties contained in Section 3.1 (Organization), Section 3.2 (Authority; Enforceability), Section 3.3(a) (No Conflicts; Consents and Approvals), Section 3.13(a) (Ownership; Liens), Section 3.13(b) (Ownership; Liens), Section 3.13(f) (Ownership; Liens); and Section 3.5 (Brokers) (collectively, the ***"Seller Fundamental Representations"***) or Section 3.10 (Taxes) or Section 3.15 (Environmental Matters)) after fifteen (15) months following the Closing Date, (ii) with respect to the Seller Fundamental Representations, representations and warranties contained in Section 3.10 (Taxes), and any Claims arising out of or related to Intentional Fraud, after sixty (60) days following the expiration of the applicable statute of limitations, (iii) with respect to those representations and warranties contained in Section 3.15 (Environmental Matters), after twenty-four (24) months following the Closing Date, (iv) with respect to Intentional Fraud, after the expiration of the applicable statute of limitations or (v) with respect to any covenants and agreements of the Parties that by their terms are to be performed or complied with after the Closing (including Section 5.2(b) and Section 5.2(c)), following the date that is six (6) months after the date on which the same have expired in accordance with their terms (except in the case of covenants and agreements that have no term, for which the right to bring a Claim under Section 9.1 for Losses arising therefrom shall survive indefinitely);

(b) any Claim under Section 9.1 for a breach of a representation and warranty, covenant or agreement must be delivered prior to the expiration of the applicable survival term set forth in Section 9.2(a), and if valid notice of any Claim under Section 9.1 shall have been given before the end of the applicable period under Section 9.2(a), the representations and warranties, covenants and agreements that are the subject of such Claim (and the right to pursue such Claim) will survive with respect to such Claim until such time as such Claim is finally resolved and (if applicable) satisfied;

(c) Other than for any breach of the Seller Fundamental Representations or any representation or warranty contained in Section 3.10 (Taxes) or a matter covered by Section 9.1(a)(ii) or Section 9.1(a)(iii), or Claims arising from Intentional Fraud, Seller shall have no liability under Section 9.1(a) (x) with respect to any individual Claim or series of related Claims under Section 9.1(a) until such Claim or series of related Claims involves indemnifiable Losses under Section 9.1(a) that exceed $100,000 (after giving effect to any Indemnity Reduction Amounts) (each such Claim or such series of related Claims that fail to meet such threshold, a ***"Buyer De Minimis Claim"***) (and such Buyer De Minimis Claims shall not be counted towards the satisfaction of the Buyer Deductible Amount) and (y) until the aggregate amount of all indemnifiable Losses under Section 9.1(a) actually suffered or incurred by the Buyer Indemnified Parties (after giving effect to any Indemnity Reduction Amounts) equals or exceeds 0.875% of the Purchase Price (the ***"Buyer Deductible Amount"***), in which event Seller shall be liable for indemnifiable Losses only to the extent they are in excess of the Buyer Deductible Amount (except as otherwise set forth in this Section 9.2);

(d) Other than for Claims arising from Intentional Fraud, Buyer shall have no liability with respect to any individual Claim or series of related Claims under Section 9.1(b)(i) arising out of or relating to indemnifiable Losses under Section 4.4 (Legal Proceedings) until (i) such Claim or series of related Claims involves indemnifiable Losses under Section 9.1(b)(i) that exceed

$100,000 (after giving effect to any Indemnity Reduction Amounts) (each such Claim or such series of related Claims that fail to meet such threshold, a ***"Seller De Minimis Claim"***) (and such Seller De Minimis Claims shall not be counted towards the satisfaction of the Seller Deductible Amount) and (ii) until the aggregate amount of all indemnifiable Losses under Section 9.1(b)(i) actually suffered or incurred by the Seller Indemnified Parties (after giving effect to any Indemnity Reduction Amounts) as a result of such Claims or series of related Claims equals or exceeds 0.875% of the Purchase Price (the ***"Seller Deductible Amount"***), in which event Buyer shall be liable for indemnifiable Losses only to the extent they are in excess of the Seller Deductible Amount;

(e) except for Claims arising out of or related to Intentional Fraud, in no event shall (i) Seller's aggregate liability arising out of or relating to indemnifiable Losses under Section 9.1(a)(i) (other than any breach of the Seller Fundamental Representations or breach of those representations and warranties contained in Section 3.15 (Environmental Matters)) exceed ten percent (10%) of the Purchase Price, (ii) Seller's aggregate liability arising out of or relating to indemnifiable Losses under Section 9.1(a)(i) for a breach of the representations and warranties contained in Section 3.15 (Environmental Matters) exceed fifteen percent (15%) of the Purchase Price, (iii) Buyer's aggregate liability arising out of or relating to indemnifiable Losses under Section 4.4 (Legal Proceedings) exceed fifteen percent (15%) of the Purchase Price, or (iv) either Party's aggregate liability arising out of or relating to this Agreement exceed in the aggregate one hundred percent (100%) of the Purchase Price; and

(f) no Indemnifying Party shall have any liability under this ARTICLE IX to indemnify any Indemnified Party with respect to a Loss to the extent that the Loss arose from or was exacerbated by any action taken directly by any Indemnified Party on or after the Closing Date.

Section 9.3. Calculation of Damages.

(a) Each Indemnified Party shall in connection with any claim for indemnification under Section 9.1 use commercially reasonable efforts to obtain any insurance proceeds available to such Indemnified Party as applicable to the claim. Commercially reasonable efforts shall obligate such Indemnified Party to submit claims but not to commence litigation against any insurer or submit claims under insurance policies held by a Person other than the Indemnified Party and its Affiliates. For the purposes of this ARTICLE IX, the amount which the Indemnifying Party is or may be required to pay to any Indemnified Party pursuant to Section 9.1 shall be reduced by (i) any insurance proceeds, (ii) any indemnity, contribution or other similar payment recoverable by the Indemnified Party or any of its Affiliates from any third party with respect thereto (it being understood that there is no obligation to recover or pursue recovery of any amounts referred to in this clause (ii)), in each case of clause (i) and (ii) immediately above, that are actually recovered by or on behalf of such Indemnified Party in reduction of the related Losses (net of any reasonable and documented costs and expenses of obtaining such insurance proceeds or other amounts and any reasonable projected increases in insurance premiums arising because of such claim), and (iii) any Tax benefit realized or reasonably expected to be realized as a result of such Loss by the Indemnified Party (such recoveries under clauses (i) through (iii) immediately above are collectively referred to as ***"Indemnity Reduction Amounts"***).

(b) If any Indemnified Party or any of its Affiliates receives any Indemnity Reduction Amounts in respect of a Claim for which indemnification is provided under this Agreement after the full amount of such Claim has been paid by an Indemnifying Party or after an Indemnifying Party has made a partial payment of such Claim and such Indemnity Reduction Amounts exceed the remaining unpaid balance of such Claim, then the Indemnified Party will promptly remit to the Indemnifying Party an amount equal to the excess (if any) of (x) the amount theretofore paid by the Indemnifying Party or any of its Affiliates in respect of such Claim, less (y) the amount of the indemnity payment that would have been due if such Indemnity Reduction Amounts in respect thereof had been received before the indemnity payment was made.

(c) If any fact, circumstance or condition forming a basis for a Claim for indemnification under this ARTICLE IX shall overlap with any fact, circumstance, condition, agreement or event forming the basis of any other claim for indemnification under this ARTICLE IX, there shall be no duplication in the calculation of the amount of Losses.

(d) After becoming aware of any event giving rise to or which could reasonably be expected to give rise to indemnifiable Losses under Section 9.1(a)(i), Section 9.1(a)(ii), Section 9.1(b)(i) or Section 9.1(b)(ii), as applicable, the applicable Indemnified Party shall take, and cause its Affiliates to take, commercially reasonable steps to mitigate such indemnifiable Losses.

Section 9.4. No Other Representations or Warranties. EXCEPT FOR THE REPRESENTATIONS AND WARRANTIES CONTAINED IN ARTICLE III OR IN ANY ANCILLARY AGREEMENT, NEITHER SELLER NOR ANY OTHER PERSON MAKES ANY OTHER EXPRESS OR IMPLIED REPRESENTATION OR WARRANTY ON BEHALF OF SELLER, WHETHER OF MERCHANTABILITY, SUITABILITY OR FITNESS FOR A PARTICULAR PURPOSE, OR QUALITY AS TO THE PURCHASED ASSETS, OR ANY PART THEREOF, OR AS TO THE CONDITION OR WORKMANSHIP THEREOF, OR THE ABSENCE OF ANY DEFECTS THEREIN, WHETHER LATENT OR PATENT. IT IS UNDERSTOOD THAT, EXCEPT FOR AND SUBJECT TO THE REPRESENTATIONS AND WARRANTIES CONTAINED IN ARTICLE III OR IN ANY ANCILLARY AGREEMENT, THE PURCHASED ASSETS ARE OTHERWISE TO BE CONVEYED HEREUNDER "AS IS" AND "WHERE IS" "WITH ALL FAULTS AND DEFECTS" EXISTING ON THE CLOSING DATE. EXCEPT FOR THE REPRESENTATIONS AND WARRANTIES CONTAINED IN ARTICLE IV OR IN ANY ANCILLARY AGREEMENT, NEITHER BUYER NOR ANY OTHER PERSON MAKES ANY OTHER EXPRESS OR IMPLIED REPRESENTATION OR WARRANTY ON BEHALF OF BUYER.

Section 9.5. Waiver of Remedies.

(a) The Parties hereby agree that, except with respect to Claims for or arising out of Intentional Fraud, following the Closing no Party shall have any liability for, and no Party shall make, and each Party hereby waives to the fullest extent permitted by applicable Law, any Claim for any Loss or other matter under, relating to or arising out of this Agreement or the Ancillary Agreements, whether based on contract, tort, strict liability, other Laws or otherwise, except as provided in Section 5.11, and in this ARTICLE IX (which, except as provided in Section 8.3 and Section 5.11, shall be the sole and exclusive remedy of each Party following the Closing with respect to any and all Claims relating to the subject matter of this Agreement or the Ancillary Agreements).

(b) NOTWITHSTANDING ANYTHING IN THIS AGREEMENT TO THE CONTRARY, EXCEPT AS SET FORTH IN SECTION 5.12 AND SECTION 5.13 OR WITH RESPECT TO A CLAIM BY A THIRD PARTY THAT FALLS WITHIN AN INDEMNIFYING PARTY'S OBLIGATIONS UNDER ARTICLE IX, NO PARTY SHALL BE LIABLE FOR SPECIAL, PUNITIVE, EXEMPLARY, INCIDENTAL, CONSEQUENTIAL OR INDIRECT DAMAGES OR LOST PROFITS, INCLUDING DAMAGES BASED ON LOSS OF FUTURE REVENUE OR INCOME, LOSS OF BUSINESS REPUTATION OR OPPORTUNITY, OR DIMINUTION IN VALUE, OR ANY DAMAGES BASED ON ANY TYPE OF MULTIPLE, WHETHER BASED ON CONTRACT, TORT, STRICT LIABILITY, OTHER LAW OR OTHERWISE AND WHETHER OR NOT ARISING FROM THE OTHER PARTY'S SOLE, JOINT OR CONCURRENT NEGLIGENCE, STRICT LIABILITY OR OTHER FAULT (***"NON-REIMBURSABLE DAMAGES"***).

Section 9.6. Procedure with Respect to Third-Party Claims.

(a) If any Indemnified Party becomes subject to a pending or threatened Claim of a third party and such Indemnified Party (the ***"Claiming Party"***) believes it has a claim for indemnification under this ARTICLE IX as a result, then the Claiming Party shall promptly notify the Party from which the indemnification is sought (the **"Responding Party"**) in writing of the basis for such Claim setting forth the nature of the Claim in reasonable detail (including the amount of the Claim, if known, and copies of any summons complaint or other pleading which may have been served on it and any written claim, demand, invoice, billing or other document evidencing or asserting the same). The failure of the Claiming Party to so notify the Responding Party shall not relieve the Responding Party of liability hereunder except to the extent that the Responding Party's ability to defend against, settle or satisfy any Loss in respect of such Claim is materially prejudiced by the failure to give such notice.

(b) If any proceeding is brought by a third party against a Claiming Party and the Claiming Party gives notice to the Responding Party pursuant to this Section 9.6, the Responding Party shall be entitled to participate in such proceeding and, to the extent that it wishes, to assume the defense of such proceeding, if (i) the Responding Party provides timely written notice to the Claiming Party that the Responding Party intends to undertake such defense, (ii) the Responding Party conducts the defense of the third-party Claim actively and diligently with counsel reasonably satisfactory to the Claiming Party and (iii) if the Responding Party is a party to the proceeding, the Responding Party or the Claiming Party has not determined in good faith that joint representation would be inappropriate because of a conflict in interest. The Claiming Party, in its sole discretion, shall have the right to employ separate counsel (who may be selected by the Claiming Party in its sole discretion) in any such action and to participate in the defense thereof, and the fees and expenses of such counsel shall be paid by such Claiming Party. Notwithstanding the preceding sentence, to the extent that the Claiming Party incurs fees and expenses because of the Claiming Party's good faith determination that it must engage separate counsel because of a conflict of interest under Section 9.6(b)(iii), the fees and expenses of such separate counsel shall be paid by the Responding Party pursuant to Section 9.6(c). The Claiming Party and the Responding Party shall fully cooperate with each other and their respective counsel in the defense or compromise of such Claim. No payment, compromise or settlement of such Claim may be effected by the Claiming Party without the Responding Party's prior written consent. No payment, compromise or settlement of such Claim may be effected by the Responding Party without the Claiming Party's prior written consent unless (x) there is no finding or admission of any violation of Law or any violation of the rights of any Person and no adverse effect on any other Claims that may be made against the Claiming Party, (y) provides for a full, unconditional and irrevocable release of the Claiming Party with respect to such Claim, and (z) the sole relief provided is monetary damages that are paid in full by the Responding Party.

(c) If (i) notice is given to the Responding Party of the commencement of any third-party legal proceeding and the Responding Party does not, within thirty (30) days after the Claiming Party's notice is given, give notice to the Claiming Party of its election to assume the defense of such legal proceeding, (ii) any of the conditions set forth in clauses (i) through (iii) of Section 9.6(b) above become unsatisfied or (iii) a Claiming Party determines in good faith that there is a reasonable probability that a legal proceeding may materially and adversely affect it other than as a result of monetary damages for which it would be entitled to indemnification from the Responding Party under this Agreement, then the Claiming Party shall (upon notice to the Responding Party) have the right to undertake the defense, compromise or settlement of such claim; provided, however, that the Responding Party shall reimburse the Claiming Party for the costs of defending against such third party claim (including reasonable attorneys' fees and expense) and shall remain otherwise responsible for any liability with respect to amounts arising from or related to such third-party claim, to the extent it is ultimately determined that such Responding Party is liable with respect to such third-party claim under this Agreement. The Responding Party may elect to participate in such legal proceedings, negotiations or defense at any time at its own expense.

ARTICLE X.

MISCELLANEOUS

Section 10.1. Notices.

(a) Unless this Agreement specifically requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be deemed properly served, given or made if delivered in person or sent by registered or certified mail, postage prepaid, or by a nationally recognized overnight courier service that provides a receipt of delivery, in each case, to the Parties at the addresses specified below:

If to Buyer, to:

Consumers Energy Company
One Energy Plaza
Jackson, MI 49201
Attn: President

With copies to:

Consumers Energy Company
One Energy Plaza
Jackson, MI 49201
Attn: General Counsel

If to Seller, to:

New Covert Generating Company, LLC
c/o Eastern Generation, LLC
300 Atlantic Street, 5th Floor
Stamford, CT 06901
Email: gcamus@easterngen.com
Attn: General Counsel

With copies to:

Eastern Generation, LLC
c/o ArcLight Capital Partners, LLC
200 Clarendon Street, 55th Floor
Boston, MA 02116
Email: tburke@arclightcapital.com
Attn: General Counsel

and

Milbank LLP
55 Hudson Yards
New York, NY 10001
Email: wbice@milbank.com
Attn: William Bice

(b) Notice given by personal delivery, mail or overnight courier pursuant to this Section 10.1 shall be effective upon physical receipt. Either Party may alter and/or add to its notice recipients and/or their contact information by notice to the other Party at any time.

Section 10.2. Entire Agreement. This Agreement (including the Exhibits and Schedules hereto) supersedes all prior discussions, negotiations and agreements between the Parties with respect to the subject matter hereof and contains the sole and entire agreement between the Parties hereto with respect to the subject matter hereof. This Agreement does not supersede the Confidentiality Agreement.

Section 10.3. Expenses. Except as otherwise expressly provided in this Agreement, whether or not the transactions contemplated hereby are consummated, each Party will pay its own costs and expenses incurred in anticipation of, relating to and in connection with the negotiation and execution of this Agreement, the Ancillary Agreements and the Transition Services Agreement and the transactions contemplated hereby and thereby.

Section 10.4. Disclosure; Additional Material Contracts.

(a) The inclusion of any information, or any references to dollar amounts, in each case in the Schedules shall not be deemed to be an acknowledgment or representation that such items are material, to establish any standard of materiality or to define further the meaning of such terms for purposes of any provision of this Agreement that establishes a standard of materiality. Information disclosed in any Schedule shall constitute a disclosure for purposes of all other Schedules notwithstanding the lack of a specific cross-reference thereto, but only to the extent the applicability of such disclosure to such other Schedule is relevant to the other Schedule and such relevance is reasonably apparent on its face.

(b) During the Interim Period, Seller shall notify Buyer of any additional Contracts Seller has entered into during the Interim Period (to the extent not in contravention of Section 5.3) that would have been required to be listed in Schedule 3.12 pursuant to clauses (a)(ii) through (xiv) of Section 3.12 (excluding clause (a)(xi)) if entered into prior to the date hereof and with such notice provide Buyer with true, accurate and complete copies of such additional Contracts (each, an ***"Additional Material Contract"***). Upon Buyer's receipt of such notice, the list of Assigned Contracts in Schedule 1.1-AC shall hereby be deemed automatically amended to include all Additional Material Contracts that relate primarily to the ownership, operation or maintenance of the Project or the other Purchased Assets; provided, however, that if the Additional Material Contract cannot be terminated by Seller (or Buyer, as assignee) on ninety (90) days' or less notice without termination payment, liquidated damages, or penalty and involving total consideration throughout its term in excess of $500,000, then Buyer may after receipt of such notice notify Seller of Buyer's determination that it will not take assignment of such Additional Material Contract at the Closing, in which case the list of Assigned Contracts in Schedule 1.1-AC shall not be deemed amended to include such Additional Material Contract. If pursuant to the foregoing Schedule 1.1-AC is deemed amended to include any Additional Material Contract, then Schedule 3.3(b) (Sellers Consents) will be deemed amended to include the requirement for Seller to obtain the consent to the assignment thereof to Buyer from the counterparty(ies) to such Additional Material Contract.

(c) If a Contract listed in Schedule 1.1-AC by its terms as exist as of the date hereof expires prior to the Closing Date, then such Contract shall be deemed not to be an Assigned Contract. Without limiting the foregoing, during the Interim Period, Seller will use commercially reasonable efforts to:

(i) either (A) enter into a new agreement similar to the Water Services Agreement, with a new provider other than Suez that Seller reasonably believes has equal or better ability to Suez to provide services consistent with the Water Services Agreement, for the provision of water treatment and related services as described in the Water Services Agreement, which such new agreement would commence upon the expiration of the Water Services Agreement and would be terminable by Seller (or Buyer as its assignee) on ninety (90) days' or less notice without termination payment, liquidated damages, or penalty, or (B) amend the Water Services Agreement to (I) extend its term through May 31, 2024, without a material price increase or scope reduction, and (II) allow the same to be terminated by Seller (or Buyer as its assignee) on thirty (30) days' or less notice without termination payment, liquidated damages, or penalty (either of the foregoing, if executed with the counterparty, the ***"Post-Closing Water Services Agreement"***); and

(ii) cause the terms of the Transaction Confirmation between Sequent Energy Management, L.P. and Seller dated as of June 27, 2018 to be extended through May 31, 2024 without material cost increase or scope reduction (if executed, such extended agreement, the ***"Post-Closing Gas Agreement"***). Seller will keep Buyer regularly and reasonably informed of its efforts in pursuit of executing a Post-Closing Water Services Agreement and Post-Closing Gas Agreement (including provision of initial, interim and final drafts of the same exchanged between Seller and the relevant counterparty thereto) and will inform Buyer if the final proposed terms from the relevant counterparty despite Seller's commercially reasonable efforts and negotiations are different from those parameters as described above so that Buyer may consider waiving the same. If pursuant to the foregoing Seller enters into a Post-Closing Water Services Agreement, the same will automatically be deemed to be an Assigned Contract. If pursuant to the foregoing Seller enters into a Post-Closing Gas Agreement, the same will automatically be deemed to be an Assigned Contract.

Section 10.5. Disputes Regarding Prudent Engineering and Operating Practices. If a dispute arises between the Parties as to whether, in connection with Section 3.9 or Section 5.3, Seller has operated or is operating the Business and the Purchased Assets in a manner that is materially consistent with Prudent Engineering and Operating Practices, and such dispute is not resolved within thirty (30) days following either Party's delivery of a written notice of such dispute to the other Party, then the Parties shall refer such dispute to a nationally recognized independent electric power industry engineering company mutually acceptable to Buyer and Seller (the ***"Independent Engineer"***), who shall make a final and binding determination as to only those matters in dispute on a timely basis and promptly shall notify the Parties in writing of its resolution. The Party whose position the Independent Engineer rejects shall bear the expenses of the Independent Engineer.

Section 10.6. Waiver. Any term or condition of this Agreement may be waived at any time by the Party that is entitled to the benefit thereof, but no such waiver shall be effective unless set forth in a written instrument duly executed by or on behalf of the Party waiving such term or condition. No waiver by any Party of any term or condition of this Agreement, in any one or more instances, shall be deemed to be or construed as a waiver of the same or any other term or condition of this Agreement on any future occasion. No failure or delay by any Party in exercising any right, power, or privilege hereunder will operate as a waiver thereof. All remedies, either under this Agreement or by Law or otherwise afforded, will be cumulative and not alternative.

Section 10.7. Amendment. This Agreement may be amended, supplemented or modified only by a written instrument duly executed by or on behalf of each Party.

Section 10.8. No Third Party Beneficiary. Except for the provisions of Section 9.1(a), Section 9.1(b) and Section 10.15 (which are intended for the benefit of the Persons identified therein), the terms and provisions of this Agreement are intended solely for the benefit of the

Parties and their respective successors or permitted assigns, and it is not the intention of the Parties to confer third-party beneficiary rights upon any other Person, including, without limitation, any employee, any beneficiary or dependents thereof, or any collective bargaining representative thereof.

Section 10.9. Assignment; Binding Effect. Buyer may assign its rights and obligations hereunder to any Affiliate or Affiliates but such assignment shall not release Buyer from its obligations hereunder. Except as provided in the immediately preceding sentence, neither this Agreement nor any right, interest or obligation hereunder may be assigned by any Party without the prior written consent of the other Party, and any attempt to do so will be void. Subject to this Section 10.9, this Agreement is binding upon, inures to the benefit of and is enforceable by the Parties and their respective successors and permitted assigns.

Section 10.10. Headings. The headings used in this Agreement have been inserted for convenience of reference only and do not define or limit the provisions hereof.

Section 10.11. Invalid Provisions. If any provision of this Agreement is held to be illegal, invalid or unenforceable under any present or future Law, and if the rights or obligations of any Party under this Agreement will not be materially and adversely affected thereby, such provision will be fully severable, this Agreement will be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part hereof, the remaining provisions of this Agreement will remain in full force and effect and will not be affected by the illegal, invalid or unenforceable provision or by its severance herefrom and in lieu of such illegal, invalid or unenforceable provision, there will be added automatically as a part of this Agreement a legal, valid and enforceable provision as similar in terms to such illegal, invalid or unenforceable provision as may be possible.

Section 10.12. Counterparts; Facsimile. This Agreement may be executed in any number of counterparts, each of which will be deemed an original, but all of which together will constitute one and the same instrument. Any electronic or facsimile copies hereof or signature hereon shall, for all purposes, be deemed originals.

Section 10.13. Governing Law; Venue; and Jurisdiction.

(a) This Agreement shall be governed by and construed in accordance with the Laws of the State of Michigan, without giving effect to any conflict or choice of law provision that would result in the imposition of another state's Law.

(b) THE PARTIES HEREBY IRREVOCABLY AGREE THAT THE EXCLUSIVE JURISDICTION TO HEAR ANY CIVIL ACTIONS ARISING OUT OF OR RELATED TO THIS AGREEMENT SHALL BE IN ANY STATE OR FEDERAL COURT IN THE STATE OF MICHIGAN AND EACH PARTY HEREBY SUBMITS AND CONSENTS TO THE JURISDICTION OF SUCH COURTS (AND OF THE APPROPRIATE APPELLATE COURTS THEREFROM) IN ANY SUCH SUIT, ACTION OR PROCEEDING AND IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY LAW, ANY OBJECTION THAT IT MAY NOW OR HEREAFTER HAVE TO THE LAYING OF THE VENUE OF ANY SUCH SUIT, ACTION OR PROCEEDING IN ANY SUCH COURT OR THAT ANY SUCH SUIT,

ACTION OR PROCEEDING THAT IS BROUGHT IN ANY SUCH COURT HAS BEEN BROUGHT IN AN INCONVENIENT FORUM. EACH PARTY HEREBY WAIVES, AND SHALL NOT ASSERT AS A DEFENSE IN ANY LEGAL DISPUTE, THAT (A) SUCH PARTY IS NOT SUBJECT THERETO, (B) SUCH ACTION, SUIT OR PROCEEDING MAY NOT BE BROUGHT OR IS NOT MAINTAINABLE IN SUCH COURT, (C) SUCH PARTY'S PROPERTY IS EXEMPT OR IMMUNE FROM EXECUTION UNDER SUCH COURT'S JURISDICTION, (D) SUCH ACTION, SUIT OR PROCEEDING IS BROUGHT IN AN INCONVENIENT FORUM OR (E) THE VENUE OF SUCH ACTION, SUIT OR PROCEEDING IS IMPROPER. EACH PARTY FURTHER AGREES IT WILL NOT OBJECT TO ANY MOTION TO TRANSFER A SUIT, ACTION OR PROCEEDING FILED IN ANY OTHER FORUM TO SUCH COURT. A FINAL JUDGMENT IN ANY ACTION, SUIT OR PROCEEDING DESCRIBED IN THIS SECTION 10.13 FOLLOWING THE EXPIRATION OF ANY PERIOD PERMITTED FOR APPEAL AND SUBJECT TO ANY STAY DURING APPEAL SHALL BE CONCLUSIVE AND MAY BE ENFORCED IN OTHER JURISDICTIONS BY SUIT ON THE JUDGMENT OR IN ANY OTHER MANNER PROVIDED BY APPLICABLE LAWS.

(c) EACH PARTY HEREBY WAIVES, TO THE FULLEST EXTENT PERMITTED BY LAW, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED HEREON, OR ARISING OUT OF, UNDER OR IN CONNECTION WITH THIS AGREEMENT OR THE TRANSACTIONS CONTEMPLATED HEREBY.

Section 10.14. No Partnership or Joint Venture. The Parties do not intend to create a partnership or joint venture by virtue of this Agreement. No Party shall owe any fiduciary duty to any other Party by virtue of this Agreement, any Ancillary Agreement or otherwise.

Section 10.15. No Recourse. This Agreement may only be enforced against, and any claim, action, suit or other legal proceeding based upon, arising out of, or related to this Agreement, or the negotiation, execution or performance of this Agreement, may only be brought against the Parties (or, in the case of Seller, Seller Parent under the Seller Parent Guaranty Agreement) and then only with respect to the specific obligations set forth herein with respect to each Party. Other than Seller Parent under the Seller Parent Guaranty Agreement, no past, present or future director, officer, employee, incorporator, manager, member, partner, stockholder, Affiliate, agent, attorney or other Representative of any Party or of any of its Affiliates, or any of its or their respective successors or permitted assigns, shall have any liability for any obligations or liabilities of any Party under this Agreement or for any claim, action, suit or other legal proceeding based on, in respect of or by reason of the transactions contemplated hereby.

[signature page follows]

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized representative of each Party as of the date first above written.

SELLER:

NEW COVERT GENERATING COMPANY, LLC

By: ____________________
Name: Daniel R. Revers
Title: President

BUYER:

CONSUMERS ENERGY COMPANY

By:
Name: GARRICK J ROCHOW
Title: PRESIDENT & CEO

[Signature Page - Purchase and Sale Agreement]

EXHIBIT 1.1(a)

TITLE ENDORSEMENTS

1. ALTA Endorsement 3.1-06 (Zoning–Completed Structure)
2. ALTA Endorsement 8.2-06 (Commercial Environmental Protection Lien)
3. ALTA Endorsement 17-06 (Access and Entry)
4. ALTA Endorsement 17.2-06 (Utility Access)
5. ALTA Endorsement 18.1-06 (Multiple Tax Parcel)
6. ALTA Endorsement 22-06 (Location)
7. ALTA Endorsement 25-06 (Same as Survey)
8. ALTA Endorsement 26-06 (Subdivision)
9. ALTA Endorsement 31-06 (Severable Improvements)
10. ALTA Endorsement 36-06 (Energy Project – Leasehold/Easement – Owner's)
11. ALTA Endorsement 36.4 (Energy Project – Covenants, Conditions and Restrictions – Owner's)
12. ALTA Endorsement 36.6-06 (Energy Project – Encroachments)
13. ALTA Endorsement 36.7-06 (Energy Project – Fee Estate – Owner's Policy)
14. ALTA Endorsement 39-06 (Policy Authentication)
15. Deletion of Arbitration Endorsement

EXHIBIT 2.1(a)

PURCHASED ASSETS

The following property shall be included as Purchased Assets:

(a) all machinery and equipment comprising the Project, including the three (3) gas turbines, three (3) heat recovery steam generators, three (3) steam turbines, generator step up transformers, unit isolation switches MOD 199, 299, 399, and associated controls, structures, instrument transformers and meters, and all equipment attached thereto or used in connection therewith and located at the Property;

(b) all chemicals, lubricants, and other supplies, raw materials and commodity materials located on the Property or in transit thereto and used, or held for use in connection with the operation or maintenance of the Purchased Assets;

(c) (i) all tools (including special tools), vehicles, forklifts, cranes or similar machines, furniture, and telephones owned by Seller as of the date of the Agreement and (ii) all office equipment and computer hardware owned by Seller as of the date of the Agreement that are located on the Property and are used primarily for the Business or the Project, in each case unless the same are replaced in the ordinary course of business during the Interim Period, in which case such replacements shall comprise Purchased Assets;

(d) all inventory used, or held for use in connection with, the Business, it being agreed between the Parties that all such inventory will be taken into account in the calculation of Closing Date Net Working Capital in accordance with the Agreement;

(e) to the extent legally transferable, all rights of Seller under the Permits (and all pending applications for the foregoing) listed on Schedule 3.14(a);

(f) all Assigned Contracts and all refunds thereunder;

(g) all Land Contracts;

(h) all Books and Records;

(i) all rights of Seller under or pursuant to all unexpired warranties, representations and guarantees made by suppliers, licensors, manufacturers or contactors to the extent applicable to the Business following the Closing;

(j) all filings, submittals and material correspondence with, from and between Seller and MISO with respect to the Business;

(k) all rights to causes of action, lawsuits, claims, counterclaims, defenses and demands of any nature, whether mature, contingent or otherwise, and whether in tort, contract or otherwise, in each case to the extent relating to any Purchased Asset or any Assumed Liability;

(l) all rights to any judgments and arbitral awards in favor of Seller to the extent relating to any Purchased Asset or any Assumed Liability;

(m) (i) all Intellectual Property owned by Seller (including the name "New Covert Generating Facility" and any derivative tradenames, trademarks, service marks or logos) and primarily used, or primarily held for use, in whole or in part, in connection with the ownership, leasing, licensing, operation or maintenance of the Purchased Assets and (ii) all licenses and other use rights of Seller to third-party Intellectual Property;

(n) except for prepaid insurance and prepaid amounts or deposits with respect to the ADM brokerage account, all prepaid expenses, items and deposits (or portions thereof) to the extent relating to the Project or the Business and reflected in Closing Date Net Working Capital;

(o) all emission reduction credits, emission allowances and clean air market allowances allocated by any Governmental Authority to the benefit of the Project or the Business prior to the Closing, including those listed on Schedule 3.15(f);

(p) the bank account in the name of Seller held with US Bank N.A., account number 105701235571 (it being agreed between the Parties that all amounts held in deposit therein as of the Closing will be taken into account in the calculation of Closing Date Net Working Capital in accordance with the Agreement);

(q) all right, title and interest of Seller in and to the Property;

(r) all other assets, property and other rights held or owned by Seller that are located on the Property and are used primarily for the Business or the Project; and

(s) all goodwill associated with any of the assets described in the foregoing clauses (a) through (r).

EXHIBIT 2.1(b)

EXCLUDED ASSETS

With reference to Section 2.1 of the Agreement, the following property shall comprise the Excluded Assets:

(a) all real property of Seller wherever located, excepting and excluding the Property;

(b) the limited liability company seals, Organizational Documents, minute books, Tax Returns, books of account or other records having to do with the limited liability company organization of Seller, all employee-related or employee benefit-related files or records (except to the extent required to be provided to Buyer under the Transition Services Agreement), and any other books and records which Seller is prohibited from disclosing or transferring to Buyer under applicable Law or the disclosure of which would result in the loss of any attorney-client privilege held by Seller (unless the books or records in question relate to an actual or threatened Claim that will become an Assumed Liability at the Closing);

(c) all equity interests of Seller or any of its Affiliates or owned by Seller or any of its Affiliates;

(d) all rights to causes of action, lawsuits, claims, counterclaims, defenses and demands of any nature, whether mature, contingent or otherwise, and whether in tort, contract or otherwise, in each case except to the extent relating to any Purchased Asset or any Assumed Liability;

(e) all rights to any judgments and arbitral awards in favor of Seller that relate to any Excluded Asset or Excluded Liability;

(f) all rights to Tax refunds, credits or similar benefits or Tax attributes relating to or attributable to any Excluded Liabilities;

(g) cash, cash equivalents, certificates of deposit, bank deposits (except to the extent of those amounts that are on deposit in a bank account that is included in the Purchased Assets and are included in Closing Date Net Working Capital), commercial paper, securities, and accounts receivable and any similar current assets of Seller or any of its Affiliates earned or accrued, or arising from or relating to the Business, prior to the Closing;

(h) all Contracts of Seller or any of its Affiliates other than (i) the Assigned Contracts and (ii) the Land Contracts;

(i) all bank accounts of Seller other than the bank account in the name of Seller held with US Bank N.A., account number 105701235571;

(j) all casualty, liability and other insurance policies maintained by Seller or any of its Affiliates and all rights of any nature relating thereto, including all rights to insurance recoveries thereunder and to assert claims thereunder, in each case, except to the extent provided in Sections 5.8, 5.12 and 5.13 of the Agreement;

(k) all rights of Seller and its Affiliates under the Agreement, the Ancillary Agreements and the Transition Services Agreement;

(l) all assets, property and other rights held or owned by Seller or any of its Affiliates that are not located on the Property and are not primarily used or held for use in connection with the ownership, leasing, licensing, operation, interconnection, or maintenance of the Business or the Project;

(m) any amounts paid to Seller under the Property Tax Indemnity Agreement dated as of June 29, 2018, by and between Seller and Eastern Generation, LLC; and

(n) all assets attributable to or related to any Benefit Plan of Seller or any of its Affiliates.

EXHIBIT 2.6(b)-1

FORM OF TAX CLEARANCE CERTIFICATE APPLICATION

[See Attached.]

Michigan Department of Treasury
5156 (Rev. 05-15)

Reset Form

Request for Tax Clearance Application

Issued under authority of Public Act 228 of 1975, as amended.

REASON FOR THE REQUEST

☐ I am selling my business or business assets.
- Complete Part 1 and Part 4 ONLY

☐ I am closing my business and my business is registered as a corporation with the Michigan Department of Licensing and Regulatory Affairs.
- Complete Part 1, Part 2, and Part 4 ONLY

☐ I have completed the sale of my business or business assets and require a tax clearance certificate.
- Complete Part 1, Part 3, and Part 4 ONLY

PART 1: GENERAL INFORMATION — To be completed by ALL applicants.

Current Business or Corporation Name			FEIN or TR Number
Previous Business or Corporation Name			
Address	City	State	ZIP Code

PART 2: CORPORATE DISSOLUTION OR WITHDRAWAL — To be completed by any business entity incorporated through the Michigan Department of Licensing and Regulatory Affairs (LARA).

NOTE: The date that the business is actually discontinued (below) should reflect the date on the Form 163 Notice of Change or Discontinuance submitted to the Michigan Business Tax Registration Unit. If this form has not been submitted, please complete and attach with this request. If the business and its FEIN number were not registered with the Michigan Department of Treasury, please submit the last four years of Federal Business Tax Returns in place of the Form 163.

Corporate ID Number Assigned by LARA	Date Incorporated with the State through LARA	Date Business Actually Discontinued in Michigan

If this corporation had no tax liability or was not required to register with the Michigan Department of Treasury, provide a detailed explanation in the space below. Substantiate with attachments:

Continue and sign on Page 2

PART 3: SALE OF BUSINESS OR ASSETS — To be completed by any business (all types) that has sold all or part of the business prior to submitting this application.

IMPORTANT: This is a request by any business entity that has sold most of its assets, but the business shell will remain in place to continue filing tax returns (when due) until the business later determines whether it will file a Certificate of Dissolution with the LARA Corporation Division.

Does the business operate under a trade name? ☐ Yes ☐ No

If yes, list the name it is doing business as. ....

Will you continue business activity after clearance under this FEIN or TR number? ☐ Yes ☐ No

If no, have you submitted a Notice of Change or Discontinuance (Form 163)? ☐ Yes ☐ No

If yes, date of discontinuance reported on Form 163 (MM-DD-YYYY)..........

If no, attach a completed Form 163 with this request.

Date of sale of business or business assets to another entity.......................................

Is money being held in escrow pending receipt of a tax clearance? ☐ Yes ☐ No

If yes, how much is held in escrow?...

PURCHASER INFORMATION

Purchaser Business Name		Purchaser FEIN	
Purchaser Address	City	State	ZIP Code

PART 4: CERTIFICATION AND AUTHORIZATION FOR DISCLOSURE OF INFORMATION

I declare under penalty of perjury that I am the owner, officer, or member of the business for which tax clearance is requested and that the information entered is true.

Name (Print or Type)	Title		
Signature	Date	Telephone Number	
Address	City	State	ZIP Code

AUTHORIZATION FOR DISCLOSURE OF TAX CLEARANCE INFORMATION (This is not a required section)

Use this section to designate a third party to receive all tax clearance information for the business listed in Part 1.

The above signed authorizes the Michigan Department of Treasury, Tax Clearance Section, to release any and all tax information and outstanding balances due for the purpose of tax clearance to the individual(s) listed below. This authorization **does not** include signature power. This authorization is only valid for 90 days from the date of the signature above.

Name			
Telephone Number	Fax Number		
Address	City	State	ZIP Code

Instructions for Form 5156,

Request for Tax Clearance

Part 1: General Information – ALL FIELDS IN THIS SECTION MUST BE COMPLETED

NOTE: If you are selling a business but the sale has not occurred, the Michigan Department of Treasury (Treasury) will provide known or estimated tax liability for the purpose of establishing a tax escrow. Once the sale is complete, submit a new request completing Part 1 and Part 3 to obtain a certificate for the release of the escrowed funds.

Current Business or Corporation Name: Enter the legal business/corporation name. If the business is a sole proprietorship, enter the owner's name here, with the last name first.

Federal Employer Identification Number (FEIN) or Treasury Issued Account Number (TR): Enter the business' IRS-issued FEIN or Treasury-issued TR number.

Business Street Address/City/State/ZIP Code: Enter the physical business address. (A PO Box is not acceptable in this field.)

Part 2: Corporate Dissolution or Withdrawal

Complete this section if you are dissolving a domestic (Michigan) corporation or if you have a foreign corporation (incorporated outside Michigan) that is withdrawing from Michigan. A corporation is any business entity that has filed and incorporated with the Michigan Department of Licensing and Regulatory Affairs (LARA).

NOTE: A Tax Clearance Certificate must be requested from Treasury within 60 days of dissolution or withdrawal of business from Michigan.

Corporate Identification Number: Enter the business' LARA-assigned Corporate Identification Number (CID). This number can be located on the annual statements filed with LARA or online at **www.michigan.gov/lara**.

Date Business Discontinued in Michigan: Enter the date your business ceased operations in Michigan. This date should reflect the date entered on the *Notice of Change or Discontinuance* (Form 163). If you have failed to complete and submit Form 163 to the Registration Unit, you must complete and remit Form 163 with this application. In the event your business' FEIN was never registered with Treasury, you must include the last four years of Federal Returns for the business in place of Form 163.

Date Incorporated with the State of Michigan through LARA: Enter the date of incorporation. For additional information, go to LARA's Web site: **www.michigan.gov/lara**.

If the corporation had no tax liability or was not required to register with Treasury, provide a detailed explanation. In rare cases, a corporation may not have had any tax liability or may not have registered for taxes with the State of Michigan. If your business falls into this category, use the space provided to explain why no taxes were due and registration was not required. Include dates of operation and the nature of the business. You must include attachments with your application to substantiate your position in order for it to be fully reviewed.

Part 3: Sale of Business or Assets has Occurred

Complete this section if your business or any of the assets have been sold.

NOTE: You must continue to file all returns by their due date until you elect to file a dissolution or withdrawal. A Tax Clearance Certificate for Sale of Business and/or Business Assets is required when a bulk sale or transfer is made under the Uniform Commercial Code. A Tax Clearance Certificate for Sale of Business and/or Business Assets is granted after Treasury determines that all Sales, Use, Income Withholding, Cigarette, Motor Fuel, Single Business, Michigan Business, and Corporate Income taxes have been paid for the period of operation. When a Tax Clearance Certificate for Sale of Business and/or Business Assets is issued, money held in escrow is released and the purchaser is relieved of successor liability. The seller agrees to keep all books and records of the business until they are released by Treasury. The seller is liable for all taxes due from the operation of the business during the time specified by Treasury.

Does the business operate under a trade name? If your business operates under any name other than the legal corporation name, check (with an "X") yes in the appropriate box. On the next line, enter the trade name, assumed name, or doing business as name. If your business only operates under its legal corporation name, check (with an "X") no.

Are you continuing business activity after clearance under this FEIN or TR number? If you plan to continue to operate your business within the State of Michigan, check (with an "X") yes in the appropriate box. If you do not plan to continue operating, check (with an "X") no. If you have already submitted a Form 163 to the Registration Unit, enter the discontinuance date listed on that form. If you have yet to file Form 163 with the Registration Unit, attach a completed Form 163 with this application.

NOTE: The following items should ONLY be filled out if the sale has occurred, not before.

Date of Sale of Business or Business Assets to Another Entity. Enter the date all or part of the business was sold.

Is money being held in escrow pending receipt of a Tax Clearance Certificate? If money is being held in escrow from the sale, check (with an "X") yes and enter the amount being held.

Business Name, Street Address, and FEIN of Purchaser. Enter purchaser's legal name, address, and FEIN.

Part 4: Certification and Authorization for Disclosure of Tax Clearance Information

NOTE: All fields directly under the Certification must be completed. If authorizing the disclosure of information, all fields in that section must be completed as well.

This section must be completed for all requests. All requests must be submitted by an owner, officer, or member of the business. By completing the Certification, you are declaring under penalty of perjury that all information entered is true.

Complete this section with your printed name, title, signature, daytime phone number, contact address, and the date in which the application was completed.

Submitting Form 5156

Complete and mail this form to:

Michigan Department of Treasury
Tax Clearance Section
P.O. Box 30778
Lansing, MI 48909

For additional information, call (517) 636-5260, Monday through Friday (excluding holidays), from 8 a.m. to 5 p.m.

EXHIBIT 2.6(b)-2

FORM OF TAX CLEARANCE CERTIFICATE

[See Attached.]

Michigan Department of Treasury
506 (Rev. 12-14)

Tax Clearance Certificate for Dissolution or Withdrawal

Date:

Re:

Corporation's Current Registered Name	Date
Federal Employer Identification Number or TR Number	Corporate Identification I(CID) Number
State Incorporated In	Date Incorporated

The above corporation wished to either dissolve or withdraw from doing business in the State of Michigan.

To comply with the Cigarette Tax Act, Public Act 265 of 1947, as amended; Diesel Motor Fuel Tax Act, Public Act 150 of 1927, as amended; Motor Carrier Fuel Tax Act, Public Act 119 of 1980, as amended; Michigan Business Tax Act, Public Act 36 of 2007, as amended; Sales Tax Act, Public Act 167 of 1933, as amended; Use Tax Act, Public Act 94 of 1937, as amended; Income Tax Act, Public Act 281 of 1967, as amended; and the Revenue Act, Public Act 122 of 1941, as amended, **the Michigan Department of Treasury hereby gives notice that the above corporation does not owe the Department of Treasury any of the aforementioned taxes for the operation of this business.**

This notice is not to be construed as prejudicing the rights of the Department of Treasury to pursue any recourse given by law in regard to a dissolved corporation, its stockholders, or its members.

STATE OF MICHIGAN, DEPARTMENT OF TREASURY

Scott Lonberger, Director
Tax Processing Bureau

EXHIBIT 2.6(c)

FORM OF BILL OF SALE

THIS BILL OF SALE, dated as of [●], is made and given by New Covert Generating Company, LLC, a Delaware limited liability company (*"**Seller**"*) to Consumers Energy Company, a Michigan corporation (*"**Buyer**"*).

RECITALS

A. Seller and Buyer are parties to that certain Purchase and Sale Agreement dated as of June [•], 2021 (as amended, the *"**Purchase Agreement**"*), pursuant to which, among other things, Buyer has agreed to purchase and Seller has agreed to sell the Purchased Assets in accordance with the terms of thereof; and

B. In accordance with the terms of the Purchase Agreement, Seller and Buyer have agreed that Seller will execute this Bill of Sale conveying to Buyer good and valid title to all of Seller's owned tangible personal property, subject only to the Permitted Liens (the *"**Personal Property**"*).

WITNESSETH:

FOR GOOD AND VALUABLE CONSIDERATION, the receipt and sufficiency of which is hereby acknowledged, and subject to the terms and conditions of the Purchase Agreement, Seller hereby sells and conveys to Buyer the Personal Property.

TO HAVE AND TO HOLD the same to Buyer, its successors and assigns forever. Except for and without prejudice to the representations, warranties and indemnities and all rights with respect thereto as set forth in the Purchase Agreement, Buyer accepts the Personal Property in an "**AS IS**" and "**WHERE IS**" condition with "**ALL FAULTS**" and without warranty.

Nothing in this Bill of Sale, express or implied, is intended or shall be construed to confer upon or give to, any person, firm or corporation other than Buyer and its successors and permitted assigns any remedy or claim under or by reason of this instrument or any term, covenant or condition hereof, and all of the terms, covenants, conditions, promises and agreements in this instrument shall be for the sole and exclusive benefit of Buyer and its successors and permitted assigns.

The provisions of Sections 10.1, 10.3 and 10.6 through 10.14 of the Purchase Agreement are hereby incorporated into this Bill of Sale, *mutatis mutandis*.

This Bill of Sale is being executed solely pursuant to the Purchase Agreement to give effect to the transactions contemplated by the Purchase Agreement. Nothing in this Bill of Sale, express or implied, is intended to or shall be construed to modify, expand or limit in any way the terms of the Purchase Agreement. To the extent that any provision of this Bill of Sale conflicts or is inconsistent with the terms of the Purchase Agreement, the terms of the Purchase Agreement shall govern. For the avoidance of doubt, none of the Excluded Assets shall be included in the Personal Property.

This Bill of Sale is given pursuant to Section 2.6(c) of the Purchase Agreement. All capitalized terms not defined herein shall have the same meaning as in the Purchase Agreement.

Signature on following page(s)

IN WITNESS WHEREOF, this Bill of Sale has been duly executed and delivered by a duly authorized representative of Seller as of the date first above written.

SELLER:

NEW COVERT GENERATING COMPANY, LLC

By:
Name:
Title:

EXHIBIT 2.6(d)

FORM OF COVENANT DEED

THIS INDENTURE, made this [●] day of [●], [●], is between New Covert Generating Company, LLC, a Delaware limited liability company whose address is c/o Eastern Generation, LLC, 300 Atlantic Street, 5th Floor, Stamford, Connecticut 06901 ("***Grantor***") and Consumers Energy Company, a Michigan corporation whose address is One Energy Plaza, Jackson, Michigan 49201 ("***Grantee***").

WITNESSETH, that Grantor, for and in consideration of: See Real Estate Transfer Affidavit attached, the receipt whereof is hereby confessed and acknowledged, has granted, conveyed, bargained, sold, remised, released, aliened and confirmed, and by these presents does grant and convey unto Grantee, and to its heirs and assigns, forever, that certain piece or parcel of land, situated, lying and being in the Township of Covert, County of Van Buren, State of Michigan known and described as follows, to-wit (the "***Property***"):

See ***Exhibit A*** attached hereto and incorporated herein

Commonly known as: 26000 77th Street

Together with all and singular the tenements, hereditaments and appurtenances thereunto belonging or in anywise appertaining and subject to building and zoning laws and ordinances and all matters identified on ***Exhibit B*** hereto as Permitted Exceptions.

And Grantor, for itself, its successors and assigns, does covenant and agree with Grantee that Grantor will forever warrant and defend the right and title to the Property, subject to the Permitted Exceptions, onto Grantee against the lawful claims of all persons claiming by, through, or under Grantor, but not otherwise.

Grantor further grants to Grantee the right to make all divisions under Section 108 of the Land Division Act, Act No. 288 of the Public Acts of 1967. The Property may be located within the vicinity of farmland or a farm operation. Generally accepted agricultural and management practices which may generate noise, dust, odors and other associated conditions may be used and are protected by the Michigan Right-To-Farm Act.

SIGNATURE AND NOTARY ON FOLLOWING PAGE(S)

[Signature Page to Covenant Deed]

IN WITNESS WHEREOF, Grantor has executed this Covenant Deed as of the date first above written.

GRANTOR:

NEW COVERT GENERATING COMPANY, LLC

BY: ______________________________
NAME:
TITLE:

STATE OF ________________)
) ss.
COUNTY OF)

The foregoing instrument was acknowledged before me this ____ day of ______________, by ___________________, as authorized member of New Covert Generating Company, LLC**,** a Delaware limited liability company on behalf of said Grantor company.

____

Notary Public, ______________ County, MI

My Commission Expires:_______________

Acting in __________________ County, MI

County Treasurer's Certificate	Township Treasurer's Certificate

When Recorded Return To: GRANTEE
Send Subsequent Tax Bills To: GRANTEE
Drafted by: Bradley J. Knickerbocker, 450 W. Fourth St., Royal Oak, MI 48067
Recording Fee Revenue Stamps
Transfer Tax: See Real Estate Transfer Affidavit

EXHIBIT A

Legal Description to Covenant Deed

Land situated in the Township Of Covert, County of Van Buren in the State of Michigan and described as follows:

Parcel ID(s):

EXHIBIT B

Permitted Exceptions

EXHIBIT 2.6(f)

FORM OF
ASSIGNMENT AND ASSUMPTION AGREEMENT

This Assignment and Assumption Agreement, dated as of [•] (this ***"Agreement"***), is by and between New Covert Generating Company, LLC, a Delaware limited liability company (***"Assignor"***) and Consumers Energy Company, a Michigan corporation (***"Assignee"*** and, together with Assignor, the ***"Parties"***).

RECITALS

A. Assignor and Assignee are parties to that certain Purchase and Sale Agreement dated as of June [•], 2021 (as amended, the ***"Purchase Agreement"***), pursuant to which Assignee has agreed to purchase the Purchased Assets and assume the Assumed Liabilities pursuant to the terms of the Purchase Agreement; and

B. In accordance with the terms of the Purchase Agreement, Assignor and Assignee have agreed to enter into this Agreement, providing for (a) Assignor's sale, conveyance, assignment, transfer and delivery to Assignee of all of the Assignor's right, title and interest in and to the Purchased Assets (other than Property conveyed under the Deed) (collectively, the ***"Assigned Assets"***), (b) Assignee's acceptance of such sale, conveyance, assignment, transfer and delivery and (c) Assignee's assumption of, and agreement to pay, perform and discharge, all of the Assumed Liabilities, in each case on and subject to the terms of the Purchase Agreement.

AGREEMENT

The parties, intending to be legally bound, agree as follows:

1. **Definitions**. Undefined capitalized terms herein are defined in the Purchase Agreement.

2. **Assignment**. Assignor hereby sells, conveys, assigns, transfers and delivers to Assignee as of the date hereof, all of its right, title and interest in and to the Assigned Assets free and clear of all Liens, except for Permitted Liens, in accordance with and subject to the terms and conditions of the Purchase Agreement, including, without limitation, Section 2.1 thereof (the ***"Assignment"***).

3. **Acceptance and Assumption**. Assignee hereby, as of the date hereof, (a) purchases, acquires and accepts the sale, conveyance, assignment, transfer and delivery of all of Assignor's right, title and interest in and to the Assigned Assets free and clear of all Liens, except Permitted Liens and (b) assumes, and agrees to pay, perform and discharge when due, and shall be liable with respect to, the Assumed Liabilities in accordance with and subject to the terms and conditions of the Purchase Agreement, including, without limitation, Section 2.2 thereof.

4. **Parties in Interest**. This Agreement shall be binding upon and inure to the benefit of the Parties and their respective successors and permitted assigns.

5. **Terms of Purchase Agreement**. The scope, nature, and extent of the Assumed Liabilities are expressly set forth in the Purchase Agreement. Nothing contained herein will itself change, amend, extend, or alter (nor should it be deemed or construed as changing, amending, extending, or altering) the terms or conditions of the Purchase Agreement in any manner whatsoever. This instrument does not create or establish rights, liabilities or obligations not otherwise created or existing under or pursuant to the Purchase Agreement. In the event of any conflict or inconsistency between the terms of the Purchase Agreement and the terms of this Agreement, the terms of the Purchase Agreement will govern.

6. **Other Provisions**. This Agreement supersedes all prior discussions, negotiations and agreements between the Parties with respect to the subject matter hereof (other than the Purchase Agreement) and contains, along with the Purchase Agreement, the sole and entire agreement between the Parties hereto with respect to the subject matter hereof. The provisions of Sections 10.1, 10.3 and 10.6 through 10.14 of the Purchase Agreement are hereby incorporated into this Agreement, *mutatis mutandis*.

[*Signature Page Follows*]

IN WITNESS WHEREOF, the parties have executed this Agreement on the date first above written.

<u>Assignor</u>:

NEW COVERT GENERATING COMPANY, LLC

By: ________________________________
Name:
Title:

Assignee:

CONSUMERS ENERGY COMPANY

By: ______________________________
Name:
Title:

EXHIBIT 2.6(g)

FORM OF OWNER'S AFFIDAVIT

(*See attached*)

Fidelity National Title
Insurance Company

COMMERCIAL TITLE AFFIDAVIT
26000 77th Street, Covert, Michigan 49043

The undersigned, in the undersigned's capacity as an officer of the Company (hereinafter defined), hereby certifies that, to the undersigned's actual knowledge:

I. PROPERTY

The undersigned is an officer of New Covert Generating Company, LLC (the "Company") and makes this affidavit regarding that certain property (the "Property") located in Van Buren County, Michigan, and more particularly described in that certain Title Commitment Number [_________] with the effective date of [_________], issued by Fidelity National Title Insurance Company (the "Title Commitment") and is authorized to make this affidavit on behalf of the Company.

II. MECHANIC'S LIENS

Within the past one hundred twenty (120) days, no person or firm has performed work or furnished any labor, services or materials in connection with the construction, maintenance or repair of any of the Company's buildings or improvements on the Property except (i) to the extent that payment has been made therefor, (ii) for such work, labor, services or materials relating to ordinary maintenance for which payment will be made in the ordinary course of business and/or (iii) as described on Exhibit A hereto.

III. TENANTS & OFF RECORD RIGHTS

That there are no existing unrecorded deeds, mortgages, leases, easements, contracts of sale and/or equities and/or agreements given by the Company or known to Affiant adversely affecting the title to the Property, that there are no tenants or additional parties in possession presently occupying the Property and that there are no disputes with any adjoining property owners as to either the location of Property lines or the encroachments of any improvements, in each case except for (i) such matters that are disclosed by the Title Commitment, (ii) such other matters that are disclosed in the public records and/or (iii) as described on Exhibit B hereto.

IV. TAXES

The Property to be insured is not subject to either a Commercial or Industrial Facility Tax established under Act 198 of Public Acts 1974 (MCL 207.551) or Act 255 of Public Acts of 1978 (MCL 207.651). There are (a) no delinquent real estate taxes or assessments against the Property, (b) no delinquent water, sewer, electric or gas charges against the Property, except for current charges which are not past due and which will be paid in the ordinary course of business, and (c) no written notices of any state or federal tax liens against the Property received by the Company, in each case except for (i) such matters that are disclosed by the Title Commitment, and/or (ii) such other matters that are disclosed in the public records.

V. GAP PERIOD

The Company agrees that it will not in any way cause the Property to be encumbered of record from the date hereof until the earlier of (i) the date of recording of the instruments with respect to the Property creating the interest or interests being insured by the Title Company, or (ii) or [fifteen][1] business days after the date of closing of such sale transaction (the "Gap Period"). The Company shall promptly remove of record any such encumbrance recorded during the Gap Period, and shall hold harmless and indemnify the Title Company for any loss, cost, expense, claim, or damage, including, without limitation, reasonable attorneys' fees, arising with respect to any such encumbrance recorded during the Gap Period; provided, however, that (i) such obligation to remove any encumbrance shall only apply to an encumbrance to which the Company is a party, and (ii) such obligations to hold harmless and indemnify the Title Company shall apply only to the extent that such loss, cost, expense, claim, or damage arises due to an encumbrance to which the Company is a party. Notwithstanding the foregoing, or any provision herein to the contrary, the provisions of this paragraph shall terminate and be of no further force or effect if the Title Company does not provide the Company with notice of any encumbrances for which the Title Company is seeking indemnification pursuant to this paragraph within [thirty (30)][2] days after the documents creating the interest or interests to be insured by the Title Company are delivered to the Title Company for recordation, and thereafter this indemnification shall apply only to any valid claims for indemnity which were made by the Title Company within such [thirty (30)][3] day period.

The Company makes this affidavit to induce Fidelity National Title Insurance Company to issue its policy of title insurance with regard to the Property, knowing that reliance will be placed on the above statements by Fidelity National Title Insurance Company when issuing such policy or policies.

[*Signature Page Follows*]

[1] Time to be adjusted as needed based on recording gap in the county record
[2] Time to be adjusted as needed based on recording gap in the county record
[3] Time to be adjusted as needed based on recording gap in the county record

DATE: ___, 20__

NEW COVERT GENERATING COMPANY, LLC

By: ______________________________
Name:
Title:

Subscribed and sworn to before me this ___ day of __________, _____

____

Notary Public
Commissioner of the Superior Court

EXHIBIT A

MECHANIC'S LIENS

EXHIBIT B

TENANTS AND OFF RECORD RIGHTS

EXHIBIT 5.9(b)

PROPERTY TAX PRORATION

Due Date Method

All Property Taxes that have become a lien on the Property as of the Closing Date will be paid by Seller, except that (1) all Property Taxes for the period in which the Closing occurs will be prorated and adjusted between Seller and Buyer as of the Closing Date on a due-date basis, without regard to Property Tax Lien Date, as if paid prospectively (e.g., taxes due July 1 will be treated as if paid for the period July 1 through the following June 30, and taxes due December 1 will be treated as if paid for the period December 1 through the following November 30); (2) Buyer will be responsible for the payment of all Property Taxes falling due on and after the Closing Date without regard to Property Tax Lien Date; and (3) for avoidance of doubt any Property Taxes allocated to Seller shall be excluded from any calculation of Net Working Capital once paid by Seller or otherwise charged to Seller at Closing.

Calendar Year Method

All Property Taxes on the Purchased Assets shall be prorated at Closing as follows: Any such Property Taxes with a Property Tax Lien Date prior to the year when Closing occurs shall be paid by Seller in full when due without any reimbursement from or proration with Buyer (and which, for avoidance of doubt, shall be excluded from any calculation of Net Working Capital once paid by Seller). Any such Property Taxes with a Property Tax Lien Date in the year when Closing occurs shall be prorated on a per diem basis at the Closing so that Seller shall be charged with such Property Taxes from the first day of the year when Closing occurs to the Closing Date (and which, for avoidance of doubt, shall be excluded from any calculation of Net Working Capital once paid by Seller or otherwise charged to Seller at Closing) and Buyer (without any charge to or reimbursement from the Seller) shall be charged with such Property Taxes for the balance of said calendar year.

Sample Calculations

See attached sample calculations (3 pages).

PURCHASE AND SALE AGREEMENT
NEW COVERT GENERATING CO, LLC
CONSUMERS ENERGY COMPANY
PROPERTY TAXES - SECTION 5.9(b)

EXHIBIT 5.9(b), Page 1

Seller - Proration at Closing					
			% Allocation		
Due From Buyer "Due Date Method"	$	2,825,117	66.67%	$	1,883,505
(Due to) Buyer "Calendar Year Method"	$	(4,038,604)	33.33%	$	(1,346,067)
Due From Buyer at Closing				**$**	**537,438**

Buyer - Proration at Closing					
(Due to) Seller "Due Date Method"	$	(2,825,117)	66.67%	$	(1,883,505)
Due From Seller "Calendar Year Method"	$	4,038,604	33.33%	$	1,346,067
(Due to) Seller at Closing				**$**	**(537,438)**

PURCHASE AND SALE AGREEMENT
NEW COVERT GENERATING CO, LLC
CONSUMERS ENERGY COMPANY
PROPERTY TAXES - SECTION 5.9(b) - "DUE DATE METHOD"

EXHIBIT 5.9(b), Page 2

Closing Date: 5/31/2023

7/1/2022		
Days Charged to Seller	334	91.5%
Days Charged to Buyer	31	8.5%

12/1/2022		
Days Charged to Seller	181	49.6%
Days Charged to Buyer	184	50.4%

Seller	Parcel	Jurisdiction	Type	Lien Date	Taxable Value	Total Tax Amount	Millage Rate (est)
New Covert Generating Co, LLC	80-07-004-003-03	Covert Township	301 - Real	7/1/2022	8,293,758	257,348.84	30.7220
New Covert Generating Co, LLC	80-07-004-007-20	Covert Township	301 - Real	7/1/2022	7,133	221.33	30.7220
New Covert Generating Co, LLC	80-07-900-084-00	Covert Township	351 - IPP (NT)	7/1/2022	140,670,930	955,045.89	6.7220
New Covert Generating Co, LLC	80-07-900-084-010	Covert Township	351 - IPP (T)	7/1/2022	122,074,464	3,787,875.40	30.7220
				Total 7/1/2022 Property Taxes		5,000,491.46	
New Covert Generating Co, LLC	80-07-004-003-03	Covert Township	301 - Real	12/1/2022	8,293,758	145,703.41	17.3939
New Covert Generating Co, LLC	80-07-004-007-20	Covert Township	301 - Real	12/1/2022	7,133	125.31	17.3939
New Covert Generating Co, LLC	80-07-900-084-00	Covert Township	351 - IPP (NT)	12/1/2022	140,670,930	2,471,284.25	17.3939
New Covert Generating Co, LLC	80-07-900-084-010	Covert Township	351 - IPP (T)	12/1/2022	122,074,464	2,144,584.53	17.3939
				Total 12/1/2022 Property Taxes		4,761,697.50	

Total Property Taxes to be Prorated at Closing per Section 5.9(b) 9,762,188.96

Seller's Property Tax Proration	
Total Prorated Taxes	(6,937,072.32)
Less: Taxes Paid 7/1/2022	5,000,491.46
Less: Taxes Paid 12/1/2022	4,761,697.50
Due from Buyer at Closing	2,825,116.64

Buyers's Property Tax Proration	
Total Prorated Taxes	(2,825,116.64)
Less: Taxes Paid 7/1/2022	-
Less: Taxes Paid 12/1/2022	-
Due to Seller at Closing	(2,825,116.64)

PURCHASE AND SALE AGREEMENT
NEW COVERT GENERATING CO, LLC
CONSUMERS ENERGY COMPANY
PROPERTY TAXES - SECTION 5.9(b) - "CALENDAR YEAR METHOD"

Closing Date: 5/31/2023

Days Charged to Seller	151	41.4%
Days Charged to Buyer	214	58.6%

Seller	Parcel	Jurisdiction	Type	Lien Date	Taxable Value	Total Tax Amount	Millage Rate (est)
New Covert Generating Co, LLC	80-07-004-003-03	Covert Township	301 - Real	7/1/2023	8,293,758	257,348.84	30.7220
New Covert Generating Co, LLC	80-07-004-007-20	Covert Township	301 - Real	7/1/2023	7,133	221.33	30.7220
New Covert Generating Co, LLC	80-07-900-084-00	Covert Township	351 - IPP (NT)	7/1/2023	140,670,930	955,045.89	6.7220
New Covert Generating Co, LLC	80-07-900-084-010	Covert Township	351 - IPP (T)	7/1/2023	122,074,464	3,787,875.40	30.7220
				Total 7/1/2023 Property Taxes		5,000,491.46	
New Covert Generating Co, LLC	80-07-004-003-03	Covert Township	301 - Real	12/1/2023	8,293,758	145,703.41	17.3939
New Covert Generating Co, LLC	80-07-004-007-20	Covert Township	301 - Real	12/1/2023	7,133	125.31	17.3939
New Covert Generating Co, LLC	80-07-900-084-00	Covert Township	351 - IPP (NT)	12/1/2023	140,670,930	2,471,284.25	17.3939
New Covert Generating Co, LLC	80-07-900-084-010	Covert Township	351 - IPP (T)	12/1/2023	122,074,464	2,144,584.53	17.3939
				Total 12/1/2023 Property Taxes		4,761,697.50	
			Total Property Taxes to be Prorated at Closing per Section 5.9(b)			9,762,188.96	

Seller's Property Tax Proration

Total Prorated Taxes	(4,038,604.20)
Less: Taxes Paid 7/1/2023	-
Less: Taxes Paid 12/1/2023	-
Due to Buyer at Closing	(4,038,604.20)

Buyers's Property Tax Proration

Total Prorated Taxes	(5,723,584.76)
Less: Taxes Paid 7/1/2023	5,000,491.46
Less: Taxes Paid 12/1/2023	4,761,697.50
Due from Seller at Closing	4,038,604.20

EXHIBIT 5.17

FORM OF MONTHLY OPERATING REPORT

New Covert Generating, LLC

Form of Monthly Operating Report

New Covert Generating, LLC

Executive Summary

Summary of Operations

Unit	Service Factor	Capacity Factor
Unit 1	[•]%	[•]%
Unit 2	[•]%	[•]%
Unit 3	[•]%	[•]%

Significant Events

[•]

Staffing

[•]

EH&S

[•]

NERC

[•]

CAMS Priorities & Issues

[•]

New Covert Generating, LLC

Summary of Key Operational Data

	Generation		Gas Burn & Heat Rate	
	Total Net Generation	Auxiliary Power Consumption	Total Gas-mmBtu	Average Net Heat Rate
UNITS	MWh	MWh	MMBTU	(btu/kwh)
Jan	[•]	[•]	[•]	[•]
Feb	[•]	[•]	[•]	[•]
Mar	[•]	[•]	[•]	[•]
Apr	[•]	[•]	[•]	[•]
May	[•]	[•]	[•]	[•]
Jun	[•]	[•]	[•]	[•]
Jul	[•]	[•]	[•]	[•]
Aug	[•]	[•]	[•]	[•]
Sep	[•]	[•]	[•]	[•]
Oct	[•]	[•]	[•]	[•]
Nov	[•]	[•]	[•]	[•]
Dec	[•]	[•]	[•]	[•]
2021	[•]	[•]	[•]	[•]
2020	[•]	[•]	[•]	[•]
2019	[•]	[•]	[•]	[•]

New Covert Generating, LLC

Performance Statistics

	Eq Availability Factor (EAF)	Net Cap Factor (NCF)	Service Factor (SF)	Eq Forced Outage Rate (EFOR)	Starting Reliability (SR)	Eq Forced Outage Rate Demand EFORd(%)
Jan	[•]	[•]	[•]	[•]	[•]	[•]
Feb	[•]	[•]	[•]	[•]	[•]	[•]
Mar	[•]	[•]	[•]	[•]	[•]	[•]
Apr	[•]	[•]	[•]	[•]	[•]	[•]
May	[•]	[•]	[•]	[•]	[•]	[•]
Jun	[•]	[•]	[•]	[•]	[•]	[•]
Jul	[•]	[•]	[•]	[•]	[•]	[•]
Aug	[•]	[•]	[•]	[•]	[•]	[•]
Sep	[•]	[•]	[•]	[•]	[•]	[•]
Oct	[•]	[•]	[•]	[•]	[•]	[•]
Nov	[•]	[•]	[•]	[•]	[•]	[•]
Dec	[•]	[•]	[•]	[•]	[•]	[•]
2021	[•]	[•]	[•]	[•]	[•]	[•]
2020	[•]	[•]	[•]	[•]	[•]	[•]
2019	[•]	[•]	[•]	[•]	[•]	[•]

New Covert Generating, LLC

Unit Statistics

Since First Flame	Unit 1 Combustion Turbine	Unit 2 Combustion Turbine	Unit 3 Combustion Turbine
Equivalent Starts	[•]	[•]	[•]
Equivalent Fired Hours (EFH)	[•]	[•]	[•]
Trips	[•]	[•]	[•]

Date of Last Major Maintenance:	[•]	[•]	[•]
Last MM Event	MI	MI	MI
Since Last Major Maintenance	Unit 1 Combustion Turbine	Unit 2 Combustion Turbine	Unit 3 Combustion Turbine
Equivalent Starts	[•]	[•]	[•]
Equivalent Fired Hours (EFH)	[•]	[•]	[•]
Trips	[•]	[•]	[•]

	EFH	Projected Date
Next Planned Maintenance Event		
[•]	[•]	[•]
[•]	[•]	[•]
[•]	[•]	[•]

New Covert Generating, LLC

Upcoming Planned Outages

Units	Description	Start Date	End Date
[•]	[•]	[•]	[•]
[•]	[•]	[•]	[•]
[•]	[•]	[•]	[•]
[•]	[•]	[•]	[•]
[•]	[•]	[•]	[•]
[•]	[•]	[•]	[•]

New Covert Generating, LLC

Generation Losses

Unit	Type	Outage Start Date	Outage End Date	Duration	Description/Cause

New Covert Generating, LLC

	Safety Metrics					Environmental Metrics (Permit Deviations)		Employee's & Hours		
	Lost Time Accidents	OSHA Recordable Events	Recordable Incident Rate	Safety Observations	Completed Training	NOV's	Exceedances	Target # of Employees	Actual # of Employees	Hours Worked
Jan-2021	[•]	[•]	[•]	[•]	[•]	[•]	[•]	[•]	[•]	[•]
Feb-2021	[•]	[•]	[•]	[•]	[•]	[•]	[•]	[•]	[•]	[•]
Mar-2021	[•]	[•]	[•]	[•]	[•]	[•]	[•]	[•]	[•]	[•]
Apr-2021	[•]	[•]	[•]	[•]	[•]	[•]	[•]	[•]	[•]	[•]
May-2021								[•]		
Jun-2021								[•]		
Jul-2021								[•]		
Aug-2021								[•]		
Sep-2021								[•]		
Oct-2021								[•]		
Nov-2021								[•]		
Dec-2021								[•]		
CYTD 2021	[•]	[•]	[•]	[•]	[•]	[•]	[•]	NA	NA	[•]

Environmental Health & Safety

[•]

NERC Regulatory Compliance

[•]

New Covert Generating, LLC

Regulatory Filings

Month	Description of Filing
Jan	[•]
Jan	[•]
Feb	[•]
Feb	[•]
Mar	[•]
Mar	[•]
Mar	[•]
Apr	[•]
Apr	[•]

New Covert Generating, LLC

Emissions Data

CO (tpy)	CO (tpy)	NOx (tpy)	SO2 (tpy)	VOC (tpy)	PM10 (tpy)	CO2e (tpy)	SU/SD Time (Hours)	DB Operating Time (Hours)
PTI Permit Limit (per turbine/DB):	357	116	N/A	48	N/A	1425081	692	3308
001	[•]	[•]	[•]	[•]	[•]	[•]	[•]	[•]
002	[•]	[•]	[•]	[•]	[•]	[•]	[•]	[•]
003	[•]	[•]	[•]	[•]	[•]	[•]	[•]	[•]
PTI Permit Limit Met?***	[•]	[•]	N/A		N/A	[•]	[•]	[•]

***PTI Tons per Year limit does not apply to SO2 and PM10. However, the emissions will be compared against the PTI application representation.

Auxiliary Boiler (12-month Rolling)

	Operating Hours
Permit Limit:	1600
Aux Boiler Hours	[•]
Permit Limit Met?	[•]

<u>Interim Period/Transition Activities</u>

- Status of ongoing tax appeals;
- Progress towards MISO reconnection and any External Resource Transaction;
- Staffing changes under the Asset Management Agreement or the O&M Agreement;
- Transition Service Agreement update;
- Buyer site visit matters;
- FERC activities;
- Status of ammonia slip issue;
- Tracking of action items from regulator/consultant reports (*e.g.*, NERC Compliance Audits, S&L Kai Upgrade Study, Vogt Thermal study, Stantec Hg minimization study, EGLE NOV reports, S&L Evaluation of condensate and feedwater study); and
- Other similar items to be added as they arise.

EXHIBIT 5.18

FORM OF SELLER PARENT GUARANTY AGREEMENT

GUARANTEE

made by

EASTERN GENERATION HOLDINGS, LLC, in favor of

CONSUMERS ENERGY COMPANY

Dated as of [●]

GUARANTEE

This Guarantee, dated as of [*insert Closing Date*] (as amended, supplemented or otherwise modified from time to time, this "Guarantee"), is made and entered into by Eastern Generation Holdings, LLC, a Delaware limited liability company ("Guarantor"), in favor of Consumers Energy Company, a Michigan corporation (the "Guaranteed Party"). Capitalized terms used but not defined in this Guarantee shall have the meanings given thereto in the Purchase Agreement (as defined below).

RECITALS

WHEREAS, New Covert Generating Company, LLC, a Delaware limited liability company (the "Seller") is an Affiliate of the Guarantor;

WHEREAS, the Seller and the Guaranteed Party have entered into that certain Purchase and Sale Agreement, dated as of [●], 2021 (the "Purchase Agreement"); and

WHEREAS, as a material inducement to the willingness of the Guaranteed Party to consummate the transactions under the Purchase Agreement, the Guaranteed Party is requiring that the Guarantor execute and deliver this Guarantee to the Guaranteed Party to guarantee the Guaranteed Obligations (as defined below).

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Guarantor agrees as follows:

ARTICLE 1.
GUARANTEE

Section 1.01 Guarantee.

(a) Subject to the terms and conditions set forth in this Guarantee, the Guarantor hereby absolutely, irrevocably and unconditionally guarantees to the Guaranteed Party the prompt and complete payment by the Seller of the payment obligations of the Seller pursuant to Section 9.1(a) of the Purchase Agreement if, as and when due in accordance with the terms thereof (the "Guaranteed Obligations"). In no event shall the Guarantor's aggregate liability under this Guarantee exceed an amount equal to 100% of the Purchase Price *plus* any amounts payable pursuant to Section 1.01(g) *less* the amount of the Guaranteed Obligations paid by the Seller (the "Cap"). The guarantee by the Guarantor of the Guaranteed Obligations under this Guarantee may be enforced for the payment of money only. All payments hereunder shall be made in lawful money of the United States, in immediately available funds. Except with respect to a claim by a third party that falls within the Guaranteed Obligations, in no event shall Guarantor be liable for special, punitive, exemplary, incidental, consequential or indirect damages or lost profits, including damages based on loss of future revenue or income, loss of business reputation or opportunity, or diminution in value, or any damages based on any type of multiple, whether based on contract, tort, strict liability, other law or otherwise and whether or not arising from the Guaranteed Party's sole, joint or concurrent negligence, strict liability or other fault.

(b) If the Seller fails to discharge the Guaranteed Obligations when due (whether or not any bankruptcy, insolvency, or similar proceeding shall have stayed the accrual or collection of any of such obligations or operated as a discharge thereof), then, upon the Guaranteed Party's demand, the Guarantor shall forthwith pay to the Guaranteed Party any payments required by the Guaranteed Obligations (subject to the Cap) (but in no event later than ten (10) Business Days after the Guaranteed Party's demand), and the Guaranteed Party may at any time and from time to time, at the Guaranteed Party's option, and so long as the Seller has failed to discharge any of the Guaranteed Obligations, take any and all actions available hereunder, under the Purchase Agreement or at law or in equity to enforce such Guaranteed Obligations, subject to the Cap. The Guarantor further agrees that this Guarantee constitutes a continuing guarantee of payment when due and not of collection and is in no way conditioned or contingent upon any requirement that the Guaranteed Party must first exercise its rights against the Seller. The Guarantor agrees that, subject to the terms and provisions of this Guarantee, its obligations under this Guarantee shall not be released, discharged or otherwise affected, in whole or in part, by, and Guarantor hereby irrevocably waives to the fullest extent permitted by applicable law any rights or defenses based upon, any of the following (each, a "Specified Condition"):

(i) any lack of validity, legality, or enforceability of the Purchase Agreement or this Guarantee, in each case other than by reason of Intentional Fraud by the Guaranteed Party;

(ii) any insolvency, bankruptcy, reorganization or other similar proceeding affecting Seller or any of its Affiliates;

(iii) any modification, amendment, consent, extension, forbearance or waiver of or any consent to departure from the Purchase Agreement or any related transaction document;

(iv) the failure or delay on the part of the Guaranteed Party to assert any claim or demand or to enforce any right or remedy against Seller or any other Person now or hereafter liable with respect to the Guaranteed Obligations or otherwise interested in the transactions contemplated by the Purchase Agreement;

(v) any waiver, release, exercise, or discharge of any right, remedy, or power with respect to the Guaranteed Obligations;

(vi) any merger or consolidation of the Seller, the Guarantor or any of their respective Affiliates into or with any Person, or any sale, lease or transfer of any of the assets of the Guarantor, the Seller or any other Person to any other Person;

(vii) any change in the time, place or manner of payment of the Guaranteed Obligations or any rescission, waiver, compromise, consolidation or other amendment to or modification of any of the terms or provisions of the Purchase Agreement (except to the extent provided in the final sentence of Section 1.01(e));

(viii) the addition, substitution or release of any collateral or Person now or hereafter liable with respect to the Guaranteed Obligations or otherwise interested in the transactions contemplated by the Purchase Agreement;

(ix) any change in the corporate existence or ownership of the Guarantor, the Seller, the Guaranteed Party or any other Person;

(x) any change in applicable Laws;

(xi) any assignment, delegation, or other transfer of this Guarantee or the Purchase Agreement in accordance with the terms hereof or thereof; or

(xii) except as otherwise expressly set forth in this Guarantee, including, without limitation, the termination of this Guarantee in accordance with Section 3.11, any other contingency, circumstance, or matter whatsoever that might in any manner or to any extent vary the obligations or risk of loss of Guarantor or otherwise constitute or give rise to a defense available to, or a legal or equitable discharge of, the Seller or Guarantor (other than the full and indefeasible payment of the Guaranteed Obligations).

(c) The Guarantor unconditionally and irrevocably waives to the fullest extent permitted by applicable law (i) diligence, presentment, promptness, acceptance of this Guarantee, demand, protest and all notices whatsoever in respect of the Guaranteed Obligations and this Guarantee, (ii) any requirement that the Guaranteed Party exhaust any right, power or remedy or proceed against the Seller or any other Person under the Purchase Agreement, (iii) any right it may have to require any election of remedies, the marshalling of assets, or the resort to any other security or remedy, and (iv) except as otherwise expressly provided in this Guarantee, including, without limitation, the termination of this Guarantee in accordance with Section 3.11, any other defense, contingency, circumstance, or matter that might constitute a legal or equitable discharge of a surety or guaranty (other than the full and indefeasible payment of the Guaranteed Obligations).

(d) Notwithstanding Section 3.11 herein, the provisions of this Guarantee shall continue to be effective or be reinstated, as the case may be, if (i) at any time and to the extent that any payment of any of the Guaranteed Obligations is rescinded or must otherwise be returned by the payee thereof, whether as the result of the insolvency, bankruptcy, reorganization or similar event of the Seller or the Guarantor or otherwise, all as though such payment had not been made or (ii) the obligations of the Guarantor under this Guarantee with respect to any of the Guaranteed Obligations are released in consideration of a payment of money or transfer of property by the Seller or any other Person, to the extent that such payment, transfer or grant is rescinded or must otherwise be returned by the recipient thereof, whether as the result of the insolvency, bankruptcy, reorganization or similar event of the Seller or the Guarantor or otherwise, all as though such payment, transfer or grant had not been made.

(e) The Guarantor reserves the right to assert defenses that the Seller may have to payment of the Guaranteed Obligations, other than defenses arising from the bankruptcy or insolvency of the Seller or any Specified Condition and any other defenses expressly waived hereunder. Notwithstanding anything to the contrary in this Guarantee, the Guaranteed Party agrees that, if the Seller is (x) relieved of all of its obligations under the Purchase Agreement by satisfaction, discharge, or release thereof or (y) any of such obligations are amended or modified in accordance with the Purchase Agreement (other than in either case of subclause (x) or (y) by reason of bankruptcy or insolvency), then (A) in the case of subclause (x), the Guarantor shall be relieved of its obligations under this Guarantee or (B) in the case of subclause (y) such obligations under this Guarantee shall be concomitantly amended or modified.

(f) No failure on the part of the Guaranteed Party to exercise, and no delay in exercising, any right, remedy or power hereunder shall operate as a waiver thereof; nor shall any single or partial exercise by the Guaranteed Party of any right, remedy or power hereunder preclude any other or future exercise of any right, remedy or power hereunder. Each and every right, remedy and power hereby granted to the Guaranteed Party or allowed it by Law, equity, or other agreement shall be cumulative and not exclusive of any other right, remedy or power, and may be exercised by the Guaranteed Party at any time or from time to time. The Guaranteed Party shall not have any obligation to proceed at any time or in any manner against, or exhaust any or all of the Guaranteed Party's rights against, the Seller or any other Person now or hereafter liable for any Guaranteed Obligations or interested in the transactions contemplated by the Purchase Agreement prior to proceeding against the Guarantor hereunder.

(g) If the Guaranteed Party is the prevailing party (as determined by a court of competent jurisdiction) in any enforcement action brought by the Guaranteed Party against Guarantor to enforce the provisions of this Guarantee, the Guarantor shall reimburse the Guaranteed Party on demand for all reasonable costs and expenses (including court costs and reasonable fees and expenses of attorneys, accountants, and other experts in connection with any such enforcement action) incurred by the Guaranteed Party or its Affiliates arising out of or in connection with such enforcement action.

Section 1.02 No Recourse.

(a) Notwithstanding anything to the contrary or that may be expressed or implied in this Guarantee, the Purchase Agreement or any document or instrument delivered by the parties hereto or thereto in connection herewith, therewith or otherwise, by its acceptance of the benefits of this Guarantee, the Guaranteed Party acknowledges and agrees that: (i) no Person other than the Guarantor shall have any obligations or liabilities under or in connection with this Guarantee, (ii) neither the Guarantor nor the Guaranteed Party shall have obligations or liabilities to the other under or in connection with this Guarantee except as expressly provided by this Guarantee, (iii) no obligations or liability under this Guarantee, whether at law or in equity or sounding in contract, tort, statute or otherwise, shall attach to any Person (including, without limitation, any Non-Recourse Party) other than Guarantor and its successors and permitted assigns, and (iv) no recourse under or in connection with this Guarantee shall be had by the Guaranteed Party, any of its Affiliates, any of their respective agents or representatives or any Person seeking or purporting to claim by or through any of them or for the benefit of any of them under any theory of liability (including, without limitation, by attempting to pierce a corporate, limited liability company, limited partnership or other entity veil, by attempting to compel the Seller to enforce any rights that it may have against any Person, by attempting to enforce any assessment, or by attempting to enforce any purported right at law or in equity, whether sounding in contract, tort, statute or otherwise), against any Person (including, without limitation, any Non-Recourse Party) other than Guarantor and its successors and permitted assigns. As used herein, "Non-Recourse Parties" shall mean the Guarantor's (and its successor's and permitted assigns') former, current or future equity holders, controlling persons, directors, officers, employees, agents, general or limited partners, managers, management companies, members, stockholders, Affiliates, successors or assignees and any and all former, current or future equity holders, controlling persons, directors, officers, employees, agents, general or limited partners, managers, management companies, members, stockholders, Affiliates, successors or assignees of any of the foregoing, and any and all former, current or future estates, heirs, executors, administrators, trustees, successors or assigns of any of the foregoing. In no event shall the Guaranteed Party be entitled to recover any Guaranteed Obligations under this Guarantee or the Purchase Agreement to the extent the Guaranteed Party has already recovered such Guaranteed Obligations pursuant to the Purchase Agreement or this Guarantee. Nothing set forth in this Guarantee shall confer or give or shall be construed to confer or give to any Person other than the Guaranteed Party (or its successors, permitted assigns or any Person acting for the Guaranteed Party in a representative capacity) any rights or remedies against any Person other than the Guarantor as expressly set forth herein.

(c) The Guaranteed Party acknowledges and agrees that the Guarantor is agreeing to enter into this Guarantee in reliance on the provisions set forth in this Section 1.02. Notwithstanding anything to the contrary, this Section 1.02 shall survive any termination of this Guarantee.

ARTICLE 2.
REPRESENTATIONS AND WARRANTIES

Section 2.01 Representations and Warranties. The Guarantor represents and warrants to the Guaranteed Party:

(a) Organization; Corporate Authority. It (i) is a limited liability company, duly formed, validly existing and in good standing under the laws of Delaware, and (ii) has all requisite limited liability company power and authority to own its assets and to carry on the business in which it is engaged and to execute, deliver and perform its obligations under this Guarantee. It is not subject to any current orders for winding up, or appointment of a receiver or liquidator or to any notice of any proposed deregistration.

(b) Authorization; Enforceability; No Conflicts. The execution and delivery by the Guarantor of this Guarantee and the performance by it of its obligations under this Guarantee and the consummation of the transactions contemplated hereby have been duly authorized by all necessary limited liability company action and do not, and will not (with or without notice or lapse of time, or both) violate, breach or contravene (i) its organizational documents or (ii) any Law or contractual restriction binding on it or require the consent of any third party, except where such violation, breach or contravention, or failure to obtain such consent, individually or in the aggregate, would not reasonably be expected to have a material and adverse effect on its ability to perform its obligations under this Guarantee, and no other action or proceedings are necessary to authorize this Guarantee or the consummation of the transactions contemplated hereby. This Guarantee has been duly executed and delivered by the Guarantor, and constitutes the legal, valid and binding obligation of it, enforceable against it in accordance with its terms, except as limited by bankruptcy, insolvency, reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally and by general principles of equity (regardless of whether such enforceability is considered in a proceeding in equity or at Law). All material consents, approvals, authorizations, permits of, filings with and notifications to, any governmental authority necessary for the due execution, delivery and performance of this Guarantee by the

Guarantor have been obtained or made and all conditions thereof have been duly complied with, and no other action by, and no notice to or filing with, any governmental authority or regulatory body is required in connection with the execution, delivery or performance of this Guarantee.

(c) Financial Capacity. It has the financial capacity to perform all of its obligations under this Guarantee, and it has currently available, and will continue to have available for so long as both this Guarantee remains in effect, the financial capacity necessary to perform its obligations under this Guarantee.

Section 2.02 Subrogation. The Guarantor hereby unconditionally and irrevocably waives any rights that it may have now or hereafter acquire against Seller that arise from the existence, payment, performance, or enforcement of the Guarantor's obligations under or in respect of this Guarantee or any other agreement in connection herewith, including, without limitation, any right of subrogation, reimbursement, exoneration, contribution or indemnification and any right to participate in any claim or remedy of the Guaranteed Party against the Seller, whether or not such claim, remedy or right arises in equity or under contract, statute or Law, including, without limitation, the right to take or receive from the Seller, directly or indirectly, in cash or other property or by set-off or in any other manner, payment or security on account of such claim, remedy or right, unless and until the Guarantee shall have terminated in accordance with Section 3.11. If any amount is paid to the Guarantor in violation of this Section 2.02, such amount shall be held in trust for the benefit of the Guaranteed Party and shall forthwith be paid or delivered to the Guaranteed Party to be credited and applied to the unsatisfied Guaranteed Obligations.

ARTICLE 3.
MISCELLANEOUS

Section 3.01 Notices.

All notices, requests and demands hereunder shall be in writing and delivered via certified U.S. Mail, return receipt requested, or nationally recognized overnight courier:

(a) if to Guarantor, to:

Eastern Generation Holdings, LLC
c/o ArcLight Capital Partners, LLC
Attn: General Counsel
200 Clarendon, Floor 55
Boston, MA 02116

With a copy to (which copy shall not constitute notice):

Milbank LLP
55 Hudson Yards
New York, New York 10001
Attn: William B. Bice, Esq.

(b) if to the Guaranteed Party, to:

Consumers Energy Company
One Energy Plaza
Jackson, Michigan 49201
Attn: Treasurer

With a copy to (which copy shall not constitute notice):

Consumers Energy Company
One Energy Plaza
Jackson, Michigan 49201
Attn: General Counsel

or (c) as to any party, at such other address as shall be designated by such party in a written notice to each other party.

Section 3.02 Amendments. The terms of this Guarantee may be waived, altered or amended only by an instrument in writing duly executed by the Guarantor and countersigned by the Guaranteed Party.

Section 3.03 Benefit, Successors and Assigns. This Guarantee shall be binding upon and shall inure to the benefit of the Guarantor and the Guaranteed Party and each of the respective successors and permitted (as provided in this Section 3.03) assigns of the foregoing, and is enforceable by the Guaranteed Party and its respective successors and permitted (as provided in this Section 3.03) assigns, and shall not be for the benefit of or enforceable by any other Person; provided, however, that as a material aspect of this Guarantee, the parties hereto intend that all Non-Recourse Parties, and such Non-Recourse Parties are, intended third party beneficiaries of this Guarantee who may rely on and enforce the provisions of this Guarantee set forth in Section 1.02. Neither the Guarantor nor the Guaranteed Party may assign this Guarantee or any rights or obligations hereunder without the prior written consent of other party hereto, except that the Guaranteed Party may, without the prior written consent of the Guarantor, assign this Guarantee or any of its rights or obligations hereunder to an Affiliate to whom it has assigned the Purchase Agreement in accordance with its terms; provided, however, that no such assignment or delegation shall relieve any party hereto of its obligations hereunder. References to any Person in this Guarantee shall be deemed to include references to such Person's successors and permitted (pursuant to this Guarantee or the Purchase Agreement, as applicable) assigns.

Section 3.04 Captions. The captions and section headings appearing herein are included solely for convenience of reference and are not intended to affect the interpretation of any provision of this Guarantee.

Section 3.05 Counterparts. This Guarantee and each amendment, waiver and consent with respect hereto may be executed and delivered (including by facsimile transmission or electronic transmission in "PDF" format) in any number of counterparts, and by different parties thereto in separate counterparts, each of which when so executed shall be deemed to be an original and all of which taken together shall constitute one and the same instrument.

Section 3.06 Severability. If any term or provision hereof is invalid and unenforceable in any jurisdiction, then, to the fullest extent permitted by Law, (a) the other terms or provisions hereof shall remain in full force and effect in such jurisdiction and (b) the invalidity or unenforceability of any term or provision hereof in any jurisdiction shall not affect the validity or enforceability of such provision in any other jurisdiction.

Section 3.07 Entire Agreement. This Guarantee constitutes the entire agreement between the Guarantor and the Guaranteed Party with respect to the specific subject matter hereof and supersedes all prior contracts or agreements with respect to such specific subject matter, whether oral or written. For avoidance of doubt, this Guarantee does not amend or supersede the Purchase Agreement.

Section 3.08 Governing Law, Jurisdiction and Venue. This Guarantee shall be governed by, and construed in accordance with, the Laws of the State of Michigan, without giving effect to any choice or conflict of Laws provision or rule (whether of the State of Michigan or any other jurisdiction) that would cause the application of the Laws of any jurisdiction other than the State of Michigan.

Section 3.09 Consent to Jurisdiction and Service of Process. THE PARTIES HEREBY IRREVOCABLY SUBMIT TO THE EXCLUSIVE JURISDICTION OF ANY STATE OR FEDERAL COURT IN THE STATE OF MICHIGAN AND EACH PARTY HEREBY CONSENTS TO THE JURISDICTION OF SUCH COURTS (AND OF THE APPROPRIATE APPELLATE COURTS THEREFROM) IN ANY SUCH SUIT, DISPUTE, CLAIM, ACTION OR PROCEEDING AND IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY LAW, ANY OBJECTION THAT IT MAY NOW OR HEREAFTER HAVE TO THE LAYING OF THE VENUE OF ANY SUCH SUIT, ACTION OR PROCEEDING IN ANY SUCH COURT OR THAT ANY SUCH SUIT, ACTION OR PROCEEDING THAT IS BROUGHT IN ANY SUCH COURT HAS BEEN BROUGHT IN AN INCONVENIENT FORUM. DURING THE PERIOD A LEGAL DISPUTE THAT IS FILED IN ACCORDANCE WITH THIS SECTION 3.09 IS PENDING BEFORE A COURT, ALL ACTIONS, SUITS OR PROCEEDINGS WITH RESPECT TO SUCH LEGAL DISPUTE OR ANY OTHER LEGAL DISPUTE, INCLUDING ANY COUNTERCLAIM, CROSS-CLAIM OR INTERPLEADER, SHALL BE SUBJECT TO THE EXCLUSIVE JURISDICTION OF SUCH COURT. EACH PARTY HEREBY WAIVES THE DEFENSE, AND SHALL NOT ASSERT AS A DEFENSE IN ANY LEGAL DISPUTE, THAT (A) SUCH PARTY IS NOT SUBJECT THERETO, (B) SUCH CLAIM, ACTION, SUIT OR PROCEEDING MAY NOT BE BROUGHT OR IS NOT MAINTAINABLE IN SUCH COURT, (C) SUCH PARTY'S PROPERTY IS EXEMPT OR IMMUNE FROM EXECUTION, (D) SUCH ACTION, SUIT OR PROCEEDING IS BROUGHT IN AN INCONVENIENT FORUM OR (E) THE VENUE OF SUCH ACTION, SUIT OR PROCEEDING IS IMPROPER. A FINAL JUDGMENT IN ANY ACTION, SUIT OR PROCEEDING DESCRIBED IN THIS SECTION 3.09 FOLLOWING THE EXPIRATION OF ANY PERIOD PERMITTED FOR APPEAL AND SUBJECT TO ANY STAY DURING APPEAL SHALL BE CONCLUSIVE AND MAY BE ENFORCED IN OTHER JURISDICTIONS BY SUIT ON THE JUDGMENT OR IN ANY OTHER MANNER PROVIDED BY LAW.

Section 3.10 WAIVER OF JURY TRIAL. EACH OF THE PARTIES HERETO HEREBY IRREVOCABLY WAIVES ANY AND ALL RIGHT TO TRIAL BY JURY IN ANY LEGAL PROCEEDING ARISING OUT OF OR RELATING TO THIS GUARANTEE OR THE TRANSACTIONS CONTEMPLATED HEREBY.

Section 3.11 Termination. Subject to Sections 1.01(d) and 1.02(c), this Guarantee shall terminate and the Guarantor shall have no further obligations or liabilities hereunder as of the earliest to occur of the date (a) on which all of the Guaranteed Obligations have been paid or satisfied in full, (b) on which the Guarantor has paid an aggregate amount of Guaranteed Obligations equal to the Cap and (c) that is the seven (7) year anniversary of the date of this Guarantee. Subject to Sections 1.01(d) and 1.02, this Guarantee shall have no further force or effect, and no Guarantor shall have any liability hereunder, upon and following any termination of this Guarantee; provided, that notwithstanding any termination of this Guarantee the rights (but not the obligations or liabilities) of the Guarantor and the Non-Recourse Parties, including, without limitation, under Section 1.02, shall survive any termination of this Guarantee.

Section 3.12 Confidentiality. This Guarantee shall be treated as confidential and is being provided to the Guaranteed Party solely in connection with the transactions contemplated by the Purchase Agreement. This Guarantee may not be used, circulated, or quoted in any document (other than the Purchase Agreement), except (i) with the written consent of the Guarantor; provided that no such written consent shall be required for disclosures by the Guaranteed Party to any of its Affiliates or Representatives with a need to know in connection with the transactions contemplated by the Purchase Agreement or this Guarantee; (ii) to the extent required by Law, the applicable rules of any national securities exchange or if required in connection with any required filing or notice with any Governmental Authority relating to the transactions contemplated by the Purchase Agreement; (iii) in connection with any claim or litigation to enforce the terms of relating to this Guarantee, the Purchase Agreement or the transactions contemplated hereby or thereby; or (iv) to the extent limited to a statement that Guarantor has guaranteed the Guaranteed Obligations under the Purchase Agreement.

[SIGNATURES FOLLOW]

IN WITNESS WHEREOF, the Guarantor has caused this Guarantee to be duly executed and delivered as of the date first above written.

GUARANTOR:

EASTERN GENERATION HOLDINGS, LLC

By: ____________________
Name:
Title:

ACCEPTED AND AGREED ON BEHALF OF THE GUARANTEED PARTY:

CONSUMERS ENERGY COMPANY

By:_________________________________
Name:
Title:

Final Form

SCHEDULES

TO

PURCHASE AND SALE AGREEMENT

by and between

NEW COVERT GENERATING COMPANY, LLC

as Seller,

and

CONSUMERS ENERGY COMPANY

as Buyer,

dated as of June 21, 2021

(the "*Agreement*")

Unless otherwise defined, capitalized terms used in these Schedules shall have the meanings ascribed thereto in the Agreement.

The inclusion of any information, or any references to dollar amounts, in each case in the Schedules shall not be deemed to be an acknowledgment or representation that such items are material, to establish any standard of materiality or to define further the meaning of such terms for purposes of any provision of this Agreement that establishes a standard of materiality. Information disclosed in any Schedule shall constitute a disclosure for purposes of all other Schedules notwithstanding the lack of a specific cross-reference thereto, but only to the extent the applicability of such disclosure to such other Schedule is relevant to the other Schedule and such relevance is reasonably apparent on its face.

Schedule Index

SCHEDULE 1.1-AC

Net Working Capital Calculation

[*See attached*]

Schedule 1.1-A

New Covert Generating Company
Net Working Capital Calculation
As of December 31, 2020

Amounts in $000s

Cash	$3,926
Cash - local checking account	531
Accounts receivable	19,669
Accounts receivable - Affiliate	1,861
Derivative assets	13,845
Inventory	5,303
Prepaid Property Tax (1)	1,765
Prepaid Insurance	482
Other current assets	462
Total GAAP Current Assets	$47,842
Adjustments (2)	
Less: Cash	($3,926)
Less: Accounts Receivable	($19,669)
Less: Accounts Receivable - Affiliate	($1,861)
Less: Derivative assets	($13,845)
Less: Prepaid Property Tax (1)	($1,765)
Less: Prepaid Insurance	($482)
Less: ADM Brokerage Account Deposit	($224)
Total Adjustments to GAAP Current Assets	($41,771)
Total Adjusted Current Assets	**$6,071**
Accounts payable and accrued expenses	($21,755)
Intercompany payables	(2,948)
Accrued interest/LOC fees	(41)
Total accounts payable and accrued expenses	($24,744)
Insurance premium financing	-
Total other current liabilities	-
Current portion of Company Indebtedness	(18,166)
Derivative liabilities	(12,299)
Total GAAP Current Liabilities	($55,209)
Adjustments (3)	
Less: Intercompany payables	2,948
Less: LTSA CWIP Liab	389
Less: Current portion of Company Indebtedness	18,166
Less: Accrued interest/LOC fees	41
Less: Insurance premium financing	-
Less: Derivative liabilities	12,299
Total Adjustments to GAAP Current Liabilities	$33,843
Total Adjusted Current Liabilities	**($21,366)**
Total Adjusted Net Working Capital	**($15,294)**

(1) Prepaid property taxes are excluded from NWC and will been treated in accordance with Section 5.9(b).
(2) Adjusted out of Net Working Capital to the extent included in Current Assets at the Closing Date
(3) Adjusted out of Net Working Capital to the extent included in Current Liabilities at the Closing Date

SCHEDULE 1.1-AC

Assigned Contracts

1. Amended and Restated Long Term Service Agreement between New Covert Generating Company, LLC, and Mitsubishi Hitachi Power Systems Americas, Inc., dated June 30, 2017, as amended by the Amendment dated February 28, 2019

2. Water Service Agreement by and among City of South Haven, Township of Covert, and Covert Generating Company, L.L.C., dated November 23, 1999

3. Agreement for Installation of Electronic Monitoring Equipment between ANR Pipeline Company and Covert Generating Company, LLC, dated September 17, 2002

4. Interconnection and Operating Agreement between ANR Pipeline Company and Covert Generating Company, LLC, dated October 30, 2000, as amended by the First Amendment to Interconnection and Operating Agreement dated as of February 5, 2002

5. Precedent Agreement, dated October 30, 2000 as referred to in the Interconnection and Operating Agreement listed in item 4 above

6. ITS-3 Service Agreement between ANR Pipeline Company and New Covert Generating Company, LLC, dated May 2, 2012

7. IPLS Service Agreement between ANR Pipeline Company and New Covert Generating Company, LLC, dated May 2, 2012

8. Master Services Agreement between New Covert Generating Company, LLC and SUEZ WTS Services USA, Inc. (f/k/a GE Mobile Water, Inc.), dated November 1, 2016

9. Base Contract for Sale and Purchase of Natural Gas between Sequent Energy Management, L.P., and New Covert Generating Company, LLC, dated June 1, 2018

10. Transaction Confirmation dated June 27, 2018 between Sequent Energy Management, L.P., and New Covert Generating Company, LLC

11. Asset Management Agreement between New Covert Generating Company, LLC, Eastern Covert, LLC, and USPG Power Services, LLC, dated June 29, 2018

12. Facilities Reimbursement Agreement by and between New Covert Generating Company, LLC and ITC Interconnection LLC, dated as of August 25, 2014, as amended by Amendment No. 1, dated February 1, 2017

13. Facilities Development Agreement by and between New Covert Generating Company, LLC and ITC Interconnection LLC, dated as of August 25, 2014, as amended by that certain Letter dated December 9, 2014

14. Substation Purchase Agreement between ITC Interconnection LLC and New Covert Generating Company, LLC, dated June 1, 2016

15. Interconnection Service Agreement (PJM Queue #AC1-072) among PJM Interconnection, L.L.C, New Covert Generating Company, LLC and ITC Interconnection LLC, dated May 8, 2018

16. Distribution Easement by and between New Covert Generating Company, LLC, a Delaware limited liability company, and Indiana Michigan Power Company, an Indiana corporation, dated May 1, 2015, and recorded June 11, 2015 at L 1620, Page 850, Register of Deeds, Van Buren County, Michigan.

17. Substation and Electric Transmission Right-of-Way and Easement Agreement by and between New Covert Generating Company, LLC, a Delaware limited liability company, and ITC Interconnection LLC, a Michigan limited liability company, dated January 28, 2015, and recorded at L 1614, Page 440, Register of Deeds, Van Buren County, Michigan (the "ITC Interconnection Easement").

18. Conditional Zoning Agreement between New Covert Generating Company, LLC and the Township of Covert, Michigan, dated as of May 8, 2014 and recorded in Liber 1602, Page 914, as effected by that certain Addendum to Conditional Zoning Agreement between New Covert Generating Company, LLC and the Township of Covert, Michigan, dated as of September 10, 2015.

19. Credit and Security Agreement, dated March 1, 2009, between MISO and New Covert Generating Company, LLC.

20. Cash Collateral Agreement, dated as of November 14, 2009, between MISO and New Covert Generating Company, LLC.

21. Water Main Extension Agreement by and among City of South Haven, Charter Township of South Haven, Township of Covert, South Haven / Casco Township Sewer and Water Authority and New Covert Generating Company, LLC f/k/a/ Covert Generating Company, LLC dated August 3, 2001.

22. If duly executed and entered into prior to Closing, the Generator Interconnection and Operating Agreement, to be entered into between Michigan Electric Transmission Company, LLC, Midcontinent Independent System Operator, Inc., New Covert Generating Company, LLC and/or other parties upon completion of the MISO interconnection process.

Subject to Section 10.4(c) of the Agreement, if any of the Contracts referred to in this Schedule 1.1-AC terminates in accordance with its terms prior to Closing, then such Contract shall not be an Assigned Contract for any purposes of the Agreement; provided, that if such terminating Contract is extended beyond Closing and, if applicable, meets the criteria set forth in Section 10.4(c) of the Agreement, such extended Contract shall be an Assigned Contract.

SCHEDULE 1.1-B

Budget

[*See attached*]

2021 MM & CapEx

	C	D	E	F	L	M	N	O	P	Q	R	S	T	U	V	W	X
2																	
3					Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	2021 Budget
4	Major Maintenance				-	-	-	994,000	-	-	-	-	-	-	-	-	994,000
5		O&M Projects			-	-	-	994,000	-	-	-	-	-	-	-	-	994,000
6			Duct Burner Repairs		-	-	-	594,000	-	-	-	-	-	-	-	-	594,000
8			HRSG Liner Repairs		-	-	-	400,000	-	-	-	-	-	-	-	-	400,000
10	CAPEX				190,000	133,000	444,040	1,664,252	15,000	-	-	-	-	-	-	-	2,446,292
11		Capital Projects (MMRA)			-	-	-	1,664,252	-	-	-	-	-	-	-	-	1,664,252
12			TCA Coolers Replacement		-	-	-	1,446,630	-	-	-	-	-	-	-	-	1,446,630
19			Hydrastep Replacement - Unit 2		-	-	-	142,622	-	-	-	-	-	-	-	-	142,622
24			HP Level Transmitter Upgrade - Unit 2		-	-	-	75,000	-	-	-	-	-	-	-	-	75,000
28		Capital Projects (Other)			190,000	133,000	444,040	-	15,000	-	-	-	-	-	-	-	782,040
29			Facility Upgrades		-	-	28,000	-	-	-	-	-	-	-	-	-	28,000
32			GTG/STG Rollup Doors - Unit 2		-	-	95,000	-	-	-	-	-	-	-	-	-	95,000
36			Sulfuric Acid Skid and Building Replacement		-	-	311,040	-	-	-	-	-	-	-	-	-	311,040
40			Alternative Weather Station		-	-	-	-	15,000	-	-	-	-	-	-	-	15,000
44			Facilities Vehicle Replacements		-	17,000	10,000	-	-	-	-	-	-	-	-	-	27,000
48			JCB Replacement		-	116,000	-	-	-	-	-	-	-	-	-	-	116,000
51			CWIP ADEX OPTIMIZER SOFTWARE		190,000	-	-	-	-	-	-	-	-	-	-	-	190,000

SCHEDULE 1.1-BA

Buyer Approvals

1. A final order of the MPSC regarding Buyer's integrated resource plan to be filed with the MPSC in June 2021, in a form that includes the following:

(a) approval of Buyer's proposed integrated resource plan, in a manner acceptable to Buyer;

(b) affirmation that Buyer's proposed integrated resource plan, including acquisition of the Project by Buyer, represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs; and

(c) a finding that the Purchase Price is specifically approved and considered reasonable and prudent for cost recovery purposes;

and in the case of each of the approvals set forth in clauses (b) and (c), without the imposition of other conditions that taken in the aggregate would have the effect of reducing the recovery of costs as proposed in Buyer's integrated resource plan (other than any *de minimis* reductions that are less than $100,000 in the aggregate).

2. Authorization from the FERC for the acquisition of the Purchased Assets by Buyer from Seller pursuant to Section 203 of the FPA, granted without material condition or limitation.

3. The waiting period (and any extensions thereof) applicable to the consummation of the transactions contemplated under the Agreement required pursuant to the provisions of the HSR Act shall have expired or been terminated.

SCHEDULE 1.1-K

Knowledge Individuals

1. Josef M. Alves
2. Mark R. Sudbey
3. Michael Bruneau
4. Christopher McDougal
5. Tim Gusick
6. Tommy Milburn

SCHEDULE 1.1-PL

Permitted Liens

1. Liens upon or in respect of the Purchased Assets securing the Indebtedness of Seller under the credit agreement, dated as of June 29, 2018, among Seller, as the borrower thereunder, the Several Lender parties thereto, BNP Paribas, as administrative agent, and other Revolving Facility Issuing Bank parties thereto, including, but not limited to:
    a. First Lien Mortgage by New Covert Generating Company, LLC to MUFG Union Bank, N.A., dated June 29, 2018, and recorded on July 2, 2018 at Liber 1670, Page 708;
    b. UCC Financing Statement filed by MUFG Union Bank, N.A. in Van Buren County, Michigan, recorded on July 2, 2018 at Liber 1670, Page 709;
    c. Delaware UCC Filing No. 2018 4472987; and
    d. Delaware UCC Filing No. 2018 4474827.

2. Liens upon or in respect of the Purchased Assets securing interest rate, energy, gas or other hedges or otherwise granted under ISDAs or Financial Transmission Rights including, but not limited to the following:
    a. All Liens granted pursuant to the Material Contracts listed on Schedule 3.12(a) under the headings "ISDAs", "Power & Gas Hedges", "Financial Transmission Rights" and "Interest Rate Hedges";
    b. Second Lien Mortgage by New Covert Generating Company, LLC to MUFG Union Bank, N.A., dated June 29, 2018, and recorded on July 2, 2018 at Liber 1670, Page 710; and
    c. UCC Financing Statement filed by MUFG Union Bank, N.A. in Van Buren County, Michigan, recorded on July 2, 2018 at Liber 1670, Page 711.

For the avoidance of doubt, nothing in this Schedule 1.1-PL is intended to require the removal of Liens granted by Seller under any Assigned Contract.

SCHEDULE 1.1-SA

Seller Approvals

1. Authorization from the FERC for the acquisition of the Purchased Assets by Buyer from Seller pursuant to Section 203 of the FPA, granted without material condition or limitation.

2. The waiting period (and any extensions thereof) applicable to the consummation of the transactions contemplated under the Agreement required pursuant to the provisions of the HSR Act shall have expired or been terminated.

3. A final order of the MPSC regarding Buyer's integrated resource plan to be filed with the MPSC in June 2021, in a form that includes the following:

   (a) approval of Buyer's proposed integrated resource plan, in a manner acceptable to Buyer;

   (b) affirmation that Buyer's proposed integrated resource plan, including acquisition of the Project by Buyer, represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs; and

   (c) a finding that the Purchase Price is specifically approved and considered reasonable and prudent for cost recovery purposes;

   and in the case of each of the approvals set forth in clauses (b) and (c), without the imposition of other conditions that taken in the aggregate would have the effect of reducing the recovery of costs as proposed in Buyer's integrated resource plan (other than any *de minimis* reductions that are less than $100,000 in the aggregate).

4. Approval by the Federal Communications Commission of transfer of FCC license WPWV765 held by Seller.

5. Approvals with respect to the Permits set forth on Schedule 3.14(a).

SCHEDULE 3.3(b)

Seller Consents

1. Defined Terms:

As used in this Schedule 3.3(b), "Original Covert" means Covert Generating Company, LLC in its capacity as a former counterparty to the applicable contract as listed below.

2. Consents required for Assigned Contracts:

(a) Consent of Mitsubishi Hitachi Power Systems Americas, Inc. under that certain Amended and Restated Long Term Service Agreement between Seller and Mitsubishi Hitachi Power Systems Americas, Inc. dated June 30, 2017, as amended by the Amendment thereto dated February 28, 2019.

(b) Consent of ANR Pipeline Company under that certain Agreement for Installation of Electronic Monitoring Equipment between ANR Pipeline Company and Original Covert, dated September 17, 2002 (Original Covert's interests were transferred to Seller pursuant to that certain Asset Transfer Agreement dated August 16, 2004 between Original Covert and Seller).

(c) Consent of ANR Pipeline Company under that certain Interconnection and Operating Agreement between ANR Pipeline Company and Original Covert dated October 30, 2000, as amended by the First Amendment to Interconnection and Operating Agreement dated as of February 5, 2002 (Original Covert's interests were transferred to Seller pursuant to that certain Asset Transfer Agreement dated August 16, 2004 between Original Covert and Seller).

(d) Consent of ANR Pipeline Company under that certain ITS-3 Service Agreement between ANR Pipeline Company and Seller, dated May 2, 2012.

(e) Consent of ANR Pipeline Company under that certain IPLS Service Agreement between ANR Pipeline Company and Seller, dated May 2, 2012.

(f) Consent of SUEZ WTS Services USA, Inc. (f/k/a GE Mobile Water, Inc.) under that certain Master Services Agreement between Seller and SUEZ WTS Services USA, Inc. (f/k/a GE Mobile Water, Inc.) dated November 1, 2016.

(g) Consent of Sequent Energy Management, L.P. under that certain Base Contract for Sale and Purchase of Natural Gas between Sequent Energy Management, L.P., and Seller dated June 1, 2018.

(h) Consent of Sequent Energy Management, L.P. under that certain Transaction Confirmation between Sequent Energy Management, L.P. and Seller dated June 27, 2018.

(i) Consent of USPG Power Services, LLC under that certain Asset Management Agreement between Seller, Eastern Covert, LLC, and USPG Power Services, LLC, dated June 29, 2018.

(j) Consent of ITC Interconnection LLC under that certain Facilities Reimbursement Agreement by and between Seller and ITC Interconnection LLC dated as of August 25, 2014, as amended by Amendment No. 1 dated February 1, 2017.

(k) Consent of ITC Interconnection LLC under that certain Facilities Development Agreement by and between Seller and ITC Interconnection LLC, dated as of August 25, 2014, as amended by that certain Letter dated December 9, 2014.

(l) Consent of ITC Interconnection LLC under that certain Substation Purchase Agreement between ITC Interconnection LLC and Seller, dated June 1, 2016.

(m) Consent of both PJM Interconnection, LLC and ITC Interconnection LLC under that certain Interconnection Service Agreement (PJM Queue #AC1-072) among PJM Interconnection, LLC, Seller and ITC Interconnection LLC, dated May 8, 2018.

(n) If Seller enters into the MISO GIA prior to Closing, any consent required thereunder to its assignment to Buyer.

(o) If Missing Contract (as defined in Schedule 3.12(b)) is located and to be assigned to Buyer in accordance with the Agreement, any consent required thereunder to its assignment to Buyer.

3. Termination Prior to Closing. Notwithstanding anything else to the contrary in the Agreement or in Section 2 of this Schedule 3.3(b), if any of the Contracts referred to in Section 2 of this Schedule 3.3(b) terminates in accordance with its terms prior to Closing, then such Contract shall not be an Assigned Contract for any purposes of the Agreement and no consent to assignment of such Contract shall be a Seller Consent for any purposes of the Agreement; provided, that if such terminating Contract is extended beyond Closing, such extended Contract shall be an Assigned Contract and the consent to assignment of such extended Contract shall be a Seller Consent.

SCHEDULE 3.6

Legal Proceedings

Seller is contesting the true cash, assessed and taxable value assessed by the Township of Covert (the "Township") for tax years 2016 -2021 in MTT Dockets #16-001888-TT, #17-001737-TT, #18-001312-TT, #19-000863-TT, #20-002115-TT and #21-001632-TT. The Michigan Tax Tribunal (the "Tax Tribunal") issued its final opinion and judgment related to the 2016 appeal, which the Township appealed to the Michigan Court of Appeals, and, subsequently, to the Michigan Supreme Court where it was denied. In May 2021, the Township filed a motion for reconsideration and Seller filed an answer.

The appeals for 2017 - 2020 are being held in abeyance by the Tax Tribunal.

SCHEDULE 3.10

Taxes

		C	A	B	B - A	C - A
Tax Year	Period	Initial Bill	Amount Paid*	Estimated Revised Tax Bills Per Final Opinion	Remaining Amount Payable to Tax Authority	Billed in excess of paid
2016	Summer (Sep'16)	$ 9,665,916.56	$ 4,100,057.87	$ 4,280,168.94	$ 180,111.07	$ 5,565,858.69
2016	Winter (Feb'17)	5,410,220.30	3,263,815.00	3,896,786.64	632,971.64	2,146,405.30
2017	Summer (Sep'17)	9,821,514.06	4,239,974.15	4,471,029.52	231,055.37	5,581,539.91
2017	Winter (Feb'18)	5,567,049.27	3,417,026.24	4,071,295.47	654,269.23	2,150,023.03
2018	Summer (Sep'18)	9,821,515.01	4,438,593.35	4,561,508.40	122,915.05	5,382,921.66
2018	Winter (Feb'19)	5,361,852.00	4,007,725.79	4,007,402.08	(323.71)	1,354,126.21
2019	Summer (Sep'19)	6,778,979.88	4,836,451.56	4,836,609.47	157.91	1,942,528.32
2019	Winter (Feb'20)	5,534,172.86	4,411,327.95	4,411,414.08	86.13	1,122,844.91
2020	Summer (Sep'20)	6,780,687.51	5,000,491.46	5,000,491.46	(0.00)	1,780,196.05
2020	Winter (Feb'21)	5,753,248.25	4,761,798.03	4,761,798.03	-	991,450.22
		$ 70,495,155.70	$ 42,477,261.40	$ 44,298,504.07	$ 1,821,242.67	$ 28,017,894.30

SCHEDULE 3.12(a)

Material Contracts

1. The Assigned Contracts.

2. FERC Reactive Supply Tariff Acceptance of Filing issued June 20, 2016 and effective June 1, 2016.

3. Energy Management Agreement between New Covert Generating Company, LLC and NextEra Energy Marketing, LLC dated as of April 1, 2019.

4. NAESB Base Contract for Sale and Purchase of Natural Gas between Sequent Energy Management, L.P. and New Covert Generating Company, LLC, dated June 26, 2018, and the Special Provisions Amendment thereto, dated June 26, 2018.

5. Security Agreement among Sequent Energy Management L.P., New Covert Generating Company, LLC and MUFG Union Bank, N.A., as Collateral Agent, dated May 24, 2019.

6. Station Service Contract between Indiana Michigan Power Company, LLC and New Covert Generating Company, LLC dated May 13, 2016, as modified by that certain Station Service Contract between Indiana Michigan Power Company, LLC and New Covert Generating Company, LLC dated as of April 4, 2018 and effective as of June 1, 2018.

7. Signage easement reserved in the Covenant Deed recorded in Liber 1625, Page 304, Van Buren County Records.

ISDAs

Agreement	Party	Counterparty	Type
ISDA Master Agreement dated as of May 3, 2018	New Covert Generating Company, LLC	J. Aron & Company	Master Agreement
Schedule to ISDA Master Agreement, dated as of May 3, 2018, as amended as of June 29, 2018 (together with the Exhibits thereto)	New Covert Generating Company, LLC	J. Aron & Company	Schedule to Master Agreement
ISDA Novation Agreement dated as of June 29, 2018, to novate the ISDA Master Agreement dated as of November 12, 2014	New Covert Generating Company, LLC	J. Aron & Company	Novation Agreement
Accession Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	J. Aron & Company	Accession Agreement
IECA Amendment adopting, incorporating and amending the ISDA August 2012 DF Supplement made as of May 3, 2018	New Covert Generating Company, LLC	J. Aron & Company	IECA Amendment

IECA Amendment adopting, incorporating and amending the ISDA March 2013 DF Supplement made as of May 3, 2018	New Covert Generating Company, LLC	J. Aron & Company	IECA Amendment
ISDA Master Agreement dated as of May 1, 2018	New Covert Generating Company, LLC	Morgan Stanley Capital Services LLC	Master Agreement
Schedule to ISDA Master Agreement, dated as of May 1, 2018	New Covert Generating Company, LLC	Morgan Stanley Capital Services LLC	Schedule to Master Agreement
ISDA Novation Agreement dated as of June 28, 2018, to novate the ISDA Master Agreement dated as of April 20, 2016	New Covert Generating Company, LLC	Morgan Stanley Capital Services LLC	Novation Agreement
ISDA Credit Support Annex to the Master Agreement dated as of May 1, 2018	New Covert Generating Company, LLC	Morgan Stanley Capital Services LLC	Credit Support Annex to Master Agreement
Amendment No. 1 to ISDA Master Agreement, dated as of June 28, 2018	New Covert Generating Company, LLC	Morgan Stanley Capital Services LLC	Amendment to Schedule to Master Agreement
IECA Amendment adopting, incorporating and amending the ISDA August 2012 DF Supplement made as of May 1, 2018	New Covert Generating Company, LLC	Morgan Stanley Capital Services LLC	IECA Amendment
IECA Amendment adopting, incorporating and amending the ISDA March 2013 DF Supplement made as of May 1, 2018	New Covert Generating Company, LLC	Morgan Stanley Capital Services LLC	IECA Amendment
Accession Agreement dated as of June 28, 2018	New Covert Generating Company, LLC	Morgan Stanley Capital Services LLC	Accession Agreement
ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	ABN AMRO BANK, N.V.	Master Agreement
Schedule to ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	ABN AMRO BANK, N.V.	Schedule to Master Agreement
Accession Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	ABN AMRO BANK, N.V.	Accession Agreement
ISDA Cross Border Swaps Representation Letter w.e.f June 29, 2018	New Covert Generating Company, LLC	ABN AMRO BANK, N.V.	Cross Border Swaps Rep
Supplemental Special Entity Representation Letter as of June 29, 2018	New Covert Generating Company, LLC	ABN AMRO BANK, N.V.	Special Entity Rep
Swap Reporting CFTC Authorization letter as of June 29, 2018	New Covert Generating Company, LLC	ABN AMRO BANK, N.V.	CFTC Reporting Authorization
ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	BNP Paribas	Master Agreement
Schedule to ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	BNP Paribas	Schedule to Master Agreement

IECA Amendment adopting, incorporating and amending the ISDA August 2012 DF Supplement made as of June 29, 2018	New Covert Generating Company, LLC	BNP Paribas	IECA Amendment
IECA Amendment adopting, incorporating and amending the ISDA March 2013 DF Supplement made as of June 29, 2018	New Covert Generating Company, LLC	BNP Paribas	IECA Amendment
Accession Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	BNP Paribas	Accession Agreement
ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	Credit Agricole Corporate and Investment Bank	Master Agreement
Schedule to ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	Credit Agricole Corporate and Investment Bank	Schedule to Master Agreement
IECA Amendment adopting, incorporating and amending the ISDA August 2012 DF Supplement made as of June 29, 2018	New Covert Generating Company, LLC	Credit Agricole Corporate and Investment Bank	IECA Amendment
IECA Amendment adopting, incorporating and amending the ISDA March 2013 DF Supplement made as of June 29, 2018	New Covert Generating Company, LLC	Credit Agricole Corporate and Investment Bank	IECA Amendment
IECA Amendment adopting, incorporating and amending the ISDA DF protocol extension: EMIR portfolio reconciliation, dispute resolution and disclosure	New Covert Generating Company, LLC	Credit Agricole Corporate and Investment Bank	IECA Amendment
Accession Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	Credit Agricole Corporate and Investment Bank	Accession Agreement
ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	Commonwealth Bank of Australia	Master Agreement
Schedule to ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	Commonwealth Bank of Australia	Schedule to Master Agreement
IECA Amendment adopting, incorporating and amending the ISDA August 2012 DF Supplement made as of June 29, 2018	New Covert Generating Company, LLC	Commonwealth Bank of Australia	IECA Amendment
IECA Amendment adopting, incorporating and amending the ISDA March 2013 DF Supplement made as of June 29, 2018	New Covert Generating Company, LLC	Commonwealth Bank of Australia	IECA Amendment
Accession Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	Commonwealth Bank of Australia	Accession Agreement
ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	Investec Bank PLC	Master Agreement

Schedule to ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	Investec Bank PLC	Schedule to Master Agreement
Dodd-Frank Transaction Reporting Terms	New Covert Generating Company, LLC	Investec Bank PLC	DF Reporting Terms
First Amendment to Dodd-Frank Reporting Terms	New Covert Generating Company, LLC	Investec Bank PLC	DF Reporting Terms
Accession Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	Investec Bank PLC	Accession Agreement
ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	MUFG Union Bank, N.A.	Master Agreement
Schedule to ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	MUFG Union Bank, N.A.	Schedule to Master Agreement
ISDA Credit Support Annex to the Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	MUFG Union Bank, N.A.	Credit Support Annex and Paragraph 13 to Master Agreement
Accession Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	MUFG Union Bank, N.A.	Accession Agreement
ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	SMBC Capital Markets, Inc.	Master Agreement
Schedule to ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	SMBC Capital Markets, Inc.	Schedule to Master Agreement
IECA Amendment adopting, incorporating and amending the ISDA August 2012 DF Supplement made as of June 29, 2018	New Covert Generating Company, LLC	SMBC Capital Markets, Inc.	IECA Amendment
IECA Amendment adopting, incorporating and amending the ISDA March 2013 DF Supplement made as of June 29, 2018	New Covert Generating Company, LLC	SMBC Capital Markets, Inc.	IECA Amendment
Accession Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	SMBC Capital Markets, Inc.	Accession Agreement
ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	Societe Generale	Master Agreement
Schedule to ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	Societe Generale	Schedule to Master Agreement
IECA Amendment adopting, incorporating and amending the ISDA August 2012 DF Supplement made as of June 29, 2018	New Covert Generating Company, LLC	Societe Generale	IECA Amendment
IECA Amendment adopting, incorporating and amending the ISDA March 2013 DF Supplement made as of June 29, 2018	New Covert Generating Company, LLC	Societe Generale	IECA Amendment

IECA Amendment adopting, incorporating and amending the ISDA DF protocol extension: EMIR portfolio reconciliation, dispute resolution and disclosure	New Covert Generating Company, LLC	Societe Generale	IECA Amendment
Accession Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	Societe Generale	Accession Agreement
ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	SunTrust (name changed through merger to Truist Bank in Dec 2019)	Master Agreement
Schedule to ISDA Master Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	SunTrust (name changed through merger to Truist Bank in Dec 2019)	Schedule to Master Agreement
Swaps Application and Terms (to address Dodd Frank reports)	New Covert Generating Company, LLC	SunTrust (name changed through merger to Truist Bank in Dec 2019)	DF Reporting Terms
Accession Agreement dated as of June 29, 2018	New Covert Generating Company, LLC	SunTrust (name changed through merger to Truist Bank in Dec 2019)	Accession Agreement

Power & Gas Hedges

Agreement	Party	Counterparty	Type
Confirmation (Transaction E5793825-1), dated November 21, 2017	New Covert Generating Company, LLC	Morgan Stanley Capital Services LLC	Commodity Hedge Agreement
Confirmation (Transaction E5860281-1), dated January 18, 2018	New Covert Generating Company, LLC	Morgan Stanley Capital Services LLC	Commodity Hedge Agreement
Confirmation (Transaction E5929597-1), dated March 14, 2018	New Covert Generating Company, LLC	Morgan Stanley Capital Services LLC	Commodity Hedge Agreement
Confirmation (Transaction E5966582-1), dated April 11, 2018	New Covert Generating Company, LLC	Morgan Stanley Capital Services LLC	Commodity Hedge Agreement
Confirmation (Transaction E5968567-1), dated April 12, 2018	New Covert Generating Company, LLC	Morgan Stanley Capital Services LLC	Commodity Hedge Agreement
Confirmation (Transaction E5968085-1), dated April 12, 2018	New Covert Generating Company, LLC	Morgan Stanley Capital Services LLC	Commodity Hedge Agreement
Confirmation (Transaction E5968094-1), dated April 12, 2018	New Covert Generating Company, LLC	Morgan Stanley Capital Services LLC	Commodity Hedge Agreement
Confirmation (Transaction SDBB4QN3333GBDFWMC1 1 1), dated April 17, 2018	New Covert Generating Company, LLC	J. Aron & Company	Commodity Hedge Agreement

Confirmation (Transaction SDBB4QN3333GBDFX9Z1 1 1), dated April 17, 2018	New Covert Generating Company, LLC	J. Aron & Company	Commodity Hedge Agreement
Confirmation (Transaction SDBB4QN3333GBDG4F31 1 1), dated April 17, 2018	New Covert Generating Company, LLC	J. Aron & Company	Commodity Hedge Agreement
Confirmation (Transaction SDBB4QN3333GBDGC661 1 1), dated April 17, 2018	New Covert Generating Company, LLC	J. Aron & Company	Commodity Hedge Agreement
Confirmation (Transaction SDBB4QN3333GBR693G1 1 1), dated April 18, 2018	New Covert Generating Company, LLC	J. Aron & Company	Commodity Hedge Agreement
Confirmation (Transaction SDBB4QN3333GBR74H91 1 1), dated April 18, 2018	New Covert Generating Company, LLC	J. Aron & Company	Commodity Hedge Agreement
Confirmation (Transaction SDBB4QN3333GBR77ND1 1 1), dated April 18, 2018	New Covert Generating Company, LLC	J. Aron & Company	Commodity Hedge Agreement
Confirmation (Transaction SDBB4QN3333GBR4W6T1 1 1), dated April 18, 2018	New Covert Generating Company, LLC	J. Aron & Company	Commodity Hedge Agreement

Financial Transmission Rights

Agreement	Party	Counterparty	Type
PJM Auction Date 3/10/2021, FTR ID 234982815	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 4/26/2021, FTR ID 237561431	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 4/26/2021, FTR ID 237561432	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/3/2021, FTR ID 237904468	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 9/12/2019, FTR ID 195112416	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563618	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563633	New Covert Generating Company, LLC	PJM	Financial Transmission Rights

PJM Auction Date 5/20/2021, FTR ID 238563634	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563635	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563636	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563637	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563648	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563649	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563650	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563651	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563652	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563653	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563654	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563655	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563656	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563663	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563664	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563665	New Covert Generating Company, LLC	PJM	Financial Transmission Rights

PJM Auction Date 5/20/2021, FTR ID 238563678	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563679	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563680	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563681	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563682	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563683	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563684	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563685	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563686	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563687	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563688	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563689	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563690	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563691	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563692	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563693	New Covert Generating Company, LLC	PJM	Financial Transmission Rights

PJM Auction Date 5/20/2021, FTR ID 238563694	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563695	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563696	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563697	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563698	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563699	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563700	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563701	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563702	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563703	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563704	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563705	New Covert Generating Company, LLC	PJM	Financial Transmission Rights
PJM Auction Date 5/20/2021, FTR ID 238563706	New Covert Generating Company, LLC	PJM	Financial Transmission Rights

Interest Rate Hedges

Agreement	Party	Counterparty	Type
25365703, dated July 3, 2018	New Covert Generating Company, LLC	ABN	Interest Rate Swap/Hedge
NEWXJ0GY, dated July 3, 2018	New Covert Generating Company, LLC	CBA	Interest Rate Swap/Hedge

20080377, dated July 3, 2018	New Covert Generating Company, LLC	BNP	Interest Rate Swap/Hedge
8864650, dated July 5, 2018	New Covert Generating Company, LLC	Credit Agricole - CIB	Interest Rate Swap/Hedge
20087693, dated July 5, 2018	New Covert Generating Company, LLC	BNP	Interest Rate Swap/Hedge
1030174784_CLP_338653, dated July 5, 2018	New Covert Generating Company, LLC	MUFG	Interest Rate Swap/Hedge
B8M3778, dated July 5, 2018	New Covert Generating Company, LLC	SMBC	Interest Rate Swap/Hedge
106651776, dated July 6, 2018	New Covert Generating Company, LLC	Investec	Interest Rate Swap/Hedge
261473, dated July 6, 2018	New Covert Generating Company, LLC	SunTrust	Interest Rate Swap/Hedge
IRD586188, dated July 6, 2018	New Covert Generating Company, LLC	Soc-Gen	Interest Rate Swap/Hedge
321083, dated December 18, 2018	New Covert Generating Company, LLC	SunTrust	Interest Rate Swap/Hedge
22346241, dated October 3, 2019	New Covert Generating Company, LLC	BNP	Interest Rate Swap/Hedge

SCHEDULE 3.12(b)

Material Contracts – Made Available

Seller has not been able to locate that certain Precedent Agreement, dated October 30, 2000 (the "Missing Contract") as referred to in that certain Interconnection and Operating Agreement between ANR Pipeline Company and Covert Generating Company, LLC, dated October 30, 2000, as amended by the First Amendment to Interconnection and Operating Agreement dated as of February 5, 2002. As such, the Missing Contract has not been provided to Buyer.

SCHEDULE 3.13(c)

Legal Descriptions of the Property

Situated in the Township of Covert, County of Van Buren, State of Michigan

Parcel 1: BEGINNING at the North Quarter Post of Section 4, Town 2 South, Range 17 West; THENCE with bearings referenced to M.D.O.T. right of way maps, North 89 degrees 44 minutes 37 seconds East on the North Section line, 1194.17 feet; THENCE South 00 degrees 08 minutes 13 seconds East, 290.40 feet; THENCE North 89 degrees 44 minutes 37 seconds East, 150.00 feet to the East line of the West half of the Northeast Fractional Quarter; THENCE South 00 degrees 08 minutes 13 seconds East on same, 2636.86 feet to the East and West Quarter line; THENCE South 00 degrees 01 minutes 52 seconds East along the East line of the West half of the Southeast Quarter, 657.25 feet to the South line of the North half of the North half of the Southeast Quarter; THENCE South 89 degrees 32 minutes 07 seconds West on said South line, 1324.46 feet to the North and South Quarter line; THENCE South 89 degrees 32 minutes 10 seconds West along the South line of the North half of the North half of the Southwest Quarter, 1678.49 feet to the Easterly line of I-196 Highway; THENCE North 16 degrees 32 minutes 17 seconds East along said Easterly line, 3755.89 feet to the North line of the Section; THENCE North 89 degrees 46 minutes 20 seconds East along said North line, 582.22 feet to the place of BEGINNING.

Parcel 2: COMMENCING at the South Quarter Post of Section 4, Town 2 South, Range 17 West; THENCE North 00 degrees 44 minutes 11 seconds East on the North and South Quarter line 477.04 feet to the place of BEGINNING of this description; THENCE North 89 degrees 57 minutes 12 seconds West 110.38 feet; THENCE North 00 degrees 00 minutes 19 seconds West 172.81 feet; thence South 89 degrees 11 minutes 10 seconds East 112.61 feet to the North and South Quarter line; thence South 00 degrees 44 minutes 11 seconds West on same, 171.32 feet to the Place of Beginning.

Parcel 3: Together with easement rights reserved in the Covenant Deed recorded in Liber 1625, Page 304, Van Buren County Records.

SCHEDULE 3.14(a)

Permits

Permits	Reference No.	Permitting Agency	Effective Date	Expiration Date
Source-Wide Permit to Install[1]	Permit No. MI-PTI-N6767-2020 incorporated into the Title V Permit	EGLE	April 2, 2020	October 2, 2021
Clean Air Act (CAA) Title IV – Phase II Acid Rain Permit	Permit No. MI-AR-55297-2020	EGLE	September 21, 2020	September 21, 2025
Title V Operating Permit / Renewable Operating Permit (ROP)	ROP No. MI-ROP-N6767-2020	EGLE	September 21, 2020	September 21, 2025
National Pollutant Discharge Elimination System (NPDES) Permit for Wastewater Discharges	Permit No. MI0056138	EGLE	May 1, 2015	April 4, 2018/ October 1, 2018 (see notes)
Storm Water General NPDES Permit Associated with Industrial Activity	Incorporated into NPDES Permit for Wastewater Discharge	EGLE	May 1, 2015	April 4, 2018/ October 1, 2018 (see notes)
Hazardous Waste Identification Number	CESQG No. MIK438923492	EGLE	n/a	n/a
Water Boiler Permit (Unit 3)	MIR403974	Michigan Department of Licensing and Regulatory Affairs Bureau of Construction Codes/Boiler Division	3/31/2020	3/31/2022
Water Boiler Permit (Unit 3)	MIR403975	Michigan Department of Licensing and Regulatory Affairs Bureau of Construction	3/31/2020	3/31/2022

[1] Section 6.10 of the Agreement shall not apply with respect to this Source-Wide Permit to Install.

		Codes/Boiler Division		
Water Boiler Permit (Unit 3)	MIR403976	Michigan Department of Licensing and Regulatory Affairs Bureau of Construction Codes/Boiler Division	3/31/2020	3/31/2022
Water Boiler Permit (Auxiliary Boiler)	MIR418146	Michigan Department of Licensing and Regulatory Affairs Bureau of Construction Codes/Boiler Division	1/31/2020	1/31/2021
Water Boiler Permit (Unit 1)	MIR403981	Michigan Department of Licensing and Regulatory Affairs Bureau of Construction Codes/Boiler Division	10/29/2020	10/29/2022
Water Boiler Permit (Unit 1)	MIR403980	Michigan Department of Licensing and Regulatory Affairs Bureau of Construction Codes/Boiler Division	10/29/2020	10/29/2022
Water Boiler Permit (Unit 1)	MIR403982	Michigan Department of Licensing and Regulatory Affairs Bureau of Construction Codes/Boiler Division	10/29/2020	10/29/2022
Water Boiler Permit (Unit 2)	MIR403977	Michigan Department of Licensing and Regulatory Affairs	2/7/2019	2/7/2021

		Bureau of Construction Codes/Boiler Division		
Water Boiler Permit (Unit 2)	MIR403978	Michigan Department of Licensing and Regulatory Affairs Bureau of Construction Codes/Boiler Division	2/7/2019	2/7/2021
Water Boiler Permit (Auxiliary Boiler)	MIR402138	Michigan Department of Licensing and Regulatory Affairs Bureau of Construction Codes/Boiler Division	1/31/2020	1/31/2021
Water Boiler Permit (Unit 2)	MIR403979	Michigan Department of Licensing and Regulatory Affairs Bureau of Construction Codes/Boiler Division	2/7/2019	2/7/2021
Other Permits/ Plans/Approvals	• SPCC Plan certified 1/2021 • 2020 Tier II annual filing submitted as required • Pollutant Minimization Plan for total Mercury approved 2/2016 • Green House Gas (GHG) reporting through e-GGRT • Compliance and Emission Database Reporting Interface (CEDRI) used for Boiler MACT			

SCHEDULE 3.15(b)

Environmental Matters – Compliance

1. Seller reported ammonia exceedances for Unit 1 that were experienced on March 15-16, 2021. A letter was submitted to EGLE on March 25, 2021. Additional tuning/ testing is scheduled for June 2021 to prevent future ammonia exceedances from occurring. Details were provided in a written notification and were reported in the 21Q1 Deviation Report.

2. On April 24, 2021, Unit 1 had a one-hour excursion above the 24-hour rolling CO ppm limit during the unit startup. During the recent Unit 1 outage in April, plant personnel troubleshot and made changes to the Overspeed Trip system. To verify that these changes were implemented correctly, an Overspeed Trip Test ("OST") was conducted. The OST (a required safety test) is typically attempted during shutdown sequence; however, the unit may not initiate a shutdown sequence until the scheduled fall outage. In an attempt to confirm that the changes made to the Overspeed Trip system were implemented correctly, the control room operator ("CRO") was instructed to attempt the OST during a startup. The CRO brought the unit to just over the startup threshold of 50% load to produce enough heat in the heat recovery steam generator to generate the minimum amount of steam required to operate the ST at low load. The CRO attempted the OST and it failed to operate after several attempts. Due to the extended period of operation at low load required to attempt the OST, Unit 1 exceeded the CO ppm limit. The CRO continued on with the startup and when the unit reached normal operating loads, the CO ppm concentration dropped below the permittable limit.

3. On May 28, 2021, Unit 3 had a short-term NOx excursion lasting less than two hours, with a maximum hourly average of 4.3 ppm during the 0100 hour. Based on a preliminary review, this short-term NOx excursion resulted in indicated 24-hour rolling average exceedances at a value of 2.1 ppm for hours 0100 through 2300.

SCHEDULE 3.15(f)

Environmental Matters – Emission Credits & Allowances

[*See attached*]

PRG_CODE	ACCOUNT_NUMBER	ACCOUNT_NAME	ACCOUNT_TYPE	VINTAGE_YEAR	START_BLOCK	END_BLOCK	TOTAL_BLOCK
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2015	461829	461892	64
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2015	461893	462194	302
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2015	462195	462412	218
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2016	354506	354618	113
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2016	354619	354920	302
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2016	354921	355138	218
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2016	1253358	1253362	5
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2016	1253363	1253368	6
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2016	1253369	1253373	5
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2017	390061	390182	122
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2017	1156510	1156514	5
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2017	1156515	1156520	6
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2017	1156521	1156524	4
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2018	389366	389631	266
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2018	389632	389948	317
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2018	389949	390177	229
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2018	1080107	1080111	5
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2018	1080112	1080117	6
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2018	1080118	1080121	4
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2019	382322	382587	266
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2019	382588	382904	317
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2019	382905	383133	229
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2019	1203145	1203148	4
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2019	1203149	1203153	5
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2019	1203154	1203157	4
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2020	393543	393808	266
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2020	393809	394125	317
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2020	394126	394354	229
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2020	1066789	1066796	8
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2020	1066797	1066806	10
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2020	1066807	1066813	7
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2021	273976	274241	266
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2021	274242	274558	317
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2021	274559	274787	229
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2022	254769	255034	266
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2022	255035	255351	317
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2022	255352	255580	229
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2023	258117	258382	266
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2023	258383	258699	317
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2023	258700	258928	229
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2024	251522	251787	266
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2024	251788	252104	317
CSNOX	055297FACLTY	New Covert Generating Project	Facility Account	2024	252105	252333	229

PRG_CODE	ACCOUNT_NUMBER	ACCOUNT_NAME	ACCOUNT_TYPE	VINTAGE_YEAR	START_BLOCK	END_BLOCK	TOTAL_BLOCK
CSOSG2	055297FACLTY	New Covert Generating Project	Facility Account	2017	388267	388272	6
CSOSG2	055297FACLTY	New Covert Generating Project	Facility Account	2021	100885	100897	13
CSOSG2	055297FACLTY	New Covert Generating Project	Facility Account	2021	100898	100918	21
CSOSG2	055297FACLTY	New Covert Generating Project	Facility Account	2021	100919	100935	17
CSOSG2	055297FACLTY	New Covert Generating Project	Facility Account	2022	87193	87205	13
CSOSG2	055297FACLTY	New Covert Generating Project	Facility Account	2022	87206	87226	21
CSOSG2	055297FACLTY	New Covert Generating Project	Facility Account	2022	87227	87243	17
CSOSG2	055297FACLTY	New Covert Generating Project	Facility Account	2023	87140	87152	13
CSOSG2	055253FACLTY	New Covert Generating Project	Facility Account	2023	87153	87173	21
CSOSG2	055297FACLTY	New Covert Generating Project	Facility Account	2023	87174	87190	17
CSOSG2	055297FACLTY	New Covert Generating Project	Facility Account	2024	84486	84498	13
CSOSG2	055297FACLTY	New Covert Generating Project	Facility Account	2024	84499	84519	21
CSOSG2	055297FACLTY	New Covert Generating Project	Facility Account	2024	84520	84536	17

PRG_CODE	ACCOUNT_NUMBER	ACCOUNT_NAME	ACCOUNT_TYPE	VINTAGE_YEAR	START_BLOCK	END_BLOCK	TOTAL_BLOCK
CSSO2G1	055297FACLTY	New Covert Generating Project	Facility Account	2015	1396026	1396026	1
CSSO2G1	055297FACLTY	New Covert Generating Project	Facility Account	2021	418687	418688	2
CSSO2G1	055297FACLTY	New Covert Generating Project	Facility Account	2021	418689	418690	2
CSSO2G1	055297FACLTY	New Covert Generating Project	Facility Account	2021	418691	418691	1
CSSO2G1	055297FACLTY	New Covert Generating Project	Facility Account	2022	374497	374498	2
CSSO2G1	055297FACLTY	New Covert Generating Project	Facility Account	2022	374499	374500	2
CSSO2G1	055297FACLTY	New Covert Generating Project	Facility Account	2022	374501	374501	1
CSSO2G1	055297FACLTY	New Covert Generating Project	Facility Account	2023	369443	369444	2
CSSO2G1	055297FACLTY	New Covert Generating Project	Facility Account	2023	369445	369446	2
CSSO2G1	055297FACLTY	New Covert Generating Project	Facility Account	2023	369447	369447	1
CSSO2G1	055297FACLTY	New Covert Generating Project	Facility Account	2024	363183	363184	2
CSSO2G1	055297FACLTY	New Covert Generating Project	Facility Account	2024	363185	363186	2
CSSO2G1	055297FACLTY	New Covert Generating Project	Facility Account	2024	363187	363187	1

PRG_CODE	ACCOUNT_NUMBER	ACCOUNT_NUMBER	ACCOUNT_NAME	PRG_CODE	VINTAGE_YEAR	START_BLOCK	END_BLOCK	TOTAL_BLOCK
CSSO2G1	055297FACLTY	055297FACLTY	New Covert Generating Project	ARP	2015	4988275	4988315	41

SCHEDULE 3.18(b)

Employees and Labor Matters – Facility Employees

Employee Id	Title
0141	Manager, Maintenance
0230	Technician, Operations & Maintenance V
0228	Technician, Operations & Maintenance IV
0198	Manager, Administrative
0201	Operator, Control Room
0203	Operator, Control Room
0206	Operator, Control Room
0207	Operator, Control Room
0213	Technician, I&C
0220	Technician, I&C
0221	Technician, I&C
0222	Technician, Operations & Maintenance IV
0223	Technician, Mechanical Maintenance
0224	Technician, Mechanical Maintenance
0226	Technician, Mechanical Maintenance
0227	Technician, Operations & Maintenance IV
0229	Technician, Operations & Maintenance V
0231	Technician, Operations & Maintenance IV
0232	Technician, Operations & Maintenance IV
0233	Technician, Operations & Maintenance V
0234	Technician, Operations & Maintenance V
0235	Manager, Operations & Safety
0236	Operator, Sr. Control Room
0237	Technician, Maintenance Lead
0238	Technician, Warehouse & Purchasing
1800	Manager, Plant
0947	Planner/Scheduler
1044	Assistant, Administrative
2596	Engineer, Plant

SCHEDULE 3.18(c)

Employees and Labor Matters – Contracts

None.

SCHEDULE 3.21

Insurance

Policy	Insurer	Policy Number	Policy Period	Coverage Limit (1)
Commercial Lines Package/ General Liability	Federal Insurance Company	3602-95-62	February 23, 2021 to February 23, 2022	$1,000,000 per occurrence; $2,000,000 aggregate limit
Automobile Liability	Zurich American Insurance Company	BAP-5948510-07	February 23, 2021 to February 23, 2022	$1,000,000 Combined Single Limit
Umbrella Liability	Federal Insurance Company	7989-56-71	February 23, 2021 to February 23, 2022	$10,000,000 per occurrence/aggregate
Excess Liability	Scottsdale Insurance Company	XNS0007109	February 23, 2021 to February 23, 2022	$90,000,000 per occurrence/aggregate in excess of $10,000,000 Umbrella Policy
	Berkley National Insurance Co.	CEX09604105-01		
	Endurance American Ins. Co.	EXC30001522201		
	Westchester Fire Insurance Company	G46868390004		
	RSUI Indemnity Company	NHA093136		
	Everest National Insurance Company	XC6EX00102-211		
Pollution Legal Liability	Lloyds Syndicate 2623/623	W21FA1210401	February 23, 2021 to February 23, 2022	$10,000,000 per condition/aggregate
All Risk Property & Business Interruption	Allianz Global Risks US Insurance Company	USE000626210	March 17, 2021 to March 17, 2022	$500,000,000 per occurrence/aggregate, subject to sublimits; $250,000,000 Earth Movement, Named Windstorm and Flood with additional sublimits
	Associated Electric & Gas Insurance Services	PO5664606P		
	General Security Indemnity Company of Arizona	FA0016061-2021-1		
	Lloyd's Syndicate 1183 TAL, Talbot (Validus)	AJF232426E21		
	The Princeton Excess & Surplus Lines Ins Co	58-A3-PP-0000262-01		
	Lloyd's Syndicate (Travelers, Lancashire)	ENGLO2100527		
	Guide One National Insurance Company	099000796		
	Lloyd's Syndicate (Argenta, Arch, Aegis, Aspen, HDI)	ENGLO2100531		
	Liberty Specialty Markets (Bermuda)	ENGLO2100539		
	OCIL Bermuda	ENGLO2100538		
	Argo Insurance Services Bermuda Ltd.	ENGLO2100970		

Policy	Insurer	Policy Number	Policy Period	Coverage Limit (1)
	Chubb Bermuda International	ENGLO2101681		
	Lloyd's Syndicate (Faraday)	ENGLO2100533		
	Lloyd's Syndicate (Hiscox, Occam)	ENGLO2101697		
	XL Catlin Insurance UK Convex Insurance UK	ENGLO2100536		
Terrorism	Lloyd's of London Syndicate No. 5000, Travelers (TRV)	ENGLO2100306	March 17, 2021 to March 17, 2022	$500,000,000 per occurrence/aggregate, subject to sublimits per All Risk policy
	Lloyd's of London Syndicate No. 0033, Hiscox et. al.	PRPNC2100464		
	Lloyd’s of London Syndicate No 2003 XL Catlin et. al	PRPNC2100467		

(1) All policies, with the exception of the Pollution Legal Liability, are shared with all other Eastern Generation, LLC entities. Pollution Legal Liability policy is shared with the other Eastern Generation, LLC owned Midwest entities.

SCHEDULE 5.1(c)

List of Replacement Security Requirements for Certain Assigned Contracts

New Covert Letter of Credit Summary
As of June 18, 2021

Relevant Agreement /Description	Beneficiary	Balance	Notes	CEC Required to provide at Closing if in PJM?	CEC Required to provide at Closing if in MISO?	CEC Required Credit Support at Closing if in PJM	CEC Required Credit Support at Closing if in MISO	Notes
Related to Assigned Contracts								
Facilities Development Agreement dated 8/25/14	ITC Interconnection, LLC	$ 11,133,545	1	Yes, can likely negotiate PG instead of L/C	Yes, can likely negotiate PG instead of L/C	$ 11,133,545	$ 11,133,545	2
Interconnection Service Agreement (PJM Queue #AC1-072) among PJM Interconnection, L.L.C, New Covert Generating Company, LLC and ITC Interconnection LLC, dated May 8, 2018	PJM Interconnection, Inc.	$ 260,000		Yes	No	$ 260,000	$ -	
Total Related to Assigened Contracts		$ 11,393,545				$ 11,393,545	$ 11,133,545	

[1] Credit requirement steps down on first of each month by $35,346.

[2] Based on today's balance; balance as of 5/31/2023 = $10,320,587

Relevant Agreement /Description	Beneficiary	Balance	Notes	CEC Required to provide at Closing if in PJM?	CEC Required to provide at Closing if in MISO?	CEC Required Credit Support at Closing if in PJM	CEC Required Credit Support at Closing if in MISO
To Be Provided During Interim Period							
[MISO DPP Study Process]	[MISO]	$ 4,800,000		Yes	No; not for interconnection, but other credit support may be required for operating in MISO	$ 4,800,000	$ -
Grand Total NCGC Current Credit Support Including MISO LC to Be Provided		$ 16,193,545		Grand Total CEC Credit Support Obligation		$ 16,193,545	$ 11,133,545

Execution Version

PURCHASE AND SALE AGREEMENT

by and among

Dearborn Industrial Generation, L.L.C.

CMS Generation Michigan Power, L.L.C.

CMS Energy Resource Management Company

Collectively, as Seller,

and

Consumers Energy Company

as Buyer

dated as of June 21, 2021

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EXHIBITS

SCHEDULES

PURCHASE AND SALE AGREEMENT

This Purchase and Sale Agreement, dated as of June 21, 2021 (this ***"Agreement"),*** is made and entered into by and among CMS Energy Resource Management Company, a Michigan corporation (***"CMS ERM"***), Dearborn Industrial Generation, L.L.C., a Michigan limited liability company (***"DIG"***), CMS Generation Michigan Power, L.L.C., a Michigan limited liability company (***"CMS GMP"***, and collectively with CMS ERM and DIG, ***"Seller"***) and Consumers Energy Company, a Michigan corporation (***"Buyer"***)**.**

W I T N E S S E T H :

WHEREAS, Seller desires to sell to Buyer, and Buyer desires to purchase from Seller, the Purchased Assets (as defined below) on the Closing Date (as defined below) on the terms and subject to the conditions set forth in this Agreement.

NOW, THEREFORE, in consideration of the premises and the mutual representations, warranties, covenants and agreements in this Agreement, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereby agree as follows:

ARTICLE I. DEFINITIONS AND CONSTRUCTION

Section 1.1. Definitions.

As used in this Agreement, the following capitalized terms have the meanings set forth below:

"Acceptable Orders" means all of the following:

(i) a final order of the MPSC that includes the following: (a) affirmation that the acquisition of the Project by Buyer is reasonable and prudent; (b) approval for Buyer to include the Base Purchase Price of the Project in its rate base, (c) recognition of the fuel costs associated with operation of the Project, and approval of the rate adjustments necessary to allow full recovery by Buyer of the non-fuel costs of operating and maintaining the Project; and in the case of each of the approvals set forth in clauses (b) and (c), without the imposition of other conditions that taken in the aggregate would have the effect of reducing such recovery; and in addition to all of the preceding, such order shall be in all other respects satisfactory to Buyer and not subject to appeal or further appeal;

(ii) a final order of the MPSC approving Buyer's integrated resource plan (to be filed with the MPSC in June 2021) in a form that is acceptable to Buyer and not subject to further appeal; and

(iii) authorization from the FERC for the acquisition of the Purchased Assets by Buyer from Seller pursuant to Section 203 of the FPA and granted without material condition or limitation.

"Acquisition Proposal" has the meaning given to it in Section 5.21.

"Affiliate" means, with respect to any Person, any other Person that directly or indirectly through one or more intermediaries, controls, is controlled by or is under common control with such Person. For purposes of this definition, "control" of a Person means the power, direct or indirect, to direct or cause the direction of the management and policies of such Person whether through ownership of voting securities or ownership interests, by Contract or otherwise, and specifically with respect to a corporation, partnership or limited liability company, means direct or indirect ownership of more than 50% of the voting securities in such corporation or of the voting interest in a partnership or limited liability company.

"Agreement" has the meaning given to it in the introduction to this Agreement.

"AK Steel" has the meaning given to it in Section 6.9.

"Ancillary Agreements" means the Assignment and Assumption Agreements, bills of sale, the Warranty Deeds, the Closing Certificates and the other documents and agreements to be delivered pursuant to this Agreement.

"Assets" of any Person means all assets and properties of every kind, nature, character and description (whether real, personal or mixed, whether tangible or intangible and wherever situated), including the related goodwill, which assets and properties are operated, owned or leased by such Person.

"Assigned Contracts" means all Contracts set forth on Schedule 1.1-AC, which schedule may be updated prior to Closing with the mutual written agreement of the Parties. The Assigned Contracts shall include the Third Party Contracts.

"Assignment and Assumption Agreements" means, collectively, an assignment and assumption agreement for each Assigned Contract, in a form acceptable to Buyer.

*"**Assumed Liabilities**"* has the meaning given to it in Section 2.2.

"Base Purchase Price" has the meaning given to it in Section 2.4.

"BEA" has the meaning given to it in Section 5.2(b).

"Benefit Plan" means all written and unwritten "employee benefit plans" within the meaning of Section 3(3) of ERISA, and any other written and unwritten profit sharing, pension, savings, deferred compensation, fringe benefit, insurance, medical, medical reimbursement, life, disability, accident, post-retirement health or welfare benefit, stock option, stock purchase, sick pay, vacation, employment, severance, termination or other plan, agreement, Contract, policy, trust fund or arrangement covering any employee, director or officer of Seller and which is established, maintained, sponsored, contributed to or entered into by Seller or with respect to which Seller has or may have any liability.

"Budget" means the major maintenance and capital expenditures budget estimates for Seller for the period from the date hereof until December 31, 2025, as set forth in Schedule 1.1-B.

"Business" means the ownership and operation of the Project as currently conducted, including the generation and sale of electricity and capacity and electric-related products by Seller or any of its Affiliates at or from the Project as currently conducted, the receipt by Seller of fuel and the conduct of other activities by Seller related or incidental to the foregoing all as currently conducted.

"Business Day" means a day other than Saturday, Sunday or any day on which banks located in the State of Michigan are authorized or obligated to close.

"Buyer" has the meaning given to it in the introduction to this Agreement.

"Buyer Approvals" means the filings, waivers, approvals, consents, authorizations and notices set forth in Schedule 1.1-BA, all in form and content satisfactory to Buyer and not subject to appeal or further appeal.

"Buyer Indemnified Parties" has the meaning given to it in Section 9.1(a).

"Buyer's Advisors" has the meaning given to it in Section 5.2(a).

"Buyer's Determination" has the meaning given to it in Section 2.8(a).

"Casualty Loss" has the meaning given to it in Section 5.11.

"Claim" means any demand, claim, action, investigation, legal proceeding (whether at law or in equity) or arbitration.

"Claiming Party" has the meaning given to it in Section 9.5(a).

"Closing" means the closing of the transactions contemplated by this Agreement, as provided for in Section 2.5.

"Closing Certificates" means the officer's certificates referenced in Section 6.3 and Section 7.3.

"Closing Date" means the date on which Closing occurs.

"Closing Date Net Working Capital" means the aggregate Net Working Capital of Seller as of the Closing Date.

"CMS ERM" has the meaning given to it in the introduction to this Agreement.

"CMS GMP" has the meaning given to it in the introduction to this Agreement.

"Code" means the Internal Revenue Code of 1986, as amended.

"Condemnation Value" has the meaning given to it in Section 5.12.

"Confidentiality Agreement" means the CEC 2021 Asset RFP Agreement of Confidentiality between Consumers Energy Company and CMS Enterprises Company dated as of January 19, 2021.

"Contract" means any legally binding contract, lease, license, evidence of Indebtedness, mortgage, indenture, purchase order, binding bid, letter of credit, security agreement or other legally binding arrangement, but shall exclude Permits.

"Controlled Group Liability" means any and all Liabilities under (i) Title IV of ERISA, (ii) Section 302 of ERISA, (iii) Sections 412 and 4971 of the Code, or (iv) the continuation coverage requirements of Section 601 et seq. of ERISA and Section 4980B of the Code.

"Deductible Amount" has the meaning given to it in Section 9.2(b).

"DIG" has the meaning given to it in the introduction to this Agreement.

"DOE" means the United States Department of Energy.

"Employees" has the meaning given to it in Section 3.18(b).

"Endorsements" has the meaning given to it in Section 5.23(a).

"Environmental Claim" means any Claim or Loss arising out of or related to any violation of, or any Liability or obligation under, any Environmental Law.

"Environmental Law" means the Comprehensive Environmental Response, Compensation and Liability Act, 42 U.S.C. § 9601 et seq.; the Resource Conservation and Recovery Act, 42 U.S.C. § 6901 et seq.; the Federal Water Pollution Control Act, 33 U.S.C. § 1251 et seq.; the Clean Air Act, 42 U.S.C. § 7401 et seq.; the Toxic Substances Control Act, 15 U.S.C. §§ 2601 through 2629; the Oil Pollution Act, 33 U.S.C. § 2701 et seq.; the Emergency Planning and Community Right-to-Know Act, 42 U.S.C. § 11001 et seq.; the Safe Drinking Water Act, 42 U.S.C. §§ 300f through 300j; implementing regulations under each of the foregoing; and all similar Laws (including implementing regulations) of any Governmental Authority having jurisdiction over the assets in question addressing pollution control or protection of public health or the environment. For purposes of this Agreement, the term "Environmental Law" does not include Laws respecting occupational health and safety.

"Environmental Liability" means any Loss arising from or relating to any asserted violation of or adjudicated Liability under Environmental Law, including: (a) any environmental matters or conditions (including on-site or off-site contamination, and regulation of chemical substances or products); and (b) any responsibility for response costs, natural resource damages, corrective action or actions to achieve compliance, including any cleanup, removal, containment or other remediation or response action ("cleanup"). The terms "removal," "remedial," and "response action" include the types of activities covered by the Federal Comprehensive Environmental Response, Compensation and Liability Act, 42 U.S.C. § 9601 et seq., as amended, or analogous state statute applicable to Seller.

"Equity Interests" means capital stock, partnership or membership interests or units (whether general or limited), and any other interest or participation that confers on a Person the right to receive a share of the profits and losses of, or distribution of assets of, the issuing entity.

"Equity Securities" means (i) Equity Interests, (ii) subscriptions, calls, warrants, options or commitments of any kind or character relating to, or entitling any Person to acquire, any

Equity Interests and (iii) securities convertible into or exercisable or exchangeable for Equity Interests.

"ERISA" means the Employee Retirement Income Security Act of 1974.

"ERISA Affiliate" means any entity, trade or business that is a member of a group described in Section 414(b) or (c) of the Code or Section 4001(b)(1) of ERISA that includes Seller, or that is a member of the same "controlled group" as Seller pursuant to Section 4001(a)(14) of ERISA.

"Estimated Closing Date Net Working Capital" has the meaning given to it in Section 2.7(a).

"***Estoppel Certificates***" shall mean: (i) an estoppel certificate in a form acceptable to Buyer signed by the current owner of the land located at 2400 Miller Road, Dearborn, Michigan and (ii) an estoppel certificate in a form acceptable to Buyer signed by Ford Motor Company.

"Excluded Liabilities" means all Liabilities of Seller or its Affiliates of every kind or nature whatsoever (including Tax Liabilities and any related party Liabilities) other than Assumed Liabilities.

"FERC" means the Federal Energy Regulatory Commission or its successor Governmental Authority.

"Financial Statements'' means, in relation to any Person, such Person's balance sheet and the related statements of income for the period then ended.

*"**Final Closing Date Net Working Capital**"* has the meaning given to it in Section 2.8(c).

"FPA" means the Federal Power Act, as amended, and FERC's implementing regulations promulgated thereunder.

"Fundamental Representations" has the meaning given to it in Section 9.2(a).

"GAAP" means generally accepted accounting principles in the United States of America.

"Governmental Authority" means the United States and any state, county, city or other political, subdivision or similar governing entity, and any court, tribunal, arbitrator, authority, agency, commission, official or other instrumentality of the United States or any state, county, city or other political subdivision or similar governing entity, and including any governmental, quasi-governmental or non-governmental body administering, regulating or having general oversight over natural gas, electricity, power or other markets, including NERC.

"Hazardous Material" means any substance designated as a hazardous waste, hazardous substance, extremely hazardous substance, hazardous material, hazardous chemical, pollutant, contaminant or toxic chemical under any Environmental Law, any petroleum or petroleum products, any radioactive material, any asbestos or any materials containing asbestos, and any urea formaldehyde or polychlorinated biphenyls.

"Indebtedness" means any of the following: (a) any indebtedness for borrowed money; (b) any obligations evidenced by bonds, debentures, notes or other similar instruments; (c) any obligations to pay the deferred purchase price of property or services, except trade accounts payable and other current Liabilities arising in the ordinary course of business consistent with past practices; (d) any obligations as lessee under capitalized leases; (e) any obligations, contingent or otherwise, under acceptance, letters of credit or similar facilities; and (f) any guaranty of any of the foregoing.

"Indemnified Parties" has the meaning given to it in Section 9.1(b).

"Indemnifying Party" means a Person required to indemnify a Seller Indemnified Party or a Buyer Indemnified Party, as the case may be, pursuant to the terms of this Agreement.

"Independent Accountants" has the meaning given to it in Section 2.8(b).

"Intellectual Property" means the following intellectual property rights, both statutory and common law rights, if applicable: (a) copyrights, registrations and applications for registration thereof, (b) trademarks, service marks, trade names, slogans, domain names, logos, trade dress, and registrations and applications for registrations thereof, (c) patents, as well as any reissued and reexamined patents and extensions corresponding to the patents, and any patent applications, as well as any related continuation, continuation in part and divisional applications and patents issuing therefrom and (d) trade secrets and confidential information, including ideas, designs, concepts, compilations of information, methods, techniques, procedures, processes and other know-how, whether or not patentable.

"Interim Period" has the meaning given to it in Section 5.1.

"Knowledge" when used in a particular representation in this Agreement with respect to Seller, means the actual knowledge, after reasonable inquiry, of the individuals listed on Schedule 1.1-K with respect to matters within the scope of their respective functional responsibilities listed therein.

"Laws" means (i) all laws, statutes, rules, regulations, ordinances, orders, decrees and court decisions of any Governmental Authority; (ii) other pronouncements of any Governmental Authority having the effect of law; and (iii) for the avoidance of any doubt, and whether or not falling within either or both of the preceding clauses (i) and (ii), all FERC-, NERC-, DOE-, and/or MISO-related requirements.

"Liabilities" means liabilities or obligations of any nature whatsoever, asserted or unasserted, known or unknown, absolute or contingent, accrued or unaccrued, matured or unmatured or otherwise.

"Lien" means any mortgage, pledge, deed of trust, assessment, security interest, charge, lien, option, restriction, easement, interest, lease, covenant, reservation, purchase right, right of first refusal, or other encumbrance of any nature whatsoever.

"Loss" or "Losses" means any and all judgments, losses, Liabilities, amounts paid in settlement, damages, fines, penalties, deficiencies, costs, charges, Taxes, obligations, demands, fees, interest, losses and expenses (including court costs and reasonable fees of attorneys, accountants and other experts in connection with any Claim). For all purposes in this Agreement the term "Losses" does not include any Non-reimbursable Damages.

"Material Adverse Effect" means a material adverse effect on the business, financial condition or results of operations of: (a) Seller or the Assets of Seller; or (b) the Buyer, as the case may be based on the relevant provision of this Agreement.

"Material Contracts" has the meaning given to it in Section 3.12(a).

"MISO" means Midcontinent Independent System Operator, Inc. or any other applicable independent system operator or interconnecting utility with respect to the Project, and any successors.

"MPSC" means the Michigan Public Service Commission or its successor Governmental Authority.

"NERC" means the North American Electric Reliability Corporation or its successor Governmental Authority, and includes any applicable regional entity (such as Reliability*First* Corporation) having authority over Seller or the Project.

"Net Working Capital" means, as of the applicable date and without duplication, the amount (expressed as a positive or negative number) determined by subtracting (a) the aggregate value of the current liabilities of the Business that are included in the Assumed Liabilities from (b) the aggregate value of the current assets of the Business that are included in the Purchased Assets, as calculated in accordance with the formula and methodology (including adjustments) as described in, and used in the preparation of, and only applying values to the categories of listed assets and liabilities as set forth in, Schedule 1.1-A. Schedule 1.1-A, which is a sample calculation of Net Working Capital as of March 31, 2020, is solely for illustrative purposes.

"Non-reimbursable Damages" has the meaning given to it in Section 9.4(b).

"NPDES Permit" has the meaning given to in Section 6.9.

"Organizational Documents" means, with respect to any Person, the articles or certificate of incorporation or organization and by-laws, the limited partnership agreement, the partnership agreement or the limited liability company agreement, or such other organizational documents of such Person, including those that are required to be registered or kept in the place of incorporation, organization or formation of such Person and which establish the legal personality of such Person.

"Owner's Affidavit" has the meaning given to it in Section 2.6(g).

"Parties" means collectively, Buyer and Seller.

"Permits" means all licenses, permits, certificates of authority, authorizations, approvals, registrations, franchises and similar consents and orders issued or granted by a Governmental Authority.

"Permitted Lien" means (a) any statutory Lien for Taxes not yet due or delinquent or being contested in good faith by appropriate proceedings; (b) the matters identified on Schedule 1.1-PL (except, at Closing, those items marked with an asterisk on such Schedule); (c) easements and restrictions that would be shown by an accurate survey that do not and will not have an adverse effect on the operation of the Business or the value of the property in question; (d) zoning, entitlement, conservation restriction and other land use and environmental regulations or rights imposed or granted by any Governmental Authority; (e) the rights of the Parties pursuant to this Agreement; and (f) such other easements, restrictions, encroachments, and use limitations, that do not and will not have an adverse effect on the operation of the Business or the value of the property in question.

"Person" means any natural person, corporation, general partnership, limited partnership, limited liability company, proprietorship, other business organization, trust, union, association or Governmental Authority.

"Project" means the electric generating facilities and all equipment, machinery, facilities, improvements and infrastructure used in connection therewith or in any way related thereto located at the Property and included in the Purchased Assets.

"Property" means the real property (whether owned or leased) on which the Project is located, as further described in Exhibit 2.1(a), including any improvements thereon and easements and rights-of-way appertaining thereto.

"Property Tax Lien Date" means, with respect to any calendar year, July 1 and December 1 of that calendar year.

"Property Taxes" means real and personal property taxes, special assessments and any payments in lieu of property taxes or under any other arrangements with the Taxing Authority.

"Prudent Engineering and Operating Practices" means the standards, practices, methods, procedures and acts which (a) conform with such degree of skill, diligence, prudence and foresight as would reasonably be expected from a skillful and experienced operator of a power station of similar type to the Project with a view to profit-making therefrom, and (b) would reasonably be expected to be applied by such Person exercising reasonable judgment in light of the facts known or that should have been known at the time a decision was made to accomplish the desired result in an efficient and workman-like manner consistent with Laws.

"Purchased Assets" has the meaning given to it in Section 2.1.

"Purchase Price" has the meaning given to it in Section 2.4.

"Purchase Price Reduction" has the meaning given to it in Section 6.9.

"Purchase Price Allocation Schedule" has the meaning given to it in Section 2.10(a).

"Recorded Documents" has the meaning given to it in Section 5.22(a).

"Release" means any release, spill, emission, migration, leaking, pumping, injection, deposit, disposal or discharge of any Hazardous Materials.

"Remediation Indemnity Obligations" has the meaning given to it in Section 6.9.

"Remediation Obligations" has the meaning given to it in Section 6.9.

"Representatives" means, as to any Person, its officers, directors, partners, members, and employees.

"Responding Party" has the meaning given to it in Section 9.5(a).

"Restoration Cost" has the meaning given to it in Section 5.11.

"Schedules" means the disclosure schedules prepared by Seller and attached to this Agreement.

"Seller'' has the meaning given to it in the introduction to this Agreement.

"Seller Approvals" has the meaning given to it in Section 3.3(c).

"*Seller Consents*" means the consents set forth in Schedule 3.3(b).

"Seller Indemnified Parties" has the meaning given to it in Section 9.1(b).

"Survey" has the meaning given to it in Section 5.22(b).

"Tax" or ***"Taxes"*** means (a) any federal, state, local or foreign income, gross receipts, ad valorem, sales and use, employment, social security, disability, occupation, industrial facilities, property, severance, value added, transfer, capital stock, excise, withholding, premium, occupation or other taxes, levies or other like assessments, customs, duties, imposts, charges surcharges or fees imposed by or on behalf of any Governmental Authority, including any interest, penalty or addition thereto and (b) any Liability for amounts described in clause (a), (i) as a result of transferee Liability, (ii) by Contract or (iii) otherwise.

"***Tax Return***" means any return, declaration, report, form, claim for refund, statement or other information (including any amendments) required to be supplied to any Governmental Authority with respect to Taxes, including information returns, any amendments thereof or schedule or attachment thereto, including any such document prepared on a consolidated, combined or unitary basis and also including any schedule or attachment thereto, and including any amendment thereof.

"Taxing Authority" means, with respect to any Tax, the governmental entity or political subdivision thereof that imposes such Tax and the agency (if any) charged with the collection of such Tax for such entity or subdivision.

"Terminated Contracts" has the meaning given to it in Section 5.4.

"Third Party Contracts" has the meaning given to it in Section 2.9(e).

"Title Commitment" has the meaning given to it in Section 5.22(a).

"Title Insurer" has the meaning given to it in Section 5.22(a).

"Title Objection" has the meaning given to it in Section 5.23(b).

"Title Policy" has the meaning given to it in Section 6.8.

"Transfer Taxes" means any and all transaction, transfer, sales, use, goods and services, recording, transaction privilege, real property transfer, stock transfer, value added, documentary, stamp duty, gross receipts, excise, transfer and conveyance Taxes and other similar Taxes, duties, fees or charges, including any related penalties, interest and additions thereto, to any Taxing Authority as a result of the transfer of the Project Assets from Seller to Buyer.

"***Transfer Tax Affidavits***" has the meaning given to it in Section 2.6(f).

"Warranty Deed" has the meaning given to it in Section 2.6(e).

"Water Limit Obligations" has the meaning given to it in Section 6.9.

"ZRC" means Zonal Resource Credit.

Section 1.2. Rules of Construction.

(a) All article, section, subsection, schedule and exhibit references used in this Agreement are to articles, sections, subsections, schedules and exhibits to this Agreement unless otherwise specified. The exhibits and schedules attached to this Agreement constitute a part of this Agreement and are incorporated in this Agreement for all purposes.

(b) If a term is defined as one part of speech (such as a noun), it shall have a corresponding meaning when used as another part of speech (such as a verb). Unless the context of this Agreement clearly requires otherwise words importing the masculine gender shall include the feminine and neutral genders and vice versa. The words "includes" or "including" shall mean "including without limitation," the words "hereof," "hereby," "herein," "hereunder" and similar terms in this Agreement shall refer to this Agreement as a whole and not any particular section or article in which such words appear. Any reference to a Law shall include any amendment thereof or any successor thereto and any rules and regulations promulgated thereunder. Currency amounts referenced in this Agreement are in U.S. Dollars.

(c) Whenever this Agreement refers to a number of days, such number shall refer to calendar days unless Business Days are specified. Whenever any action must be taken hereunder on or by a day that is not a Business Day, then such action may be validly taken on or by the next day that is a Business Day.

(d) Each Party acknowledges that it and its attorneys have been given an equal opportunity to negotiate the terms and conditions of this Agreement and that any rule of construction to the effect that ambiguities are to be resolved against the drafting Party or any similar rule operating against the drafter of an agreement shall not be applicable to the construction or interpretation of this Agreement.

(e) All accounting terms used herein and not expressly defined herein shall have the respective meanings given such terms under GAAP.

ARTICLE II. PURCHASE AND SALE AND CLOSING

Section 2.1. Purchase and Sale.

On the terms and subject to the conditions set forth in this Agreement, at the Closing, Buyer agrees to purchase from Seller, and Seller agrees to sell to Buyer, all of the Assets used in the Business, including without limitation, the Assets described in Exhibit 2.1(a) and the Property, together with all improvements, buildings, structures, fixtures, easements, rights-of-way, division rights, hereditaments and appurtenances associated with that real property, all as described in Exhibit 2.1(a) (collectively, the ***"Purchased Assets"***), together with exclusive possession thereof. Notwithstanding the previous sentence, the Purchased Assets will not include the Assets listed on Exhibit 2.1(b) (the ***"Excluded Assets"***). The Purchased Assets will be transferred to Buyer free and clear of all Liens, except for Permitted Liens. For purposes of greater clarity, the only assets of CMS ERM included in the Purchased Assets are the Third Party Contracts as defined in Section 2.9(e).

Section 2.2. Assumed Liabilities.

Subject to the terms and conditions set forth herein, Buyer shall assume and agree to pay, perform and discharge only the following Liabilities of Seller (collectively, the ***"Assumed Liabilities"***), and no other Liabilities:

(a) all trade accounts payable of Seller to third parties in connection with the Business that remain unpaid and are not delinquent as of the Closing Date and that are reflected in the Closing Date Net Working Capital;

(b) all Liabilities in respect of the Assigned Contracts but only to the extent that such Liabilities thereunder are required to be performed after the Closing Date, were incurred in the ordinary course of business and do not relate to any failure to perform, improper performance, warranty or other breach, default or violation by Seller on or prior to the Closing Date; and

(c) all Liabilities in respect of Permits, easements, rights-of-way, division rights, hereditaments and appurtenances included in the Purchased Assets that are required to be performed after the Closing Date and do not relate to any failure to perform, improper performance, breach, default or violation by Seller on or prior to the Closing Date; for the avoidance of doubt, Buyer is not assuming any Liabilities of Seller relating to violations of any applicable Laws by Seller on or prior to the Closing Date.

Section 2.3. Excluded Liabilities.

Notwithstanding the provisions of Section 2.2 or any other provision in this Agreement to the contrary, Buyer shall not assume and shall not be responsible to pay, perform or discharge any Excluded Liabilities. Seller shall, and shall cause each of its Affiliates to, pay and satisfy in due course all Excluded Liabilities which they are obligated to pay and satisfy.

Section 2.4. Purchase Price.

The purchase price (the ***"Purchase Price"***) for the purchase and sale described in Section 2.1 is equal to $515,000,000 (the ***"Base Purchase Price"***), as adjusted pursuant to Sections 2.7(a), 2.8, 2.9, and 6.9 (if applicable).

Section 2.5. Closing.

The Closing shall take place at the offices of Consumers Energy Company, One Energy Plaza, Jackson, MI 49201 or via electronic exchange of documents at 10:00 A.M. local time, on (a) the later of (i) the tenth Business Day after the conditions to Closing set forth in ARTICLE VII and ARTICLE VIII (other than actions to be taken or items to be delivered at Closing) have been satisfied or waived and (ii) April 30, 2025 or (b) such other date and at such other time as Buyer and Seller mutually agree in writing. All actions listed in Section 2.6 or Section 2.7 that occur on the Closing Date shall be deemed to occur simultaneously at the Closing.

Section 2.6. Closing Deliveries by Seller to Buyer.

At the Closing, Seller shall deliver, or shall cause to be delivered, to Buyer

(a) a certification of non-foreign status in the form prescribed by Treasury Regulation Section 1.1445-2(b) with respect to Seller, and with respect to the owner of Seller if Seller is treated as a disregarded entity for federal income Tax purposes. If, on or before the Closing Date, Buyer shall not have received the non-foreign status affidavit(s), Buyer may withhold from the Purchase Price payable at Closing to Seller pursuant hereto such sums as are required to be withheld therefrom under Code Section 1445;

(b) [Intentionally Omitted]

(c) Copies of relevant title documents set forth in Sections 5.22 and 5.23;

(d) a bill of sale reasonably acceptable to Buyer and duly executed by Seller, conveying title to all of such Seller's owned personal property included in the Purchased Assets;

(e) warranty deeds reasonably acceptable to Buyer and duly executed by Seller, conveying good and marketable title to the Property to Buyer, subject only to the Permitted Liens (each a ***"Warranty Deed"*** *and collectively, the* ***"Warranty Deeds"***);

(f) real estate transfer tax valuation affidavits (the ***"Transfer Tax Affidavits"***) in form and substance reasonably acceptable to Buyer;

(g) affidavits reasonably acceptable to Buyer (each an ***"Owner's Affidavit" and collectively, the "Owner's Affidavits"***) for the removal of standard printed exceptions on each Title Policy; provided however, Seller agrees to modify such Owner's Affidavits as reasonably requested by the Title Insurer to make each such Owner's Affidavit consistent with the Title Insurer's standard Owner's Affidavit for similar transactions at the time of the Closing;

(h) such other affidavits and agreements required by the Title Insurer to issue the Title Policies;

(i) resolutions of the managers, members, directors and shareholders of Seller authorizing the transactions contemplated by this Agreement;

(j) releases of any security interest or similar Liens held on any of the Purchased Assets (other than Permitted Liens);

(k) the certificate referenced in Section 7.3;

(l) the Assignment and Assumption Agreements duly executed by Seller and any other counterparties;

(m) the resignations and removals referenced in Section 6.6;

(n) Promptly after the date of this Agreement, Seller shall obtain and provide to Buyer the Estoppel Certificates. No earlier than 60 days prior to the Closing Date, Seller shall provide Buyer updated Estoppel Certificates with an effective date no earlier than 60 days prior to the Closing Date; and

(o) such other customary instruments of transfer, assumption, filings or documents, in form and substance reasonably satisfactory to Buyer, as may be required to give effect to this Agreement.

Section 2.7. Closing Deliveries by Buyer to Seller.

At the Closing, Buyer shall deliver to Seller the following:

(a) a wire transfer of immediately available funds (to such account or accounts as Seller shall have notified Buyer of at least 2 Business Days prior to the Closing Date) in an amount equal to the sum of: (i) the Base Purchase Price, plus (ii) the Parties' mutually-agreed-upon estimate of the Closing Date Net Working Capital (the ***"Estimated Closing Date Net Working Capital"***) (it being understood that if Buyer and Seller are unable to mutually agree, despite good faith efforts to do so, then the Estimated Closing Date Net Working Capital shall equal the average of Seller's and Buyer's respective estimates of Closing Date Net Working Capital), minus (iv) any amounts owing or payable by Seller under Section 5.8; and (v) plus or minus the adjustment set forth in Section 2.9; and

(b) an executed counterpart by Buyer of each other Ancillary Agreement to which Buyer is a party.

Section 2.8. Post-Closing Adjustment.

(a) After the Closing Date, Seller and Buyer shall cooperate and provide each other access to their respective books, records and employees as are reasonably requested in connection with the matters addressed in this Section 2.8. Within 60 days after the Closing Date, Buyer shall determine the Closing Date Net Working Capital and shall provide Seller with written notice of such determination, along with reasonable supporting information and calculations (the ***"Buyer's Determination"***).

(b) If Seller objects to Buyer's Determination, then it shall provide Buyer written notice thereof within 30 days after receiving Buyer's Determination; provided that Seller and Buyer shall be deemed to have agreed upon all items and amounts that are not disputed by Seller in such written notice. If the Parties are unable to agree on the Closing Date Net Working Capital, within 120 days after the Closing Date, the Parties shall refer such dispute to a firm of nationally recognized independent public accountants mutually acceptable to Buyer and Seller (the ***"Independent Accountants"***), which firm shall make a final and binding determination as to only those matters in dispute with respect to this Section 2.8(b) on a timely basis and promptly shall notify the Parties in writing of its resolution. The Independent Accountants shall not have the power to modify or amend any term or provision of this Agreement. The Parties shall equally bear and pay the fees and other costs charged by the Independent Accountants. If Seller does not object to Buyer's Determination within the time period and in the manner set forth in the first sentence of this Section 2.8(b) or if Seller accepts Buyer's Determination, the Closing Date Net Working Capital as set forth in Buyer's Determination shall become final and binding upon the Parties for all purposes hereunder.

(c) If the Closing Date Net Working Capital (as agreed between the Parties or as determined by the Independent Accountants or otherwise) (the ***"Final Closing Date Net Working Capital"***) is greater than the Estimated Closing Date Net Working Capital, then Buyer shall pay the amount of such excess to Seller, within 5 Business Days after such amounts are agreed or determined pursuant to Section 2.8(b), by wire transfer of immediately available funds to an account designated by Seller. If the Final Closing Date Net Working Capital is less than the Estimated Closing Date Net Working Capital, then Seller shall pay the amount of such deficiency to Buyer within 5 Business Days after such amounts are agreed or determined pursuant to Section 2.8(b), by wire transfer of immediately available funds to an account designated by Buyer.

Section 2.9. Purchase Price Adjustment Based on Capacity and Third Party Contracts.

(a) The Base Purchase Price is based on the capacity of the Project recognized by MISO for the applicable planning period and made available by Seller for sale to Buyer for the applicable Planning Years as set forth in the chart below. These capacity amounts of the Purchased Assets reflect Seller's existing commitments for the provision of capacity from the Purchased Assets to third parties:

Planning Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Capacity (ZRC)	358	482	480	596	688	739	739	789	800	800	828	828	828	828	828

(b) To accommodate Seller's desire to provide capacity for additional sales to third parties from the Purchased Assets prior to Closing, the following formula will be used to adjust the Purchase Price paid at Closing (subject to the limitations on additional sales in Section 2.9(c)):

Purchase Price Adjustment = ZRCs of capacity sold per year x ($71,250 – price of capacity sale in $/ZRC-year)

(c) Seller may only provide capacity for sales of additional amounts of capacity from the Purchased Assets prior to Closing as set forth below. Any revenues for such sales will be for the benefit of Buyer.

1. MISO Planning Year 2025 (June 1, 2025 through May 31, 2026) = 0 ZRCs
2. MISO Planning Year 2026 (June 1, 2026 through May 31, 2027) = 0 ZRCs
3. MISO Planning Years 2027 through 2039 (June 1, 2027 through May 31, 2040) = 45 ZRCs each year

(d) If Seller or its Affiliates reacquire some or all of the capacity that was sold to third parties up to the amounts shown in the chart below (reacquired capacity amounts no more than those amounts sold by year), then the Purchase Price will be increased by the following formula as long as the reacquired capacity is fully available to Buyer at Closing.

Planning Year	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
Capacity (ZRC)	93	97	99	23	23	28	28	28	28	28	0	0	0	0	0

Purchase Price Increase = ZRCs Reacquired (up to 475 ZRCs) x $20,250/ZRC-year.

For the avoidance of doubt, the June 1 – May 31 timing above covers either a planning year (under the current MISO construct) or any subset of the planning periods occurring within that 365-day period.

(e) At Closing, contracts of DIG and CMS GMP for the provision of capacity and energy from the Purchased Assets to CMS ERM shall be terminated. At Closing, CMS ERM shall use commercially reasonable efforts to assign to Buyer CMS ERM's contracts for the sale of capacity and energy to third parties which rely on capacity and energy from the Purchased Assets for time periods after Closing (**"Third Party Contracts")** and such Third Party Contracts shall be included in the Assigned Contracts, and Buyer will be responsible to provide capacity and energy under the assigned Third Party Contracts, and the associated costs, from the Purchased Assets. Buyer shall be entitled to receive all revenues associated with the sales of capacity and energy from the Purchased Assets under the assigned Third Party Contracts.

Section 2.10. Allocation of Purchase Price.

(a) Within 30 days after the Closing Date, Buyer shall deliver to Seller a schedule allocating the Purchase Price (and all other capitalized costs) among the Purchased Assets, grouped by the seven asset classes referred to in Treasury Regulations Section 1.1060- 1(c) (the ***"Purchase Price Allocation Schedule"***). Buyer shall permit Seller thirty (30) days to review and comment on Buyer's proposed Purchase Price Allocation Schedule. Buyer shall make such revisions to its proposed Purchase Price Allocation Schedule as are reasonably requested by Seller within such 30-day period and shall deliver to Seller a final Purchase Price Allocation Schedule within fifteen (15) days of receiving Seller's comments. The Purchase Price Allocation Schedule shall be revised to take into account subsequent adjustments to the Purchase

Price, including the Final Closing Date Net Working Capital and any indemnification payments (which shall be treated for Tax purposes as adjustments to the Purchase Price), as mutually agreed by the Parties and in accordance with the provisions of Section 1060 of the Code and the Treasury Regulations thereunder.

(b) The Parties shall report the transaction for federal and state income Tax purposes on IRS Form 8594 in accordance with the Purchase Price Allocation Schedule described in Section 2.7(a). Neither Party will take a position inconsistent with such allocation except with the written consent of the other Party. Each of Seller and Buyer agrees to provide the other promptly with any other information required to complete Form 8594.

(c) If the Parties are unable to agree on the Purchase Price Allocation Schedule pursuant to Section 2.10(a) or any subsequent adjustment to the Purchase Price Allocation Schedule, the Parties shall refer such dispute to the Independent Accountants, which firm shall make a final and binding determination as to all matters in dispute with respect to this Section 2.10(and only such matters) on a timely basis and promptly shall notify the Parties in writing of its resolution. The Independent Accountants shall not have the power to modify or amend any term or provision of this Agreement. Each Party shall bear and pay one-half of the fees and other costs charged by the Independent Accountants with respect to its activities under this Section 2.10.

ARTICLE III. REPRESENTATIONS AND WARRANTIES OF SELLER

Except as otherwise disclosed in the Schedules delivered by Seller to Buyer corresponding to the particular section or subsection contained in this Article III (it being understood that disclosure for one section shall be deemed to be disclosure for any other section as to which the applicability is reasonably apparent from the face of the disclosure), Seller hereby represents and warrants to Buyer, as of the date hereof and as of the Closing (except where such representation or warranty is expressly made as of another specific date), as follows:

Section 3.1. Organization.

DIG is a Michigan limited liability company validly existing and in good standing under the Laws of its jurisdiction of formation. CMS GMP is a Michigan limited liability company validly existing and in good standing under the Laws of its jurisdiction of formation. CMS ERM is a Michigan corporation validly existing and in good standing under the Laws of its jurisdiction of incorporation. Seller is duly qualified or licensed to do business in each other jurisdiction where the actions to be performed by it hereunder makes such qualification or licensing necessary, except in those jurisdictions where the failure to be so qualified or licensed would not reasonably be expected to result in a Material Adverse Effect on Seller's ability to perform such actions under this Agreement or the Ancillary Agreements to which Seller is party.

Section 3.2. Authority; Enforceability.

Seller has all requisite corporate or limited liability company power and authority, as applicable, to execute and deliver this Agreement and the Ancillary Agreements to which Seller is a party, to perform its obligations hereunder and thereunder and to consummate the transactions contemplated hereby and thereby. The execution and delivery by Seller of this

Agreement and the Ancillary Agreements to which Seller is a party, and the performance by Seller of its obligations hereunder and thereunder, have been duly and validly authorized by all necessary corporate and limited liability company action, as applicable. This Agreement has been duly and validly executed and delivered by Seller and constitutes, and each Ancillary Agreement to which Seller is a party when executed and delivered on the Closing Date will constitute, the legal, valid and binding obligation of Seller enforceable against Seller in accordance with its terms, except as the same may be limited by bankruptcy, insolvency, moratorium or other similar Laws relating to or affecting the rights of creditors generally, or by general equitable principles.

Section 3.3. No Conflicts; Consents and Approvals.

The execution and delivery by Seller of this Agreement and the Ancillary Agreements to which Seller is a party do not, and the performance by Seller of its obligations under this Agreement and the Ancillary Agreements to which Seller is a party will not:

(a) conflict with or result in a violation or breach of any of the terms, conditions or provisions of the Organizational Documents of Seller;

(b) assuming all of the Seller Consents set forth in Schedule 3.3(b) have been obtained, be in violation of or result in a breach of or default (or give rise to any right of termination, cancellation or acceleration) under (with or without the giving of notice, the lapse of time, or both) any Contract to which Seller is a party, except for any such violations or defaults (or rights of termination, cancellation or acceleration) which would not, individually or in the aggregate, reasonably be expected to result in a Material Adverse Effect on Seller's ability to perform its obligations hereunder; and

(c) assuming all required filings, waivers, approvals, consents, authorizations and notices set forth on Schedule 3.3(c) (collectively, the ***"Seller Approvals"),*** Seller Consents and other notifications provided in the ordinary course of business have been made, obtained or given, (i) conflict with, violate or breach any term or provision of any Law applicable to Seller; or (ii) require any consent or approval of any Governmental Authority, or notice to, or declaration, filing or registration with, any Governmental Authority, under any applicable Law.

Section 3.4. [Intentionally Omitted.]

Section 3.5. Brokers.

Seller has no Liability or obligation to pay fees or commissions to any broker, finder or agent with respect to the transactions contemplated by this Agreement for which Buyer could become liable or obligated.

Section 3.6. Legal Proceedings.

No Claim is pending against Seller, Seller has not been served with notice of any Claim, and to Seller's Knowledge, none has been threatened against Seller that (a) affects Seller or the Assets of Seller and would, individually or in the aggregate, reasonably be expected to result in a Material Adverse Effect with respect to Seller or the Assets of Seller or (b) seeks a writ, judgment, order, injunction or decree restraining, enjoining or otherwise prohibiting or making illegal any of the transactions contemplated by this Agreement.

Section 3.7. Compliance with Laws and Orders.

Seller is, in all material respects, in compliance with all Laws applicable to it and its operations or Purchased Assets, including the Project.

Section 3.8. Financial Statements; No Undisclosed Liabilities.

Seller has previously delivered to Buyer the Financial Statements of Seller as of and for the fiscal years ended December 31, 2019 and December 31, 2020, and unaudited Financial Statements of Seller as of and for the three months then ended March 31, 2021. The Financial Statements have been prepared in accordance with GAAP. Seller has no Liability that would be required to be reflected on any Financial Statement which is not reflected or reserved against in such Financial Statement.

Section 3.9. Absence of Certain Changes.

Since December 31, 2020, Seller has operated in the ordinary course of business, consistent with past practices and there has not been any (a) Material Adverse Effect with respect to Seller or the Assets of Seller or (b) event or condition that would reasonably be expected to prevent or delay Seller from consummating the transactions contemplated by this Agreement.

Section 3.10. Taxes.

(a) All Tax Returns that are required to be filed on or before the Closing Date by Seller have been or will be duly and timely filed, taking into account all permitted extensions, and are true, correct and complete in all material respects, (b) all Taxes required to be paid by Seller with respect to the Purchased Assets (whether or not shown on any Tax Return) that are due and payable have been timely paid in full, (c) all withholding Tax requirements imposed on Seller have been satisfied in full, except for amounts that are being contested in good faith, (d) Seller does not have in force any waiver of any statute of limitations in respect of Taxes or any extension of time with respect to a Tax assessment or deficiency, (e) there are no pending or active audits, examinations, Claims, assessments or legal proceedings involving Tax matters or, to Seller's Knowledge, threatened audits or proposed deficiencies or other Claims for unpaid Taxes of Seller, (f) Seller, with respect to the Purchased Assets, has no Liability for the Taxes of any other Person (i) as a transferee or successor, (ii) by contract or (iii) otherwise, (g) Seller, under the federal check-the-box regulations, is classified as an entity disregarded as separate from its owner for federal income Tax purposes and all applicable state income Tax purposes and has been since inception, (h) there are no deficiencies asserted or assessments made as a result of any examination of Tax Returns of Seller, (i) there are no Liens for Taxes (other than Permitted Liens) on any of the Assets of Seller, (j) with respect to the Purchased Assets, there are no outstanding closing agreements, ruling requests, requests to change a method of accounting or other matters pending with any Taxing Authority and (k) Seller is not a "tax-exempt entity" or a "tax-exempt controlled entity" within the meaning of Section 168(h) of the Code. Seller will provide copies of any correspondence with any Taxing Authority regarding Seller, the Business or Seller Assets for any Tax year still open under the applicable statute of limitations, including but not limited to, any federal or state letter ruling requests or audit notices.

Section 3.11. [Intentionally Omitted]

Section 3.12. Contracts.

(a) Schedule 3.12 sets forth a list as of the date of this Agreement of the following Contracts to which Seller is a party or by which the Assets of Seller may be bound (Contracts that meet the descriptions in this Section 3.12 being collectively, the ***"Material Contracts"):***

(i) Contracts for the purchase, exchange or sale of natural gas;

(ii) Contracts for the purchase, exchange, transmission or sale of electric power in any form, including energy, capacity or any ancillary services;

(iii) Contracts for the transportation of natural gas;

(iv) interconnection Contracts;

(v) Contracts for the purchase or sale of any Asset or that grant a right or option to purchase or sell any Asset;

(vi) Contracts for the provision or receipt of any work, goods or services or that grant a right or option to provide or receive any work, goods or services;

(vii) Contracts under which it has created, incurred, assumed or guaranteed any outstanding Indebtedness, or under which it has imposed a security interest on any of its Assets, tangible or intangible, which security interest secures outstanding Indebtedness;

(viii) any collective bargaining Contracts or other employment Contracts;

(ix) outstanding futures, swap, collar, put, call, floor, cap, option or other Contracts that are intended to benefit from or reduce or eliminate the risk of fluctuations in interest rates or the price of commodities, including electric power, in any form, including energy, capacity or any ancillary services, natural gas or securities;

(x) Contracts that limit Seller's freedom to compete in any line of business or in any geographic area in connection with the Project;

(xi) partnership, joint venture, or limited liability company agreements;

(xii) Contracts that affect the Property including leases (including ground leases) or other land use agreements relating to the Property;

(xiii) Contracts with Governmental Authorities regarding Taxes, tax abatements, tax incentive agreements or any payments in lieu of Property Taxes or under any other arrangements with a Taxing Authority, and water services; and

(xiv) any other Contracts reasonably necessary for Seller to conduct its Business.

(b) Seller has provided Buyer with, or access to, copies of all Material Contracts.

(c) Each of the Material Contracts (other than any Material Contract which will terminate or expire by its terms prior to Closing without any further Liability on the part of Seller) is in full force and effect and constitutes a legal, valid and binding obligation of Seller and, to Seller's Knowledge, of the other parties thereto.

(d) Seller is not in breach or default under any Material Contract and, to Seller's Knowledge, no other party to any of the Material Contracts is in breach or default thereunder nor has Seller given or received written notice to or from any Person relating to any alleged or potential default that has not been cured, nor, has any event or circumstance occurred that, with notice or lapse of time or both, would constitute an event of default thereunder.

Section 3.13. Ownership; Liens.

(a) Seller has good and valid title to all of the Purchased Assets. The Purchased Assets are free and clear of Liens except for Permitted Liens. The title insurance premium on each Title Policy has been paid and each Title Policy is in effect. The Property, the Project and the Business comply with all applicable zoning, subdivision and land use Laws and special use Permits.

(b) Seller otherwise owns the Project and all other of the Purchased Assets free and clear of all Liens (except for Permitted Liens).

Section 3.14. Permits.

(a) Schedule 3.14(a) sets forth all Permits held by Seller. Said Permits set forth on Schedule 3.14(a) constitute all Permits that are required for the ownership and operation of the Project by Seller in the manner in which they are currently owned and operated. All Permits set forth on Schedule 3.14(a) are in full force and effect.

(b) Seller is in compliance with all Permits set forth on Schedule 3.14(a) and Seller has not received any written notification from any Governmental Authority alleging that it is in violation of any such Permits.

(c) To Seller's Knowledge, no event has occurred which with notice or lapse of time would constitute non-compliance with such terms and conditions or cause any adverse modification, revocation, suspension or termination of any such Permit.

(d) No material action, or written deficiency notice, demand or notice of any challenge is pending or, to Seller's Knowledge, threatened, which challenges the legality, validity or enforceability of any such Permit, or that attempts to modify in any manner the requirements pertaining to any obtained Permit or application for a Permit.

Section 3.15. Environmental Matters.

(a) Seller has made available or disclosed to Buyer any knowledge of environmental matters or copies of all assessments, notices of violation(s) or reports in the possession of Seller that relate to environmental matters in connection with operation of the Project.

(b) Seller has constructed, owned and operated the Project, since its inception, in compliance with all applicable Environmental Laws, including holding and complying with all Permits required under Environmental Laws for the ownership and operation of the Project, and Seller's representations and warranties under Section 3.14 apply with equal force to such Permits and are incorporated in this Section 3.15 by reference;

(c) Except as set forth in Schedule 3.15(f), Seller has not been served with notice of any Environmental Claims, actions, proceedings or investigations that are currently outstanding, and no Environmental Claims are pending or, to Seller's Knowledge, threatened, against Seller by any Governmental Authority or third party under any Environmental Laws;

(d) there is no site to which Seller has transported or arranged for the transport of Hazardous Materials associated with the Project which, to Seller's Knowledge, is, or is threatened to become or otherwise likely to be, the subject of any Environmental Claim; and

(e) there has been no Release or threatened Release of any Hazardous Material at or from the Project in connection with construction of the Project or any operations of or relating to the Project; and

(f) Schedule 3.15(f) sets forth all emission reduction credits and emissions allowances that have been allocated to or are otherwise held by Seller as of the date of this Agreement.

(g) This Section 3.15 contains the sole and exclusive representations and warranties of Seller with respect to environmental matters.

Section 3.16. Intellectual Property.

(a) Seller owns, or has permanent and indefeasible licenses or rights to use, all Intellectual Property currently used in or reasonably necessary for the Business and otherwise for the operation and maintenance of the Project.

(b) Seller has not received from any third party a Claim in writing that Seller is infringing the Intellectual Property of such third party.

Section 3.17. [Intentionally Omitted.]

Section 3.18. Employees and Labor Matters.

(a) Except as identified on Schedule 3.18(a), Seller does not have any employees with respect to the Project;

(b) the persons identified on Schedule 3.18(b) provide full-time or recurring and continuous part-time on site services to Seller with respect to the Project and are employed by a third party vendor pursuant to an agreement with such third-party vendor (persons identified on Schedules 3.18(a) and 3.18(b), collectively, the ***"Employees");***

(c) Schedule 3.18(c) lists each Contract between a third-party vendor and Seller or any Affiliate of Seller pursuant to which employees of a third-party vendor provide material on site employee services principally dedicated to Seller with respect to the Project;

(d) there has not occurred, nor, to Seller's Knowledge has there been threatened, a labor strike, request for representation, organizing campaign, work stoppage, slowdown, or lockout or other labor dispute by or involving any of the Employees with respect to Seller in the past ten years;

(e) neither Seller nor any of its Affiliates has received written notice of any unfair labor practice charge against Seller or any of its Affiliates regarding practices/acts of Seller pending before the National Labor Relations Board; and neither Seller nor any of its Affiliates has received notice that any petition respecting any Employees, or respecting any former employees of Seller or of its Affiliates or of a third-party vendor who were principally dedicated to Seller, has been filed with the National Labor Relations Board;

(f) neither Seller nor any of its Affiliates have received any notice with respect to the Employees, or with respect to any former employees of Seller or its Affiliates or a third-party vendor who were principally dedicated to Seller, of any charges before any Governmental Authority responsible for the prevention of unlawful employment practices; and Seller and its Affiliates and, to Seller's Knowledge, any applicable third-party vendor are in compliance with all applicable Laws respecting employment practices, occupational health and safety, labor relations, terms and conditions of employment and similar Laws with respect to the Employees, and with respect to any former employees of Seller or its Affiliates or, to Seller's Knowledge, of a third-party vendor who were principally dedicated to Seller; and

(g) neither Seller nor any of its Affiliates have received notice of any investigation related to the Employees, or related to any former employees of Seller or its Affiliates or, to Seller's Knowledge, a third-party vendor who were principally dedicated to Seller, by a Governmental Authority responsible for the enforcement of labor or employment Laws and regulations and, to Seller's Knowledge, no such investigation is threatened.

Section 3.19. <u>Employee Benefits</u>.

(a) Schedule 3.19 contains a complete list of all Benefit Plans. Complete copies of all Benefit Plans and of summary plan descriptions have been made available to Buyer for review. Each Benefit Plan has been administered in accordance with its terms in all material respects and Seller has met its obligations with respect to such Benefit Plan and has made all required contributions thereto. Seller and all Benefit Plans are in compliance in all material respects with applicable Laws, including but not limited to, provisions of ERISA and the Code.

(b) All the Benefit Plans that are intended to be qualified under Section 401(a) of the Code have received determination or opinion letters from the Internal Revenue Service to the effect that such Benefit Plans are qualified and the plans and the trusts related thereto are exempt from federal income Taxes under Sections 401(a) and 501(a), respectively, of the Code; no such determination or opinion letter has been revoked; and, to the Knowledge of Seller, (i) such revocation has not been threatened and (ii) no act or omission has occurred, that would adversely affect a Benefit Plan's qualification.

(c) There does not now exist, nor do any circumstances exist that would result in, any Controlled Group Liability that would be a Liability of Buyer following the Closing. Without limiting the generality of the foregoing, neither Seller nor any ERISA Affiliate has engaged in any transaction described in Section 4069 or Section 4204 of ERISA.

(d) No act or omission has occurred and no condition exists with respect to any Benefit Plan that would subject Seller to any material fine, penalty, Tax or Liability of any kind imposed under applicable Laws, including but not limited to, ERISA or the Code.

(e) No Benefit Plan contains any term or provision, or is subject to any Law, that would prohibit the transactions contemplated by this Agreement or that would give rise to the vesting of benefits, payments, or Liabilities as a result of the transactions contemplated by this Agreement, except to the extent that full vesting is required under Section 411 of the Code.

(f) All Benefit Plans may be amended or terminated by Seller in any manner and at any time, without the consent of any person covered by any such Benefit Plan and without any further material Liability for benefits that may be accrued or expenses that may be incurred after the date of such termination or amendment, other than benefits that may be required under the terms of such Benefit Plans or benefits required under Code Section 4980B.No suit, action or other litigation, excluding Claims for benefits incurred in the ordinary course of plan activities have been brought against or with respect to any Benefit Plan, and no suit, action or other litigation is threatened by, against, or relating to any Benefit Plan, and Seller does not have any knowledge of any fact that could form the basis for any such suit, action or litigation. No Benefit Plans are presently under audit or examination by the Internal Revenue Service, the Department of Labor, or any other governmental agency or entity, and no matters are pending with respect to any Benefit Plan under the Employee Plans Compliance Resolution System, the Delinquent Filer Compliance Program, or the Voluntary Fiduciary Correction Program.

Section 3.20. Inventory.

All of Seller's inventory (including spare parts) are of a quality and quantity usable in the ordinary and usual course of business, except for obsolete items and items of below-standards quality, all of which have been written off or written down to net realizable value.

Section 3.21. Insurance.

Seller has in full force and effect policies of insurance with respect to the Business and the Purchased Assets of the Project against such casualties and contingencies and in such amounts, types and forms as are customarily appropriate for its Business and Purchased Assets. Schedule 3.21 contains a list and description of all policies of insurance and bonds carried and owned by Seller relating to the Business or the Assets of Seller; including any claims or claims notices filed under those policies. Seller is not default under any such policy of insurance or bond such that it can be canceled and all claims thereunder have been filed in a timely fashion. Seller has filed claims with, or given notice of claims, to its insurers or bonding companies in timely fashion with respect to all matters and occurrences for which it believes Seller has coverage. Schedule 3.21 includes all outstanding claims notices filed by Seller relating to the Business or the Assets of Seller.

Section 3.22. [Reserved.]

Section 3.23. FERC, NERC, DOE and/or MISO Matters.

(a) Seller has made available to Buyer copies of all reports of assessments, investigations, compliance audits, remedial actions, or other investigative or response activities conducted at or with respect to the Project regarding any FERC-, NERC-, DOE-, and/or MISO-related requirements, including cyber security and testing requirements, that are in the possession of Seller.

(b) Except as set forth on Schedule 3.23(b), Seller and the Project have operated in compliance in all material respects with all applicable FERC-, NERC-, DOE- and/or MISO-related requirements, including cyber security and testing requirements.

(c) Except as set forth on Schedule 3.23(c), Seller has not been served with notice of any actual or threatened notice of violation of any FERC-, NERC-, DOE-, and/or MISO-related requirements, or other action, proceeding, investigation, or inquiry pursuant to any FERC-, NERC-, DOE-, and/or MISO-related requirements, and no Claim regarding any FERC-, NERC-, DOE-, and/or MISO-related requirements is pending or, to Seller's Knowledge, threatened, against Seller.

ARTICLE IV. REPRESENTATIONS AND WARRANTIES OF BUYER

Except as otherwise disclosed in the disclosure schedules delivered by Buyer to Seller corresponding to the particular section or subsection contained in this Article IV (it being understood that disclosure for one section shall be deemed to be disclosure for any other section as to which the applicability is reasonably apparent from the face of the disclosure) or as otherwise expressly disclosed in this Agreement, Buyer hereby represents and warrants to Seller, as of the date hereof and as of the Closing (except where such representation or warranty is expressly made as of another date), as follows:

Section 4.1. Organization.

Buyer is a corporation duly formed, validly existing and in good standing under the Laws of the State of Michigan.

Section 4.2. Authority; Enforceability.

Buyer has all requisite corporate power and authority to enter into this Agreement and the Ancillary Agreements to which Buyer is a party, to perform its obligations hereunder and thereunder and to consummate the transactions contemplated hereby and thereby. The execution and delivery by Buyer of this Agreement and the Ancillary Agreements to which Buyer is a party and the performance by Buyer of its obligations under this Agreement and the Ancillary Agreements to which Buyer is a party have been duly and validly authorized by all necessary corporate action on behalf of Buyer. This Agreement has been duly and validly executed and delivered by Buyer and constitutes, and each Ancillary Agreement to which the Buyer is a party when executed and delivered on the Closing Date will constitute, the legal, valid and binding obligation of Buyer enforceable against Buyer in accordance with its terms except as the same may be limited by bankruptcy, insolvency, moratorium or other similar Laws relating to or affecting the rights of creditors generally or by general equitable principles.

Section 4.3. No Conflicts.

The execution and delivery by Buyer of this Agreement and the Ancillary Agreements to which Buyer is a party do not, and the performance by Buyer of its obligations hereunder and thereunder and the consummation of the transactions contemplated hereby and thereby will not:

(a) conflict with or result in a violation or breach of any of the terms, conditions or provisions of Buyer's Organizational Documents;

(b) assuming all Buyer Approvals have been made, obtained or given, (i) conflict with, violate or breach any term or provision of any Law applicable to Buyer or any of its Assets which would reasonably be expected to result in a Material Adverse Effect on Buyer's ability to perform its obligations hereunder or (ii) require any material consent or approval of any Governmental Authority or notice to, or declaration, filing or registration with, any Governmental Authority, under any applicable Law, other than such consents, approvals, notices, declarations, filings or registrations which, if not made or obtained, would not reasonably be expected to result in a Material Adverse Effect on Buyer's ability to perform its obligations hereunder.

Section 4.4. Legal Proceedings.

No Claim is pending against Buyer, Buyer has not been served with notice of any Claim, and to Buyer's knowledge, none is threatened, against Buyer which seeks a writ, judgment, order or decree restraining, enjoining or otherwise prohibiting or making illegal the transactions contemplated by this Agreement.

Section 4.5. Brokers.

Buyer does not have any Liability or obligation to pay fees or commissions to any broker, finder or agent with respect to the transactions contemplated by this Agreement for which Seller could become liable or obligated.

Section 4.6. Sufficiency of Funds.

Buyer has sufficient cash on hand or other sources of immediately available funds to enable it to make payment of the Purchase Price and consummate the transactions contemplated by this Agreement.

Section 4.7. Solvency.

Immediately after giving effect to the transaction contemplated hereby, Buyer shall be solvent and shall: (a) be able to pay its debts as they become due; (b) own property that has a fair saleable value greater than the amounts required to pay its debts (including a reasonable estimate of the amount of all contingent Liabilities); and (c) have adequate capital to carry on its business. No transfer of property is being made and no obligation is being incurred in connection with the transactions contemplated hereby with the intent to hinder, delay or defraud either present or future creditors of Buyer or Seller. In connection with the transaction contemplated hereby, Buyer has not incurred, nor plans to incur, debts beyond its ability to pay as they become absolute and matured.

Section 4.8. Independent Investigation.

(a) Buyer acknowledges that (i) Buyer, either alone or together with any Persons Buyer has retained to advise it with respect to the transactions contemplated hereby ("Advisors") has knowledge and experience in transactions of this type and in the business of Seller, and is therefore capable of evaluating the risks and merits of acquiring the Purchased Assets, (ii) it has relied on its own independent investigation, and has not relied on any information furnished by Seller or any representative or agent thereof or any other Person in determining to enter into this Agreement (except for such representations or warranties contained in this Agreement or the Ancillary Agreements), (iii) neither Seller nor any representative or agent of Seller or any other Person has given any investment, legal or other advice or rendered any opinion as to whether the transaction is prudent, and Buyer is not relying on any representation or warranty by Seller or any representative or agent thereof except as set forth in this Agreement, (iv) Buyer has conducted due diligence that it deems appropriate, including a review of the documents contained in a data room prepared by or on behalf of Seller, (v) Seller made available to Buyer documents, records and books pertaining to Seller that Buyer's attorneys, accountants, Advisors, if any, and Buyer have requested and (vi) Buyer and its Advisors, if any, have had the opportunity to visit Seller, its facilities, plants, offices and other properties and ask questions and receive answers to Buyer's satisfaction concerning Seller and the terms and conditions of this Agreement. Nothing in this Section shall preclude Buyer from bringing a Claim against Seller for fraud.

(b) Buyer has received certain projections and other forecasts, including projected financial statements, cash flow items, capital expenditure budgets and certain business plan information and acknowledges that (i) there are uncertainties inherent in attempting to make such projections and forecasts and, accordingly, it is not relying on them, (ii) Buyer is familiar with such uncertainties and is taking full responsibility for making its own evaluation of the adequacy and accuracy of all such projections and forecasts, (iii) Buyer has no Claim under this Agreement against anyone with respect to the accuracy of such projections and forecasts and (iv) Seller has made no representation or warranty with respect to such projections and forecasts. Nothing in this Section shall preclude Buyer from bringing a Claim against Seller for fraud.

ARTICLE V. COVENANTS

The Parties hereby covenant and agree as follows:

Section 5.1. Regulatory and Other Approvals.

From the date of this Agreement until Closing (the ***"Interim Period"):***

(a) The Parties will, in order to consummate the transactions contemplated hereby, take all commercially reasonable efforts necessary, and proceed diligently and in good faith and use all commercially reasonable efforts, as promptly as practicable to obtain the Seller Approvals, Seller Consents, the Acceptable Orders and Buyer Approvals and to make all required filings required to be made by it with, and to give all required notices to, Governmental Authorities, and provide such other information and communications to such Governmental Authorities or other Persons as such Governmental Authorities or other Persons may reasonably request in connection therewith. Additionally, Seller will cooperate with Buyer in making Buyer the "Asset Owner" (as defined in the rules of MISO) with respect to the Project as soon as permitted following the Closing.

(b) The Parties will provide prompt notification to each other when any such approval referred to in Section 5.1(a) is obtained, taken, made, given or denied, as applicable, and will advise each other of any material communications with any Governmental Authority or other Person regarding any of the transactions contemplated by this Agreement.

(c) In furtherance of the foregoing covenants:

(i) Each Party shall prepare, as soon as is reasonably practical following the execution of this Agreement, all necessary filings in connection with the transactions contemplated by this Agreement that may be required to be filed by such Party with the FERC, the MPSC or any other federal, state or local Laws. Each Party shall submit such filings as soon as reasonably practicable. Notwithstanding the foregoing, the filing for authorization from the FERC for the acquisition of the Purchased Assets by Buyer from Seller pursuant to Section 203 of the FPA shall be made within 540 days of the execution of this Agreement, subject to extension of such period upon consent of the other Party, which consent shall not be unreasonably withheld. The Parties shall promptly furnish each other with copies of any notices, correspondence or other written communication from the relevant Governmental Authority, shall promptly make any appropriate or necessary subsequent or supplemental filings, and shall cooperate in the preparation of such filings as is reasonably necessary and appropriate. Each Party shall have the right to review in advance all information related to Seller or Buyer, as applicable, and the transactions contemplated by this Agreement with respect to any filing made by the other Party in connection with the transactions contemplated by this Agreement.

(ii) The Parties shall not, and shall cause their respective Affiliates not to, take any action that is intended to adversely affect the approval of any Governmental Authority of any of the filings referenced in clause (i).

(iii) Seller shall file with the appropriate Governmental Authority an application for the transfer of all Permits held by Seller with respect to the Project to Buyer.

(d) During the Interim Period, Seller shall timely and properly make all submittals and reports, shall pay all fees, and otherwise do all things necessary to maintain in full force and effect and comply in all material respects with, each and every Permit required for the ownership and operation of the Project as it is currently operated. In the event of any actual or threatened cancellation, revocation, termination, suspension, nonrenewal, or adverse modification of any such Permit, Seller shall promptly notify Buyer in writing and shall pursue all available legal and equitable remedies for the purpose of preserving such Permit and the currently prevailing terms thereof.

(e) Notwithstanding the foregoing, nothing in this Section 5.1 shall require, or be construed to require, Buyer or any of its Affiliates to agree to (i) sell, hold, divest, discontinue or limit, before or after the Closing Date, any assets, businesses or interests of Buyer or any of its Affiliates; (ii) any conditions relating to, or changes or restrictions in, the operations of any such assets, businesses or interests which, in either case, could reasonably be expected to result in a Material Adverse Effect with respect to Buyer or materially and adversely impact the economic or business benefits to Buyer of the transactions contemplated by this Agreement; or (iii) any material modification or waiver of the terms and conditions of this Agreement.

Section 5.2. Access of Buyer and Seller.

(a) During the Interim Period, Seller will, and will cause its Representatives to (i) provide Buyer and its Representatives with reasonable access, upon reasonable prior notice and during normal business hours, to the Property and to the officers and employees of Seller and its Affiliates who have significant responsibility for the Project, but only to the extent that such access does not unreasonably interfere with the business of Seller or the Business and that such access is reasonably related to the requesting Party's obligations and rights hereunder, and subject to compliance with applicable Laws and any Contracts or Permits to which Seller or any of its Affiliates is a party; provided, however, that Seller shall have the right to (x) have a Representative present for any communication with employees or officers of Seller or its Affiliates, (y) impose reasonable restrictions and requirements for safety purposes and (z) restrict access to any privileged information relating to any pending or threatened Claim, (ii) subject to the foregoing clause (z), furnish Buyer, Buyer's Representatives and Buyer's prospective lenders and their representatives (collectively, ***"Buyer's Advisors")*** with copies of all such Contracts, books and records, and other existing documents and data as Buyer may reasonably request, and (iii) furnish Buyer and Buyer's Advisors with such additional financial, operating, and other data and information as Buyer may reasonably request.

(b) During the Interim Period, Seller shall afford Buyer and Buyer's Advisors the right to conduct an environmental assessment of the Property in one or more phases, including the procurement and analysis of samples of soil, groundwater, indoor air, or any other environmental medium, and any building component or other material located at the Property. The cost of the environmental assessment will be borne by Buyer. Seller will provide access and information to, and otherwise cooperate with, Buyer and Buyer's Advisors in the environmental assessment. Buyer and Buyer's Advisor's will have the right to interview representatives of Seller having knowledge of conditions and events relevant to the operating history or environmental condition of the Property. If any Property is a "facility" within the meaning of Part 201 of the Michigan Natural Resources and Environmental Protection Act, MCL 324.20101 et seq., Buyer may prepare and submit to the Michigan Department of Environment, Great Lakes & Energy a baseline environmental assessment pursuant to MCL 324.20126 (***"BEA"***).

Section 5.3. <u>Certain Restrictions</u>.

Except as expressly consented to in writing by Buyer, during the Interim Period, Seller will (a) operate the Project and all Purchased Assets in the ordinary course of business consistent with Prudent Engineering and Operating Practices, (b) preserve, maintain and protect in all material respects consistent with past practices the Project, all Purchased Assets, rights, the Property and other properties and goodwill of Seller (including maintaining in all material respects Seller's relationships with customers, suppliers and Governmental Authorities), and (c) maintain the Permits in accordance with past practices. Without limiting the foregoing, except as expressly consented to in writing by Buyer, during the Interim Period, Seller shall not, with respect to the Project, Purchased Assets or the Property:

(i) (A) create any Lien (other than a Permitted Lien) against any of the Assets of Seller, or (B) permit any Lien (other than a Permitted Lien) against any of the Assets of Seller;

(ii) (A) enter into any Contract that is effective beyond May 1, 2025 involving total consideration throughout its term in excess of $50,000 individually or $500,000 in the aggregate for all such Contracts or (B) grant any waiver of any material term under, or give any material consent with respect to, any Contract involving total consideration throughout its term in excess of $50,000 individually or $500,000 in the aggregate for all such waivers;

(iii) sell or dispose of any of its material assets or properties, other than sales or dispositions in the ordinary course of business (including sales or dispositions pursuant to power purchase or sale Contracts), sales or dispositions of obsolete or surplus assets, sales or dispositions in connection with the normal repair and/or replacement of assets or properties, sales or dispositions of Excluded Assets, or sales or dispositions in accordance with any Material Contract.

(iv) sell, transfer, assign or convey the emissions allowances or emission reduction credits set forth on Schedule 3.15(f) or any emissions allowances or emission reduction credits allocated to Seller after the date hereof; provided that nothing in this clause (iv) shall restrict the use after the date hereof by Seller of any emissions allowances or emission reduction credits in the ordinary course of business;

(v) other than accounts payable in the ordinary course of business, incur, create, assume or otherwise become liable for Indebtedness, issue any debt securities or assume or guarantee the obligations of any other Person;

(vi) change any accounting method or practice in a manner that is inconsistent with past practice in a way that may adversely affect the Business, the Purchased Assets or the Property;

(vii) fail to maintain its corporate or limited liability company existence, as applicable, merge or consolidate with any other Person or acquire all or substantially all of the Assets of any other Person or take any other action that would cause Seller to be treated as other than a disregarded entity for federal income Tax purposes prior to the Closing;

(viii) issue, reserve for issuance, pledge or otherwise encumber, sell or redeem or enter into any Contract with respect to any Equity Interests or other Equity Securities of Seller;

(ix) liquidate, dissolve, recapitalize, reorganize or otherwise wind up its business or operations;

(x) purchase any securities of any Person, except for short-term investments made in the ordinary course of business consistent with past practices;

(xi) amend or modify its Organizational Documents;

(xii) cancel any Indebtedness or settle or waive any Claims or rights having a value in excess of $25,000;

(xiii) make any new, or change any existing, election with respect to Taxes, or settle any Tax Liability that may adversely affect Buyer or Seller after the Closing;

(xiv) incur any capital expenditure or major maintenance expenditure in excess of the amounts set forth on the Budget;

(xv) except in the ordinary course of business consistent with past practices or as otherwise required by the terms of any collective bargaining agreement, increase salaries or benefits payable to the Employees;

(xvi) fail to discharge any material Liability of Seller or make any material payment of Seller as it comes due except in connection with a reasonable good faith dispute;

(xvii) (A) amend, modify or grant any waiver with respect to any Assigned Contract, except for (i) amendments, modifications or waivers that (A) do not extend the term of any Assigned Contract beyond the Closing Date, (B) are not material, or (C) are needed in order to operate the Business in accordance with Prudent Engineering and Operating Practices;

(xviii) declare or pay any dividends or other distributions of cash or other Assets of Seller; or

(xix) agree or commit to do any of the foregoing.

(xx) Notwithstanding the foregoing, Seller shall have the right to conduct, prosecute, compromise or settle any and all hearings, appeals, rate cases or other proceedings. Seller shall provide Buyer the opportunity to review and advise on any material matters under this subsection (x)(x).

Section 5.4. Termination of Certain Services and Contracts.

Notwithstanding anything in this Agreement to the contrary, at or prior to the Closing, Seller shall (a) terminate or sever, effective upon or before the Closing, any services provided to Seller with respect to the Project or the Property by an Affiliate of Seller and that are not being assigned to Buyer, including the termination or severance of insurance policies (including those policies referred to in Section 5.7), Tax services, legal services and banking services (to include the severance of any centralized clearance accounts), terminate or assign to Buyer each Contract listed on Schedule 5.4, and cause all Claims or obligations (contingent or otherwise) with respect to the Project or the Property between Seller, on one hand, and an Affiliate of Seller, on the other, to be released effective immediately prior to Closing (collectively such services, Contracts, Claims or obligations, the ***"Terminated Contracts")***.

Section 5.5. Employee and Benefit Matters.

(a) From time to time prior to the Closing Date, Seller shall update Schedules 3.18(a) and 3.18(b) to (i) remove any Person who ceases to be an Employee after the date hereof and (ii) add any Person who becomes an Employee after the date hereof.

(b) Within a reasonable time prior to Closing, Seller shall provide Buyer with such pertinent data or information as Buyer shall reasonably require to determine each Employee's service, compensation or any other information related to benefits. To the extent the consent of an Employee is required in order for Seller to deliver any such pertinent data, records or information to Buyer, Seller agrees to use its commercially reasonable efforts to secure such consent.

Section 5.6. Indebtedness.

Notwithstanding anything in this Agreement to the contrary, prior to or at the Closing, Seller shall cause any and all Indebtedness of Seller with respect to the Project or the Purchased Assets to be paid in full and any and all Liens securing any such Indebtedness to be released such that Buyer shall acquire the Purchased Assets free of any such Indebtedness or any such Liens.

Section 5.7. Insurance.

Seller shall maintain or cause to be maintained in full force and effect the material insurance policies covering the Assets of Seller with respect to the Project and the Purchased Assets until the Closing or shall replace them with reasonably comparable policies. All such insurance coverage shall be terminated as of the Closing. Without limiting the rights of Buyer set forth elsewhere in this Agreement, for a period of two years after the Closing Date, if any claims may reasonably be made, or Losses occur prior to the Closing Date, that relate to the Project or the Business, and such claims, or the claims associated with such Losses, may be made against third-party insurance policies retained by Seller or its Affiliates, then Seller (on behalf of itself and its Affiliates) shall, at Buyer's request, use its commercially reasonable efforts in an effort to permit Buyer in cooperation with Seller, after the Closing Date, to file, notice and otherwise continue to pursue such claims and recover proceeds under the terms of such policies (but only to the extent the terms and conditions of such policies reasonably would provide coverage for such claims, or the claims associated with such Losses), and, subject to all of the foregoing, Seller (on behalf of itself and its Affiliates) agrees to otherwise reasonably cooperate with Buyer or its Affiliates to make the benefits of any such third-party insurance policies available to Buyer or its Affiliates.

Section 5.8. Transfer Taxes; Property Taxes.

(a) *Transfer Taxes*. Notwithstanding anything in this Agreement to the contrary, Seller shall pay for any Transfer Taxes imposed on Buyer or Seller by Law as a result of the transactions hereunder. The Transfer Tax Affidavits shall: (i) be mutually prepared by Buyer and Seller, (ii) be acceptable to Buyer and Seller, and (iii) conform to Michigan Law.

(b) *Property Taxes*.

(i) Any special assessments outstanding on or with respect to the Property and/or the Project (or proposed to be assessed on or with respect to the Property and/or the Project even if not yet a Lien), whether or not same have become due and payable on or before the Closing Date (including, in the case of special assessments payable in installments, any installments that will become payable after the Closing Date), shall be paid by Seller in full prior to Closing without any charge to, reimbursement from or proration with the Buyer.

(ii) All Property Taxes, other than special assessments as addressed in SubSection 5.8(b)(i), on the Property or otherwise on the Project shall be prorated at Closing as follows: Any such Property Taxes shall be deemed to cover the calendar year in which the applicable Property Tax Lien Date occurs. Any such Property Taxes for which the applicable Property Tax Lien Date occurs in calendar years prior to the calendar year of Closing shall be paid by Seller in full prior to Closing without any reimbursement from or proration with Buyer. Any such Property Taxes for which the applicable Property Tax Lien Date occurs in the calendar year of Closing shall be prorated at the Closing so that Seller (without any charge to or reimbursement from the Buyer) shall be charged with such Property Taxes from the first of the calendar year to the Closing Date and Buyer charged with such Property Taxes for the balance of said calendar year. With respect to any bill for Property Taxes proratable hereunder that has not yet been issued as of the Closing Date, the current taxable value and tax rate shall be assumed to apply and used in proration hereunder.

(iii) With respect to Property Taxes for which the applicable Property Tax Lien Date occurs in the calendar year of Closing, Buyer shall have the right to participate in the appeal, settlement or compromise of any proceeding to determine the value of the Project for purposes of Property Taxes. Seller shall take such action in connection with any such proceeding as Buyer shall reasonably request from time to time to implement the preceding sentence, including the selection of counsel and experts and the execution of powers of attorney. During the Interim Period, Seller shall not settle any proceeding with respect to Property Taxes that could materially affect Buyer in the calendar year of Closing without Buyer's prior written consent.

(iv) During the Interim Period, Seller shall take appropriate action to ensure the continuation of existing Project Property Tax incentives, exemptions and abatements, including but not limited to, air and water pollution control tax exemption certificates, industrial facility tax abatements payment in lieu of taxes or renaissance zones. Further, Seller shall participate and take appropriate actions to transfer ownership or registration of such incentives, abatements or exemptions to the Buyer.

Section 5.9. Books and Records.

Seller shall deliver the books and records set forth on Schedule 5.9 to Buyer as promptly as practicable following the Closing Date (it being agreed that Seller may retain a copy thereof). Not later than 30 days after Closing, a breakdown of the Purchase Price in accordance with the property retirement unit categories and other systems of account together with all books and records substantiating the Purchase Price breakdown shall be delivered to Buyer. For physical Project Assets, Seller will provide the following: retirement unit, quantity, cost, ID number, make, model, serial number and unit number. For land, Seller will provide the parcel and deed information.

Section 5.10. Intentionally Omitted.

Section 5.11. Casualty.

If any Asset of Seller is damaged or destroyed by fire, storm, explosion or other casualty loss after the date hereof and prior to the Closing (a ***"Casualty Loss"),*** and (a) the cost of restoring such damaged or destroyed Asset to a condition reasonably comparable to its prior condition plus (b) the amount of any lost profits reasonably expected to accrue after Closing as a result of such Casualty Loss (net of and after giving effect to any insurance proceeds available to the Buyer for such restoration and lost profits) (such costs and lost profits, as estimated by a qualified firm selected by Buyer and reasonably acceptable to Seller acting in good faith, the ***"Restoration Cost")*** does not exceed 10% of the Base Purchase Price, the amount of the Purchase Price shall be reduced by the estimated Restoration Cost, and such Casualty Loss shall not affect the Closing. If the estimated Restoration Cost is in excess of 10% of the Base Purchase Price, Buyer may, by notice to Seller within 90 days after the date of such Casualty Loss, elect to (y) reduce the Purchase Price by the estimated Restoration Cost, or (z) terminate this Agreement, in each case by providing written notice to Seller. If Buyer does not make any such election within 90 days after the date of such Casualty Loss, Seller may elect to terminate this Agreement, provided that Seller first gives Buyer written notice of termination within 10 Business Days after the end of such 90-day period and Buyer does not make an election within the 10-Business Day period.

Section 5.12. Condemnation.

If any Purchased Assets of Seller is taken by condemnation after the date hereof and prior to the Closing and such Purchased Assets have the sum of (a) the reduction or loss in value of the Property and/or Project and/or portion(s) thereof plus (b) to the extent not included in preceding clause (a), the amount of any lost profits reasonably expected to accrue after Closing as a result of such condemnation (net of and after giving effect to any condemnation award) (such reduction or loss in value and lost profits, as estimated by a qualified firm selected by Buyer and reasonably acceptable to Seller acting in good faith, the ***"Condemnation Value'')*** not in excess of 10% of the Base Purchase Price, the Purchase Price shall be reduced by such estimated Condemnation Value (less the amount of any condemnation award that will accrue to Buyer), and such condemnation shall not affect the Closing. If the estimated Condemnation Value is in excess of 10% of the Base Purchase Price, Buyer may, by notice to Seller within 90 days after the award of condemnation proceeds, elect to (y) reduce the Purchase Price by such estimated Condemnation Value (after giving effect to any condemnation award that will accrue to Buyer) or (z) terminate this Agreement, in each case by providing written notice to Seller. If Buyer does not make any such election within 90 days after the date of such condemnation award, Seller may elect to terminate this Agreement, provided that Seller first gives Buyer written notice of termination within 10 Business Days after the end of such 90-day period and Buyer does not make an election within the 10-Business-Day period.

Section 5.13. Confidentiality.

(a) Any information or materials furnished by Seller to Buyer or Buyer to Seller on and after the date of this Agreement shall be subject to the Confidentiality Agreement; provided that Buyer shall not have any obligation to maintain the confidentiality of any information with respect to the Purchased Assets, the Project, the Business or any other information transferred to Buyer under this Agreement from and after the Closing. In the event of any conflict between this Agreement and the Confidentiality Agreement, this Agreement shall prevail.

(b) Notwithstanding the above and anything in the Confidentiality Agreement to the contrary, Buyer may provide confidential information to any Governmental Authority with jurisdiction as necessary to comply with Section 5.1.

Section 5.14. Public Announcements.

Unless required by Law, court process or by the rules of a national securities exchange to make such disclosure, (in which case, Seller shall, if permissible under Law, give Buyer at least 24 hours' notice prior to such required disclosure), neither Seller nor any of its Affiliates shall make any public announcement of this Agreement or the transactions contemplated hereby or otherwise communicate with any news media before Buyer has made a public announcement of this Agreement or the transactions contemplated hereby.

Section 5.15. Distributions.

For the avoidance of doubt, the Parties hereby acknowledge and agree that Seller shall not, during the Interim Period, distribute any of the cash, accounts receivable or other assets held by Seller with respect to the Project or the Purchased Assets to its Affiliates.

Section 5.16. Further Assurances.

Subject to the terms and conditions of this Agreement, at any time or from time to time after the Closing, at any Party's request and without further consideration, the other Party shall execute and deliver to such Party such other instruments of sale, transfer, conveyance, assignment and confirmation, provide such materials and information and take such other actions as such Party may reasonably request in order to consummate the transactions contemplated by this Agreement.

Section 5.17. Monthly Operating Report.

During the Interim Period, Seller will, promptly after its preparation, and in no event later than 10 days after the end of each calendar month, provide Buyer with a monthly operating report in the form of attached Schedule 5.17.

Section 5.18. Intentionally Omitted.

Section 5.19. Financial Statements.

During the Interim Period, Seller shall deliver to Buyer true and correct copies of Financial Statements of Seller prepared in accordance with GAAP no later than 60 days after each year end and no later than 45 days after each quarter end.

Section 5.20. Intentionally Omitted.

Section 5.21. No Solicitation of Other Bids.

(a) Seller shall not, and shall not authorize or permit any of its Affiliates or any of its or their Representatives to, directly or indirectly, (i) encourage, solicit, initiate, facilitate or continue inquiries regarding an Acquisition Proposal; (ii) enter into discussions or negotiations with, or provide any information to, any Person concerning a possible Acquisition Proposal; or (iii) enter into any agreements or other instruments (whether or not binding) regarding an Acquisition Proposal. Seller shall immediately cease and cause to be terminated, and shall cause its Affiliates and all of its and their Representatives to immediately cease and cause to be terminated, all existing discussions or negotiations with any Persons conducted heretofore with respect to, or that could lead to, an Acquisition Proposal. For purposes hereof, ***"Acquisition Proposal"*** means any inquiry, proposal or offer from any Person (other than Buyer or any of its Affiliates) relating to the direct or indirect disposition, whether by sale, merger or otherwise, of all or any portion of the Business, the Project or the Purchased Assets, but does not include any inquiry, proposal or offer with respect to the sale of electricity, capacity or ancillary services by Seller.

(b) In addition to the other obligations under this Section 5.21, Seller shall promptly (and in any event within 3 Business Days after receipt thereof by Seller or its Representatives) advise Buyer orally and in writing of any Acquisition Proposal, any request for information with respect to any Acquisition Proposal, or any inquiry with respect to or which could reasonably be expected to result in an Acquisition Proposal, the material terms and conditions of such request, Acquisition Proposal or inquiry, and the identity of the Person making the same.

(c) Seller agrees that the rights and remedies for noncompliance with this Section 5.21 shall include having such provision specifically enforced by any court having equity jurisdiction, it being acknowledged and agreed that any such breach or threatened breach shall cause irreparable injury to Buyer and that money damages would not provide an adequate remedy to Buyer.

Section 5.22 Current Evidence of Title. At any time prior to the Closing, Buyer may obtain for each parcel, tract and subdivided land lot of real property included in the Property:

(a) *Title Commitments*. From a title company selected by Buyer ***("Title Insurer")***, title commitments issued by the Title Insurer to insure title to all Property and insurable appurtenances, if any, in the amount of the Purchase Price covering such Property, naming Buyer as the proposed insured and having an effective date after the date of this Agreement, wherein Title Insurer will agree to issue an owner's policy of title insurance (or leasehold owner's policy as the case may be) (ALTA 1992 Form B), without the standard printed exceptions and with the Endorsements (defined below) (each a "***Title Commitment***", *and collectively, the* "***Title Commitments***") and complete legible copies of all recorded documents listed therein (the ***"Recorded Documents"***). Seller and Buyer shall split 50/50 the cost of each such Title Commitment.

(b) *Survey*. An ALTA/ASCM land title survey of each parcel, tract and subdivided land lot of real property included in the Property, as-built, by a land surveyor licensed in Michigan and bearing a certificate, signed and sealed by the surveyor, that is selected by Buyer that reflects, without limitation, the locations of all building lines, easements and areas affected by any Recorded Documents affecting such Property as disclosed in the applicable Title Commitment (identified by recording or filing information) as well as any encroachments onto the Property or by any part of the Property onto any easement area or adjoining property (each, a ***"Survey"***). Buyer will be responsible for the cost of the Survey.

Section 5.23 Title Policy.

(a) *Requirements*. Each Title Commitment will include the Title Insurer's requirements for issuing its ALTA 1992 Form B title policy (owner's or leasehold owner's as the case may be) without standard printed exceptions, which requirements will be met by Seller on or before the Closing Date (including those requirements to issue the endorsements described below and those that must be met by releasing or satisfying Liens, but excluding Permitted Liens and those requirements that are to be met solely by Buyer). Each Title Commitment will provide for the following endorsements, together with any other endorsements that Buyer or its lender may reasonably request after receiving the Title Commitment and Survey (endorsements only applicable to leasehold owner's policies in *italics*) (***"Endorsements"***):

i. ALTA 17-06/17.1-06 (Access and Entry)
ii. ALTA 18-06 (Single Tax Parcel)
iii. ALTA 22-06 (Location)
iv. ALTA 9.2-06 (Covenants, Conditions and Restrictions)
v. ALTA Form 13-06 (Leasehold-Owner's Policy)
vi. ALTA 28.1-06 (Encroachments-Boundaries and Easements)
vii. ALTA 35-06 (Minerals and Other Subsurface Substances)
viii. ALTA 25-06 (Same as Survey)
ix. ALTA 3.1-06 (Zoning)
x. Removal of Standard Exceptions
xi. Deletion of Arbitration
xii. ALTA Form 36-06 Energy (Leasehold/Easement-Owners Policy)
xiii. ALTA Form 36.2-06 Energy (Leasehold- Owners Policy)

xiv. ALTA Form 36.4-06 *Energy* (Covenants, Conditions and Restrictions)
xv. ALTA Form 36.6-06 Energy (Encroachments) (TC)
xvi. ALTA Form 36.7-06 Energy (Fee Estate-Owners Policy)
xvii. Zoning (ALTA 3.1 plus parking), covenants, conditions and restrictions

(b) *Objections*. If any of the following occur (collectively, a ***"Title Objection"***): (i) any Title Commitment or other evidence of title or search of the appropriate real estate records discloses that any party other than Seller has title to the insured estate covered by the Title Commitment; (ii) any title exception is disclosed in any Title Commitment that is not one of the Permitted Liens; or (iii) the Survey discloses any material matter that does or may have an adverse effect on the operation of the Business or the value of the property in question; then Buyer will notify Seller in writing of such matters at least 180 days prior to the Closing Date (unless such matter is first disclosed to Buyer after such date in which case Buyer shall promptly notify Seller upon receipt of such disclosure).

(c) *Curing*. Seller will use its best efforts to cure each Title Objection and take all steps required by the Title Insurer to eliminate each Title Objection as an exception applicable to any Title Commitment.

(d) *No Waiver*. Nothing herein waives Buyer's right to Claim a breach of a representation or warranty or to Claim a right to indemnification if Buyer suffers any damages as a result of a misrepresentation with respect to the condition of title to the Property.

(e) *Fees*. At Closing, Seller will pay all recording and filing costs in connection with curing title to the Property and the transfer taxes for the Warranty Deeds. Buyer will pay the recording fee for the Warranty Deeds. Seller and Buyer will each pay one-half of any closing fee charged by the title company conducting the Closing. At Closing, Buyer shall pay the title premium for Buyer's owner's policy of title insurance for the Property in the amount of the Purchase Price allocated to such property and all endorsements thereto.

ARTICLE VI. BUYER'S CONDITIONS TO CLOSING

The obligation of Buyer to consummate the Closing is subject to the fulfillment of each of the following conditions (except to the extent waived in writing by Buyer):

Section 6.1. Representations and Warranties.

(a) All representations and warranties made by Seller in ARTICLE III shall be true and accurate on and as of the Closing Date as though made on and as of the Closing Date, except for (i) changes expressly permitted or contemplated hereby, or (ii) representations and warranties which are as of a specific date, which shall be true and accurate as of such date.

(b) Since the date of this Agreement, there has not been any Material Adverse Effect with respect to Seller or the Assets of Seller.

Section 6.2. Performance.

Seller shall have performed and complied with all agreements, covenants and obligations required by this Agreement to be performed or complied with by Seller at or before the Closing.

Section 6.3. Officer's Certificate.

Seller shall have delivered to Buyer at the Closing a certificate of an officer of Seller, dated as of the Closing Date, affirming and certifying the matters set forth in Section 6.1 and Section 6.2.

Section 6.4. Orders and Laws.

There shall be no effective injunction, writ or restraining order or any order of any nature issued by a Governmental Authority of competent jurisdiction to the effect that the purchase and sale of the Purchased Assets and the other transactions contemplated pursuant to this Agreement may not be consummated as provided in this Agreement and no proceeding or lawsuit shall have been commenced by any Governmental Authority which may result in any such injunction, writ or restraining order or to otherwise prohibit or make illegal the consummation of the transactions contemplated by this Agreement.

Section 6.5. Consents and Approvals.

The Buyer Approvals, Seller Approvals, Seller Consents, and the Acceptable Orders shall have been duly obtained, made or given and shall be in full force and effect, and all terminations or expirations of waiting periods imposed by any Governmental Authority shall have occurred.

Section 6.6. Resignation of Members, Managers, Officers and Directors.

Seller shall have caused the resignation or removal of all members, managers, partners, officers and directors, as applicable, nominated or appointed by Seller or its Affiliates to any board or operating, management or other committee relating to the Project or established under Seller's Organizational Documents, and shall have delivered to Buyer at the Closing evidence of such resignations or removals.

Section 6.7. Release of Indebtedness; Release of Liens.

Seller shall have delivered to Buyer evidence, satisfactory to Buyer, of Seller's compliance with Section 5.6.

Section 6.8. Owner's Title Policy.

Buyer shall have obtained an owner's title policy (or leasehold owner’s title policy as the case may be) for each parcel, tract and subdivided land lot of real property included in the Property acceptable to Buyer, in the amounts, with the endorsements and otherwise meeting the requirements of Section 5.22 and 5.23 (each a "***Title Policy***" and collectively, the "***Title Policies***").

Section 6.9. Remediation Obligations.

The Dearborn Industrial Generating facility currently has obligations to AK Steel Corporation ("***AK Steel***") regarding certain water discharges under the Conformed and Amended Agreement between Dearborn Industrial Generation, LLC and AK Steel Corporation (as successor to Severstal North America, Inc.), dated February 1, 2008, as amended by the First Amendment to Conformed and Amended Agreement dated December 31, 2019 (the "***Water Limit Obligations***"). The Dearborn Industrial Generating facility is authorized to discharge from the facility under National Pollutant Discharge Elimination System Permit No. MI0056235 issued by the Michigan Department of Environmental Quality (now the Michigan Department of Environment, Great Lakes & Energy or "EGLE") (the "***NPDES Permit***"). Prior to Closing, at its own cost Seller shall complete, to Buyer's reasonable satisfaction, a solution to achieve full compliance with the Water Limit Obligations, all existing or future NPDES Permit limits, and any limits contained in any other existing or future permits, Laws, rules, or regulations governing discharges from the Dearborn Industrial Generating facility (the "***Remediation Obligations***"). All plans for the Remediation Obligations shall be subject to Buyer's reasonable review and approval prior to their implementation. If the Remediation Obligations are not completed as provided in this Section, then the Purchase Price shall be reduced up to $20,000,000 (the "***Purchase Price Reduction***") based on a mutual agreement between Buyer and Seller. Once the Purchase Price Reduction is reflected in the Closing statement, then (i) all indemnity obligations by Seller set forth in Section 9.1(a) and termination rights by Buyer under Section 8.1 solely in connection with breaches of the Remediation Obligations, shall be deemed terminated; and (ii) Buyer shall be deemed to have assumed responsibility for all costs and expenses attributable to the Remediation Obligations and all Losses with respect thereto shall be deemed as Assumed Liabilities, except with respect to any Claim by AK Steel, EGLE and Ford Motor Company solely in connection with Seller's Remediation Obligations (collectively, "***Remediation Indemnity Obligations***"). Seller agrees to indemnify Buyer for all such Remediation Indemnity Obligations pursuant to Section 9.1 against all Losses subject to Section 9.2 resulting from such breaches of Seller's Remediation Obligations.

Section 6.10. Due Diligence.

Buyer is satisfied with each Estoppel Certificate and the results of its environmental and real property due diligence.

ARTICLE VII. SELLER'S CONDITIONS TO CLOSING

The obligation of Seller to consummate the Closing is subject to the fulfillment of each of the following conditions (except to the extent waived in writing by Seller):

Section 7.1. Representations and Warranties.

The representations and warranties made by Buyer in ARTICLE IV shall be true and accurate on and as of the Closing Date as though made on and as of the Closing Date, except for (i) changes expressly permitted or contemplated hereby; or (ii) representations and warranties which are as of a specific date, in which event they shall be true and accurate as of such date.

Section 7.2. Performance.

Buyer shall have performed and complied with all agreements, covenants and obligations required by this Agreement to be so performed or complied with by Buyer at or before the Closing.

Section 7.3. Officer's Certificate.

Buyer shall have delivered to Seller at the Closing a certificate of an officer of Buyer, dated as of the Closing Date, affirming and certifying the matters set forth in Section 7.1 and Section 7.2.

Section 7.4. Orders and Laws.

There shall be no effective injunction, writ or restraining order or any order of any nature issued by a Governmental Authority of competent jurisdiction to the effect that the purchase and sale of the Purchased Assets and the other transactions contemplated pursuant to this Agreement may not be consummated as provided in this Agreement and no proceeding or lawsuit shall have been commenced by any Governmental Authority which may result in any such injunction, writ or restraining order or to otherwise prohibit or make illegal the consummation of the transactions contemplated by this Agreement.

Section 7.5. Consents and Approvals.

The Seller Approvals shall have been duly obtained, made or given and shall be in full force and effect, and all terminations or expirations of waiting periods imposed by any Governmental Authority shall have occurred.

ARTICLE VIII. TERMINATION

Section 8.1. Termination.

This Agreement may be terminated, and the transactions contemplated hereby may be abandoned, at any time before the Closing as follows:

(a) by Seller, by written notice to Buyer, if Buyer has breached any representation, warranty, covenant, agreement or obligation in this Agreement and such breach has not been cured within 30 days following written notification thereof; provided, however, that if, at the end of such 30-day period, Buyer is endeavoring in good faith, and proceeding diligently, to cure such breach, Buyer shall have an additional 90 days in which to effect such cure;

(b) by Buyer, by written notice to Seller, if Seller has breached any representation, warranty, covenant, agreement or obligation in this Agreement and such breach has not been cured within 30 days following written notification thereof; provided, however, that if, at the end of such 30-day period, Seller is endeavoring in good faith, and proceeding diligently, to cure such breach, Seller shall have an additional 90 days in which to effect such cure;

(c) by Buyer or Seller, by notice to the other, on or after May 1, 2027, or such later date as the Buyer and Seller may agree in writing; provided that Buyer cannot terminate under this provision if the failure of the Closing to occur is the result of the failure on the part of Buyer to perform any of its obligations hereunder and Seller cannot terminate this Agreement under this provision if the failure of the Closing to occur is the result of the failure on the part of Seller to perform any of its obligations hereunder;

(d) by Buyer or Seller, in accordance with Section 5.11 or Section 5.12;

(e) by Buyer if it is not satisfied with the results of its environmental or real property due diligence so long as notice is given by October 31, 2022;

(f) to the extent that any of the exhibits or schedules indicate that they will be completed after the signing this Agreement, then the parties will work together to complete such exhibits and/or schedules. If any of the exhibits or schedules are not completed within one month following the date of this Agreement, then either party will have the right to terminate this Agreement; or

(g) by mutual written consent of Buyer and Seller.

Section 8.2. Effect of Termination.

(a) If this Agreement is validly terminated pursuant to Section 8.1, there will be no Liability or obligation on the part of Seller or Buyer (or any of their respective Representatives or Affiliates), except as provided in this Section 8.2 and Section 8.3.

(b) Regardless of the reason for termination, Section 5.13 (with respect to information or materials subject to the Confidentiality Agreement), Section 5.14, this Section 8.2, Section 8.3, Section 9.4(a), and Section 9.4(b) and ARTICLE X will survive any termination of this Agreement, and each Party shall continue to be liable for any breach of this Agreement by it occurring prior to such termination.

Section 8.3. Specific Performance and Other Remedies.

Each Party hereby acknowledges that the rights of each Party to consummate the transactions contemplated hereby are special, unique and of extraordinary character and that, if either Party violates or fails or refuses to perform any covenant or agreement made by it herein, the non-breaching Party may be without an adequate remedy at law. If either Party violates or fails or refuses to perform any covenant or agreement made by such Party herein, the non-breaching Party or Parties may, subject to the terms hereof and in addition to any remedy at law for damages or other relief, institute and prosecute an action in any court of competent jurisdiction to enforce specific performance of such covenant or agreement or seek any other equitable relief.

ARTICLE IX. INDEMNIFICATION, LIMITATIONS OF LIABILITY AND WAIVERS

Section 9.1. Indemnification.

(a) Subject to Section 9.2, from and after the Closing, Seller shall defend and hold harmless Buyer and its stockholders, partners, members, officers, employees, Affiliates and

Representatives (collectively, the ***"Buyer Indemnified Parties")*** from and against all Losses incurred or suffered by any Buyer Indemnified Party resulting from:

(i) any breach or inaccuracy as of the Closing Date (as though made on and as of the Closing Date except to the extent otherwise provided in this Agreement) of any representation or warranty of Seller contained in this Agreement, any Ancillary Agreement or any certificates delivered in connection herewith or therewith;

(ii) any breach of any covenant or agreement of Seller contained in this Agreement, any Ancillary Agreement or any certificates delivered in connection herewith or therewith;

(iii) the Excluded Liabilities; and

(iv) any Environmental Liability of Seller related to the Property.

(b) Subject to Section 9.2, from and after Closing, Buyer shall indemnify, defend and hold Seller and its stockholders, partners, members, officers, employees, Affiliates and Representatives (collectively, the ***"Seller Indemnified Parties"*** and, together with Buyer Indemnified Parties, the ***"Indemnified Parties")*** harmless from and against all Losses incurred or suffered by any Seller Indemnified Party resulting from:

(i) any breach or inaccuracy as of the Closing Date (as though made on and as of the Closing Date except to the extent otherwise provided in this Agreement) of any representation or warranty of Buyer contained in this Agreement, any Ancillary Agreement or any certificates delivered in connection herewith or therewith; and

(ii) any breach of any covenant or agreement of Buyer contained in this Agreement, any Ancillary Agreement or any certificates delivered in connection herewith or therewith.

(c) For purposes of this Section 9.1, the amount of any Losses associated with any inaccuracy in or breach of any representation or warranty set forth in this Agreement (but not for purposes of determining the existence of such inaccuracy or breach) shall be determined without regard for any materiality, "Material Adverse Effect" or similar qualification.

Section 9.2. Limitations of Liability.

Notwithstanding anything in this Agreement to the contrary:

(a) the representations, warranties, covenants, agreements and obligations in this Agreement or any Ancillary Agreement shall survive the Closing; provided, however, that except for Claims arising out of or related to fraud (but not constructive fraud) no Party may make or bring a Claim for Liability (i) with respect to any representations or warranties (or in any certificate relating thereto) contained in ARTICLE III or ARTICLE IV (other than those representations and warranties contained in Section 3.1 (Organization), Section 3.2 (Authority; Enforceability), Section 3.3 (No Conflicts; Consents and Approvals), Section 3.5 (Brokers), Section 3.13 (Ownership; Liens), (collectively, the ***"Fundamental Representations")*** or Section

3.10 (Taxes)) after two years following the Closing Date, (ii) with respect to the representations and warranties contained in the Fundamental Representations, after the five-year anniversary of the Closing Date, and (iii) with respect to the representations and warranties contained in Section 3.10 (Taxes), after 60 days following the expiration of the applicable statute of limitations;

(b) Seller shall have no Liability for a breach of this Agreement (other than any Excluded Liabilities, any breach of the Fundamental Representations, a breach of a representation or warranty contained in Section 3.10 (Taxes) or a matter covered by Section 5.8 (Transfer Taxes; Property Taxes)) until the aggregate amount of all Losses incurred by Buyer equals or exceeds $1,000,000 (the ***"Deductible Amount"),*** in which event Seller shall be liable for Losses only to the extent they are in excess of the Deductible Amount (except as otherwise set forth in this Section 9.2);

(c) except for fraud (but not constructive fraud), intentional or willful misconduct, in no other event shall Seller's aggregate Liability arising out of or relating to Losses under Section 9.1(a)(i) or Buyer's aggregate Liability arising out of or relating to Losses under Section 9.1(b)(i) exceed $100,000,000; and

(d) no Indemnifying Party shall have any Liability under this ARTICLE IX to indemnify any Indemnified Party with respect to a Loss to the extent that the Loss arose from or was exacerbated by any action taken directly by any Indemnified Party on or after the Closing Date.

Section 9.3. No Other Representations or Warranties.

EXCEPT FOR THE REPRESENTATIONS AND WARRANTIES CONTAINED IN ARTICLE III, NEITHER SELLER NOR ANY OTHER PERSON MAKES ANY OTHER EXPRESS OR IMPLIED REPRESENTATION OR WARRANTY ON BEHALF OF SELLER. EXCEPT FOR THE REPRESENTATIONS AND WARRANTIES CONTAINED IN ARTICLE IV, NEITHER THE BUYER NOR ANY OTHER PERSON MAKES ANY OTHER EXPRESS OR IMPLIED REPRESENTATION OR WARRANTY ON BEHALF OF BUYER.

Section 9.4. Waiver of Remedies.

(a) The Parties hereby agree that, except with respect to Claims for fraud (but not constructive fraud), no Party shall have any Liability, and no Party shall make any Claim, for any Loss or other matter under, relating to or arising out of this Agreement, or the Closing Certificates, whether based on contract, tort, strict Liability, other Laws or otherwise, except as provided in Section 5.10, ARTICLE VIII and ARTICLE IX.

(b) NOTWITHSTANDING ANYTHING IN THIS AGREEMENT TO THE CONTRARY, EXCEPT WITH RESPECT TO (1) A CLAIM BY A THIRD PARTY THAT FALLS WITHIN AN INDEMNIFYING PARTY'S OBLIGATIONS UNDER ARTICLE IX AND (2) FOR PURPOSES OF CALCULATING RESTORATION COST UNDER SECTION 5.11 OR CONDEMNATION VALUE UNDER SECTION 5.12, NO PARTY SHALL BE LIABLE FOR SPECIAL, PUNITIVE, EXEMPLARY, INCIDENTAL, CONSEQUENTIAL OR INDIRECT DAMAGES OR LOST PROFITS, WHETHER BASED ON CONTRACT, TORT, STRICT LIABILITY, OTHER LAW OR OTHERWISE AND WHETHER OR NOT ARISING

FROM THE OTHER PARTY'S SOLE, JOINT OR CONCURRENT NEGLIGENCE, STRICT LIABILITY OR OTHER FAULT ***("NON-REIMBURSABLE DAMAGES")***.

Section 9.5. Procedure with Respect to Third-Party Claims.

(a) If any Party becomes subject to a pending or threatened Claim of a third party and such Party (the ***"Claiming Party")*** believes it has a Claim against the other Party (the ***"Responding Party")*** as a result, then the Claiming Party shall promptly notify the Responding Party in writing of the basis for such Claim setting forth the nature of the Claim in reasonable detail. The failure of the Claiming Party to so notify the Responding Party shall not relieve the Responding Party of Liability hereunder except to the extent that the defense of such Claim is materially prejudiced by the failure to give such notice.

(b) If any proceeding is brought by a third party against a Claiming Party and the Claiming Party gives notice to the Responding Party pursuant to this Section 9.5, the Responding Party shall be entitled to participate in such proceeding and, to the extent that it wishes, to assume the defense of such proceeding, if (i) the Responding Party provides written notice to the Claiming Party that the Responding Party intends to undertake such defense, (ii) the Responding Party conducts the defense of the third-party Claim actively and diligently with counsel reasonably satisfactory to the Claiming Party and (iii) if the Responding Party is a party to the proceeding, the Responding Party or the Claiming Party has not determined in good faith that joint representation would be inappropriate because of a conflict in interest. The Claiming Party, in its sole discretion, shall have the right to employ separate counsel (who may be selected by the Claiming Party in its sole discretion) in any such action and to participate in the defense thereof, and the fees and expenses of such counsel shall be paid by such Claiming Party. Notwithstanding the preceding sentence, to the extent that the Claiming Party incurs fees and expenses because of the Claiming Party's good faith determination that it must engage separate counsel because of a conflict of interest under Section 9.5(b)(iii), the fees and expenses of such separate counsel shall be paid by the Responding Party pursuant to Section 9.5(c). The Claiming Party and the Responding Party shall fully cooperate with each other and their respective counsel in the defense or compromise of such Claim. If the Responding Party assumes the defense of a proceeding, no compromise or settlement of such Claims may be effected by the Responding Party without the Claiming Party's consent unless (x) there is no finding or admission of any violation of Law or any violation of the rights of any Person and no adverse effect on any other Claims that may be made against the Claiming Party and (y) the sole relief provided is monetary damages that are paid in full by the Responding Party.

(c) If (i) notice is given to the Responding Party of the commencement of any third-party legal proceeding and the Responding Party does not, within 30 days after the Claiming Party's notice is given, give notice to the Claiming Party of its election to assume the defense of such legal proceeding, (ii) any of the conditions set forth in clauses (i) through (iii) of Section 9.5(b) above become unsatisfied or (iii) a Claiming Party determines in good faith that there is a reasonable probability that a legal proceeding may adversely affect it other than as a result of monetary damages for which it would be entitled to indemnification from the Responding Party under this Agreement, then the Claiming Party shall (upon notice to the Responding Party) have the right to undertake the defense, compromise or settlement of such Claim; provided, however, that the Responding Party shall reimburse the Claiming Party for the costs of defending against such third-party Claim (including reasonable attorneys' fees and expenses) and shall remain otherwise responsible for any Liability with respect to amounts arising from or related to such third-party Claim, to the extent it is ultimately determined that such Responding Party is liable with respect to such third-party Claim for a breach under this Agreement. The Responding Party may elect to participate in such legal proceedings, negotiations or defense at any time at its own expense.

ARTICLE X. MISCELLANEOUS

Section 10.1. Notices.

(a) Unless this Agreement specifically requires otherwise, any notice, demand or request provided for in this Agreement, or served, given or made in connection with it, shall be in writing and shall be deemed properly served, given or made if delivered in person or sent by registered or certified mail, postage prepaid, or by a nationally recognized overnight courier service that provides a receipt of delivery, in each case, to the Parties at the addresses specified below:

If to Buyer, to:

Consumers Energy Company
One Energy Plaza
Jackson, MI 49201
Attn: President

With copies to:

Consumers Energy Company
One Energy Plaza
Jackson, MI 49201
Attn: General Counsel

If to Seller, to:

c/o CMS Enterprises
One Energy Plaza
Jackson, MI 49201
Attn: Richard R. Mukhtar

With copies to:

Pillsbury Winthrop Shaw Pittman LLP
31 West 52nd Street
New York, NY 10019
Attn: Mona E. Dajani

(b) Notice given by personal delivery, mail or overnight courier pursuant to this Section 10.1 shall be effective upon physical receipt.

Section 10.2. Entire Agreement.

This Agreement supersedes all prior discussions and agreements between the Parties with respect to the subject matter hereof, and this Agreement, the Ancillary Agreements and the other documents delivered pursuant to this Agreement contain the sole and entire agreement between the Parties hereto with respect to the subject matter hereof.

Section 10.3. Expenses.

Except as otherwise expressly provided in this Agreement, whether or not the transactions contemplated hereby are consummated, each Party will pay its own costs and expenses incurred in anticipation of, relating to and in connection with the negotiation and execution of this Agreement and the transactions contemplated hereby.

Section 10.4. Disclosure.

From time to time prior to the Closing Date, Seller will add, supplement or amend and deliver updates to with respect to any matter hereafter arising or discovered which, if existing or known as of the date of this Agreement or thereafter, would have been required to be set forth or described in such Schedules or as necessary to complete or correct any information in such Schedules or include in the Schedules items that are not material in order to avoid any misunderstanding. Any such inclusion, or any references to dollar amounts, shall not be deemed to be an acknowledgment or representation that such items are material, to establish any standard of materiality or to define further the meaning of such terms for purposes of any provision of this Agreement that establishes a standard of materiality. Information disclosed in any Schedule shall constitute a disclosure for purposes of all other Schedules notwithstanding the lack of specific cross-reference thereto, but only to the extent the applicability of such disclosure to such other Schedule is relevant to the other Schedule and reasonably apparent. For purposes of determining whether the conditions set forth in ARTICLE VI have been fulfilled, the Schedules to Seller's representations and warranties contained in this Agreement shall be deemed to include only that information contained therein on the date of this Agreement and shall be deemed to exclude all information contained in any addition, supplement or amendment thereto; *provided, however*, that if Closing shall occur, then all matters disclosed pursuant to any such addition, supplement or amendment at or prior to Closing shall be waived and deemed part of the Schedules for all purposes. Disclosure of such additional information will not be deemed to enlarge or enhance any of the representations or warranties in this Agreement.

Section 10.5. Waiver.

Any term or condition of this Agreement may be waived at any time by the Party that is entitled to the benefit thereof, but no such waiver shall be effective unless set forth in a written instrument duly executed by or on behalf of the Party waiving such term or condition. No waiver by any Party of any term or condition of this Agreement, in any one or more instances, shall be deemed to be or construed as a waiver of the same or any other term or condition of this

Agreement on any future occasion. All remedies, either under this Agreement or by Law or otherwise afforded, will be cumulative and not alternative.

Section 10.6. Amendment.

This Agreement may be amended, supplemented or modified only by a written instrument duly executed by or on behalf of each Party.

Section 10.7. No Third-Party Beneficiary.

Except for the provisions of Section 9.1(a) and (b) (which are intended for the benefit of the Persons identified therein), the terms and provisions of this Agreement are intended solely for the benefit of the Parties and their respective successors or permitted assigns, and it is not the intention of the Parties to confer third-party beneficiary rights upon any other Person, including, without limitation, any employee, any beneficiary or dependents thereof, or any collective bargaining representative thereof.

Section 10.8. Assignment; Binding Effect.

Buyer may assign its rights and obligations hereunder to any Affiliate or Affiliates, or to Buyer's lenders for collateral security purposes, but such assignment shall not release Buyer from its obligations hereunder. Except as provided in the preceding sentence, neither this Agreement nor any right, interest or obligation hereunder may be assigned by any Party without the prior written consent of the other Party, and any attempt to do so will be void, except for assignments and transfers by operation of Law. Subject to this Section 10.8, this Agreement is binding upon, inures to the benefit of and is enforceable by the Parties and their respective successors and permitted assigns.

Section 10.9. Headings.

The headings used in this Agreement have been inserted for convenience of reference only and do not define or limit the provisions hereof.

Section 10.10. Invalid Provisions.

If any provision of this Agreement is held to be illegal, invalid or unenforceable under any present or future Law, and if the rights or obligations of any Party under this Agreement will not be materially and adversely affected thereby, such provision will be fully severable, this Agreement will be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part hereof, the remaining provisions of this Agreement will remain in full force and effect and will not be affected by the illegal, invalid or unenforceable provision or by its severance herefrom and in lieu of such illegal, invalid or unenforceable provision, there will be added automatically as a part of this Agreement a legal, valid and enforceable provision as similar in terms to such illegal, invalid or unenforceable provision as may be possible.

Section 10.11. Counterparts; Facsimile.

This Agreement may be executed in any number of counterparts, each of which will be deemed an original, but all of which together will constitute one and the same instrument. Any electronic or facsimile copies hereof or signature hereon shall, for all purposes, be deemed originals.

Section 10.12. Governing Law; Venue; and Jurisdiction.

(a) This Agreement shall be governed by and construed in accordance with the Laws of the State of Michigan, without giving effect to any conflict or choice of law provision that would result in the imposition of another state's Law.

(B) THE PARTIES HEREBY IRREVOCABLY AGREE THAT THE EXCLUSIVE JURISDICTION TO HEAR ANY CIVIL ACTIONS ARISING OUT OF OR RELATED TO THIS AGREEMENT SHALL BE IN ANY STATE OR FEDERAL COURT IN THE STATE OF MICHIGAN AND EACH PARTY HEREBY SUBMITS AND CONSENTS TO THE JURISDICTION OF SUCH COURTS (AND OF THE APPROPRIATE APPELLATE COURTS THEREFROM) IN ANY SUCH SUIT, ACTION OR PROCEEDING AND IRREVOCABLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY LAW, ANY OBJECTION THAT IT MAY NOW OR HEREAFTER HAVE TO THE LAYING OF THE VENUE OF ANY SUCH SUIT, ACTION OR PROCEEDING IN ANY SUCH COURT OR THAT ANY SUCH SUIT, ACTION OR PROCEEDING THAT IS BROUGHT IN ANY SUCH COURT HAS BEEN BROUGHT IN AN INCONVENIENT FORUM. EACH PARTY HEREBY WAIVES, AND SHALL NOT ASSERT AS A DEFENSE IN ANY LEGAL DISPUTE, THAT (A) SUCH PARTY IS NOT SUBJECT THERETO, (B) SUCH ACTION, SUIT OR PROCEEDING MAY NOT BE BROUGHT OR IS NOT MAINTAINABLE IN SUCH COURT, (C) SUCH PARTY'S PROPERTY IS EXEMPT OR IMMUNE FROM EXECUTION UNDER SUCH COURT'S JURISDICTION, (D) SUCH ACTION, SUIT OR PROCEEDING IS BROUGHT IN AN INCONVENIENT FORUM OR (E) THE VENUE OF SUCH ACTION, SUIT OR PROCEEDING IS IMPROPER. EITHER PARTY FURTHER AGREES IT WILL NOT OBJECT TO ANY MOTION TO TRANSFER A SUIT, ACTION OR PROCEEDING FILED IN ANY OTHER FORUM TO SUCH COURT. A FINAL JUDGMENT IN ANY ACTION, SUIT OR PROCEEDING DESCRIBED IN THIS SECTION 10.12 FOLLOWING THE EXPIRATION OF ANY PERIOD PERMITTED FOR APPEAL AND SUBJECT TO ANY STAY DURING APPEAL SHALL BE CONCLUSIVE AND MAY BE ENFORCED IN OTHER JURISDICTIONS BY SUIT ON THE JUDGMENT OR IN ANY OTHER MANNER PROVIDED BY APPLICABLE LAWS.

(c) EACH PARTY HEREBY WAIVES, TO THE FULLEST EXTENT PERMITTED BY LAW, ANY RIGHT IT MAY HAVE TO A TRIAL BY JURY.

Section 10.13. No Partnership or Joint Venture.

The Parties do not intend to create a partnership or joint venture by virtue of this Agreement. No Party shall owe any fiduciary duty to any other Party by virtue of this Agreement, any Ancillary Agreement or otherwise.

Section 10.14 Acknowledgment.

(a) BUYER ACKNOWLEDGES THAT NEITHER SELLER NOR ANY OTHER PERSON HAS MADE ANY REPRESENTATION OR WARRANTY, EXPRESSED OR

IMPLIED, AS TO THE ACCURACY OR COMPLETENESS OF ANY INFORMATION REGARDING SELLER OR THE CONDITION OF THE PURCHASED ASSETS, VALUE OR QUALITY OF THE PURCHASED ASSETS OR OPERATIONS OR THE PROSPECTS, (FINANCIAL OR OTHERWISE), RISKS, AND OTHER INCIDENTS OF SELLER NOT INCLUDED IN THIS AGREEMENT AND THE SCHEDULES. NOTHING IN THIS SECTION SHALL PRECLUDE BUYER FROM BRINGING A CLAIM AGAINST SELLER FOR FRAUD.

(b) EXCEPT AS OTHERWISE EXPRESSLY PROVIDED HEREIN OR IN THE ANCILLARY AGREEMENTS, SELLER EXPRESSLY DISCLAIMS ANY REPRESENTATIONS OR WARRANTIES OF ANY KIND OR NATURE, EXPRESS OR IMPLIED, AS TO THE CONDITION, VALUE OR QUALITY OF THE ASSETS OR OPERATIONS OF SELLER OR THE PROSPECTS (FINANCIAL AND OTHERWISE), RISKS AND OTHER INCIDENTS OF SELLER AND SPECIFICALLY DISCLAIMS ANY REPRESENTATION OR WARRANTY OF MERCHANTABILITY, USAGE, SUITABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE WITH RESPECT TO SUCH ASSETS, OR ANY PART THEREOF, OR AS TO THE WORKMANSHIP THEREOF, OR THE ABSENCE OF ANY DEFECTS THEREIN, WHETHER LATENT OR PATENT, OR COMPLIANCE WITH ENVIRONMENTAL REQUIREMENTS, OR AS TO THE CONDITION OF, OR THE RIGHTS OF SELLER IN, OR ITS TITLE TO, ANY OF ITS ASSETS, OR ANY PART THEREOF. EXCEPT AS EXPRESSLY PROVIDED HEREIN OR IN THE RELATED AGREEMENTS, NO MATERIAL OR INFORMATION PROVIDED BY OR COMMUNICATIONS MADE BY SELLER OR ANY OF THEIR RESPECTIVE REPRESENTATIVES WILL CAUSE OR CREATE ANY WARRANTY, EXPRESS OR IMPLIED, AS TO THE CONDITION, VALUE OR QUALITY OF SUCH ASSETS. NOTHING IN THIS SECTION SHALL PRECLUDE BUYER FROM BRINGING A CLAIM AGAINST SELLER FOR FRAUD.

[signature page follows]

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized representative of each Party as of the date first above written.

SELLER:

DEARBORN INDUSTRIAL GENERATION, L.L.C.

By: ______________________
Name: Richard R. Mukhtar
Title: President and Chief Executive Officer

APV'D AS TO FORM
KMK

CMS GENERATION MICHIGAN POWER, L.L.C.

By: ______________________
Name: Richard R. Mukhtar
Title: President and Chief Executive Officer

APV'D AS TO FORM
KMK

CMS ENERGY RESOURCE MANAGEMENT COMPANY

By: ______________________
Name: Richard R. Mukhtar
Title: President and Chief Executive Officer

APV'D AS TO FORM
KMK

BUYER:

CONSUMERS ENERGY COMPANY

By: ______________________
Name: ______________________
Title: ______________________

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized representative of each Party as of the date first above written.

SELLER:

DEARBORN INDUSTRIAL GENERATION, L.L.C.

By: ___________________________________
Name: _________________________________
Title: __________________________________

CMS GENERATION MICHIGAN POWER, L.L.C.

By: ___________________________________
Name: _________________________________
Title: __________________________________

CMS ENERGY RESOURCE MANAGEMENT COMPANY

By: ___________________________________
Name: _________________________________
Title: __________________________________

BUYER:

CONSUMERS ENERGY COMPANY

By: [signature]
Name: GARRICK J. ROCHOW
Title: PRESIDENT & CEO

Exhibit 2.1(a)
Purchased Assets

On the terms and subject to the conditions set forth in this Agreement, at the Closing, Buyer agrees to purchase from Seller, and Seller agrees to sell to Buyer, all of the Assets used in the Business, including without limitation, the Assets described in Exhibit 2.1(a) and the Property, together with all improvements, buildings, structures, fixtures, easements, rights-of-way, division rights, hereditaments and appurtenances associated with that real property, all as described in Exhibit 2.1(a).

(a) All inventory, spare parts, plant equipment (more particularly described below in this Exhibit 2.1(a)), peaker units, tooling, and structures;

(b) all accounts or notes receivable held by Seller, and any security, claim, remedy or other right related to any of the foregoing;

(c) all Assigned Contracts described in Schedule 1.1-AC;

(d) all Intellectual Property Assets;

(e) all furniture, fixtures, equipment, machinery, tools, vehicles, office equipment, supplies, computers, telephones and other tangible personal property located on or associated with the Property;

(f) the Property, more particularly described below in this Exhibit 2.1(a);

(g) all Permits, including Environmental Permits, which are held by Seller and required for the conduct of the Business as currently conducted or for the ownership and use of the Purchased Assets;

(h) all rights to any litigation or other action, of any nature, available to or being pursued by Seller to the extent related to the Business, the Purchased Assets or the Assumed Liabilities, whether arising by way of counterclaim or otherwise;

(i) all prepaid expenses, credits, advance payments, claims, security, refunds, rights of recovery, rights of set-off, rights of recoupment, deposits, charges, sums and fees;

(j) all of Seller's rights under warranties, indemnities and all similar rights against third parties to the extent related to any Purchased Assets;

(k) all insurance benefits, including rights and proceeds, arising from or relating to the Business, the Purchased Assets or the Assumed Liabilities;

(l) originals, or where not available, copies, of all books and records, including, but not limited to, books of account, ledgers and general, financial and accounting records, machinery and equipment maintenance files, customer lists, customer purchasing histories, price lists, distribution lists, supplier lists, production data, quality control records and procedures, customer complaints and inquiry files, research and development files, records and data (including all correspondence with any Governmental Authority), sales material and records (including pricing history, total sales, terms and conditions of sale, sales and pricing policies and practices), strategic plans, internal financial statements, marketing and promotional surveys, material and research and files relating to the Intellectual Property Assets; and

(m) all goodwill and the going concern value of the Business.

Plant Equipment

Dearborn Industrial Generation - Major Equipment List

Combustion Turbines

1. GE Frame 7FA Model MS7241FA Serial number – 296637 (GT1100)
2. GE Frame 7FA Model MS7241FA Serial number – 297482 (GT2100)
3. GE Frame 7FA Model MS7241FA Serial number – 297483 (GT3100)
4. Steam Turbine Generator(STG) – ABB Model DKE-2N34B Serial# GM214923

Generators

1. STG – ABB Model 60WY23Z-109 Serial GM214923
2. CTG-1100 – GE Serial# 337X014
3. CTG-2100 – GE Serial# 337X806
4. CTG-3100 – GE Serial#337X807

Transformers

1. STG GSU – Ferranti Packard Serial# TP-393
2. CTG-1100 – GE Serial# G550-01
3. CTG-2100 – Pennsylvania Serial# C-07473-5-1
4. CTG-3100 – GE Serial# G621-01
5. AUX A – Virginia Transformer Serial# 4501MA001-9396A
6. AUX B - Virginia Transformer Serial# 4501MA002-9396A

Steam Generators

1. Three Aalborg Blast Furnace Gas Boilers rated at 500,000 lb/hr
2. Two Heat Recovery Steam Generators – Aalborg rated at 530,000 lb/hr

Balance of Plant

Emergency generators

1. Caterpillar Model SR-4B 3516 Serial#5WN00709
2. Caterpillar Model SR-4B 3516 Serial#5WN00708

Reverse Osmosis System

Michigan Power - Major Equipment List

Kalamazoo Facility

Combustion Turbine

- GE – 1982 Model MS-7001E Serial# 281928

Generator

- GE – 1985 Model 7A4 Serial#335X381

Transformer

- GSU – GE 1999 Serial# G428-01
- AUX – RE Uptegraff Serial# 160K98

Balance of Plant

- Four-fan two-cell finned tube glycol oil cooler
- Filtration system for processing water and a 25,000gallon tank

Livingston Facility

Combustion turbines

- Model 1968 Pratt & Whitney GG4A-7 (8 in use and 2 spares)

Serial#

- 675208
- 675478
- 675206
- 675221
- 675245
- 675210
- 675247
- 675477
- 675225
- 675223

Generators

- P1 – Electric Machinery MFG Company Serial#170144711
- P2 - Electric Machinery MFG Company Serial#468166711
- P2 - Electric Machinery MFG Company Serial#268166711
- P2 - Electric Machinery MFG Company Serial#168166711

Transformers

- P1 – Ferranti-Packard 1999, Serial# CM5000710101
- P2 – Ferranti-Packard 1999, Serial# CM5000710102
- P3 – Ferranti-Packard 1999, Serial# CM5000710103
- P4 – Ferranti-Packard 1999, Serial# CM5000710104

Balance of Plant

- Each unit has Forced Air Flow heat exchanger constructed of metal finned tube
- 600,000 gallon water storage tank

Significant spares

- Rotor (Thetford)
- Expander (Thetford)

<u>Property</u>

Ground Lease Interest Subject to an Option to Purchase:

2400 MILLER, DEARBORN, MI 48120

Parcel Number: 82 10 292 01 002

BEG AT THE INT OF THE ELY LINEOF MILLER RD & NLY LINE OF DIXAVE N-28-07-15-W 2736.92 FT, TH N-61-08-31-E 364.73 FT, TH S-28-12-55-E 1369.78 FT, TH S-22-00-37-E 239.87 FT, TH S-23-05-10-E 42.63 FT, TH S-28-12- 21-E 426.42 FT, TH S-25-12-58-E 185.48 FT, TH ALG THE ARC OFA CURVE TO THE RIGHT 373.42 FTR-491.88 FT, CENTRAL ANGLE 43-29-51, CH BEARING S-03-28-03-ECH LENGTH 364.52 FT, TH S-71- 43-07-E 26.26 FT, TH S-28-24- 43-W 233.72 FT TO THE TRUE POB20.972 A MORL EXCEPT FOR A PARCEL OF LAND IN PRIVATE CLAIM 567, CITY OF DEARBORN, WAYNE COUNTY, MICHIGAN BOUNDED AND DESCRIBED AS FOLLOWS; COMMENCING AT A 3/4 INCH IRON ROD IN A MONUMENT BOX FOUND AT THE INTERSECTION OF THE WEST LINE OF SAID PC 567 (ORIGINAL CENTERLINE OF MILLER ROAD) AND THE CENTERLINE OF DIX AVENUE; TH N 00-00-42 W 108.09 FT ALG SAID W LINE OF PC 567 TO A POINT; TH N 89-59-18 E 87 FT TO THE INTERSECTION OF THE E ROW LINE OF MILLER ROAD AND THE N ROW LINEOF DIX AVENUE AND THE POB; TH N 00-00-42 W 51.97 FT ALG SAIDEAST ROW LINE TO A POINT; TH ALG A CUR TO THE LEFT HAVING ARAD OF 28 FT THROUGH A CENTRALANGLE OF 123-22-20 FOR AN ARC DISTANCE OF 60.29 FT, SAID CURVE HAVING A CHORD BEARING S 61-41-52 W FOR 49.30 FT TO THE N ROW LINE OF DIX AVENUE; TH S 56-36-58 W 51.97 FT ALG SAIDN ROW LINE TO THE POB CONTAINING 611 SQ FT MORE OR LESS.

Fee Interest:

6800 CELERY ST, KALAMAZOO, MI 49048

Parcel Number: 07-20-260-010

SEC 20-2-10 COM AT E1/4 POST SEC 20 TH S 89DEG 36'35" W ALG E&W1/4 LI SD SEC 503.24 FT TO CTR OF EXISTING ACCESS ESMT TH CONT S 89DEG 36'35" W 8.50 FT TO POB TH PAR & 8.5 FT WLY OF SD ESMT S 0DEG 30'32" W 299.68 FT TH N 89DEG 39'40" W 958.38 FT TO E LI ROE ST TH N 0DEG 14'55" E ALG SD E LI ROE ST 287.46 FT TO E&W1/4 LI TH S 89DEG 36'35" W ALG SD E&W1/4 LI 142.29 FT TO PT 1010 FT E OF CTR SD SEC TH PAR N&S1/4 LI N 0DEG 17'25" W 832.3 FT TO INT TRAV LI S SIDE KAL RIVER TH ALG SD TRAV LI S 47DEG 20'49" E 584.34 FT TH N 82DEG 23'35" E 521.87 FT TH S 84DEG 47'52" E 34.26 FT TO PT 8.5 FT WLY OF SD ACCESS ESMT & CONT 8.5 FT PAR TO

SD ESMT WHICH FOLLOWS FOLLOWING COURSES S 5DEG 8'48" W 48.95 FT TH ALG CRV LEFT 258.13 FT RAD 317.03 FT DELTA ANG 46DEG 39'2" CHD 251.06 FT BRG S 18DEG 10'28" E TH ALG CRV RT 154.02 FT RAD 214.10 FT DELTA ANG 41DEG 13'1" CHG 150.72 FT BRG S 20DEG 5'56" E TH S 0DEG 30'32" W 66.01 FT TO POB.

221 TOWNLINE RD N, GAYLORD, MI, 49735

Parcel Number: 080-031-300-015-02

COM AT SW COR S89D 14M 20S E 1444.78 FT ALG S LN, N00D 27M 10S W 659.03 FT ALG W 1/8 LN TO POB, N89D 15M 00S W 404.77 FT, N 00D 42M 54S E 673.59 FT TO S 1/8 LN, N00D 42M 54S E 100 FT, S89D 47M 24S E 388.94 FT PAR OF S 1/8 LN, S00D 27M 10S E 100.01 FT ALG W 1/8 LN TO S 1/8 LN, S00D 27M 10S E 677.42 FT ALG W 1/8 LN TO POB SEC 31 T31N-R3W CONT 7.06 AC M/L.

Exhibit 2.1(b)
Excluded Assets

Notwithstanding the previous sentence, the Purchased Assets will not include the Assets listed on Exhibit 2.1(b) (the ***"Excluded Assets"***).

a) Cash and cash equivalents;
b) All related party accounts receivable and notes receivable; and
c) All Assets of CMS ERM other than the Third Party Contracts, as defined in Section 2.9(e) of the Agreement.

Schedule 1.1-A
Net Working Capital Calculation
[Please see attached]

Schedule 1.1A

Net Working Capital Calculation

Amounts in $000's

In Thousands			
March 31	DIG 2021	MI Power 2021	Total
Current Assets			
Cash and cash equivalents	$ 3	$ -	$ 3
Accounts receivable	2,186	1,245	3,431
Accounts receivable – related parties	6,246	633	6,879
Notes receivable – related parties	25,951	4,929	30,880
Inventories at average cost			
Materials and supplies	4,867	550	5,417
Prepaid Insurance	262	458	720
Prepaid Property Taxes	1,138	-	1,138
Prepaid Other	282	-	282
Total GAAP Current Assets	40,935	7,815	48,750
Adjustments (1)			
Less: Cash	(3)	–	(3)
Less: Accounts receivable - related party	(6,246)	(633)	(6,879)
Less: Notes receivable - related party	(25,951)	(4,929)	(30,880)
Less: Materials and Supplies	(4,867)	(550)	(5,417)
Less: Prepaid Property Taxes	(1,138)	–	(1,138)
Total Adjustments to GAAP Current Assets	(38,205)	(6,112)	(44,317)
Total Adjusted Current Assets	**$ 2,730**	**$ 1,703**	**$ 4,433**
Current Liabilities			
Accounts payable	$ 1,911	$ 61	$ 1,972
Accounts payable – related parties	599	90	689
Accrued taxes	3,954	461	4,415
IPP contract liabilities	2,802	3,424	6,226
Accrued trade payable	2,364	-	2,364
Other current liabilities	4,577	605	5,182
Total GAAP Current Liabilities	16,207	4,641	20,848
Adjustments (2)			
Less: Accounts payable – related parties	(599)	(90)	(689)
Less: Accrued Taxes	(3,954)	(461)	(4,415)
Less: IPP contract liabilities	(2,802)	(3,424)	(6,226)
Less: Other current liabilities	(4,577)	(605)	(5,182)
Total Adjustments to GAAP Current Liabilities	(11,932)	(4,580)	(16,512)
Total Adjusted Current Liabilities	**4,275**	**61**	**4,336**
Total Adjusted Net Working Capital	**$ (1,545)**	**$ 1,642**	**$ 97**

(1) *Adjusted out of Net Working Capital to the extent included in Current Assets at the Closing Date*

(2) *Adjusted out of Net Working Capital to the extent included in Current Liabilities at the Closing Date*

Schedule 1.1-AC
Assigned Contracts

Management, Operations and Maintenance Agreement, by and between Dearborn Industrial Generation L.L.C. and Dearborn Industrial Operating, L.L.C. dated May 18, 2000.

Metering Agreement between Dearborn Industrial Generation, L.L.C. and DTE Electric Company, dated April 5, 2019.

Enhanced Interruptible Transportation Service Agreement between CMS Energy Resource Management Company and Panhandle Eastern Pipeline Company, LP, dated December 18, 2018, as amended by Amendment dated December 1, 2020.

Gas Parking Service Agreement between CMS Energy Resource Management Company and Panhandle Eastern Pipe Line Company, LP dated December 18, 2018, as amended by Amendment dated December 1, 2020.

All Third Party Contracts, as defined in Section 2.9(e) of the Agreement.

Amended and Restated Long Term Service Agreement, by and between Dearborn Industrial Generation L.L.C. and General Electric International, Inc., dated March 5, 2008, as amended.

Conformed and Amended Agreement by and between AK Steel Corporation (as successor to Severstal North America, Inc.) and Dearborn Industrial Generation, L.L.C., dated February 1, 2009, as amended by that First Amendment dated December 31, 2019.

Easement Agreement by and between by and between AK Steel Corporation and Dearborn Industrial Generation, L.L.C., dated March 29, 2019.

Conformed and Amended Agreement, by and between Ford Motor Company and Dearborn Industrial Generation, L.L.C., dated February 1, 2008.

Schedule 1.1-B
Budget

"Budget" means the major maintenance and capital expenditures budget estimates for Seller for the period from the date hereof until December 31, 2025, as set forth in Schedule 1.1-B.

	2021	2022	2023	2024	2025
DIG					
Major Maintenance	$ 14,300,000	$ 15,400,000	$ 14,000,000	14,100,000	12,000,000
Capital Expenditures	$ 4,045,250	$ 4,000,000	$ 4,000,000	$ 4,000,000	$ 4,000,000
KRGS					
Major Maintenance	$ -	$ -	$ -	$ -	$ -
Capital Expenditures	$ 1,825,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
LGS					
Major Maintenance	$ -	$ -	$ -	$ -	$ -
Capital Expenditures	$ 1,090,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000

Schedule 1.1-BA
Buyer Approvals

None

Schedule 1.1-K
Knowledge

- Tim Aufdencamp – Health and Safety
- Jim Chong – Dearborn Industrial Generation, L.L.C.
- Todd Mortimer – Marketing
- Neil Pansey – Operations
- Thomas Weigman – Dearborn Industrial Generation, L.L.C.
- Timothy Morrison – Kalamazoo Generating Station.
- Adam Brentlinger – Livingston Generating Station
- Rich Mukhtar

Schedule 1.1-PL
Permitted Liens

None

Schedule 3.3(b)
Seller Consents

Master Power Purchase and Sale Agreement by and between CMS Energy Resource Management Company and Full Requirements Customer 3, dated April 9, 2015.

Management, Operations and Maintenance Agreement, by and between Dearborn Industrial Generation L.L.C. and Dearborn Industrial Operating, L.L.C. dated May 18, 2000.

Metering Agreement between Dearborn Industrial Generation, L.L.C. and DTE Electric Company, dated April 5, 2019.

Enhanced Interruptible Transportation Service Agreement between CMS Energy Resource Management Company and Panhandle Eastern Pipeline Company, LP, dated December 18, 2018, as amended by Amendment dated December 1, 2020.

Gas Parking Service Agreement between CMS Energy Resource Management Company and Panhandle Eastern Pipe Line Company, LP dated December 18, 2018, as amended by Amendment dated December 1, 2020.

Applicable Consents:

Consents will be updated as applicable.

Schedule 3.3(c)
Seller Approvals

CMS Energy Corporation Board of Directors approval.

CMS Enterprises Company Board of Directors approval.

FERC approval.

MPSC approval.

Estoppel Certificates.

Schedule 3.12
Material Contracts

(a) Schedule 3.12 sets forth a list as of the date of this Agreement of the following Contracts to which Seller is a party or by which the Assets of Seller may be bound (Contracts that meet the descriptions in this Section 3.12 being collectively, the ***"Material Contracts"):***

Natural Gas Contracts

DIG

- Amended and Restated Special Gas Transportation & Storage Agreement, by and between Michigan Consolidated Gas Company and Dearborn Industrial Generation, L.L.C., dated April 1, 2007.
- End-Use Gas Transportation Agreement, by and between DTE Gas Company and Dearborn Industrial Generation, L.L.C., dated April 1, 2021.

KZO

- Interconnect Agreement between CMS Generation Michigan Power, LLC and Panhandle Eastern Pipe Line Company, LP dated September 13, 2017.
- Gas Parking Service Agreement between CMS Energy Resource Management Company and Panhandle Eastern Pipe Line Company, LP dated December 18, 2018
- Gas Transportation Agreement between CMS Generation Michigan Power, LLC and Consumers Energy Company, dated December 13, 2018.

LGS

- Gas Transportation Agreement between CMS Generation Michigan Power, LLC and DTE Gas Company (successor to Michigan Consolidated Gas Company), dated November 1, 2009.

Electric & Capacity Contracts[1]

ERM - Electric

- Heat Rate Call Option on DIG 2100
- Heat Rate Call Option on DIG 3100
- Full requirements Agreement with Customer 1.
- Full requirements Agreement with Customer 2.
- Full requirements Agreement with Customer 3.

ERM – Capacity

- Capacity Sale to ERM as reflected on the table below:[2]

[1] Note: Seller removed references to specific customers for confidentiality purposes.
[2] Note: Table in process.

Other DIG Contracts

- Operating Agreement for Dearborn Industrial Generation, L.L.C., dated November 9, 1998.
- Conformed and Amended Agreement by and between AK Steel Corporation (as successor to Severstal North America, Inc.) and Dearborn Industrial Generation, L.L.C., dated February 1, 2009, as amended by that First Amendment dated December 31, 2019.
- Generator Interconnection Agreement, by and between Dearborn Industrial Generation, L.L.C. and International Transmission Company, dated April 5, 2019.
- Application for Approval of the Acquisition of Assets pursuant to Section 203 of the Federal Power Act, dated June 29, 2018, submitted by International Transmission Company to the Federal Energy Regulatory Commission
- Conditional Consent of Lease Holder, by and between International Transmission Company and Dearborn Industrial Generation, L.L.C., dated April 5, 2019.
- Easement Agreement by and between by and between AK Steel Corporation and Dearborn Industrial Generation, L.L.C., dated March 29, 2019.
- Conformed and Amended Agreement, by and between Ford Motor Company and Dearborn Industrial Generation, L.L.C., dated February 1, 2008.
- Management, Operations and Maintenance Agreement, by and between Dearborn Industrial Generation L.L.C. and Dearborn Industrial Operating, L.L.C. dated May 18, 2000.
- Amended and Restated Long Term Service Agreement, by and between Dearborn Industrial Generation L.L.C. and General Electric International, Inc., dated March 5, 2008, as amended.
- DTE-DIG Metering Agreement
- Retention Agreement with Jim Chong.
- Retention Agreement with Thomas Weigman.

Other Contracts

- Generator Interconnection Agreement dated August 15, 2018 by and among CMS Energy Resource Management Company, Michigan Electric Transmission Company, LLC, and Midcontinent Independent System Operator, Inc.
- Generator Interconnection Agreement related to Livingston Generating Station.

Schedule 3.14(a)
Permits

- Michigan Department of Environmental Quality Air Quality Division Permit to Install 72-15 issued to Dearborn Industrial Generation, L.L.C.
- Michigan Department of Environmental Quality Air Quality Division Renewable Operating Permit No. MI-ROP-N6631-2012a
- National Pollutant Discharge Elimination System (NPDES) Permit No. MI0056235 issued to Dearborn Industrial Generation, L.L.C.
- Michigan Department of Environmental Quality Air Quality Division Permit to Install 163-17 issued to Dearborn Industrial Generation, L.L.C.
- Michigan Department of Environmental Quality Air Quality Division Permit to Install 8-17 issued to Dearborn Industrial Generation, L.L.C.
- Michigan Department of Environment, Great Lakes and Energy Air Quality Division Renewable Operating Permit No. MI-ROP-N6731-2015b issued to CMS Generation-Kalamazoo Generating Station.
- Michigan Department of Environmental Quality Air Quality Division Renewable Operating Permit No. MI-ROP-N6526-2014a issued to CMS Generation Michigan Power, L.L.C. Livingston Generating Station.

Schedule 3.15(f)
Emissions Credits and Allowances

(b) Except as set forth in Schedule 3.15(f), Seller has not been served with notice of any Environmental Claims, actions, proceedings or investigations that are currently outstanding, and no Environmental Claims are pending or, to Seller's Knowledge, threatened, against Seller by any Governmental Authority or third party under any Environmental Laws;

(f) Schedule 3.15(f) sets forth all emission reduction credits and emissions allowances that have been allocated to or are otherwise held by Seller as of the date of this Agreement.

Program	Account Number	Account Name	Facility ID (ORISPL)	Allowance Vintage Year	Serial Number Start	Serial Number End	Block Totals
ARP	055101FACLTY	Kalamazoo River Generating Station	55101	2006	4007551	4007551	1
ARP	055101FACLTY	Kalamazoo River Generating Station	55101	2006	8633956	8633958	3
ARP	055101FACLTY	Kalamazoo River Generating Station	55101	2009	5473466	5473500	35
ARP	055102FACLTY	Livingston Generating Station	55102	2009	5473501	5473510	10
ARP	055102FACLTY	Livingston Generating Station	55102	2009	6917164	6917213	50
ARP	055088FACLTY	Dearborn Industrial Generation	55088	2014	1612318	1612718	401
ARP	055088FACLTY	Dearborn Industrial Generation	55088	2015	7584923	7589922	5000

Schedule 3.18(a)
Employees of Seller

(a) Below are employees of seller as of 6/4/2021, subject to change.

James Chong

Thomas Wiegman

Brian McElyea

Laura Burton

Thomas Andreski

Theon Heisserer

Ryan Murray

Brian T. Muschong

JEFFREY B. RING

Michael S. McManus

Adam D. Brentlinger

Timothy A. Morrison

Daniel J. Lenhart

Keith R. Jarois

Timothy A. Furchak

Vernon M. Johnson III

David Bogosian

Carey A. Rogers Sr

Christopher A. Lusk

Christopher L. Clark

Gerald P. Delano

Benjamin W. Kuczewski

Charles E. Huntoon

Christopher Davis

Edward V. Zimmerman

Kasey L. Ore

Brian A. Snoes

Brian J. Gembacz

Cory S. Strong

Mark A. Ostrowski

Billy J. Donahue Jr

CHRISTOPHER A. COOTER

David C. Weberlein

James P. Abraham II

John R. Burden

Keith A. Charette

Malcolm L. Sibole

RICHARD M. ALLOR

William M. Kozfkay

Aaron S. Martin

Sivashankar Damodharan

Schedule 3.18(b)
Employees

None.

Schedule 3.18(c)
Third Party Vendor Contracts

Contract for Labor and Material by and between Dearborn Industrial Generation, L.L.C. and Securitas Security Services dated December 2018, as amended by that Addendum dated December 28, 2018 and Amendment dated March 12, 2020.

Planned Service Agreement by and between Dearborn Industrial Generation, L.L.C. and Johnson Controls, Inc., dated January 1, 2019.

General Contract for Technical and Consulting Services by and between Dearborn Industrial Generation, L.L.C. and Evoqua Water Technologies, LLC, dated October 31, 2020.

Sales Agreement by and between Dearborn Industrial Generation, L.L.C. and Suez WTS USA, effective January 1, 2021.

Schedule 3.19
Employee Benefits

Dearborn Industrial Generation, L.L.C. Incentive Compensation Program.

Michigan Power Incentive Compensation Program.

Dearborn Industrial Generation, L.L.C. Incentive Compensation Program.

Michigan Power Incentive Compensation Program.

Dearborn Industrial Generation, LLC Incentive Compensation Program, effective January 1, 2021.

Michigan Power LLC Incentive Compensation Program, effective January 1, 2021.

Retention Agreement with James Chong.

Retention Agreement with Thomas Weigman.

Consumers Energy Company Pension Plan, Cash Balance Version, Plan No. 001, version effective July 1, 2003 as last amended January 1, 2017.

Consumers Energy Company Employees' Savings Plan, including the Defined Company Contribution Plan, Plan No. 002, effective November 1, 1963, as last amended December 17, 2015. Group Health Care Plan for Active Employees of Consumers Energy and Other CMS Companies, Plan No. 518, as described in the Summary Plan Description, dated January 1, 2013, as revised June 1, 2013 and offering the following benefits:

- Blue Cross/Blue Shield Community Blue PPO
- Blue Cross/Blue Shield Health Blue HSA Medical with Health Savings Account
- HMO/EPO Medical Plans
- Express Scripts/Medco Prescription Coverage for BCBS (PPO and Health Blue HSA)
- Flexible Spending Accounts through Acclaris

Consumers Energy and other CMS Energy Companies Delta Dental Plan, as described in the Summary of Benefits, dated September 26, 2011.

Vision benefits offered through Eye Med, as described in the EyeMed Summary of Benefits for Consumers Energy.

Schedule 3.21
Insurance

MAJOR INSURANCES

THE FOLLOWING INSURANCE PROGRAMS ARE CMS ENERGY CORPORATION BLANKET INSURANCE PROGRAMS THAT INCLUDE, AMONG OTHER CMS ENTITIES, COVERAGE FOR THE FOLLOWING ENTITIES. THIS IS NOT AN EXHAUSTIVE LIST OF CMS' INSURANCE BUT REPRESENTS THOSE INSURANCE PROGRAMS MOST LIKELY TO BE INVOLVED IN A CLAIM FOR ONE OF THE ENTITIES.

Entity #1 Dearborn Industrial Generation, LLC & DIG Plant
Entity #2 CMS Generation Michigan Power, LLC & Kalamazoo and Livingston Plants
Entity #3 CMS Generation Co.

INSURANCE PROGRAM	INSURANCE COMPANY	POLICY NUMBER	LIMITS	DEDUCTIBLES	POLICY PERIOD
Property Damage (DIG Plant)	AEGIS AIG Allianz Global Corporate & Specialty Energy Insurance Mutual	PO5289509P 31187775 USN00027421 311328-21GP	$200,000,000	$1,500,000	6/1/2021 to 6/1/2022
Property Damage (Livingston Plant) (Kalamazoo Plant)	AEGIS & Lloyds syndicates Allianz Global Risks Energy Insurance Mutual HDI Global Ins Co Princeton Excess & Surplus Lines	PO5825602P USE00079420 311259-20GP CPD56138-01 58-A3-PP-0000251-01	$200,000,000	$5,000,000	11/1/2021 to 11/1/2022
Commercial General Liability	Federal Ins. Co.	3710-17-84	$1,000,000	$5,000 property damage	11/1/2020 to 11/1/2021
Excess Liability	AEGIS is the lead insurer with ~12 different insurers providing excess coverage layers.	Various	$465,000,000	$1,000,000 per occurrence	6/30/2020 to 6/30/2021
Automobile Liability	Federal Ins. Co.	7319-70-47	$1,000,000	$500 physical damage	11/1/2020 to 11/1/2021

Workers' Compensation and Employer's Liability	Great Northern Insurance Company	7162-96-95	Statutory - work comp $1,000,000 - employers liability	NIL	11/1/2020 to 11/1/2021
Fiduciary Liability	AEGIS XL Speicalty Energy Insurance Mutual	FP5016920P ELU168237-20 274664-20FL	$60,000,000	NIL individuals $500,000 - company	6/30/2020 to 6/30/2021
Crime	Great American Insurance Company	SAA585-87-22-14-00	$20,000,000	$250,000	4/1/2021 to 4/1/2022
Cyber Liability	AEGIS	CP5646905P	$50,000,000	$2,500,000	12/15/2020 to 12/15/2021

June 9, 2021

Schedule 3.23(b)
FERC/NERC Requirements Non-Compliance

DIG has the following NERC non-compliance incidents in the past 3 years:

REGULATORY COMPLIANCE PERFORMANCE

Updated 3/15/2021

PLANT	Regulatory Area	Date Of event	Agency /Divisic	STATUTE	DEFFICIENCY	Number of Non Complianc	Agency NOV Issued?	AGENCY Communication	SUMMARY / RESOLUTION
DIG	**NERC**	**3/5/2019**	Reliability First	MOD-027 R3	RFC2019021200 Failed to provide a written response to its Transmission Planner within 90 calendar days of receiving written notification from ITC that the turbine/governor and load control model was not "usable" without further clarification by responding 136 days after the request.	1	Yes	Self Reported	Mitigation Plan: DIG will include tracking compliance information requests in the Compliance Assurance Tracking System (CATS). The CATS will automatically alert task assignees of approaching due dates and assist in tracking compliance activities to better assure timely completion and prevent a recurrence of this issue. Closed 08/30/2019 07/15/20 RF issued notice that violation is treated as compliance exception treatment and is considered closed.
DIG	**NERC**	**12/2/2019**	Reliability First	MOD-032 R2	RFC2019022709 Non-compliances were for MOD-032 R2 (no evidence of communication with MISO in 2016 and 2018)	1	Yes	Audit Finding	05/14/20 Mitigation plan and certification form is complete 01/14/2021 RF issued a notice of compliance Exception Treatment.
DIG	**NERC**	**12/2/2019**	Reliability First	PRC-024 R2	RFC2019022710 PRC-024 R2 (frequency and voltage relays incorrectly set to trip in "no-trip zone"). Since these were identified during an audit it is anticipated that they will result in non-compliances.	1	Yes	Audit Finding 2/22/21 RF issued FFT notice requesting a affidavit of completion	07/01/20 Mitigation plan and certification form is complete

Livingston and Kalamazoo Generating Stations have had the following NERC non-compliance incidents in the past 3 years:

REGULATORY COMPLIANCE PERFORMANCE

Updated 3/15/2021

PLANT	Regulatory Area	Date Of event	Agency /Divisic	STATUTE	DEFFICIENCY	Number of Non Complianc	Agency NOV Issued?	AGENCY Communication	SUMMARY / RESOLUTION
CMS Michigan Power (Kalamazoo)	**NERC**	**6/6/2019**	Reliability First	MOD-025 R1	RFC2019021688 Did not report real and reactive power capability due to ITC within 90 days.	1	Yes	Self Reported	6/6/19 The PNC was because CMSMP provided the Real and Reactive Power Capability data for its KRGS and LGS to ITC after the due date (due within 90 calendar days of the date the data was recorded). We discovered this during the prep for the 2019 RF audit with enough time to self-report. Closed 02/24/2020 10/7/20 RF issued a notice that this violation is closed
CMS Michigan Power (Kalamazoo)	**NERC**	**11/15/2019**	Reliability First	PRC-024 R1	R1 - RFC2019022595 Non-compliances for PRC-024 R1which require evaluation of **Frequency protective relays** and voltage relays set to trip in "no-trip zone".	1	Yes	Audit Finding	NERC Audit of Michigan Power closed on November 15, 2019 with two potential non-compliances. 06/24/20 RF has decided that CMSMP's PNC with R1 and R2 of PRC-024-2 qualifies for a Find Fix and Track (FFT) enforcement treatment. 04/09/2021 notice from RF: The following Violation has been Closed.
CMS Michigan Power (Kalamazoo)	**NERC**	**11/15/2019**	Reliability First	PRC-024 R2	R2 - RFC2019022596 Non-compliance for PRC-024 R2 which require evaluation of **voltage protective relays** set to trip in "no-trip zone".	1	Yes	Audit Finding	NERC Audit of Michigan Power closed on November 15, 2019 with two potential non-compliances. 06/24/20 RF has decided that CMSMP's PNC with R1 and R2 of PRC-024-2 qualifies for a Find Fix and Track (FFT) enforcement treatment. 04/09/2021 notice from RF: The following Violation has been Closed.
CMS Michigan Power (Livingston)	**NERC**	**1/21/2021**	Reliability First	PRC-024 R1	RFC2021024503 PRC-024 R1 require **Frequency protective relays** set outside "no-trip zone". Livingston's Units' 1, 2, 3, and 4 protection relays to be set outside the "no trip zone". Units' Generator protection relays set at 57.9 hertz verses max allowable 57.8 hertz.	1	Yes	1/29/2021 Self-report was submitted to RF. 1/29/21 RF issued email identifying the incident being referred to Compliance for review. 03/11/2021 Mitigation Plan submitted 04/30/2021 Mitigation plan accepted	1/22/21 reviewed finding. The non-compliance was found as a result of performing an analysis of Livingston's 4 protection relays. Additional evaluation with the Consumers Energy System Protection Engineer, an approval will be provided to the engineer to reset this relay, and we will make a self-report to ReliabilityFirst. 1/29/21 RF issued email identifying the incident being referred to Compliance.

Schedule 3.23(c)
FERC/NERC Violation Notices

DIG, Livingston or Kalamazoo Generating Stations have had no FERC, DOE or MISO related non-compliance incidents in the past 3 years.

CMS Energy Resource Management Company received a violation with a penalty from the MISO Market Monitor in 2018 for a 2017 marketing event relating to energy marketing for DIG as shown below:

REGULATORY COMPLIANCE PERFORMANCE

Updated 3/15/2021

PLANT	Regulatory Area	Date Of event	Agency /Divisio	STATUTE	DEFFICIENCY	Number of Non Complianc	Agency NOV Issued?	AGENCY Communication	SUMMARY / RESOLUTION
ERM	FERC	9/22/2017	Market Monitor	MISO Tariff	ERM offered DIGs units into the real-time energy market with economic limits more than 25% of reference level	1	Yes	12/6/2018 MISO issued a notice to impose a penalty for the market event in 2017 of $59.3K which was doubled to $118.6K due to repeat violation by an affiliate (CE) in 2017.	2/1/2019 IMM Penalty was assessed at $118.6K and was paid through MISO Statement as a miscellaneous charge. This penalty was doubled based on tariff language due to affiliate preceding conduct.

Schedule 5.4
Terminated Contracts

Notwithstanding anything in this Agreement to the contrary, at or prior to the Closing, Seller shall (a) terminate or sever, effective upon or before the Closing, any services provided to Seller with respect to the Project or the Property by an Affiliate of Seller and that are not being assigned to Buyer, including the termination or severance of insurance policies (including those policies referred to in Section 5.7), Tax services, legal services and banking services (to include the severance of any centralized clearance accounts), [terminate or assign to Buyer each Contract listed on Schedule 5.4,]and cause all Claims or obligations (contingent or otherwise) with respect to the Project or the Property between Seller, on one hand, and an Affiliate of Seller, on the other, to be released effective immediately prior to Closing (collectively such services, Contracts, claims or obligations, the ***"Terminated Contracts")*.**

Schedule 5.9
Books and Records

Seller shall deliver the books and records set forth on Schedule 5.9 to Buyer as promptly as practicable following the Closing Date (it being agreed that Seller may retain a copy thereof). Not later than 30 days after Closing, a breakdown of the Purchase Price in accordance with the property retirement unit categories and other systems of account together with all books and records substantiating the Purchase Price breakdown shall be delivered to Buyer. For physical Project Assets, Seller will provide the following: retirement unit, quantity, cost, ID number, make, model, serial number and unit number. For land, Seller will provide the parcel and deed information.

Schedule 5.17
Monthly Operating Report

Please find attached below the Monthly Report for DIG for the month of April 2021.

Operations
Monthly Report - Ap

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
______________________________________	)	

EXHIBITS

OF

KEITH G. TROYER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS
ENERGY AND CAPACITY CONTRACTS

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Energy & Capacity Company	Contract Capacity MW	Fuel Type	MPSC Order Approving Capacity Rate	Expected Termination Date	Expected to Pursue New PURPA PPA After Existing Contract Termination*
1	13 Mile Solar, LLC	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes
2	Ada Cogeneration Ltd Partnership	29.400	Natural Gas	June 22, 1989 – U-8871/U-8833	1/4/2026	No
3	Adrian Energy Associates	2.500	Landfill Gas	March 31, 1993 – U-10127	12/12/2029	Yes
4	Albion North Solar	10.000	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
5	Allegheny Solar	10.699	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
6	Aluminum Solar	8.000	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
7	Angola Solar, LLC	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes
8	Arthur Solar Farm	1.827	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
9	Bamboo Solar	10.000	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
10	Bay Windpower I	1.800	Wind	November 14,2019 - U-20604	5/31/2021	Yes
11	Beaverton, City of	0.500	Hydro	July 23, 2020 - U-20838	5/31/2039	Yes
12	Bingham Solar, LLC	20.000	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes
13	Black River Power Limited Partnership	0.840	Hydro	July 23, 2020 - U-20838	5/31/2039	Yes
14	Blue Elk Solar I	20.000	Solar PV	April 15, 2020 - U-20604	5/31/2043	Yes
15	Blue Elk Solar III	20.000	Solar PV	April 15, 2020 - U-20604	5/31/2043	Yes
16	Blue Elk Solar IV	20.000	Solar PV	April 15, 2020 - U-20604	5/31/2043	Yes
17	Blue Elk Solar VII	12.331	Solar PV	April 15, 2020 - U-20604	5/31/2043	Yes
18	Boyce Hydro Power, LLC (f/k/a Wolverine Power Corporation)**	11.000	Hydro	December 13, 1988 - U-8866	5/30/2022	Yes
19	Bullhead Solar, LLC	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes
20	Burns Park Solar	10.000	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
21	Byrne Solar	5.000	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
22	C&C Energy, LLC - C&C 1 (f/k/a Gas Recovery Systems)	2.750	Landfill Gas	July 21, 1993 – U-10270	2/19/2030	Yes
23	Cadillac Renewable Energy	34.000	Wood Waste	June 22, 1989 – U-8871	7/15/2028	No
24	Captain Solar, LLC	2.000	Solar PV	December 19, 2019 - U-20604	5/31/2041	Yes
25	Cement City Solar, LLC	20.000	Solar PV	December 19, 2019 - U-20604	5/31/2041	Yes
26	Cloudbreak Solar	20.000	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes

*Based on a PURPA "Must Buy Obligation" of 20 MW. Subject to change based on the Company's June 14, 2021 application to FERC to reduce it's Must Buy Obligation from 20 MW to 5 MW

**Total Contract Capacity is 11 MW. The Company has only included the output from Sanford, Secord, and Smallwood facilities due the license revocation by FERC for the Edenville facility

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS
ENERGY AND CAPACITY CONTRACTS

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Energy & Capacity Company**	**Contract Capacity MW**	**Fuel Type**	**MPSC Order Approving Capacity Rate**	**Expected Termination Date**	**Expected to Pursue New PURPA PPA After Existing Contract Termination***
27	Coldwater Solar, LLC	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes
28	Commonwealth Power Company – Irving	0.240	Hydro	March 31, 1993 – U-10127	8/24/2030	Yes
29	Commonwealth Power Company – LaBarge	0.700	Hydro	September 26, 2019 - U-20604	5/31/2039	Yes
30	Commonwealth Power Company – Middleville	0.200	Hydro	March 31, 1993 – U-10127	12/12/2030	Yes
31	Congo Solar	10.000	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
32	Durban Solar	12.000	Solar PV	July 23, 2020 - U-20604	5/31/2043	Yes
33	Elk Rapids	0.700	Hydro	July 23, 2020 - U-20604	5/31/2039	Yes
34	Entergy Nuclear Power Marketing (Palisades)	813.000	Nuclear	March 27, 2007 - U-14992/ August 20, 2020 - U-20734	5/31/2022	No
35	Esmarelda Solar	9.000	Solar PV	July 23, 2020 - U-20604	5/31/2042	Yes
36	Energy Developments Grand Blanc, LLC (f/k/a Granger Electric Company – Grand Blanc)	3.812	Landfill Gas	February 4, 2021 - U-20838	5/31/2039	Yes
37	Energy Developments Pinconning, LLC (f/k/a Granger Electric of Pinconning)	3.042	Landfill Gas	February 4, 2021 - U-20838	5/31/2039	Yes
38	Energy Developments Byron Center, LLC (f/k/a Granger Electric of Byron Center)	3.000	Landfill Gas	February 4, 2021 - U-20838	5/31/2039	Yes
39	Energy Developments Coopersville, LLC (f/k/a Granger Electric of Coopersville, LLC - Ottawa)	6.109	Landfill Gas	February 4, 2021 - U-20838	5/31/2039	Yes
40	Geddes 1 Solar, LLC	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes
41	Geddes 2 Solar, LLC	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes
42	Genesee Power Station Limited Partnership	35.000	Wood Waste	June 22, 1989 - U-8871	12/12/2030	No
43	Golden Solar Farm	1.828	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
44	Good Fruit Storage, LLC	0.179	Solar PV	December 6, 2019 - U-20604	5/31/2040	Yes
45	Grayling Generating Station Limited Partnership	36.170	Wood Waste	June 22, 1989 - U-8871/U-10274	12/31/2027	No
46	Greenstone Solar	20.000	Solar PV	April 15, 2020 - U-20604	5/31/2043	Yes
47	Grenfell Hydro, Inc	0.300	Hydro	December 13, 1988 - U-8866	5/31/2039	Yes
48	Hazel Solar, LLC	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes
49	Hendershot Solar, LLC	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes
50	Hillman Power Company LLC	18.000	Wood Waste	August 18, 1984 - U-7990/ July 2, 2019 - U-20496	5/31/2022	No
51	Hogan Solar	12.000	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes

*Based on a PURPA "Must Buy Obligation" of 20 MW. Subject to change based on the Company's June 14, 2021 application to FERC to reduce it's Must Buy Obligation from 20 MW to 5 MW

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS
ENERGY AND CAPACITY CONTRACTS

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Energy & Capacity Company**	**Contract Capacity MW**	**Fuel Type**	**MPSC Order Approving Capacity Rate**	**Expected Termination Date**	**Expected to Pursue New PURPA PPA After Existing Contract Termination***
52	Interchange Solar, LLC	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes
53	Jack Francis Solar, LLC	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes
54	Johnsfield Solar	10.000	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
55	Kent County	15.680	Solid Waste	July 23, 2020 - U-20838	5/31/2039	Yes
56	Kleber Hydro	1.200	Hydro	July 23, 2020 - U-20838	5/31/2039	Yes
57	Letts Creek Solar, LLC	15.000	Solar PV	December 19, 2019 - U-20604	5/31/2041	Yes
58	Lightfoot Solar	10.000	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
59	Lyons Road Solar	20.000	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
60	Macbeth Solar, LLC	20.000	Solar PV	December 6, 2019 - U-20604	5/31/2042	Yes
61	May Shannon Solar, LLC	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes
62	Michiana Hydroelectric Co (Bellevue)	0.075	Hydro	July 23, 2020 - U-20838	5/31/2039	Yes
63	Michigan Power Limited Partnership	123.000	Natural Gas	March 31, 1993 – U-10127	10/22/2030	No
64	Midcontinent Solar	20.000	Solar PV	April 15, 2020 - U-20604	5/31/2043	Yes
65	Midland Cogeneration Venture Limited Partnership**	1240.000	Natural Gas	June 10 , 2008 - U-15320	3/15/2030	No
66	NextSun Energy LLC - Lake City Solar	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2042	Yes
67	NextSun Energy LLC - Morey Road Solar	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2042	Yes
68	NextSun Energy LLC - Surrey Road Solar	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2042	Yes
69	North American Natural Resources -Peoples	3.061	Landfill Gas	July 21, 1993 – U-10266	9/7/2030	Yes
70	North American Natural Resources (Rathbun)	1.600	Landfill Gas	September 26, 2019 - U-20604	5/31/2039	Yes
71	Pullman Solar, LLC	20.000	Solar PV	December 19, 2019 - U-20604	5/31/2041	Yes
72	River Fork Solar	100.000	Solar PV	September 26, 2019 U-15805	5/31/2042	No
73	Robert Swift Solar Farm	1.828	Solar PV	December 6, 2019 - U-20604	5/31/2042	Yes
74	Rosco Solar	10.000	Solar PV	December 6, 2019 - U-20604	5/31/2042	Yes
75	Shady Solar	10.000	Solar PV	July 23, 2020 - U-20604	5/31/2042	Yes
76	Shipsterns Solar	20.000	Solar PV	July 23, 2020 - U-20604	5/31/2043	Yes
77	Stoneheart Solar, LLC	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes

*Based on a PURPA "Must Buy Obligation" of 20 MW. Subject to change based on the Company's June 14, 2021 application to FERC to reduce it's Must Buy Obligation from 20 MW to 5 MW
** Expected Termination Date assumes the Company would exercise the option to extend the PPA. More recently, the Commission approved Amendment No. 2 to the PPA with an expected termination date of 5/31/2030 in its March 4, 2021 Order in Case No. U-20896, however the difference in costs between the PPA option and Amendment No. 2 are not reflected in this filing.

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS
ENERGY AND CAPACITY CONTRACTS - CONTINUED

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Energy & Capacity Company**	**Contract Capacity MW**	**Fuel Type**	**MPSC Order Approving Capacity Rate**	**Expected Termination Date**	**Expected to Pursue New PURPA PPA After Existing Contract Termination***
78	STS Hydropower Ltd - Ada Hydro Plant	1.400	Hydro	June 23, 2017 -U-18425	5/31/2022	Yes
79	STS Hydropower Ltd – Cascade Hydro Plant	1.400	Hydro	July 23, 2020 - U-20838	5/31/2039	Yes
80	STS Hydropower Ltd – Fallasburg Hydro Plant	0.850	Hydro	July 23, 2020 - U-20838	5/31/2039	Yes
81	STS Hydropower Ltd – Morrow Hydro Plant	1.000	Hydro	December 13, 1988 - U-8868	12/31/2021	Yes
82	Surbrook Solar	10.000	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
83	Swede Solar	12.000	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
84	TART Solar	8.490	Solar PV	April 15, 2020 - U-20604	5/31/2043	Yes
85	Temperance Solar, LLC	20.000	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes
86	T.E.S. Filer City Station Limited Partnership	50.000	Coal	February 19, 1987 - U-8562	6/15/2025	No
87	Thorn Lake Solar, LLC	20.000	Solar PV	December 19, 2019 - U-20604	5/31/2041	Yes
88	Topanga Solar	20.000	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
89	Tower Hydro	0.560	Hydro	July 23, 2020 - U-20838	5/31/2039	Yes
90	Viking Energy of Lincoln, LLC	18.000	Wood Waste	April 18, 2019 - U-20496	5/31//2027	No
91	Viking Energy of McBain, LLC	18.000	Wood Waste	April 18, 2019 - U-20496	5/31//2027	No
92	White's Bridge Hydro Company	0.817	Hydro	July 23, 2020 - U-20838	5/31/2039	Yes
93	Wilford Solar	20.000	Solar PV	April 15, 2020 - U-20604	5/31/2042	Yes
94	WM Renewable Energy - Venice Park (f/k/a Bio Energy Partners)	1.500	Landfill Gas	June 22, 1989 – U-8871/U-10272	5/3/2027	Yes
95	Woodley Solar, LLC	0.821	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes
96	Workman Road Solar	2.000	Solar PV	December 6, 2019 - U-20604	5/31/2041	Yes
97	PURPA Aggregate	10.000	Solar PV	TBD	5/31/2042	Yes
98	2019 RFP Solar Aggregate (PY2022)	150.000	Solar PV	TBD	5/31/2047	No
99	2020 RFP Solar Aggregate (PY2023)	150.000	Solar PV	TBD	5/31/2048	No
100	2021 RFP Solar Aggregate (PY2024)	250.000	Solar PV	TBD	5/31/2049	No

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS
ENERGY-ONLY CONTRACTS

	Energy-Only Company	**Contract Capacity MW**	**Fuel Type**	**MPSC Order Approving Capacity Rate**	**Expected Termination Date**	**Expected to Pursue New PURPA PPA After Existing Contract Termination**
101	City of Grand Rapids	N/A	Landfill Gas	N/A	Year-to-Year	No
102	City of Midland	N/A	Landfill Gas	N/A	Month-to-Month	No
103	Grand Valley State University	N/A	Fuel Cell	N/A	Month-to-Month	No
104	Great Lakes Tissue Company	N/A	Hydro	N/A	Year-to-Year	No
105	Mahle Engine Components USA, Inc.	N/A	Waste Energy	N/A	Month-to-Month	No
106	Michigan State University	N/A	Coal	N/A	Year-to-Year	No
107	Otsego Paper - USG	N/A	Waste Energy	N/A	Month-to-Month	No
108	Western Michigan University	N/A	Natural Gas	N/A	Month-to-Month	No

Notes:
*Based on a PURPA "Must Buy Obligation" of 20 MW. Subject to change based on the Company's June 14, 2021 application to FERC to reduce it's Must Buy Obligation from 20 MW to 5 MW

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS
RENEWABLE RESOURCE PROGRAM CONTRACTS

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Renewable Resource Company**	**Contract Capacity MW**	**Fuel Type**	**MPSC Order Approving Capacity Rate**	**Expected Termination Date**	**Expected to Pursue New PURPA PPA After Existing Contract Termination***
109	C&C Energy, LLC (C&C Electric 2 Plant)	2.500	Landfill Gas	October 18, 2005 - U-14626	2/27/2027	Yes
110	North American Natural Resources (Venice Park), combination of White Lake, Venice Park second unit, Peoples fourth unit	3.200	Landfill Gas	October 18, 2005 - U-14626	2/9/2026	Yes
111	Michigan Wind I, LLC (f/k/a Noble Thumb Windpark, LLC.)	12.000	Wind	October 18, 2005 - U-14626	12/17/2028	No

*Based on a PURPA "Must Buy Obligation" of 20 MW. Subject to change based on the Company's June 14, 2021 application to FERC to reduce it's Must Buy Obligation from 20 MW to 5 MW

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS
PUBLIC ACT 295 CONTRACTS

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Public Act 295 Company**	**Contract Capacity MW**	**Fuel Type**	**MPSC Order Approving Capacity Rate**	**Expected Termination Date**	**Expected to Pursue New PURPA PPA After Existing Contract Termination***
112	Apple Blossom Wind, LLC (f/k/a Geronimo Huron Wind, LLC)	100.000	Wind	November 19, 2015 - U-15805	5/31/2033	No
113	Beebe Renewable Energy (f/k/a Blissfield)	81.600	Wind	July 27, 2010 - U-15805	12/17/2032	No
114	Fremont Community Digester	2.850	Gas Digester	October 13, 2009 - U-15805	12/26/2032	Yes
115	Harvest II Windfarm	59.400	Wind	July 27, 2010 - U-15805	10/31/2032	No
116	Heritage Garden Wind Farm I	20.880	Wind/Solar	November 19, 2010 - U-15805	9/13/2032	No
117	Heritage Stoney Corners Wind Farm I (Phase 2)	12.250	Wind	November 19, 2010 - U-15805	12/31/2031	No
118	Heritage Stoney Corners Wind Farm I (Phase 3)	8.350	Wind	January 26, 2012 - U-15805	12/31/2031	No
119	Michigan Wind 2	90.000	Wind	July 27, 2010 - U-15805	12/17/2028	No
120	North American Natural Resources (Lennon)	1.600	Landfill Gas	October 13, 2009 - U-15805	12/15/2030	Yes
121	WM Renewable Energy (Northern Oaks)	1.600	Landfill Gas	October 13, 2009 - U-15805	11/10/2030	Yes
122	WM Renewable Energy (Pine Tree Acres)	12.800	Landfill Gas	July 27, 2010 - U-15805	2/28/2032	No

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS
PUBLIC ACT 295 CONTRACTS - EXPERIMENTAL ADVANCED RENEWABLE PROGRAM - ANAEROBIC DIGESTION

	Public Act 295 Company	**Contract Capacity MW**	**Fuel Type**	**MPSC Order Approving Capacity Rate**	**Expected Termination Date**	**Expected to Pursue New PURPA PPA After Existing Contract Termination***
123	Brook View Dairy	0.600	Gas Digester	April 23, 2015 - U-15805	12/31/2035	Yes
124	Green Meadow Farms, Inc.	0.800	Gas Digester	April 23, 2015 - U-15805	7/14/2027	Yes
125	Scenic View Dairy	0.400	Gas Digester	April 23, 2015 - U-15805	12/31/2035	Yes

*Based on a PURPA "Must Buy Obligation" of 20 MW. Subject to change based on the Company's June 14, 2021 application to FERC to reduce it's Must Buy Obligation from 20 MW to 5 MW

PURCHASED POWER CONTRACT RATES AND MPSC APPROVAL ORDERS
PUBLIC ACT 295 CONTRACTS - EXPERIMENTAL ADVANCED RENEWABLE PROGRAM - SOLAR

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Public Act 295 Company	Contract Capacity MW	Fuel Type	MPSC Order Approving Capacity Rate	Expected Termination Date*	Expected to Pursue New PURPA PPA After Existing Contract Termination**
126	Experimental Advanced Renewable Program ("EARP") residential Phase 1	0.180	Solar	December 21, 2010 - U-15805	Varies	Yes
127	Experimental Advanced Renewable Program ("EARP") non-residential Phase 1	1.002	Solar	December 21, 2010 - U-15805	Varies	Yes
128	Experimental Advanced Renewable Program ("EARP") residential Phase 2	0.291	Solar	May 10, 2011 - U-15805	Varies	Yes
129	Experimental Advanced Renewable Program ("EARP") non-residential Phase 2	0.548	Solar	May 10, 2011 - U-15805	Varies	Yes
130	Experimental Advanced Renewable Program ("EARP") non-residential Phase 3	0.024	Solar	February 28, 2013 - U-15805	Varies	Yes
131	Experimental Advanced Renewable Program ("EARP") residential Phase 4	0.108	Solar	February 28, 2013 - U-15805	Varies	Yes
132	Experimental Advanced Renewable Program ("EARP") non-residential Phase 5	0.050	Solar	February 28, 2013 - U-15805	Varies	Yes
133	Experimental Advanced Renewable Program ("EARP") residential Phase 6	0.093	Solar	February 28, 2013 - U-15805	Varies	Yes
134	Experimental Advanced Renewable Program ("EARP") residential Phase 7	0.091	Solar	February 28, 2013 - U-15805	Varies	Yes
135	Experimental Advanced Renewable Program ("EARP") non-residential Phase 8	0.029	Solar	February 28, 2013 - U-15805	Varies	Yes
136	Experimental Advanced Renewable Program ("EARP") residential Phase 9	0.105	Solar	February 28, 2013 - U-15805	Varies	Yes
137	Experimental Advanced Renewable Program ("EARP") residential Phase 10	0.078	Solar	May 2, 2014 - U-15805	Varies	Yes
138	Experimental Advanced Renewable Program ("EARP") non-residential Phase 11	0.334	Solar	May 2, 2014 - U-15805	Varies	Yes
139	Experimental Advanced Renewable Program ("EARP") residential Phase 12	0.068	Solar	May 2, 2014 - U-15805	Varies	Yes
140	Experimental Advanced Renewable Program ("EARP") residential Phase 13	0.051	Solar	May 2, 2014 - U-15805	Varies	Yes
141	Experimental Advanced Renewable Program ("EARP") non-residential Phase 14	0.281	Solar	May 2, 2014 - U-15805	Varies	Yes
142	Experimental Advanced Renewable Program ("EARP") residential Phase 15	0.133	Solar	May 2, 2014 - U-15805	Varies	Yes
143	Experimental Advanced Renewable Program ("EARP") residential Phase 16	0.104	Solar	April 23, 2015 - U-15805	Varies	Yes
144	Experimental Advanced Renewable Program ("EARP") non-residential Phase 17	0.171	Solar	April 23, 2015 - U-15805	Varies	Yes
145	Experimental Advanced Renewable Program ("EARP") residential Phase 18	0.085	Solar	April 23, 2015 - U-15805	Varies	Yes
146	Experimental Advanced Renewable Program ("EARP") residential Phase 19	0.119	Solar	April 23, 2015 - U-15805	Varies	Yes
147	Experimental Advanced Renewable Program ("EARP") non-residential Phase 20	0.580	Solar	April 23, 2015 - U-15805	Varies	Yes
148	Experimental Advanced Renewable Program ("EARP") residential Phase 21	0.149	Solar	April 23, 2015 - U-15805	Varies	Yes
149	Experimental Advanced Renewable Program ("EARP") residential Phase 26	0.179	Solar	February 11, 2016 - U-15805	Varies	Yes
150	Experimental Advanced Renewable Program ("EARP") non-residential Phase 27	0.430	Solar	February 11, 2016 - U-15805	Varies	Yes
151	Experimental Advanced Renewable Program ("EARP") residential Phase 28	0.161	Solar	February 11, 2016 - U-15805	Varies	Yes
152	Experimental Advanced Renewable Program ("EARP") residential Phase 29	0.222	Solar	February 11, 2016 - U-15805	Varies	Yes
153	Experimental Advanced Renewable Program ("EARP") non-residential Phase 30	0.208	Solar	February 11, 2016 - U-15805	Varies	Yes
154	Experimental Advanced Renewable Program ("EARP") residential Phase 31	0.118	Solar	February 11, 2016 - U-15805	Varies	Yes
155	Experimental Advanced Renewable Program ("EARP") residential Phase 32	0.091	Solar	February 11, 2016 - U-15805	Varies	Yes
156	Experimental Advanced Renewable Program ("EARP") non-residential Phase 33	0.148	Solar	February 11, 2016 - U-15805	Varies	Yes
157	Experimental Advanced Renewable Program ("EARP") residential Phase 34	0.068	Solar	February 11, 2016 - U-15805	Varies	Yes
158	Experimental Advanced Renewable Program ("EARP") non-residential Phase 35	0.101	Solar	February 11, 2016 - U-15805	Varies	Yes

* Contracts terminate no later than August 31, 2029.
**Based on a PURPA "Must Buy Obligation" of 20 MW. Subject to change based on the Company's June 14, 2021 application to FERC to reduce it's Must Buy Obligation from 20 MW to 5 MW

Procurement Trends and Potential Strategies for Renewable Power Purchase Agreements (RPPA)

Prepared for Consumers Energy

June 9, 2021

Wood Mackenzie
A Verisk Business

Trusted Intelligence
Final Version

Consumers Energy
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Contents

1. Executive summary

Overall value to rate payers may be increased with more flexibility with RPPA contracting

1 Current and emerging RPPA trends

- RPPA structures and trends are evolving with most of the innovation being driven by C&I segment
- Demand for RPPAs is driven by sustainability goals and renewable energy targets by utilities and C&Is
- Types of RPPAs sought by these two segments vary; utilities prefer physical or hybrid PPAs, while C&I prefer financial PPAs, although the trend is changing with some of the entities seeking asset backed PPAs
- RPPA tenor ranges between 10 to 25 years with the C&I seeking shorter tenors. Furthermore, developers can successfully finance renewable projects with PPA tenors of 12 years
- Project developers view that it is much easier to transact with C&I compared to a regulated utility despite shorter contract tenors

2 Evaluation of Consumers RPPA procurement and contracting strategy

- Integrated Resource Plan (IRP) is the foundation for the long-term supply procurement plan for the company
- Procurement of new supply is handled through a competitive bidding process per the guidelines approved by MPSC
- At least 50% of the new capacity procured is via PPAs; remaining is procured through BTA*, DAA** or self build schemes
- Consumers RPPA contracts are mostly physical PPAs or hybrid PPAs with tenors of at least 20 years
- Some recent trends observed in other utilities' RFPs can help fine tune Consumers RPPA contracting strategies in the future procurement cycles - technology diversification of supply, hybrid renewable projects paired with storage, contracts with assets located external to MISO Zone 7 and financially settled, and PPAs with shorter tenors (~12 to 15 years)
- Evaluate and mitigate impacts of supply-demand mismatch further out in time
- We recommend that Consumers consider a "laddered RPPA" approach with varying procurement quantities with varying contract lengths ranging from 12 years to afford flexibility given uncertainties around future load shapes

* BTA – Build Transfer Agreement; ** DAA – Development Asset Acquisition

2. Current and emerging RPPA trends

RPPA structures and trends are evolving, and innovation is driven by C&I segment

Sustainability goals and renewable energy targets are driving up the demand for RPPAs

1 Utilities segment

- IRP serves as the primary vehicle to inform the long-term capacity needs for a regulated electric utility, such as, Consumers Energy ("Consumers")
- Utility clients rely heavily on physical PPAs and are seldom interested in financial PPAs.
- Typical PPA contract tenors are 20 years or longer.
- Project developers can successfully finance renewable projects with PPA tenors of 12 years
- Consider the proposed recommendations to improve the Consumers RPPA process and risk mitigation strategies

2 Commercial and industrial (C&I) segment

- C&I segment has successfully implemented both physical and financial PPA structures effectively
- C&I Customers are continuing to contract at record breaking pace and the trend is expected to continue in the near term due to several factors
- Ambitious Environmental, Social and Governance (ESG) goals and zero carbon targets are pushing corporates to innovate. Entities like, Google, Amazon and Facebook are in the forefront
- Renewable project developers view that it is much easier to transact with a corporate compared to a utility even though the contract tenors are shorter (~12 to 15 years); primarily because, faster procurement timeline and less onerous to get across the finish line

RPPA contracting structures vary across the board…

NOT EXHAUSTIVE

Structures are influenced by the needs of the off-taker with utilities relying heavily on Physical PPAs

PPA contracting structure risk analysis

Low Risk ○ → ● *High Risk*

Offtake or hedging structure	Non-price related risks			Electricity price risk	Contract length (years)	Off-taker
	Weather	Curtailment	Contracted volume	Busbar vs. Hub (Basis)		
Physical PPA	◐	◐	○	○	10 – 25	Corporates & Utilities
Hybrid PPA (Energy: Financial; Capacity/REC: Physical)*	◐	◐	○	○	20 – 25	Utilities
Virtual PPA (Busbar Settled)	◐	◐	○	○	12 – 15	Corporates
Virtual PPA (Hub Settled)	◐	◐	○	●	12 – 15	Corporates
Bank Hedge (Fixed Shaped Energy)	●	●	●	●	10 – 15	Financial & Corporates
Proxy Revenue Swap	○	●	○	●	10	Corporates
Utility Green Tariff	◐	◐	○	○	Up to 20	Corporates

* Bus bar settled; if hub settled, basis risk exists, and the Harvey Ball should be fully shaded
Note: Risks are analyzed from the perspective of the renewable energy generator
Source: Wood Mackenzie, Interviews

...and the taxonomy of RPPAs clearly show the diversity of contracting options

Offtake instrument	Brief description
Physical PPA	A Physical PPA is a contract structure where a customer (or off-taker) enters a long-term contract with a renewable electricity generator (the seller) who agrees to build, maintain, and operate a renewable energy system. Regardless of whether the system is on-site or not, the off-taker receives the physical delivery of (or title to the) electricity through the grid. The off-taker agrees to purchase the power at a set price over an agreed upon term, and the seller assumes the risks associated with owning and operating the system.
Hybrid PPA*	A Hybrid PPA is a contract structure that is a blend of a Physical PPA and a Financial PPA. The capacity and RECs are physical and is tied to a particular renewable asset while the energy is financial in nature. The energy settlement may occur at the hub or busbar of the asset.
Financial PPA	A Financial PPA is a financial arrangement between a renewable electricity generator (the seller) and a customer (or off-taker), that enables both parties to hedge against electricity market price volatility. Unlike with a Physical PPA, there is no physical delivery of power from the seller to the off-taker. Rather, it is a hedge arrangement that offers off-takers cost predictability for their electricity use and promotes growth in the renewable energy sector by offering project developers long-term contracts with predictable revenues — a key element to attracting project financing and investment. Financial PPAs are also sometimes known as **virtual or synthetic PPAs, a contract for differences, or a fixed-for-floating swap.**
Virtual PPA (Hub)	VPPA is a contract structure under which the customer (or off-taker) agrees to purchase renewable energy from a generator (seller) for a fixed price, while the generator receives the floating market price. If the fixed VPPA price is greater than the actual market price, then the generator pays the difference to the off-taker. If the market price is greater than the VPPA price, then the generator keeps the difference. In this way, a VPPA is a financial hedge against volatile electricity prices. **If the market price for settlement is tied to a liquid trading hub, the VPPA is referred to as Hub Settled VPPA**. In a VPPA, the off-taker typically receives the renewable attributes but does not take physical delivery of the energy. The off-taker continues to purchase its electricity through their local utility.
Virtual PPA (Busbar)	A contract where the market price for settlement is tied to the generator busbar or node (or point of interconnection of the generator) is referred to as a **Busbar Settled VPPA**.
Bank Hedge	A fixed volume price swap, often called a bank hedge (aka fixed shaped energy). RECs may or may not be sold to the off-taker.
Proxy Revenue Swap	Proxy revenue swap hedging contract provides renewable energy projects with protection against exposure to these uncontrollable risks. Under a Proxy Revenue Swap, a renewable energy project exchanges its variable revenue stream for a fixed payment - providing an unprecedented level of cash flow certainty. This structure mitigates irradiance/wind speed risk, price risk and shape risk for the project
Utility Green Tariff Program	A utility green tariff program is another form of a "sleeved PPA" that has been gaining momentum in regulated electricity markets. Typically, PPA sleeving programs are set up through a regulated utility's rate structure. The utility, with approval from the state public utility commission, offers customers renewable energy through a "Green Tariff".

* Virtual PPA backed by a real asset
Source: Wood Mackenzie, EPA, Norton Rose Fulbright

The IRP informs the long-term capacity needs for regulated electric utilities and feeds into the sourcing strategies

The competitive solicitation process is heavily influenced by policy and regulation

Integrated Resource Planning

IRP serves as the mechanism to identify the future capacity needs to operate the system reliably and cost-effectively by the utility to meet the projected energy and peak demand.

Resource Analysis & Forecast

- Demand
- Supply
- Transmission and Distribution

Resiliency Analysis

- Regulatory framework (Federal and State)
- Economic outlook
- Political motivations
- Environmental and emissions goals
- Consumer willingness to pay
- Technological progress

Utilities are regulated by public service commissions (PSCs) with oversight provisions and are required to balance multiple objectives:

System reliability

- Adequate supply - Diverse resource mix, including intermittent resources
- Address transmission congestion
- Ensure loss of load expectation stays at or below the threshold limits

Environmental responsibility

- Retirement of direct and indirect greenhouse gas emitting units
- Inclusion of renewable technologies in the portfolio mix

Least-cost planning principle

- Optimization of resources
- Balance between PPAs and owned facilities

These objectives, added to social, political and economical constraints, affect the utilities' strategy and methodology for competitive solicitation processes.

Competitive solicitation process

Utility RFPs have followed certain characteristics adopted over time due to regulatory constraints and recommendations from PSCs:

- Traditional RFP process
- Inclusion of non-economic variables in evaluation process
- Participation of an independent evaluator throughout the competitive solicitation process
- Focus on long-term PPAs although the tenors have been declining
- Threshold limits for new renewable capacity and diversification
- PURPA qualifying facility requirements

Changing market dynamics are introducing new PPA procurement trends within the C&I segment

Growing interest in PPAs, evolving ESG targets and shorter PPA tenors shape how developers target corporates

Last year was a record-breaking year for the volume of utility-scale RPPAs executed (~10.6 GW) by the C&I segment despite facing numerous overlapping market crises

- The largest segment within C&I are the corporates
- Historically C&I demand for wind power has been greater than for solar power. However, since 2019 solar beat out wind in new C&I RPPAs signed and we expect to see this trend continue going forward with offsite utility PV becoming the go-to option for C&I procurement

Amazon, Facebook, Google, Microsoft, and other big technology and data firms remain the biggest off-takers of U.S. wind and solar but the long tail of smaller C&I buyers has grown considerably

- While big technology and data companies have been the largest segment of C&I off-takers, companies of the industrial sector are gaining momentum and signing up for RPPAs
- The guidance from several C&I off-takers indicates they will continue to move forward with contracts to hit renewable energy targets

Companies are seeking procurement strategies that affords flexibility and selecting contract types based on the prevailing market structure

- C&I customers are shortening the tenor of the contracts and pushing some of the risks towards the project developers, who appear to be willing to accept them
- The most common contract types for C&I off-takers are physical PPA, VPPA (deregulated markets) and Utility Green Tariff (regulated markets)

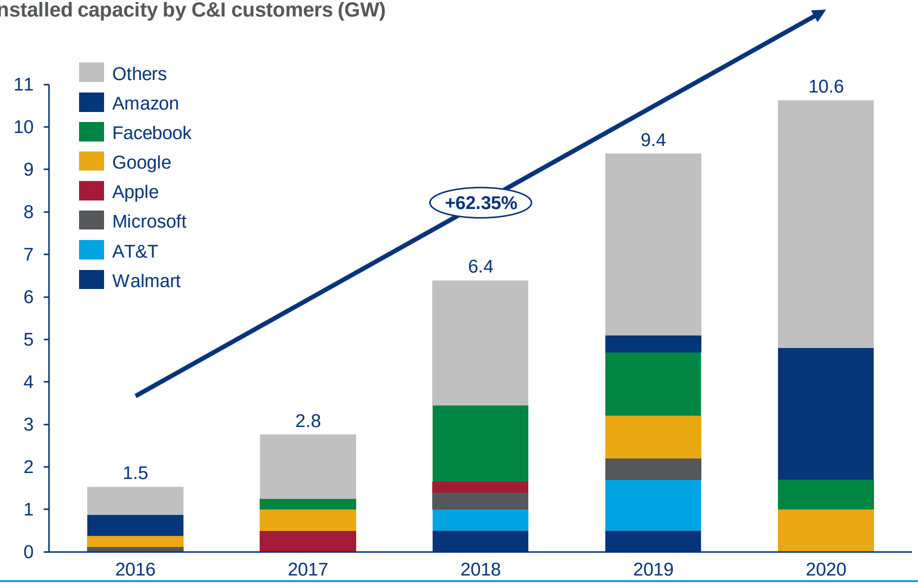
Ambitious ESG goals and zero carbon targets are pushing industry leaders to innovate

- The need to match supply and usage on a real-time basis, "usage matching" RPPA contracts are becoming of interest to the more progressive companies like Google as they work towards net zero goals and power the data centers with 24/7 carbon-free energy
- The recent 10-year, 500 MW RPPA between Google and AES to power Google's data center located in Virginia using a portfolio of assets consisting of wind, solar, storage and hydro shows creativity and innovation in developing a custom solution that is first-of-a-kind in the industry

C&I customers are continuing to contract at record-breaking pace

The trend is expected to continue in the near term due to several factors

Installed capacity by C&I customers (GW)



# of Customers	21	31	75	83	100

Source: REBA Deal Tracker

- Renewable energy procurement is being accelerated by large energy buyers
- Over the last five years, the volumes of contracted renewable capacity by C&I customers have increased by ~7x, and the number of C&I customers executing RPPA contracts have increased by ~5x
- Corporate sustainability goals are driving the increased interest in renewable energy procurement to serve their power needs (net zero and green house gas reduction goals)
- Corporate reporting requirements and evolving ESG standards are forcing European flagged companies to transition to carbon-free energy alternatives much faster than others

…and their corporate RPPA strategy is influenced by ambitious ESG targets and higher projected demand growth rates in the future

C&I customers focus on fulfilling their energy and REC requirements through procurement of renewable energy contracts and at the same time are pushing for shorter tenors to gain flexibility

Best practices and indicators observed in industry for RPPA Procurement

Attribute	Industry practice
Settlement point	• More PPAs are priced at the zonal level as developers are still willing to take the basis risk for no material risk premium
Pricing components	• C&I customers are more interested in energy and RECs • Carbon offsets (if tradeable) are also products of interest
Contract term	• PPA terms are broad, between 10 and 20 years (12 or 15 years seems to be the sweet spot). The shortest contract is 10 years • Corporates allow for developers to provide different prices for different terms in a single RFP
Factors influencing PPA price	• A longer-term PPA may not always be more expensive than a shorter-term PPA • Commercial operations date plays a key role in the economics (availability of tax credits and equipment price timing)
PPA supply-demand balance	• Corporate appetite for PPAs is increasing. The same project hardly ever shows up twice on multiple RFPs like before, and corporate project developers now have multiple corporates to pitch the same project to
PPA transaction process	• From a developer standpoint, it is much easier to transact a corporate C&I PPA versus a utility PPA • Some corporates are streamlining the contracting process by creating standard contracts for projects under a minimum capacity threshold or creating a lean deal approval process for projects under a predetermined cash outflow

The key attributes to focus on during RPPA negotiations are…

Every customer has different preferences for PPA terms. But there are a handful of PPA characteristics that consistently rise to the top of customers' minds

Most Important

- **Price.** Customers are willing to adjust other aspects of the contract in order to receive the lowest PPA price. For example, customers will request short PPA terms, but will ultimately accommodate longer PPAs when they see the impact on price.
- **Rate escalator.** Developers report that customers prefer PPAs that have a fixed price with no escalator or a very minimal price escalator.
- **REC.** The default position is that environmental attribute is to be included as part of the PPA and is reflected in the price (bundled PPA).

Very Important

- **Term length.** Corporate and private customers want contract terms that are as short as possible. As a result, contract lengths have decreased in recent years. Some developers have reported execution of corporate PPAs with tenors of 12 to 15 years. Public sector customers, such as schools or government facilities, don't typically follow this trend — since they intend to stay in their buildings for the long-term, they are more willing to sign 20 to 25-year PPAs.
- **Settlement point.** Most PPAs settle at a liquid trading hub and not at the plant busbar. In some regions, the settlement point may be in another zone
- **Availability guarantee.** PPAs often request a minimum availability guarantee for summer and non-summer months; LDs* will apply for non-performance
- **Performance guarantee.** Performance assurances are typically provided via domestic branch letters of credit and surety bonds, all institutions must maintain a BBB+ or better ratings.

Relatively Important

- **Termination clauses.** Termination clauses can give customers sticker shock since these stipulations usually require that customers pay for all lost revenue from the system, the value of the tax credits and depreciation benefits, and removal of the system. Over time, customers and lawyers have got more comfortable with termination clauses, especially as operating projects prove their performance reliability. But these clauses can still be a "hot-button" issue that can cause PPA renegotiations.
- **Purchase option.** Purchase option is typically not available to customers until after the first 6-7 years of the project (when the tax equity investors' ownership share has flipped). To reduce risk, developers typically require the customer pay fair market value (FMV) at the end of the contract rather than set a predetermined fixed price. Furthermore, a right of first refusal (ROFR) clause is also built into some contracts to ensure the off-taker has the option to purchase the asset prior to owner selling it to a third party.

*LDs: Liquidity damages

Based on our interviews with the Consumers team and other market insights, we have identified some opportunities that may improve Consumers RPPA process

Suggested modifications to the current RFP process are backed by RPPA trends observed in the market

RPPA trends observed and suggestions

Element	Trend observed	Opportunity for Consumers Energy
PPA term	• Ranges from 8 – 35 years but most (54%) are 15 years or less • Analyzing the data for contract term lengths greater than 15 years, nearly all the contracts had a tenor of 20 years	• There is a market for contract tenors of 10 – 15 years • Shorter term allows for more long-term flexibility • Consider a "laddered" approach of varying tenors as the basket of PPAs are contracted to better match the changing demand outlook in the future
Price type	• All contracts are "fixed" but 23% have risk adjustment mechanisms for negative pricing or basis claw back	• Developers are willing to take on negative pricing and basis risk. As renewable penetration grows in the footprint ability to pass this risk on becomes more important
Volume type	• All contracts are unit contingent • Several facilities are split between multiple off-takers – contracting percentage of output to each • Several facilities present an option to purchase quantities in excess of minimum volumes	• Spread procurement between multiple facilities to diversify project and production risk • Minimum quantities can provide production certainty. Fixed volumes can be contracted based on P90 or greater with the option to purchase excess
Environmental attributes	• Majority (76%) have environmental attributes bundled. 20% have environmental attributes priced separately.	• Request unbundled pricing for greater transparency
Energy settlement point	• 75% have settlement at generation node, 25% have settlement at hub or load zone	• Generation node is not de facto settlement point. Eliminate basis risk by settling at the zone
Buyout option	• Buyout clauses centered around present value of remaining contract term plus penalty rates ranging from 3% to 5%	• Build ROFR clauses into the agreement and combine those with FMV clauses to ensure there is an option to purchase the asset at contract expiry prior to owner selling it to a third party

*

We believe, different clauses can be built into the RPPA structure to mitigate risk

Similar clauses could be implemented by Consumers to increase flexibility and reduce risk exposure, where applicable

Risk mitigation strategies

Risk observed	Description	Mitigation measure
Basis risk	• Spread between Gen Node and Load Zone (CONS.CETR) averaged -\$1.00 since 2016, with ranges between +\$0.35, and -\$2.86 depending on location	• Match delivery point to load obligation location to address basis risk
Exposure to negative prices	• Increased renewable penetration may increase exposure to negative pricing	• Build in negative pricing clauses
Production, shape, and project risk	• Production, shape, and project risk are inherent with new renewables	• Fulfill procurement requirement by purchasing percentage of P90 output from more projects instead of P50 from fewer projects • Purchase fixed shapes or minimum volumes based on P90 or greater
Forecast obsolescence	• Load forecasts and market price curves will not be accurate 10+ years forward	• Contract for shorter terms. 10 to 12 years still allow developers to finance projects while affording for long-term flexibility
Decreasing PPA Prices	• Capital costs are expected to fall in the future, and all else being equal, the PPA prices are expected follow that trend. Locking in long-term PPAs will limit the off-taker’s ability to benefit from falling PPA prices	• Request pricing for 10 to 20-year terms to get a market-based view on how terms affect premiums

Other risk mitigation products

- Weather Options to cover short term load volatility associated with weather
- Call Options to establish ceiling on energy prices of unhedged volumes
- Basis Trades (Not necessary if delivery is at load zone)

3. Evaluation of Consumers RPPA procurement & contracting strategy

Affording Consumers more flexibility with RPPA contracting may increase the overall value to rate payers

RPPA procurement is governed by MPSC Order, FERC Order and Michigan Statute

1 Status quo contracting strategy

- The IRP informs the long-term supply procurement plan for the company
- Procurement of new supply is handled through a competitive bidding process conforming to the guidelines approved by MPSC
- At least 50% of the new capacity procured shall be from PPAs with a maximum length of 25 years. The remaining 50% is procured competitively through BTA, DAA or self build schemes
- Most RPPA contracts are physical PPAs or hybrid PPAs with a tenor of at least 20 years
- The current process is narrowed to solar, local projects in the Lower Peninsula as well as unit-contingent, busbar-settled projects at day-ahead market prices
- Current methodology design is attractive to developers, simplifies bid evaluation, guarantees ability to meet capacity requirements, and allows project owner to mitigate both basis risk and volume risk
- However, the current process has a few limitations too - limits attractive bids from other technologies and external to MISO Zone 7, restricts the ability to continuously balance the portfolio, and exposes Consumers to be locked into a PPA rate that may be above market over time as capital costs fall

2 Recommendations to enhance the current contracting strategy

- Some recent trends observed in other utilities' RFPs can help fine tune the RPPA contracting strategies in the future procurement cycles, such as, technology diversification of supply, hybrid renewable projects paired with storage, contracts with assets located external to MISO Zone 7 that are financially settled, shorter term PPAs with tenors 10-15 years with an option to extend
- Consider a "laddered RPPA" approach with varying procurement quantities with varying contract lengths (shorter and longer term) to afford flexibility given uncertainties around future load shape and demand growth (due to energy efficiency, demand response, distributed energy resources), capital costs for wind and solar, PPA prices, efficiency improvements and tax incentives. This may also reduce costs to rate payers
- Evaluate and mitigate impacts of supply-demand mismatch further out in time
- Diversify the RPPA supply mix to increase overall system reliability and resiliency. Minimize the loss of load expectation for the system in a regime with high penetration levels of renewable / intermittent resources

Consumers is mandated to procure its long-term supply needs through a competitive bid process and is defined by the IRP

Current structure of Consumers RPPA strategy is mainly influenced by policy and regulatory framework

Consumers Energy IRP Filing

- Consumers is one of two largest electric utilities serving more than 6.7 million Michiganders living within the MISO Michigan/ MISO Zone 7 footprint
- Consumers filed its last IRP in June 2018 and a Settlement Agreement was reached between the various stakeholders in March 2019
- The next IRP filing is scheduled for June 2021

Competitive Bidding Process

- Competitive supply procurement is governed by the *2008 Guidelines for Competitive RFP for Renewable and Advanced Clean Energy (12/04/2008 Order Case No. U-15806)*
- Competitive bidding process serves as the mechanism through which the future capacity needs are procured and the competitive bid methodology is used to determine PURPA avoided cost rates
- All new capacity to be procured through the competitive bidding process
  - ✓ At least 50% of the new capacity procured shall be from PPAs. Consumers affiliates are excluded
  - ✓ The remaining 50% shall be owned by the company through BTA, DAA or self-build scheme
- The competitive bid process is administered by an independent third party
- Five-year outlook to determine capacity needs
- Annual solicitations for the technologies specified in the Proposed Course of Action (PCA)
- Remaining capacity not filled by responses would be available to PURPA Qualifying Facilities
- Maximum length of contracts will be equivalent to depreciation schedule of a similar Company-owned asset (25 years for solar projects)
- For PPAs subject to Financial Compensation Mechanism, Consumers will earn the PPA payments of the year x WACC (5.88% of the company's capital structure)

Consumers RPPA strategy is attractive to developers, but may carry additional risks

Consumers aims to meet energy and capacity needs defined in the IRP economically, transparently and impartially

Element	Pros	Cons
Single technology focus (solar)	• Simplifies bid evaluation	• May limit attractive bids from other emerging technologies • Homogenous technology may increase exposure to weather events
Narrow Geography (Lower Peninsula)	• Guarantees ability to meet Zone 7 capacity requirement • Spread between busbar and zone pricing is relatively stable • Simplifies bid evaluation • Local societal benefits	• May limit attractive bids from nearby areas that are external to Zone 7
Contract term of 20 to 25 years	• Attractive to developers (for financing) • Standard term simplifies bid evaluation • Fills in far out capacity retirements now, meeting long glidepath goals • Rate certainty	• Capacity requirements are expected to change over a 25-year period • Long-term price and load forecasts may not be dependable beyond 5 years • Increased renewables will change congestion dynamics, upending long-term assumptions underpinning long-term agreements • Locked-in rate may creep above market over time and is passed on to the rate payers. Capital costs are expected to fall in the future, and all else being equal, the PPA prices are expected follow that trend. Entering into long-term PPAs will limit the off-taker's ability to benefit from falling PPA prices • Reduced ability to continuously balance portfolio diminishes the utility's flexibility • Committed to antiquated technologies toward end of term
Unit-contingent contracts	• Attractive to developers	• Volumetric risk as the contracts are "as generated" • Requires a procurement buffer to ensure that requirements are met
Busbar PPA settlement for projects at transmission voltage	• Attractive to developers	• Consumers carries additional energy cost associated with spread between CONS.CETR and Busbar.
Day-ahead market price settlement	• Matches to load obligation in day-ahead market, removing day-ahead to real-time (DA-RT) spread risk	• None identified

Other utilities have implemented measures to increase flexibility and mitigate risks

Some of the trends observed could be leveraged to strengthen Consumers RPPA procurement strategy

Element	Current Trend
Technology focus	• Technology-agnostic RFPs • Technology specific carveouts limits for capacity within the RFPs • Renewable (on-shore wind or solar) + storage frequently requested
Geography	• Bids from physical assets in neighboring zones and control areas entertained. Ensure deliverability criteria is addressed • Preference is for assets located within footprint / load zone • More geographical flexibility with financially settled PPAs
Contract terms	• Typical utility contracts are 20 years. Electric cooperatives and C&I are executing with tenors ranging from 10 to 15 years. Developers can finance renewable projects with a 12-year PPA • Options to extend are common
Unit-contingent contracts	• Still most popular volume type • Off-takers will contract with multiple facilities for a share of production to meet goals • Minimum volume guarantees emerging
Price settlement point	• Most settle at the busbar • About 25% settle at the hub or load zone. Developer manages the basis risk
Market price settlement	• Majority settles at Real-Time price
Other Considerations	• Physical PPAs sleeved through competitive retail electric supplier • Corporate PPAs replacing REC only purchases as sustainability initiatives become more sophisticated

Consumers has a robust RPPA contracting strategy in place that may be improved with a few minor modifications

Learnings from contracting strategies adopted by other leading utilities and C&Is can bolster the overall value

- Some recent trends observed in other utilities' RFPs can help fine tune the RPPA contracting strategies in the future procurement cycles, if applicable
  - ✓ Technology diversification of supply
  - ✓ Renewable projects paired with storage
  - ✓ Contracts with assets located external to MISO Zone 7 that are financially settled
  - ✓ Shorter term PPAs with tenors 10-15 years with an option to extend
- Consider a "laddered RPPA" approach with varying procurement quantities with varying contract lengths (shorter and longer term) to afford flexibility given uncertainties around future load shape and demand growth (due to energy efficiency, demand response, distributed energy resources), capital costs for wind and solar, PPA prices, efficiency improvements and tax incentives. This is likely to reduce costs to rate payers (see illustrative example) by providing:
  - ✓ Higher probability of adapt to market conditions
  - ✓ Opportunity to realize capital cost reduction benefits
- Evaluate and explore ways to mitigate impacts of supply-demand mismatch further out in time
- Diversify the RPPA supply mix to increase overall system reliability and resiliency. Minimize the loss of load expectation for the system in a regime with high penetration levels of renewable / intermittent resources

Cost Impact of PPAs of Varying Tenors

For Illustrative Purposes Only

PPA ID / Tenor	PPA Price (Nom$/MWh)	Capital Cost (Nom$/Wdc)	Value of PPA ($ MM USD)
PPA 1: 25-Year PPA (2021-2045)	32.00	1.09	210.24
PPA 2: 12-Year PPA (2021-2032)	33.00	1.09	104.07
PPA 3: 13-Year PPA (2033-2045)	25.00	0.67	85.41
Total Savings from PPA 2 and PPA 3 over PPA 1			**20.76**
Breakeven PPA Price for PPA 3 (13-Year PPA)	**31.08**		

Source: Wood Mackenzie

- The decrease in capital costs from 2021 to 2033 is 38%
- The decrease in PPA price for 2021 to 2033 is 24%
- For the total costs to be equal to PPA 1, the PPA 3 price must be **$31.08/MWh**.

What is the likelihood for the PPA price to drop by less than $1/MWh from 2021 to 2033 when the capital costs drop by 38%?

Disclaimer

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MICHIGAN PUBLIC SERVICE COMMISSION

CONSUMERS ENERGY COMPANY

Case No.: U-21090
Exhibit No.: A-47 (KGT-3)
Page: 1 of 1
Witness: KGTroyer
Date: June 2021

Consumers Energy
U-20697 Embedded Capacity Costs
$/Peak kW Sales

Line			Source:
1	Total Capacity Related Cost ($k)	$ 1,633,298	Exhibit A-17 (JCA-3); Page 1, Line 9, Column (b)
2	Bundled Test Year Max Demand - MW @ System Output	7,052	EM Breuring
3	Test Year Projected Sales - GWH	32,595	Exhibit A-15 (EMB-2); Page 1, Line 8, Column (e)
4	Test Year Projected System Output - GWH	35,036	Exhibit A-15 (EMB-2); Page 1, Line 8, Column (h)
5	Sales Conversion Factor	0.930	Line 3 / Line 4
6	Bundled Test Year Max Demand - MW @ Sales	6,561	Line 2 * Line 5
7	Consumers Embedded Capacity: $/MW-Year	$ 248,951	Line (1 * 1,000) / Line 6
8	CMS Enterprises (Proposal 2)* Bid Price: $	$ 525,000,000	Proposal
9	CMS Enterprises (Proposal 2)*: MW-year	17,320.0	Proposal MW-year for each facility x assumed useful life**
10	CMS Enterprises (Proposal 2)* UCAP: $/MW-year	$ 30,312	Line 8 / Line 9

*Includes the purchase of the DIG Plant, Kalamazoo Plant, and Livingston Plant
**20 years assumed useful life for existing combined cycle facilities. 15 year assumed useful life for existing combustion turbine facilities.

Report of the Independent Administrator

Consumers Energy Company – Request For Proposals for Solar Generation Projects

Public Report Issued on: March 18, 2020

Independent Administrator Report Contents

Executive Summary

Introduction

Consumers Energy Company ("Consumers Energy" or the "Company") retained Enel X North America, Inc. ("Enel X") through its *Independent Administrator (IA) for Consumers Energy's Integrated Resource Plan ("IRP") Program Request for Proposals* ("IA RFP") to serve as an independent third-party administrator in support of its supply-side resource solicitations ("IRP Solicitations").

Enel X is based in Boston, MA and has been conducting large-scale energy solicitations on behalf of its utility clients for nearly two decades. Enel X built its proprietary procurement technology and developed robust processes exclusively for energy solicitations. Enel X has continued to invest in technology and has continued to hone its processes with the vision of being the undisputed leader in the high-stakes, high-scrutiny world of large-scale utility energy solicitations.

Enel X has prepared this final Independent Administrator Report ("Final IA Report") in support of the *Consumers Energy Company Request for Proposals for Solar Generation Projects* ("Consumers Energy RFP" or the "RFP") issued on September 30, 2019.

RFP Purpose, Background

The purpose of the Consumers Energy RFP was to 1) solicit offers for Consumers Energy to acquire solar generation projects and/or solar power purchase agreements ("PPAs") backed by projects located in that portion of the lower peninsula of the State of Michigan that is serviced by the Midcontinent Independent System Operator, Inc. ("MISO") and 2) solicit offers for PURPA qualifying facilities 20 MW and below located within Consumers Energy's electric distribution service territory. Proposals located within this region (MISO's Local Resource Zone 7) were requested to support Consumers Energy's IRP. With its RFP, Consumers Energy sought to acquire solar generation projects and PURPA qualifying facilities that provided the lowest net costs to its customers.

Consumers Energy sought to acquire up to 300 MW of additional aggregate nameplate capacity projects with commercial operation dates on or before May 31, 2022, all located in the State of Michigan's Lower Peninsula to support Consumers Energy's IRP. Of the 300 MW solicited, Consumers Energy sought to acquire 150 MW via long-term PPAs and 150 MW via either build transfer agreements ("BTAs") or Company proposed projects.

RFP Schedule

The Consumers Energy RFP has followed, and is intended to continue to follow, the schedule detailed below (select dates within the RFP Schedule were/are subject to change as-warranted by Consumers Energy):

ID	RFP Milestone	Date
1	Notification of Upcoming RFP Issued via Email to Potential Respondents	Wednesday, September 25, 2019
2	RFP Issued, Solicitation Website, Documents Go-Live	Monday, September 30, 2019
3	Questions and Answers Window Opens	Monday, September 30, 2019
4	Pre-Bid Conference Call Held	Thursday, October 3, 2019
5	Notice of Intent Package Due	Monday, October 14, 2019
6	Invoices for RFP Application Fees Issued	Wednesday, October 16, 2019
7	Respondents Requiring Remediation Contacted	Monday, October 21, 2019
8	Electronic Versions of LoCs or Wire Transfer Remittance Forms Due	Monday, October 21, 2019
9	Remediation Materials, Actions Due	Thursday, October 24, 2019
10	RFP Application Fees Due	Thursday, October 24, 2019
11	Pre-Bid Financial Security (Hard-Copy LoCs or Cash Deposits) Due	Monday, October 28, 2019
12	Notifications of Pre-Qualification Status Issued to Respondents	Wednesday, November 6, 2019
13	Questions and Answers Window Closes	Friday, November 8, 2019
14	Proposals Due Date	Tuesday, November 12, 2019
15	Initial Respondent/Proposal Eligibility Screening Period Concludes	Monday, November 18, 2019
16	Respondents Notified of Ineligible Proposals	Wednesday, November 20, 2019
17	PPA, BTA Offer Shortlists, Proposal Rankings Provided to Consumers Energy	Monday, December 2, 2019
18	Consumers Energy Provides Enel X with Selected Proposals from PPA, BTA Lists	Wednesday, December 11, 2019
19	Preliminary Award Decisions, Statuses Distributed by Enel X	Friday, December 13, 2019
20	Enel X Provides Consumers Energy with Details of Selected Proposals, Respondents	Friday, December 13, 2019
21	Consumers Energy Begins Due Diligence Review of Selected Proposals, Respondents, Initiates Contracting Phase	Friday, December 13, 2019
22	Consumers Energy Informs Enel X of Need for Alternate Proposals, Responents	Tuesday, February 25, 2020
23	If Applicable; Consumers Energy Provides Enel X with Selected Alternate Proposals from PPA, BTA Lists	Wednesday, March 4, 2020
24	Final Award Decisions, Statuses Distributed by Enel X	Friday, March 6, 2020
25	If Applicable; Enel X Provides Consumers Energy with Details of Alternate Proposals, Respondents Selected	Friday, March 6, 2020
26	If Applicable; Consumers Energy Begins Due Diligence Review of Selected Alternate Proposals, Respondents, Initiates Contracting Phase	Friday, March 6, 2020
27	Pre-Bid Credit for Unawarded Respondents Cancelled, Returned	Tuesday, June 30, 2020
28	Agreements, Contracts for Selected Proposals Finalized, Executed	-
29	Pre-Bid Credit for Awarded Respondents Cancelled, Returned	Following Contract Execution
30	Contracts, Agreements Submitted to MPSC	-

Summary of Findings

Enel X conducted and monitored the Consumers Energy RFP process in its entirety. As demonstrated throughout this report, Enel X attests that each element of the RFP process was run in a fair and transparent manner and that RFP results were competitive and reflective of market conditions.

Preparation Phase

Overview

Enel X's involvement within the Consumers Energy RFP Preparation Phase spanned from August 1, 2019 (when verbal notice of Enel X's award from the Consumers Energy IA RFP was conveyed) to September 30, 2019 (the date of issuance for the Consumers Energy RFP). The Preparation Phase covered a number of key tasks associated with the development and finalization of RFP documents and materials, the engagement and support of RFP stakeholders, the development and issuance of RFP advertisements, the development of an RFP listserv containing over 200 organizations, and other pertinent pre-RFP release tasks.

RFP Documents

Enel X reviewed and provided various comments and proposed modifications to a host of Consumers Energy-developed RFP documents and templates. Additionally, Enel X drafted multiple supporting RFP documents and materials for review and approval by Consumers Energy.

The following RFP documents and materials were developed by Consumers Energy:

1. Consumers Energy Company Solar Generation Projects RFP
2. Appendix B: Technical Bid Form
3. Appendix C-1: Build Transfer Agreement Pricing Bid Form
4. Appendix C-2: Power Purchase Agreement Pricing Bid Form
5. Appendix D: Build Transfer Agreement Template
6. Appendix E: Power Purchase Agreement (Transmission) Template
7. Appendix F: Power Purchase Agreement (Distribution) Template
8. Appendix G: Technical Specifications
9. Appendix H: Exceptions to Technical Specifications
10. Appendix I: Value Added Criteria
11. Appendix J: Acceptable Manufacturers List Process
12. Appendix K: Low Income County List
13. Economic Model - BTA
14. Economic Model - PPA

The following RFP documents and materials were developed by Enel X:

1. Megawatt Daily RFP Advertisement
2. Utility Dive RFP Advertisement
3. RFP Notice Email Templates
4. Appendix A: Notice of Intent Package - Due by 5:00 PM EPT on October 14, 2019
5. CECo IRP Pre-Bid Conference Call for Consumers Energy Company Solar Generation Projects Held 10032019 - Slide Deck
6. CECo Pre-Bid Letter of Credit Package (for Respondents intending to utilize a Letter of Credit in support of pre-bid credit posting requirements)

7. CECo Wire Transfer Remittance Form (for Respondents intending to utilize a cash deposit in support of pre-bid credit posting requirements)
8. CECo Questions and Answers Log Templates
9. CECo IRP 2019 Solar RFP Enel X Solicitation Platform Proposal Submittal Instructions

Stakeholders were granted an advanced look at draft RFP materials and documents, which were posted on Consumer Energy's public Electric Power Notices website (https://www.consumersenergy.com/electricpowernotices) prior to the Stakeholder Workshop held on August 26, 2019. Stakeholders were encouraged to provide feedback, which was considered as the final RFP documents and materials were being developed.

Stakeholder Engagement

Enel X participated within an IRP Competitive Solicitation Workshop ("Stakeholder Workshop") held at Consumers Energy's headquarters in Jackson, MI on August 26, 2019. During the Stakeholder Workshop, representatives from Consumers Energy and Enel X reviewed the Consumers Energy RFP plan and the proposal submittal and selection process before fielding clarifying questions and comments/suggestions from present stakeholders and via email from those not in attendance.

A host of Stakeholder questions and feedback were received and detailed along with Company responses within the *2019 IRP Request for Proposal Stakeholder Workshop Stakeholder Comments and Company Responses* document posted to the Consumers Energy Electric Power Notices website on September 17, 2019.

Further, Enel X attended, and participated within, a meeting with Michigan Public Service Commission ("MPSC") Staff held at MPSC headquarters in Lansing, MI on September 17, 2019. During the September 17, 2019 meeting with MPSC Staff, representatives from Consumers Energy and Enel X discussed and reviewed the final Consumers Energy RFP package and recently published responses to items raised during the Stakeholder Workshop.

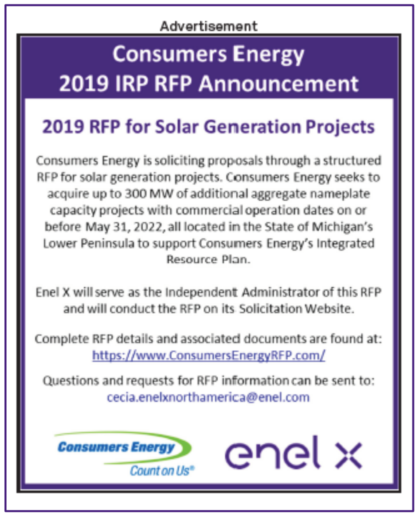
Ample opportunity was afforded to all stakeholders to examine and opine on various Consumers Energy RFP related matters, including a full suite of draft RFP documents. Throughout the Preparation Phase, market participants and stakeholders were kept apprised of the development of the Consumers Energy RFP and solicitation processes.

RFP Advertisements

Enel X developed and scheduled the publication of two Consumers Energy RFP advertisements, which were reviewed and approved for publication by Consumers Energy. RFP advertisements were run within a daily issue of the S&P Global Platts Megawatt Daily publication and on the public homepage of the Utility Dive website.

S&P Global Platts Megawatt Daily

Platts Megawatt Daily is a leading energy industry publication providing a broad audience of market participants with a primary source of daily news and price information. An in-text block Consumers Energy RFP advertisement was inserted within the October 1, 2019 edition of Megawatt Daily (published/distributed on September 30, 2019). The advertisement run contained an overview of the Consumers Energy RFP, a link to the public Solicitation Website (https://www.consumersenergyrfp.com), and an email address to the Independent Administrator.



Utility Dive

Utility Dive is public energy industry news website and daily newsletter that covers a wide breadth of news and trends of impact within the utility industry. The public Utility Dive website attracts 215,000+ monthly unique visitors, with primary viewership by the following company types: Investor Owned Utilities, Municipalities, Solar/Renewables Contractors, Developers, and Energy Performance Contractors.

A banner advertisement for the Consumers Energy RFP was run at the top of the Utility Dive homepage from October 1, 2019 through October 5, 2019, which contained a link to the public Solicitation Website (https://www.consumersenergyrfp.com) and an email address to the Independent Administrator.

The publication of RFP advertisements marked the conclusion of the Preparation Phase, at which point the RFP process pivoted into its second stage, the Solicitation Phase.

Solicitation Phase

The Solicitation Phase of the Consumers Energy RFP process covered a wide range of tasks from the issuance of a preliminary RFP notice on September 25, 2019 through the collection of submitted proposals by November 12, 2019.

During the Solicitation Phase, the Consumers Energy RFP was formally issued, would-be Respondents were engaged by Enel X through various communications channels, Notice of Intent forms and associated Respondent pre-qualification materials were collected, a formal Questions and Answers process was managed, pre-bid credit was collected, proposals were submitted, and an initial IRP solicitation summary was generated, among a host of other support tasks.

RFP Issuance

On September 25, 2019, a preliminary RFP notice was distributed via email by Enel X to the previously developed RFP listserv. The preliminary RFP notice contained general details regarding the soon-to-be-released RFP and associated documents as well as the email address for the Independent Administrator. Enel X made note of undeliverable email notices and worked to obtained substitute email address for such organizations with invalid email addresses and/or contacts.

On September 30, 2019, a formal RFP release notice containing access instructions was distributed via email by Enel X to the RFP listserv, at which point the public Solicitation Website and RFP documents, materials were made accessible on the Enel X Solicitation Platform (usernames and passwords were not required to access such content). All parties could access the Solicitation Platform website without restriction and without any prerequisite set up work by Enel X (in the same fashion any public website could be accessed). By hosting and promoting (via advertisements) a public RFP website, Enel X ensured that all potential Respondents and other interested parties could access all RFP materials – even if they were not included on the initial RFP listserv.

Solicitation Website

The Enel X public Solicitation Website containing all Consumers Energy RFP information and associated documents, materials were published on September 30, 2019. The Solicitation Website served as a central RFP data repository throughout the Solicitation Phase and provided all Respondents with a single-site resource for accessing all RFP content necessary to participate within the RFP process and submit proposals.

By utilizing a single site to host all relevant RFP information and documents, Enel X was able to ensure that all Respondents received access to the same materials at the same time. Further, any RFP materials that received updates or amendments were to be uploaded to the Solicitation Website and notice of their upload was to be published, ensuring that parties did not work from stale versions of amended documents.

enel x

ANNOUNCEMENT VIEW: 15162 - CONSUMERS ENERGY COMPANY - REQUEST FOR PROPOSALS FOR SOLAR GENERATION PROJECTS - PRE-BID CONFERENCE CALL SCHEDULED FOR 10/3 - NOTICE OF INTENT DUE 10/14

Introduction

RFP Overview:

Consumers Energy Company ("Consumers Energy" or the "Company") will seek competitive bids in response its Request for Proposals ("RFP") from participants in the MISO Energy Market in accordance with the Company's Proposed Course of Action in its Integrated Resource Plan. Enel X North America, Inc. ("Enel X") will administer the solicitation through this Solicitation Website on Consumers Energy's behalf in accordance with the RFP, currently hosted in the 'Documents' section of this website. With this RFP, Consumers Energy will solicit proposals for solar generation projects as described within the posted RFP. Responses to the upcoming RFP will only be accepted through the Enel X Solicitation Website.

Company Background:

Consumers Energy is the principal subsidiary of Jackson-based CMS Energy Corporation and is Michigan's largest energy provider, providing electricity and/or gas to almost 7 million of the state's 10 million residents in all 68 counties in the Lower Peninsula. Consumers Energy provides electric service to 1.8 million customers and serves 275 cities and villages in 61 counties.The Company operates 5 coal-fueled generating units, two oil/gas-fueled and two gas-fueled generating units, 13 hydroelectric plants, a pumped storage electric generating plant, two wind-powered energy parks, two solar photovoltaic generation systems and several combustion-turbine plants that produce electricity when needed during peak demand periods. The Company also purchases power from several independent power producers through long term power purchase agreements.

RFP Purpose and Background:

The purpose of this Consumers Energy RFP is to 1) solicit offers for Consumers Energy to acquire solar generation projects and/or solar power purchase agreements ("PPAs") backed by projects located in that portion of the lower peninsula of the State of Michigan that is serviced by the Midcontinent Independent System Operator (MISO) and 2) solicit offers for PURPA qualifying facilities 20 MW and below located within Consumers Energy's service territory. Proposals located within this region (MISO's Local Resource Zone 7) are requested to support Consumers Energy's IRP. With this RFP, Consumers Energy is seeking to acquire solar generation projects and PURPA qualifying facilities that provide the lowest net costs to its customers. The structures that Consumers Energy will consider to accomplish the foregoing objectives are described in more detail in Subsection 5.4 of the RFP document.

Requested Proposals, Projects:

Consumers Energy seeks to acquire up to 300 MW of additional aggregate nameplate capacity projects with commercial operation dates on or before May 31, 2022, all located in the State of Michigan's Lower Peninsula to support Consumers Energy's IRP. Of the 300 MW solicited, at least 150 MW will be acquired through long-term PPAs.

Proposal Submittal Process:

Respondents must be pre-qualified and meet all relevant participation pre-requisites outlined within this RFP and communicated by Enel X in order to submit proposals. Following the communication of pre-qualification statuses on November 6, 2019, pre-qualified Respondents will be provided with detailed proposal submittal instructions. As an overview; Respondents qualified to submit proposals will download relevant proposal templates from the 'Documents' section of this Announcement webpage, complete and save their proposal templates, and then upload those proposal templates into either the PPA submittal portal or BTA submittal portal.

The Solicitation Website remained publicly accessible through the duration of the pre-qualification window. Following the pre-qualification window, the Solicitation Website became private (accessible behind-the-password) and Respondents that were pre-qualified received user accounts to access the private version of the Solicitation Website.

Respondent Engagement

Enel X made best efforts to engage every invited Respondent individually to ensure receipt of the RFP notice, confirm that they were able to access the Solicitation Website and RFP materials, provide platform training sessions, ensure Respondents were aware of the RFP schedule and milestones, and encourage any open/outstanding questions to be submitted for inclusion within the Questions and Answers log. Enel X also distributed numerous email reminders to all invited Respondents to provide alerts regarding upcoming scheduling milestones and approaching RFP events.

The Enel X Independent Administrator team was accessible to Respondents throughout the RFP process through a variety of communications channels to provide Respondents with any level of required support and guidance.

Pre-Bid Conference Call

On October 3, 2019, Enel X and Consumers Energy hosted a publicly accessible pre-bid conference call for all interested parties. A recording of the pre-bid conference call was posted on the Solicitation Website the following day, October 4, 2019, for those that were unable to attend the call live. Nearly 70 individuals attended the pre-bid conference call live and numerous other individuals downloaded a recording of the call afterwards.

During the Pre-Bid Conference Call, Consumers Energy and Enel X reviewed pertinent details regarding Consumers Energy RFP for Solar Generation Projects and discussed various RFP participation requirements. While some questions were submitted during the pre-bid conference call, such questions were added to the central Questions and Answers log and not addressed live during the call.

Questions and Answers Log, Process

A formal Questions and Answers process was launched alongside the issuance of the Consumers Energy RFP on September 30, 2019. All parties were able to submit questions to the central Independent Administrator email account.

Enel X fielded, collated, anonymized, and provided answers to questions on Consumers Energy's behalf when-able within a centrally hosted Questions and Answers document. In the event that Enel X was unable to answer a question, such questions were provided to Consumers Energy for guidance while masking any identifying characteristics of the question submitter. All questions submitted and answers provided were approved by Consumers Energy prior to posting.

In addition to the previously addressed questions contained within the *2019 IRP Request for Proposal Stakeholder Workshop Stakeholder Comments and Company Responses* document posted to the Consumers Energy Electric Power Notices website, a total of 42 unique questions (many parties submitted substantively the same question/questions) were received and addressed across three different issuances of the Questions and Answers log. Each time an updated Questions and Answers log was made available on the Solicitation website a correspondent email notice was issued to the RFP listserv to ensure all parties were aware of its publication.

The third and final iteration of the Questions and Answers log was published on November 5, 2019. On November 8, 2019 the Questions and Answers process concluded.

Respondent Pre-Qualification

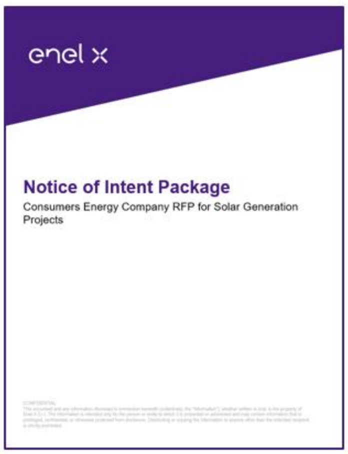
In order to achieve pre-qualification status and obtain permission to submit proposals, RFP Respondents were required to meet a number of participation prerequisites, including the following primary tasks:

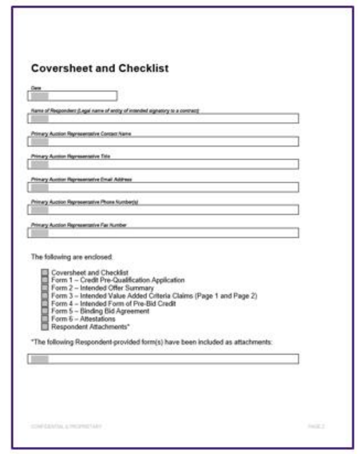
- Submit a fully completed Notice of Intent Package (Appendix A) including Forms 1-6
- Furnish non-refundable application fees
- Submit fully completed Credit Pre-Qualification Applications
- Post refundable pre-bid security

Notice of Intent Package

The Notice of Intent package (Appendix A) included forms that Respondents were required to complete and submit to provide a formal indication of their interest in participating in the RFP process. Notice of Intent packages were due to Enel X on October 14, 2019.

The Notice of Intent package was created as a locked Microsoft Word document with editable fields. Respondents could complete the bulk of the Notice of Intent electronically before printing and physically signing forms requiring signature or utilizing e-signatures. All Notice of Intent packages were sent to Enel X via email.





The following six forms were contained within the Notice of Intent document package:

- **Form 1 – Credit Pre-Qualification Application**
  - Within Form 1 of the Notice of Intent, Respondents were asked to provide general information about their organization and information regarding their financial standing and credit. Respondents were permitted to provide attachments in support of required Form 1 information.

- **Form 2 – Intended Offer Summary**
  - Form 2 of the Notice of Intent served to capture details about the projects Respondents were intending to propose through the RFP process. Respondents were encouraged to carefully select projects that were to-be-conveyed via Form 2 as RFP application fees were calculated and invoiced based on the number of individual projects proposed on Form 2.

- **Form 3 – Intended Value Added Criteria Claims**
  - Form 3 of the Notice of Intent allowed Respondents to convey which value-added criteria they intended to claim for each to-be-proposed project. In the tables on Page 1 and Page 2 of Form 3; Respondents were requested to note the Project IDs as listed in the Project List contained on Form 2 and select the Value Added Criteria they intended to claim for each. Respondents that were not intending to claim any Value-Added Criteria were asked to indicate so by marking the check-box on Page 1 and 2 of Form 3.

- **Form 4 – Intended Form of Pre-Bid Credit**
    - Within Form 4 of the Notice of Intent package, Respondents were asked to note which type of pre-bid security they intended to utilize to meet pre-bid security posting requirements.

- **Form 5 – Binding Bid Agreement**
    - Form 5 of the Notice of Intent package was the Binding Bid Agreement. The Binding Bid Agreements served to bind Respondents to their respective proposal bids per the outlined Award and Confirmation process within the Consumers Energy RFP. An authorized signatory/company representative was required to physically sign the Binding Bid Agreement.

- **Form 6 – Attestations**
    - Form 6 of the Notice of Intent package covered six statements that Respondents were required to attest to. An authorized signatory/company representative was required to physically sign the Attestation form.

Enel X reviewed the information provided by Respondents within submitted Notice of Intent forms and worked with select Respondents to clarify various Notice of Intent form contents as-needed, if-needed.

Under the initial RFP construct, Consumers Energy was to evaluate the credit worthiness of each Respondent based on information conveyed by Respondents within Form 1 of the Notice of Intent package and determine whether or not each Respondent met the established Consumers Energy creditworthiness criteria.

In the interest of limiting the amount of Respondent-identifying information being shared during the Solicitation phase of the RFP process, Consumers Energy elected to change the credit review process and instead perform credit checks on Respondents once proposals had been selected. Consumers Energy requested that Enel X collect relevant financial documentations from Respondents to ensure that Consumers Energy would have sufficient information to conduct its credit checks during the Selection Phase of the RFP process.

Notice of Intent Packages Submitted

The following table details a summary of the submitted Notice of Intent packages received by Enel X in advance of the October 14, 2019 submission deadline. No Notice of Intent packages were received by Enel X after October 14, 2019 nor were any Respondents denied permission to participate within the RFP process due to inability to meet the Notice of Intent submission deadline (given that all interested parties submitted required forms by October 14, 2019).

Criteria	Value
Total Number of Respondents Submitting Notices of Intent	23
Total Number of Proposed Projects	80
Number of PURPA QF (Up to 20 MW)	48
Number of Solar Generation Facilities (Greater than 20 MW)	32
Total Amount of Proposed Capacity (MW)	3,148.21
PURPA QF Capacity (MW)	632.51
Solar Generation Facilities (Greater than 20 MW) Capacity (MW)	2,515.70

Respondents that submitted Notice of Intent packages received receipt confirmation notices from Enel X, which contained a summary of next-steps within the RFP process.

RFP Application Fees

Respondents submitting proposals for solar generation facilities with capacities greater than 20 MW were required to pay an application fee of $300.00 for each project that it intended to offer through the RFP. Respondents submitting proposals for PURPA qualifying facilities with capacities less than 20 MW were required to pay an application fee of $150.00 for each project that it intended to offer through the RFP. Application fees were only refunded to Respondents in the event that they either failed to obtain pre-qualification status or the RFP was terminated prior to its completion.

Respondents that did not submit owed application fees in-full prior to the remittance deadline outlined within the Enel X invoice (October 24, 2019) were disqualified from submitting proposals through the RFP. Out of the 23 Respondents that submitted Notice of Intent forms, six declined to continue forward in the RFP process and did not ultimately submit RFP application fees. In total, 17 Respondents submitted RFP application fees to Enel X.

The six Respondents that declined to post RFP application fees and withdrew from the RFP process noted a variety of reasons for their decisions – ranging from realization that their proposals did not conform to RFP requirements to simply deciding to pursue other transactional opportunities. Enel X requested additional detail from every Respondent that initially expressed interest in participating within the RFP and later declined, although Respondents often did not provide detailed reasoning(s) behind their withdrawal decisions. No Respondents were denied permission to participate further within the RFP process due to inability to post RFP application fees in a timely manner.

Pre-Bid Security Collection

All Respondents were required to post pre-bid credit in United States Dollars (“USD”). Respondents were allowed to either post a Letter of Credit or remit cash collateral to satisfy pre-bid credit requirements.

The pre-bid credit posting requirement for all Respondents was set at $1,500 per MW proposed. As an example, a Respondent submitting multiple proposals with a cumulative offer capacity of 200 MW would be required to post $300,000 in pre-bid security. Pre-bid credit posting amounts are unique to the projects being proposed – i.e. a Respondent proposing the same project via PPA and BTA arrangements did not need to post double the amount of pre-bid security.

Pre-bid credit posting requirements for Letters of Credit and cash deposits were detailed within the RFP document and posted on the Solicitation Website. Interest was not to be paid on any pre-bid credit provided.

Failure to provide a Pre-Bid Letter of Credit or a cash deposit would result in Respondent’s disqualification from submitting proposals within the RFP. Pre-bid credit for parties selected for award will be held through the execution of definitive agreements. Pre-bid credit for parties not selected for award will be returned following the conclusion of the Valid Proposal Duration (by June 30, 2020).

Of the 17 Respondents that submitted RFP application fees, 15 continued forward in the RFP process and posted required pre-bid security.

The two Respondents that did not post pre-bid security noted that they felt that their projects were not far along enough in development to bid given the pre-bid security conditions and anticipated timeline. No Respondents were denied permission to participate further within the RFP process due to inability to post required pre-bid security in a timely manner. Further, Respondents were able to make adjustments if needed to pre-bid security in advance of pre-qualification determinations should their intended offer plan within their Intent to Bid package change.

Pre-Qualification Statuses

Upon review by Enel X; a total of 15 Respondents were eligible to receive pre-qualification status and permission to offer proposals within the Consumers Energy RFP. Prior to the final determination and conveyance of the pre-qualification status of each Respondent, one of the 15 Respondents withdrew from the RFP process upon realization that they would not be able to submit a conforming proposal.

Ultimately, 14 Respondents received pre-qualification status on November 6, 2019, as detailed below:

Criteria	Value
Total Number of Pre-Qualified Respondents	14

Within the pre-qualification status emails from Enel X, Respondents were provided with a summary of the pre-bid security they posted, a maximum allowed aggregate offer capacity, an Enel X Solicitation Platform username and password, and a detailed Enel X Solicitation Platform user guide (proposal submittal guide).

Proposal Submissions

The proposal submission window opened for offers at 4:00 PM EPT on November 6, 2019 and was initially scheduled to close at 12:00 PM EPT on November 12, 2019. Proposals were expected from 14 pre-qualified Respondents, all of whom met each relevant RFP participation prerequisite and received authorization to submit proposals.

On the final day of the proposal submittal window, one of the 14 prequalified Respondents contacted Enel X and noted that they decided to withdraw from the RFP process, although they did not provide specific reason(s) for withdrawal when requested by Enel X. The remaining 13 pre-qualified Respondents had either already submitted proposals or expressed verbal or written intent to submit proposals.

Extension of Submission Window

On the day proposal submissions were due (November 12, 2019), two Respondents noted that they were unable to finalize the proposal submittal process prior to the close of the submittal portal at 12:00 PM EPT that day. The Respondents in question were able to upload their proposal documents to the solicitation platform, although they ran out of time before the final submittal confirmation was clicked through on the platform.

Given the sealed nature of the proposal submittal portal, the pre-qualification status of these Respondents, and the evidence of these Respondents' active efforts to submit their proposals through the solicitation platform, Enel X recommended to Consumers Energy that the proposal submittal window be extended to later in the day on November 12, 2019 to allow the remaining two Respondents to finalize their proposal submittals within the platform.

The Respondents in question did not gain any competitive advantage in completing the submittal of their sealed proposals later than others (still same day) nor were the Respondents that have submitted sealed proposals earlier in the day be disadvantaged.

Consumers Energy agreed to extend the proposal submittal window and all proposals were successfully submitted by 3:30 PM EPT on November 12, 2019.

Preliminary Solicitation Summary

Within one business day of the close of the proposal submittal window, Enel X prepared a preliminary, blind (all Respondent-identifying data removed) IRP Solicitation Summary containing the aggregate number of projects offered, the aggregate number of developers, aggregate MWs, highest bid price, and lowest bid price.

Enel X also incorporated a load weighted average price for BTA proposals given that low BTA price would be associated with smaller projects and therefore it would not be representative given the wide range of project capacities bid.

Enel X was instructed to further categorize the aggregate number of projects and total MWs only in the event that each category includes more than 1 project, by technology and whether the project is a Qualifying Facility (“QF”) under the Public Utility Regulatory Policy Act of 1978 (“PURPA”).

The following table details key components of the Preliminary Solicitation Summary prepared/provided to Consumers Energy on November 13, 2019:

Criteria	Value
Total Number of Respondents Submitting Proposals	13
Total Number of Proposals Submitted	49
BTA Proposals Submitted	24
PPA Proposals Submitted	25
Total Number of Submitted Projects	34
Number of PURPA QF (Up to 20 MW)	15
Total Number of Non-Solar Projects (Landfill Gas)	1
Number of Solar Generation Facilities (Greater than 20 MW)	19
Total Amount of Submitted Capacity (MW)	1,883.33
PURPA QF Capacity (MW)	222.08
Solar Generation Facilities (Greater than 20 MW) Capacity (MW)	1,661.25

Conclusion of Solicitation Phase

Enel X affirms that all remaining pre-qualified Respondents (excluding the withdrawing party) were able to successfully submit proposals within the Enel X Solicitation Platform. No pre-qualified Respondents were denied the ability to submit proposals or otherwise limited in their ability to submit proposals, apart from self-derived constraints (posted bid security, application fees, etc.).

Enel X also affirms that throughout the Solicitation Phase, no detail was provided or shared with Consumers Energy containing any Respondent-identifying information that could create any selection bias.

Evaluation Phase

The Evaluation Phase of the Consumers Energy RFP process spanned from November 13, 2019 through December 11, 2019, with primary components of the Evaluation Phase encompassing the initial screening of submitted proposals and the preparation and delivery of blind final evaluation results to Consumers Energy.

Initial Screening for Eligibility

Given the level of detail provided within the Consumers Energy RFP materials regarding proposal/project requirements and the full slate of Respondent prerequisite participation requirements, Enel X observed that Respondent proposals were naturally 'self-screened' through the RFP process for the most part. As highlighted by Respondent and project attrition seen through various RFP stages (Notice of Intent submission, RFP application fee posting, pre-bid credit posting, etc.), Respondents removed numerous proposals from the RFP process that did not meet various requirements or had been deemed infeasible.

Upon conducting its initial screening to determine proposal eligibility, Enel X noted that two submitted BTA proposals were invalid due to their proposed acquisition structure. The Respondent that submitted both BTA proposals that were deemed invalid was proposing that Consumers Energy acquire the proposal projects at the time the projects received a Notice to Proceed ("NTP"), at which point Consumers Energy would gain control of the projects and manage the construction process (versus acquiring said projects prior to COD as specified within the Consumers Energy RFP).

Enel X informed the submitting Respondent of the ineligibility of their submitted BTA proposals and the Respondent noted that they expected such an outcome given the non-conforming nature of their proposals. The Respondent in question also submitted standard, valid, PPA proposals and had intended to make another form of offer available under a quasi-BTA construct. No points of contention or arguments were raised regarding the determination of proposal validity.

No further proposals were removed from the Final Evaluation Results. While Enel X was afforded ability, at its discretion, to remove proposals from consideration due to any number of factors, it saw fit to present the most complete array of projects deemed eligible within its' evaluation results.

Requests for Clarification, Additional Proposal Details

Enel X issued multiple requests for clarification and/or additional proposal details from Respondents that submitted appropriate proposal forms with select fields denoted as either "TBD", "Confidential", or fields that were not entirely clear upon review. Requests for clarification were primarily focused on BTA proposals, with such requests primarily related to obtaining costs to remedy noted technical specification exceptions and land lease cost estimates.

All requests for clarification and/or additional proposal details were related to proposal contents not including bid price (either Net Levelized Energy Payment for PPA proposals or Total Build Transfer Pricing for BTA proposals). At no point were any Respondents allowed to change and/or modify their bid price (in the event a Respondent would attempt to do so while providing clarifying proposal data).

Additionally, Respondents were not allowed to modify any proposal terms that would alter the conforming nature of their proposals. Respondents were not given any advantage or disadvantage as a result of the request for clarification process. By requesting and obtaining additional proposal details, Enel X was simply able to develop a clearer picture of each submitted proposal.

Enel X requested that all Respondents in receipt of requests for clarification provide request proposal detail(s) as soon as possible. Despite efforts to obtain/fulfill all outstanding requests prior to the internal (between Consumers Energy and Enel X) process milestone to circulate blind final evaluation results on December 2, 2019, Enel X received the last of the requested clarifying data on December 5, 2019.

Redlines to BTA and PPA Agreements

Enel X received BTA and PPA contract redlines from Respondents, although given that the Consumers Energy RFP afforded Respondents with the ability to redline provided contracts and negotiate contractual terms, Enel X elected not to disqualify or remove any Respondent on the basis of presented redlines given that such redlines could potentially be remedied during due diligence negotiations.

While the Consumers Energy RFP provided examples of material modifications that would not be considered, a comprehensive list of unacceptable contractual changes was not provided. Further, Enel X elected not to qualify or determine the acceptability of redlined contract changes on behalf of Consumers Energy or pursue contractual discussions related to certain redlined changes.

As stated in Section 9.3 of the Consumers Energy RFP, Consumers Energy's commencement of and participation in negotiations with Respondents selected for preliminary award shall not be construed as a commitment to execute a contract. Only execution of a definitive agreement by both Consumers Energy and the Respondent on mutually acceptable terms will constitute a "winning proposal". As such, Respondents and Consumers Energy are afforded opportunity to establish mutually acceptable forms of contract during due diligence discussions.

Blind Final Evaluation Results

During the Final Evaluation Results phase of the Consumers Energy RFP process, Enel X developed ranked lists of each eligible/valid PPA and BTA proposals utilizing the PPA and BTA Economic Models developed by Consumers Energy.

Within the blind Evaluation Results ranking sheets, Enel X included an individual proposal line item for each valid proposal variant. As an example, if a Respondent submitted the same project and proposal format with an offered cost for a 20-yr term and an offered cost for a 25-yr term, each offered variant would be evaluated and each would receive its own proposal identifier and line item within the ranked list. Enel X would make note of proposals bearing mutually-exclusive award consideration under such scenarios.

Through the conclusion of the Solicitation Phase and during both the Evaluation and Selection Phases, Respondents did not have any insight into the total number of Respondents that had submitted proposals into the RFP, the total number, quantity, or type of projects offered, or the ranking of their submitted proposals against others. As detailed within Section 9.2 of the Consumers Energy RFP, Respondents were aware of the method of which proposals would be evaluated.

Per Section 9.2 of the Consumers Energy RFP; Proposals were to be evaluated based on projected costs, projected commodity value, and value added criteria. The economic evaluation would consist of first calculating the total projected cost of a proposal. Second, the projected value of the commodities provided by the proposed project would be subtracted from the total projected cost to calculate a net cost for the proposal. Lastly, the value-added criteria will be subtracted from the net cost to determine the final, adjusted net cost of the proposal. Projects were then be ranked based on their adjusted net cost.

Enel X was to provide two separate blind rankings of proposals, one consisting of PPA proposals and another consisting of BTA proposals. Consumers Energy intended to make its selections based on the blind ranking. Consumers Energy would then select winning proposals in order of lowest to highest adjusted net costs with regards to both blind rankings.

Amendments Made to BTA Economic Model

Per guidance provided by Consumers Energy within its response to Question 31 within the Questions and Answers log, the following adjustments were made to the BTA Economic Model:

- **Investment Tax Credit (“ITC”) Rate**
  - Rather than utilize the BTA Economic Model default ITC rate to evaluate proposal economics, the actual to-be-claimed ITC rate provided by each respondent was input and utilized.

- **Land Lease Cost, Payment Estimates**
  - Respondents were provided with an option to convey their land lease payments, cost structure, and terms instead of being evaluated based on the Economic Model default land lease rate of $5.00 kW-yr with a 2.5% annual escalator. If land lease values were provided by Respondents and were able to be normalized for the purpose of evaluations, such values were used within the Economic Model.

Land Lease Considerations (for BTA Proposals)

Enel X produced two versions of the BTA evaluation results to present two means of calculating/applying costs for proposals using land leases or easements; one of which utilized the default land lease rate of $5.00 kW-yr with a 2.5% annual escalator for all projects with land leases/easements and another that utilized Respondent-provided lease/easement details where-available (not all Respondents provided/disclosed specific lease/easement terms or provided such values that could be normalized for the purpose of uniform evaluation). Provided land terms varied between Respondent proposals – with differing term lengths, lease structures, hybrid land arrangements (utilizing a combination of owned land, leased land, and easements), and variety of costs included.

Within the BTA evaluation results not including actual lease terms, the default land lease rate was used to normalize lease payment evaluation and application across proposals with land lease or easement structures given the variation in Respondent noted lease and easement payment terms, contract durations, and contract optionality.

Enel X provided two versions of the BTA evaluation results so that Consumers Energy could determine whether or not selections should/would be made on the basis of assumed land lease/easement rates or forecasted, proposal-specific, land lease/easement rates.

Amendments Made to Results Summary Table Templates

The format of the standard Results Summary tables as provided within the PPA and BTA Economic Models were modified by Enel X on the primary ranking sheets to include two additional columns to designate whether or not a proposal has received price adjustments.

Price adjustments were only made to BTA proposals and were attributed to either identified non-reimbursable transmission/network costs not contained within the BTA acquisition price and/or the costs to remedy Respondent-noted technical exceptions. The following table illustrates how a BTA proposal's total acquisition price would be adjusted based on identified costs to remedy/address technical exceptions:

Criteria	Value
Respondent BTA Total Acquisition Price	$100,000,000.00
Respondent Costs to Remedy Technical Exemptions	$1,000,000.00
BTA Cost Used to Evaluate, Rank Proposal	$101,000,000.00

Within the version of the BTA Results Summary table that utilized Respondent-provided land lease costs/values, Enel X added four additional columns to designate/describe the details of land arrangements and the source of the land value(s) used for the purpose of evaluating proposals.

Distribution of Blind Evaluation Results

On December 5, 2019, Enel X obtained responses to the last remaining requests for clarification and additional information. A final version of the Blind Evaluation Results file was developed and circulated shortly thereafter on December 5, 2019 as well.

Within the email message to which the final iteration of the blind Evaluation Results file was attached, Enel X detailed the nature of the requests for clarification and additional proposal detail received and the proposals to which such information were attributed. As with the initial, interim, version of the blind Evaluation Results file, no Respondent-specific data was conveyed nor were any details provided between the interim and final distribution of the Evaluation Results that would reveal any Respondent-identifying data.

Enel X also made note of any mutually-exclusive proposal variants.

The final Evaluation Results file distributed on December 5, 2019 immediately superseded the interim Evaluation Results file distributed on December 2, 2019 and served as the basis for ultimate selections.

Members of the Consumers Energy and Enel X teams then took part in a conference call on December 6, 2019 to review general questions regarding the RFP process, the process of obtaining requests for clarification and proposal details, and the process of updating the initial, interim, Evaluation Results file. During the December 6, 2019 conference call, no Respondent or project specific details were revealed or provided and Consumers Energy did not convey its provisional award selections or intent. Per an internal process milestone schedule, Consumers Energy planned to convey its award selections to Enel X on or by December 11, 2019. Award selections were also to be conveyed in writing via email rather than verbally on a conference call.

Final Blind Evaluation Results Tables

As contained within the PPA and BTA Economic Models, blind Evaluation Results tables were provided to Consumers Energy by Enel X via email on December 5, 2019.The adjusted net cost of the best-ranked PPA proposal was ($20.62)/MWh and the adjusted net cost of the best-ranked BTA proposal was ($15.94)/MWh.

Enel X affirms that throughout the Evaluation Phase, no detail was provided or shared with Consumers Energy containing any Respondent-identifying information that could create any selection bias.

Selection Phase

The Selection Phase of the Consumers Energy RFP process primarily consisted of an independent, internal, review of the Final Evaluation Results conducted by Consumers Energy, which culminated in Consumer Energy's conveyance to Enel X of proposals selected from the Final Evaluation Results for provisional award.

Consumers Energy utilized the final, updated, version of the PPA and BTA Proposal Rankings distributed by Enel X on December 5, 2019 to make its provisional award selections. Consumers Energy ultimately elected to make BTA award selections utilizing the secondary BTA ranking sheet that incorporated Respondent-provided, proposal-specific, land lease/easement cost estimates.

Consumers Energy Confirmation of Selected Proposals

On December 11, 2019, Consumers Energy informed Enel X via email of the proposal(s) it had selected for provisional award.

A total of cumulative capacity 145.00 MW was selected for provisional award from PPA proposal(s) and a total cumulative capacity of 199.00 MW was selected for provisional award from BTA proposal(s).

Enel X Reveal of Selected Blind Proposals

On December 13, 2019, Enel X provided Consumers Energy with details of the proposals it selected from the Final Evaluation Results, including the identities of submitting Respondents and associated projects.

Summary tables were provided via email to Consumers Energy on December 13, 2019 for both PPA and BTA provisional award selections (marking the first time that Consumers Energy has been made privy to proposal details):

Enel X provided Consumers Energy with a cataloged inventory of all relevant proposal materials submitted by the Respondents associated with each selected proposal. Enel X provided such information within zip folders via email and redacted/withheld any information regarding other projects/proposals submitted by selected Respondents that are not being chosen for provisional award.

Enel X did not provide Consumers Energy with a complete catalog of all Respondent proposals, as Consumers Energy should remain effectively blind to the proposals not selected for provisional award (should replacement selections need to be made).

Identification of Selected Proposals on Final Blind Evaluation Results Tables

Previously distributed Evaluation Results tables were updated to reveal the project names and developers of the now-selected proposals and recirculated to Consumers Energy.

Provisional Award Notices

On December 13, 2019, Enel X distributed provisional award status notices via email to each of the 13 Respondents that submitted proposals into the Consumers Energy RFP. The provisional award status notices for each Respondent contained a listing of the proposals they submitted and a notation regarding whether or not the corresponding proposal had been selected for a provisional award. Respondents were not able to see any proposal data associated with other Respondents, any detail regarding the ranking of their submitted proposals against selected proposals, or any details regarding number of proposals awarded or the detail of such.

Respondents were advised that, pursuant to Subsection 9.2 of the Consumers Energy RFP; Consumers Energy has made provisional award selections and will soon initiate a due diligence review of selected proposals and Respondents.

Included within the provisional award status notifications was language that affirmed that a Respondent's selection for a "provisional award" does not mean that the Respondent is guaranteed a contract with Consumers Energy. Furthermore, Consumers Energy's commencement of, and participation in, due diligence reviews and contract negotiations shall not be construed as a commitment to execute a contract with a Respondent. Only execution of a definitive agreement by both Consumers Energy and the Respondent on mutually acceptable terms will constitute a "winning proposal". Additionally, Respondents not selected for provisional awards were reminded that they must hold proposal terms, and pricing, valid until June 30, 2020 ("Valid Proposal Duration") in the event Consumers Energy elects to pursue alternate proposals.

Additional verbiage within the provisional award notices advised Respondents that if they are selected and they and Consumers Energy cannot agree to acceptable terms within the schedule set forth in Subsection 3.6 of the Consumers Energy RFP, Consumers Energy reserves the right to eliminate them from further consideration and potentially enter negotiations with other projects in the blind Evaluation Results shortlist(s).

Respondents were encouraged to utilize the Consumers Energy agreements in their current form and to limit modifications. Respondents were informed that Consumers Energy will not accept material modifications to the provided template contracts, including but not limited to, essential provisions such as, early termination, indemnity, limitation of liability, commercial operation date and regulatory disallowance.

All Respondents were informed that if Respondents selected for provisional award are later eliminated from award consideration, and it becomes necessary for Consumers Energy to select one or more alternate proposals, such selection(s) are intended to be made within Q1 of 2020.

Enel X affirms that throughout the Selection Phase, no detail was provided or shared with Consumers Energy containing any Respondent-identifying information that could create any selection bias.

Independent Administrator Conclusions

Analysis of RFP Process

From the onset of the Consumers Energy RFP process, sharp focus was placed on ensuring the fairness and transparency of the RFP process – across all of its primary phases. Enel X was involved in all primary facets of the RFP process from August 1, 2019 onward and concludes that each primary facet of the RFP process was conducted and managed professionally, fairly, and without bias.

During the Preparation Phase, great efforts were made to engage RFP stakeholders and ensure that stakeholder feedback, comments, questions, and concerns were addressed as much as able.

During the Solicitation Phase, a very wide net, via advertisements and email notices, was cast to ensure a broad market canvasing of the RFP and open-access to all RFP materials by all parties. Across a number of participation prerequisites, all Respondents were held to a uniform standard and provided support to ensure that they could meet such standards. Through the proposal submittal process, all Respondents utilized a standard suite of proposal forms and submitted such forms through the same, central, location on the Enel X Solicitation Platform.

During the Evaluation Phase, Respondents were contacted to clarify proposal attributes and all Respondent proposals were evaluated and scored utilizing the same tools, which had been made available to all parties during the RFP process so that they could see exactly how their proposals would be assessed. During the development of blind Evaluation Results files, Consumers Energy was restricted from accessing any Respondent or project identifying data to ensure that selections could be made in a completely blind environment with no Respondent bias.

During the Selection Phase, Consumers Energy followed a formal process to convey its blind selections prior to receipt of details regarding selected proposals from Enel X. Enel X notified all Respondents of their provisional award statuses in a uniform fashion while providing clear detail and guidance regarding the nature of provisional awards.

Throughout the RFP process, Consumers Energy was effectively limited in its involvement and Enel X, as the Independent Administrator, was able to manage the RFP process without undue influence.

Attestations

Enel X attests that the following conditions were satisfied:

- The solicitation process was fair;
- The screening factors and weights were applied consistently and comparably to all bids;
- All reasonably available data and information necessary in order for a potential bidder to submit a bid was provided;

- The IA was provided with or given access to all data, information and models relevant to the solicitation process in order to permit full and timely scoring, testing and verification of assumptions, models, inputs, outputs, and results;
- The confidentiality claims and concerns between the IA and the Owner were resolved in a manner that preserved confidentiality as necessary, yet permitted dissemination and consideration of all information reasonably necessary for the bidding process to be conducted fairly and thoroughly; and
- Evaluations were performed consistent with criteria and methods stated under the solicitation protocol document.

Conflict of Interest Declarations

Enel X contends that there were not real conflicts of interest present with the solicitation Respondents. Consumers Energy and Enel X did, however, receive concerns from a Respondent regarding the Respondent's perceived conflict of interest in having Enel X serve as the Independent Administrator given the presence of other Enel Group entities within the renewable energy development community.

Enel X affirmed to all Respondents that it is a distinct and independent operating company from Enel Green Power (a renewable energy developer). Further, Enel X stated that it does not have a renewable energy development arm or ability/intent to participate within the Consumers Energy RFP process. While both separate Enel entities share part of a common name and holding company, there are no overlapping components between each entity and absolutely no preferential treatment(s), reciprocal or otherwise, given between Enel X and Enel Green Power.

Enel X, as the Independent Administrator, does not, did not, and will not share the sensitive information provided by Respondents with affiliates of Enel or other Enel Group companies. Further, Enel X has conducted and managed all facets of the Consumers Energy RFP process with the utmost transparency while ensuring that all Respondents are treated fairly, equitably, and without bias (real or perceived).

Enel X takes both our partners' and Respondents' confidentiality and the establishment of a level playing field for all Respondents seriously and has detailed protocols to ensure that all confidential information remains confidential and that all administered RFPs afford equal opportunity to every Respondent.

Enel X employees must observe an obligation of confidentiality and neutrality while performing Independent Administrator services, and may not disclose confidential information outside of Enel X (including employees of other companies of the Enel Group, respondents, other customers, etc.) or provide preferential treatment to any respondent. For this purpose, Enel X has established:

- Physical separation of databases belonging to different companies within the Enel group;
- Regulation of access to the Enel X Solicitation Website; and
- Signature of a specific confidentiality and neutrality declaration by each Enel X employee providing these services in order to define a general duty of confidentiality and neutrality in the performance of their activities.

To further enforce such positions, Enel X also offered all Respondents the opportunity to establish a non-disclosure agreement (NDA). Ultimately, two Respondents established NDAs with Enel X to alleviate perceived concerns and no Respondents declined to participate due to any noted conflict of interest (be it with Enel X or other perceived Respondents).

Recommended RFP Process Improvements

Enel X recommends that Consumers Energy considers the following potential RFP process improvements for future solicitations:

1. Migration from sealed bid proposal submittal process to a live online reverse auction structure. Enel X contends that migration to a live online reverse auction structure will drive multiple RFP process efficiencies, enable greater competition between Respondents, and greatly simplify the evaluation and selection processes.

2. Establishment of a formal process for managing award selections when top ranked proposals are for fractional quantities of sought totals. In the event a top ranked proposal is not for the full quantity solicited by Consumers Energy, Enel X recommends that a process be developed that would afford Consumers Energy with greater flexibility to select proposals that would afford desired quantities.

3. Establishment of locked, forced-response, proposal documents. Enel X recommends that proposal documents be revised and that select fields within proposal documents contain logic that would require Respondents to enter certain values in order to complete.

4. Front-load the collection and review of various proposal documents that are not price-sensitive. Enel X recommends that more proposal-related documents and details be collected from Respondents in advance of the proposal submittal deadline to afford the IA with additional time to review proposal details and to limit the amount of required documents and detail due from Respondents on a single day.

5. Consider extending the RFP timeline (from RFP issuance to proposal submittal deadline). Enel X would recommend releasing the RFP notice and documents further in advance of proposal submittal deadlines.

6. Create a standard process for which macro-level aggregate proposal details may be shared with Respondents. Following the conveyance of provisional awards, many Respondents have requested insight into the level of response seen within the RFP, detail regarding the rank of their proposals, and information relative to the range of pricing seen across BTA and PPA proposals submitted.

7. Consider having Respondents agree-in-principle to accepting an established list of contract terms. Enel X suggests implementing measures to make the contracting process less open-ended and potentially requiring Respondents to formally agree to utilize various components of the provided contract templates in the forms provided.

8. Create contingency RFP schedules and allow the IA greater discretion to enact scheduling adjustments as-needed/warranted. In the event unforeseen circumstances are encountered or should Enel X, Respondents, Consumers Energy, or Stakeholders require additional time during certain periods within

the RFP process, Enel X would recommend that the select scheduling adjustments be allowed and that contingency schedules be created for select RFP tasks.

9. Establishment of Evaluation Models with additional fixed/default calculation/ranking mechanisms. Given the bespoke nature of long-term renewable contracts, both PPAs and BTAs, Enel X recommends that the Consumers Energy Evaluation Models be revised to further limit the amount of Respondent-provided costs, particularly those that are ultimately accounted for outside of proposal prices that are captured within the models.

10. Revisit Valid Proposal Duration length (proposal hold-open period) and pre-bid security return process. Enel X recommends considering a near-term hold-open period and an earlier return of pre-bid security so that Respondents not selected from contract award may seek other transactional opportunities (which could allow Respondents to attribute less risk to participating within the RFP process).

MPSC Staff Audit

On January 7, 2020, Enel X and Consumers Energy hosted an MPSC Staff audit within a conference room at the Consumers Energy annex in Lansing, MI. The purpose of the audit was to provide MPSC Staff with full visibility into all facets of the RFP, allow MPSC staff to conduct an independent review of RFP processes, the competitive bidding dynamic, proposal rankings, and selections/results while making both the Enel X and Consumers Energy RFP teams accessible for any questions. All MPSC Staff members present signed Non-Disclosure Agreements regarding the information to-be-shared during the audit and no supporting audit materials were allowed outside of the assigned audit conference room.

The audit session began with Consumers Energy providing MPSC Staff with an overview of its RFP and supporting processes, a summary of proposals and capacities selected for provisional award, and a summary of near-term milestones relating to the current RFP and future IRP solicitations. Following its initial remarks, the Consumers Energy team vacated the audit conference room, leaving just the Enel X team and MPSC Staff. Enel X then gave an overview of the RFP materials provided in support of the audit and detailed its involvement in the RFP process as the Independent Administrator.

Enel X made available to MPSC Staff hard and electronic copies of all RFP materials, process documents, response summaries, proposal submissions, proposal evaluations, proposal scoresheets/rankings, and its Draft IA Report. Enel X clearly labeled any confidential materials that were to be kept from Consumers Energy, all of which were removed and hidden in advance of Consumers Energy's re-entrance to the audit conference room. Confidential materials included summaries containing pertinent details of all proposals received as well as all proposal documents submitted by RFP Respondents.

Enel X answered any MPSC Staff questions related to RFP processes and procedures and provided guidance on the materials it made available in support of the audit. In the event questions arose regarding Consumers Energy-developed RFP templates, models, or methodologies, Enel X contacted the Consumers Energy team and requested that they re-enter the audit conference room to address such questions. After the Consumers Energy team addressed open questions, they would then exit the audit conference room to allow MPSC Staff to continue its review of the full scope of RFP materials and documents, including those that were to remain confidential to Consumers Energy.

Prior to the conclusion of the audit, the Consumers Energy team re-entered the audit conference room and provided closing remarks regarding the next-steps within the RFP process and the audit was adjourned. Enel X then collected and securely destroyed all sensitive and confidential materials that were made available in support of the audit. The audit itself ran from approximately 9:00 AM EPT to approximately 3:00 PM EPT on January 7, 2020.

Enel X affirms that during the MPSC Staff Audit no materials were provided to or shared with Consumers Energy containing any Respondent-identifying information apart from the previously circulated details related to proposals selected for provisional award. Further, Enel X affirms that no sensitive RFP materials or proposal documents were ever removed from the audit conference room by parties in attendance.

CRA Charles River Associates

DELIVERED VIA EMAIL

CRA No. D32430-00

March 12, 2021

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Manager Electricity Supply Contracts
Consumers Energy
1 Energy Plaza
Jackson, MI 49201

Deborah Moss
Attorney
Consumers Energy
1730 Rhode Island Avenue, NW Suite 1007
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Re: Consumers Energy's 2021 Requests for Proposals for Natural Gas Fired Generating Assets

Dear Ms. Moss and Mr. Smith:

In late 2020, Consumers Energy ("CEC" or "Consumers") retained CRA International d/b/a Charles River Associates, Inc. ("CRA") to assist in the design, administration and bid evaluation of a Request for Proposals ("RFP") process. This RFP was designed to identify MISO LRZ7 capacity resources in support of CEC's needs identified in association with CEC's Integrated Resource Plan ("IRP"). The following Opinion Letter provides CRA's review of the RFP and CRA's recommendation on assets to advance for further due diligence.

CRA is an economics and management consulting firm, founded in 1964, and headquartered in Boston, Massachusetts. CRA has worked on behalf of a wide range of stakeholders in the design, management and execution of structured sales and procurement processes conducted both through formal auctions and RFPs. CRA clients in these engagements have included regulated utilities, government agencies, state and federal regulators as well as cooperatives and private corporations. CRA has directly managed or monitored structured processes that have resulted in over $25 billion worth of transactions in the United States and abroad. CRA has worked with a broad set of utilities on resource planning and capacity strategy decisions. In addition, CRA has extensive experience in managing default service procurement processes for utilities in the Midwest and mid-Atlantic United States and currently manages the default service procurement processes for FirstEnergy's Ohio Utilities, FirstEnergy's Pennsylvania Utilities, Duke Energy Ohio, Duquesne Light Company and AES Ohio. All such procurements have been reviewed and approved by the respective utility commissions or regulatory bodies with oversight over the processes. CRA advises energy sector clients on asset valuation for the purposes of acquisition and divestiture and senior members of CRA's team have testified as experts on sales and procurement process design before regulatory agencies and in civil litigation.

TIMELINE FOR THE RFP PROCESS

The RFPs was issued January 6, 2021. CRA and Consumers had developed an extensive marketing list and parties that may have had an interest in the RFP were notified by CRA through the RFP's email account. CRA conducted a bidder Information Session approximately 1 week after the launch on January 14, 2021. Prospective bidders were required to provide a Notice of Intent, Bilateral Confidentiality Agreement and Pre-Qualification Application due on January 20, 2021. Final bid proposals ("Proposals") were due on February 26, 2021.

RFP bids selected for advancement to a potential Definitive Agreement phase were made consistent with the CEC guidance on the timing and magnitude of their potential capacity needs.

OVERVIEW OF THE RFP DESIGN AND EXECUTION

Prior to issuing the RFP in January 2021, CRA worked with the CEC team to define the process objectives and requirements. CEC advised CRA that in order to ensure reliable, adequate capacity supplies to meet customer needs, they intended to acquire one or more existing, natural gas fired combined cycle or combustion turbine generating assets that at a minimum, would meet established industry-wide reliability and performance criteria for electric generation facilities. CEC had identified a total need of approximately 2,000 MW on a MISO Unforced Capacity ("UCAP") basis and would consider individual facilities sized between 50 and 1,400 MW in support of those needs. The physical location of such facilities was required to be in the portion of the lower peninsula of the State of Michigan that is serviced by MISO and/or be capable of being classified as MISO local resource zone 7 ("LRZ7") capacity. CEC sought proposals for the purchase of 100% ownership of the facility or individual units at the specified facility.

CRA worked with CEC to prepare the RFP documentation, ensure the product requested was clearly defined and clearly specify the evaluation criteria in the RFP documentation.

CRA managed the outreach to potential bidders interested in the process. CRA and CEC mutually identified existing assets within LRZ7 that appeared to meet the minimum requirements for participation in the RFP. In addition, CRA included in the outreach other parties that had expressed interest in being informed about opportunities like the CEC RFP and parties that had been active in past RFPs managed by CRA. Representatives from this broad set of potential bidders were contacted via electronic mail notices informing them of the RFP and relevant due dates. In addition, as noted above, CEC and CRA conducted a public information session presentation to inform interested parties about the process and approach.

CRA maintained a public Information Website that warehoused all key documents related to the RFP process. Through that Information Website, interested parties could submit questions and comments related to the process, the documents or the RFP requirements. In addition, CEC published a press release related to this RFP on its website and CRA ran trade press advertising in Megawatt Daily on January 8, 2021. All qualified parties were allowed to submit Proposals in the RFP.

Five (5) potential bidders submitted pre-qualification applications by the prequalification deadline. All bidders offering facilities that met the stated qualification requirements for the RFP were prequalified. Three (3) of the five applicants were not approved for participation. Non qualifiers included one participant offering a facility or facilities that did not meet the requirement that projects to be in service and operational as of the issuance date of the RFP. Others offered resources that did not meet the location requirement as the facilities did not currently qualify as MISO LRZ7 and were not capable of reclassifying as a LRZ7 resource.

CRA notified all parties that submitted a prequalification application of their pre-qualification status following a review of the materials submitted. Non-qualifiers were informed of the reason their applications were not approved to provide them an opportunity to clarify or address any issues leading to non-qualification.

Four (4) facilities were bid into the RFP across the prequalifying bidders. Bids including two (2) combined cycle projects and two (2) combustion turbine facilities. In total, the facilities bid into the RFP had approximately 2,000 MW of unforced capacity (“UCAP”). Figure 1 Illustrates the location and size of each of the facilities bid by prequalified bidders.

Figure 1: Project Location, Technology and ICAP

Plant	Technology	MW ICAP
Covert	Gas CCGT	1,176 MW
Kalamazoo	Gas SCGT	75 MW
Livingston	Gas SCGT	156 MW
Dearborn	Gas CCGT + SCGT	770 MW

Projects were not necessarily offered into the RFP as separate, stand-alone, a-la-carte offerings; some were tied into bundles of assets offered as a package or not at all. In addition, a portion of the physical capacity bid is designated to serve existing offtake agreements that would transfer with the facilities under some of the bundled acquisition scenarios. Table 1 reflects project capacity and does not cover the different acquisition options offered by the bidders.

Table 1: Proposal ICAP UCAP by and Pricing by Technology

							Price	
Bidder	**Facility**	**State**	**City**	**Type**	**ICAP**	**UCAP***	**$ (000s)**	**$/kW (ICAP)**
Segreto Power Holdings	Covert	MI	Covert Township	CC	1,176	1,058	$850,000	$722.79
CMS Enterprises	Dearborn Industrial Generation	MI	Dearborn	CC	770	729	$473,000	$614.29
CMS Enterprises	Livingston	MI	Gaylord	CT	132	127	$29,000	$219.70
CMS Enterprises	Kalamazoo	MI	Comstock	CT	75	71	$23,000	$306.67
					2,153	**1,985**	**$1,375,000**	**$638.64**

* Reported UCAP reflects 2020 rating

Table 2 illustrates the installed capacity ("ICAP") for project packages bid into the RFP along with representative pricing. In cases where there were multiple projects are included in the same asset bundle, the cost per kW reflects the capacity weighted average price.

Table 2: Bid Options and Representative Pricing

					Price	
Bid	**Bidder**	**Facilities**	**ICAP**	**UCAP***	**$ (000s)**	**$/kW (ICAP)**
1	Segreto Power Holdings	Covert	1,176	1,058	$850,000	$722.79
2	CMS Enterprises	Dearborn, Livingston, Kalamazoo **	977	927	$525,000	$537.36
3	CMS Enterprises	Livingston, Kalamazoo	207	198	$52,000	$251.21
4	CMS Enterprises	Livingston	132	127	$29,000	$219.70
5	CMS Enterprises	Kalamazoo	75	71	$23,000	$306.67

* Reported UCAP reflects 2020 rating

** Under CMS's 977 MW proposal (2), Consumers would be required to accept certain offtake agreements along with the assets identified

CRA evaluated the economics and other scoring considerations related to each Proposal independent of CEC or any CEC affiliates. CRA reserved the right, in its sole and exclusive discretion, to reject any and all Proposals on the grounds that such Proposal did not conform to the terms and conditions of the RFP or on the grounds that the bidder did not comply with provisions of the RFP.

PROPOSAL REVIEW AND EVALUATION

After the Proposals were received, CRA as the RFP Manager:

1. Reviewed all Proposals and screened the responses to ensure they conformed with all response requirements;
2. Conducted follow up conference calls with representatives of each company submitting a conforming Proposal to clarify asset-specific issues with the information provided;
3. Evaluated all conforming Proposals according to the pre-specified criteria as outlined in Appendix F of the RFP document;

4. Managed bidder communication and outreach; and
5. Confirmed the winning Proposals and the short list of assets to include for advancement to the Definitive Agreement phase

CRA reviewed all Proposals that met pre-determined qualifying criteria set forth in the RFP documentation and evaluated each based on certain pre-specified evaluation criteria. Generating assets offered into the RFP were evaluated based on:

1. Estimated Net Present Value ("NPV") for the project over a 25-year period
2. Asset age and reliability
3. Asset-specific benefits and risk factors

Consumers was not directly involved in the evaluation of Proposals nor were they made aware of bidder identities as part of the RFP FAQ process. Upon receipt of bids, CEC was provided general information about the level of interest in the RFP, the MW of capacity offered by asset type and the general level of prices received. During the bid evaluation, CEC was only made generally aware of CRA's progress. There were no bidder-specific issues encountered during the review that required policy or technical guidance from CEC subject matter experts. Because of CEC's limited involvement, CRA is issuing this Opinion Letter to provide a final overview and evaluation of the RFP and its execution and to confirm that the RFP were performed in a transparent, fair and nondiscriminatory manner.

EVALUATION AND SCORING

As noted above, there were three (3) components of proposal scoring. Weightings were as follows:

1. Estimated NPV – 500 Points
2. Asset age and reliability – 250 Points
3. Asset-specific benefits and risks – 250 Points

The proposals were reviewed and points were awarded consistent with the predetermined evaluation criteria. Proposals were rank ordered in accordance with the total number of points awarded for each scoring category.

In cases where bids reflected bundles of assets, the NPV score was calculated by summing the total NPV dollars across the assets in the bid and dividing by the total MW UCAP for assets included in the bid. Reliability and asset specific scores for bundles were calculated using the individual asset level scores for those categories weighted by each facility's UCAP. Effectively, packages of assets were scored based on the UCAP weighted value of the scores for each asset included in the bid. Table 3 shows the scoring of each option based on the predetermined evaluation methodology and criteria. Bids in Table 3 have been sorted by their rank order of point awarded.

Table 3: Points Awarded to Proposals by Scoring Category

Bid	Bidder	Facilities	UCAP	NPV	Reliability	Asset Specific	Total
1	Segreto Power Holdings	Covert	1,058	435	180	(30)	585
2	CMS Enterprises	Dearborn, Livingston, Kalamazoo	927	189	139	(25)	303
4	CMS Enterprises	Livingston	127	201	80		281
3	CMS Enterprises	Livingston, Kalamazoo	198	142	98		240
5	CMS Enterprises	Kalamazoo	71	36	130		166

Note that the NPV value in Table 3 are scores and not actual NPV dollar values or NPV dollar per MW UCAP values.

CRA recommends that CEC advance both bids 1 and 2 through to the Definitive Agreement phase for final due diligence. These bids include all of the underlying assets bid into the RFP. The terms of CMS's bid 2 require that CEC take on certain offtake agreements that reduce the available capacity acquired through the transaction. However, acquiring the offtakes will allow CEC to secure resources at or near their projected resource requirements. The total unadjusted UCAP of the projects recommended for advancement is 1,985 however, over 900 MW are tied into offtakes through the 2023/24 planning year. Offtake commitments decline over time from 2023/24 forward. Approximately half of the offtakes expire by the 2025/26 MISO Planning Year and obligations continue to step down from that point forward.

CEC was offered the option to acquire only the CMS peaking units without any associated contracts. That offering showed a lower NPV per MW UCAP for CEC. In addition, under that structure, CEC would secure only approximately 207 MW (ICAP). And because 207 MW are peaking units, they would provide less energy than a package that includes Dearborn. By acquiring the entire package of assets, by 2025, CEC would have access to over 450 MW of ICAP in support of customer needs.

Each individual project recommended for advancement realized a positive NPV valuation as a standalone asset. Dearborn's standalone NPV value was calculated with an adjustment for the total CMS offtake commitments. Aside from Dearborn other individual assets offered in the CMS package bid were available on a standalone basis not tied to the acceptance any offtake. As a result, the individual valuation of Dearborn reflected the full adjustment for all offtakes in the CMS portfolio.

Assets were scored on the age metric based on a capacity weighted average of the in service date for each unit at the facility. All facilities bid into the RFP were of similar vintage, ranging in age from 17 to 22 years of service time. All assets were categorized as low risk or no risk based on the recent and projected forced outage rates versus the MISO wide averages for their asset classes.

Two projects received asset specific deductions. The Covert facility is currently a PJM asset and not a MISO asset. While physically located in MISO LRZ7, the asset was MISO interconnected from its in-service date through May 31, 2016. If selected to move forward in this RFP process Covert will begin the process of re-interconnecting the Facility into MISO by applying to enter MISO's 2021 Definitive Planning Phase ("DPP") Cycle in July. All physical infrastructure from Covert's previous MISO interconnection remains in place, which is expected to minimize costs and streamline the interconnection study process. The Seller has initiated congestion studies related to a potential return to MISO and no significant concerns have been identified or raised. The Seller also indicated they anticipate they would be responsible for the lion's share of the costs associated with a reintegration with MISO. While there is limited cost or technology exposure for CEC associated with this asset, the need to return to MISO does raise certain regulatory and timeline challenges. As a result, the facility did receive a deduction in its score related to this uncertainty.

Dearborn Industrial Generation ("DIG") also received an asset specific score adjustment due to potential uncertainty around delivered fuel costs related to ongoing rate proceedings for DTE. Because the magnitude and timing of any adjustment to fuel delivery charges is uncertain at this time, modeling a specific cost increase was considered too speculative to include in the NPV scoring. CRA preferred that the NPV modeling allow for an apples to apples comparison of the economics of the assets. Instead, 25 points were deducted from DIG's score under the asset specific category, which would roughly equate to a 5.0% to 7.5% increase in delivered fuel cost.

Under the process rules, CRA was tasked with identifying the asset or portfolio of assets best suited to meet CEC's capacity needs consistent with CEC resource planning requirements. CEC's current resource needs are anticipated to be up to approximately 2,000 MW (UCAP) in aggregate. Based on these resource requirements and the economics of the facilities bid into the RFP, CRA recommends advancing each of the four (4) projects bid into the RFP for more detailed due diligence and review.

CONCLUSION

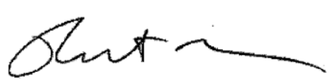
CRA recommends that CEC advance the shortlisted assets through to the Definitive Agreement phase of the process. Process bidders were asked to hold bids firm for 6 months from the proposal due date to facilitate the Definitive Agreement process and the associated due diligence. CRA's recommendations on advancement to the Definitive Agreement phase is subject to any potential resource constraints CEC may have with respect to initiating commercial negotiations with multiple counterparties in advance of that date. Through this Opinion Letter, CRA confirms that the process used to solicit and evaluate Proposals was executed consistent with the process as defined and envisioned by CEC and CRA at the outset. In CRA's opinion, the RFP was performed in a transparent, fair and nondiscriminatory manner and no bidder was given an undue advantage or preference in the RFP.

CRA has included Attachments to this Opinion Letter that provide the project level scoring for all bids received in the process along with recommendations for the projects that should be advanced to the Definitive Agreement phase for further due diligence efforts.

Please do not hesitate to contact me should you have any questions.

Sincerely,

Charles River Associates



Robert Lee
Vice President

cc:

Exhibits:

- Attachment 1: Detailed Proposal Scoring

CRA Charles River Associates

Attachment 1: Detailed Proposal Scoring

Assets highlighted in green are assets recommended for down selection to the Definitive Agreement phase.

Table A1 – Scoring Summary

	Bidder	Facilities	UCAP	NPV	Reliability	Asset Specific	Total
1	Segreto Power Holdings	Covert	1,058	435	180	(30)	585
2	CMS Enterprises	Dearborn, Livingston, Kalamazoo	927	189	139	(25)	303
3	CMS Enterprises	Livingston, Kalamazoo	198	142	98		240
4	CMS Enterprises	Livingston	127	201	80		281
5	CMS Enterprises	Kalamazoo	71	36	130		166

Table A2 – NPV Summary

	Bidder	Facilities	ICAP	UCAP*	NPV $	NPV per MW (UCAP)	Points
1	Segreto Power Holdings	Covert	1,176	1,058	921,020,773	870,536	435
2	CMS Enterprises	Dearborn, Livingston, Kalamazoo	977	927	350,269,583	377,853	189
3	CMS Enterprises	Livingston, Kalamazoo	207	198	56,244,572	284,063	142
4	CMS Enterprises	Livingston	132	127	51,157,856	402,818	201
5	CMS Enterprises	Kalamazoo	75	71	5,086,716	71,644	36

Table A3 – Facility Level NPV Summary

Facility	NPV $(M)	NPV $(000s) Per MW UCAP
Covert	$921.0	$870.5
Dearborn Industrial Generation	$294.0	$403.3
Livingston	$51.2	$402.8
Kalamazoo	$5.1	$71.6

Table A4 – Reliability Scoring

RFP Date 1/6/2021

		In Service Date	ICAP	Recent XEFORd	Projected EFORd	Years in Service	Point Deduct Age	Resource Class	MISO Class EFORd	Risk Category	Point Deduct Risk	Score
Covert	Unit 1	11/16/03	392	1.2%	1.1%							
Covert	Unit 2	12/12/03	392	1.9%	1.7%							
Covert	Unit 3	1/17/04	392	0.8%	1.0%							
	TOTAL	**12/15/03**	**1,176**	**1.3%**	**1.3%**	**17**	**(70)**	**CC**	**5.7%**	**No Risk**	**0**	**180**
DIG	Unit 1	7/1/99	160	1.1%	1.6%							
DIG	Unit 2	7/1/01	203	0.3%	0.9%							
DIG	Unit 3	7/1/01	203	0.8%	0.8%							
DIG	Unit 4	7/1/01	203	0.1%	0.4%							
	TOTAL	**1/30/01**	**770**	**0.5%**	**0.9%**	**20**	**(100)**	**CC**	**5.7%**	**No Risk**	**0**	**150**
Livingston	Unit 1	7/1/99	33	3.2%	8.3%							
Livingston	Unit 2	7/1/99	33	5.4%	5.6%							
Livingston	Unit 3	7/1/99	33	3.3%	7.0%							
Livingston	Unit 4	7/1/99	33	2.7%	3.0%							
	TOTAL	**7/1/99**	**132**	**3.7%**	**6.0%**	**22**	**(120)**	**CT**	**4.7%**	**Low Risk**	**(50)**	**80**
Kalamazoo	Unit 1	7/1/99	75	1.4%	1.5%							
	TOTAL	**7/1/99**	**75**	**1.4%**	**1.5%**	**22**	**(120)**	**CT**	**4.7%**	**No Risk**	**0**	**130**

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
______________________________________	)	

EXHIBITS

OF

NORMAN J. KAPALA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Capital Expenditures and Operations and Maintenance Expenses
January 1, 2020 through May 31, 2031
($000)

Case No.: U-21090
Exhibit No.: A-50 (NJK-1)
Page: 1 of 6
Witness: NJKapala
Date: June 2021

Generation Operations - Capital Scenarios

Base Case - Retire Karn 1&2 5/31/2023, Campbell 1&2 & Karn 3&4 5/31/2031, Campbell 3 5/31/2039

Line No.	(a) Karn 1 & 2 Total	(b) Karn 3 & 4 Total	(c) Karn 3 & 4 Separation Total	(d) Campbell 1 Total	(e) Campbell 2 Total	(f) Campbell 3 Total	(g) Campbell 3 Separation Total
1	$ 13,294	$ 82,598	$ 28,651	$ 57,878	$ 79,020	$ 250,254	$ 64,146

Retire Karn Units 3 & 4 5/31/2023

Line No.	Karn 3 & 4 Total	Karn 3 & 4 Variance to Base Case	Karn 3 & 4 Separation Variance to Base Case
2	$ 6,950	$ (75,648)	$ (15,465)

Retire Karn Units 3 & 4 5/31/2025

Line No.	Karn 3 & 4 Total	Karn 3 & 4 Variance to Base Case	Karn 3 & 4 Separation Variance to Base Case
3	$ 19,611	$ (62,987)	$ (9,161)

Retire Campbell Unit 3 5/31/2025

Line No.	Campbell Unit 3 Total	Campbell Unit 3 Variance to Base Case	Campbell Unit 3 Separation Variance to Base Case
4	$ 59,641	$ (190,613)	$ (64,146)

Retire Campbell Unit 3 5/31/2032

Line No.	Campbell Unit 3 Total	Campbell Unit 3 Variance to Base Case	Campbell Unit 3 Separation Variance to Base Case
5	$ 218,854	$ (31,400)	$ (64,146)

Retire Campbell 1 5/31/2024

Line No.	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
6	$ 15,037	$ 79,273	$ (42,840)	$ 253

Retire Campbell 1 5/31/2025

Line No.	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
7	$ 21,926	$ 79,020	$ (35,951)	$ -

Retire Campbell 1 5/31/2026

Line No.	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
8	$ 23,831	$ 79,020	$ (34,046)	$ -

Retire Campbell 1 5/31/2028

Line No.	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
9	$ 43,436	$ 79,020	$ (14,442)	$ -

1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).
3. Lines 1, 3 and 4 include costs at Campbell 3 through 2039.

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Generation Operations - Capital Scenarios

Line	(a)	(b)	(c)	(d)	(e)
	Retire Campbell 2 5/31/2024				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	
10	$ 58,200	$ 22,950	$ 322	$ (56,070)	
	Retire Campbell 2 5/31/2025				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	
11	$ 57,878	$ 32,446	$ -	$ (46,573)	
	Retire Campbell 2 5/31/2026				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	
12	$ 57,878	$ 33,746	$ -	$ (45,273)	
	Retire Campbell 2 5/31/2028				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	
13	$ 57,878	$ 60,687	$ -	$ (18,333)	
	Retire Campbell 1&2 5/31/2024				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Campbell 3 Variance to Base Case
14	$ 15,037	$ 22,950	$ (42,840)	$ (56,070)	$ -
	Retire Campbell 1&2 5/31/2025				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Campbell 3 Variance to Base Case
15	$ 21,926	$ 32,446	$ (35,951)	$ (46,573)	$ -
	Retire Campbell 1&2 5/31/2026				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Campbell 3 Variance to Base Case
16	$ 23,831	$ 33,746	$ (34,046)	$ (45,273)	$ -
	Retire Campbell 1&2 5/31/2028				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Campbell 3 Variance to Base Case
17	$ 43,436	$ 60,687	$ (14,442)	$ (18,333)	$ -

1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

($000)

Generation Operations - Major Maintenance Scenarios

Base Case - Retire Karn 1&2 5/31/2023, Campbell 1&2 & Karn 3&4 5/31/2031, Campbell 3 5/31/2039

	(a)	(b)	(c)	(d)	(e)
Line No.	Karn 1 & 2 Total	Karn 3 & 4 Total	Campbell 1 Total	Campbell 2 Total	Campbell 3 Total
1	$ 9,465	$ 11,050	$ 29,361	$ 28,814	$ 74,700

Retire Karn Units 3 & 4 5/31/2023

Line No.	Karn 3 & 4 Total	Karn 3 & 4 Variance to Base Case
2	$ 1,000	$ (10,050)

Retire Karn Units 3 & 4 5/31/2025

Line No.	Karn 3 & 4 Total	Karn 3 & 4 Variance to Base Case
3	$ 5,350	$ (5,700)

Retire Campbell Unit 3 5/31/2025

Line No.	Campbell Unit 3 Total	Campbell Unit 3 Variance to Base Case
4	$ 17,145	$ (57,555)

Retire Campbell Unit 3 5/31/2032

Line No.	Campbell Unit 3 Total	Campbell Unit 3 Variance to Base Case
5	$ 44,716	$ (29,984)

Retire Campbell 1 5/31/2024

Line No.	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
6	$ 14,845	$ 28,814	$ (14,516)	$ -

Retire Campbell 1 5/31/2025

Line No.	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
7	$ 17,247	$ 28,814	$ (12,114)	$ -

Retire Campbell 1 5/31/2026

Line No.	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
8	$ 18,666	$ 28,814	$ (10,696)	$ -

Retire Campbell 1 5/31/2028

Line No.	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
9	$ 23,262	$ 28,814	$ (6,100)	$ -

1. Excludes environmental costs related to SEEG and 316(b).
2. Lines 1, 3 and 4 include costs at Campbell 3 through 2039.

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Date: June 2021

Generation Operations - Major Maintenance Scenarios

Line	(a)	(b)	(c)	(d)	(e)
	Retire Campbell 2 5/31/2024				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	
10	$ 29,361	$ 14,189	$ -	$ (14,625)	
	Retire Campbell 2 5/31/2025				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	
11	$ 29,361	$ 15,428	$ -	$ (13,385)	
	Retire Campbell 2 5/31/2026				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	
12	$ 29,361	$ 16,629	$ -	$ (12,185)	
	Retire Campbell 2 5/31/2028				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	
13	$ 29,361	$ 22,387	$ -	$ (6,427)	
	Retire Campbell 1&2 5/31/2024				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Campbell 3 Variance to Base Case
14	$ 14,845	$ 14,189	$ (14,516)	$ (14,625)	$ -
	Retire Campbell 1&2 5/31/2025				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Campbell 3 Variance to Base Case
15	$ 17,247	$ 15,428	$ (12,114)	$ (13,385)	$ -
	Retire Campbell 1&2 5/31/2026				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Campbell 3 Variance to Base Case
16	$ 18,666	$ 16,629	$ (10,696)	$ (12,185)	$ -
	Retire Campbell 1&2 5/31/2028				
	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Campbell 3 Variance to Base Case
17	$ 23,262	$ 22,387	$ (6,100)	$ (6,427)	$ -

1. Excludes environmental costs related to SEEG and 316(b).

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Case No.: U-21090
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Page: 5 of 6
Witness: NJKapala
Date: June 2021

Generation Operations - Base O&M Retirement Scenarios

Base Case - Retire Karn 1&2 5/31/2023, Campbell 1&2 & Karn 3&4 5/31/2031, Campbell 3 5/31/2039

Line No.	(a) Karn 1 & 2 Total	(b) Karn 3 & 4 Total	(c) Campbell 1 Total	(d) Campbell 2 Total	(e) Campbell 3 Total
1	$ 86,987	$ 119,895	$ 110,877	$ 151,804	$ 574,054

Retire Karn Units 3 & 4 5/31/2023

Line No.	Karn 3 & 4 Total	Karn 3 & 4 Variance to Base Case
2	$ 27,693	$ (92,202)

Retire Karn Units 3 & 4 5/31/2025

Line No.	Karn 3 & 4 Total	Karn 3 & 4 Variance to Base Case
3	$ 46,675	$ (73,220)

Retire Campbell Unit 3 5/31/2025

Line No.	Campbell Unit 3 Total	Campbell Unit 3 Variance to Base Case
4	$ 141,264	$ (432,791)

Retire Campbell Unit 3 5/31/2032

Line No.	Campbell Unit 3 Total	Campbell Unit 3 Variance to Base Case
5	$ 341,242	$ (232,813)

Retire Campbell 1 5/31/2024

Line No.	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Campbell 3 Variance to Base Case
6	$ 39,791	$ 151,804	$ (71,086)	$ 9,334	$ 28,524

Retire Campbell 1 5/31/2025

Line No.	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Campbell 3 Variance to Base Case
7	$ 49,353	$ 151,804	$ (61,524)	$ 8,173	$ 26,953

Retire Campbell 1 5/31/2026

Line No.	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Campbell 3 Variance to Base Case
8	$ 59,106	$ 151,804	$ (51,771)	$ 6,983	$ 25,313

Retire Campbell 1 5/31/2028

Line No.	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Campbell 3 Variance to Base Case
9	$ 79,202	$ 151,804	$ (31,675)	$ 4,531	$ 21,990

1. Excludes environmental costs related to SEEG and 316(b).
2. Lines 1, 3 and 4 include costs at Campbell 3 through 2039.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Capital Expenditures and Operations and Maintenance Expenses
January 1, 2020 through May 31, 2031
($000)

Case No.: U-21090
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Witness: NJKapala
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Generation Operations - Base O&M Retirement Scenarios

Line	Scenario	(a) Campbell 1 Total	(b) Campbell 2 Total	(c) Campbell 1 Variance to Base Case	(d) Campbell 2 Variance to Base Case	(e) Campbell 3 Variance to Base Case
10	**Retire Campbell 2 5/31/2024**	$ 110,877	$ 14,189	$ 9,857	$ (137,616)	$ 38,029
11	**Retire Campbell 2 5/31/2025**	$ 110,877	$ 15,428	$ 8,626	$ (136,376)	$ 35,919
12	**Retire Campbell 2 5/31/2026**	$ 110,877	$ 16,629	$ 7,375	$ (135,176)	$ 33,759
13	**Retire Campbell 2 5/31/2028**	$ 110,877	$ 22,387	$ 4,785	$ (129,417)	$ 29,319
14	**Retire Campbell 1&2 5/31/2024**	$ 39,791	$ 54,534	$ (71,086)	$ (97,270)	$ 9,497
15	**Retire Campbell 1&2 5/31/2025**	$ 49,353	$ 67,618	$ (61,524)	$ (84,186)	$ 8,989
16	**Retire Campbell 1&2 5/31/2026**	$ 59,106	$ 80,964	$ (51,771)	$ (70,840)	$ 8,439
17	**Retire Campbell 1&2 5/31/2028**	$ 79,202	$ 108,461	$ (31,675)	$ (43,343)	$ 7,331

1. Excludes environmental costs related to SEEG and 316(b).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
Exhibit No.: A-51 (NJK-2)

Witness: NJKapala
Date: June 2021

Generation Operations - Capital - Base Retirement Case

Base Case - Retire Karn 1&2 5/31/2023, Campbell 1&2 & Karn 3&4 5/31/2031, Campbell 3 5/31/2039

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Year	Karn 1/2 Total	Karn 3/4 Total	Campbell 1 Total	Campbell 2 Total	Campbell 3 Total
1	2020	7,176	8,679	10,025	9,268	12,860
2	2021	2,859	4,172	3,493	13,512	19,576
3	2022	2,135	15,416	7,300	5,257	17,125
4	2023	1,124	10,072	7,215	9,472	20,767
5	2024		9,775	9,753	11,252	35,781
6	2025		10,134	2,550	7,800	30,179
7	2026		9,900	3,300	4,420	29,053
8	2027		8,950	4,050	6,845	30,563
9	2028		2,000	3,500	7,394	4,400
10	2029		2,000	3,879	2,500	11,750
11	2030		1,000	2,564	1,050	4,650
12	2031		500	250	250	2,400
13	2032					2,750
14	2033					11,750
15	2034					5,400
16	2035					3,650
17	2036					4,650
18	2037					2,400
19	2038					550
20	2039					
21	Total	$ 13,294	$ 82,598	$ 57,878	$ 79,020	$ 250,254

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
Exhibit No.: A-51 (NJK-2)

Witness: NJKapala
Date: June 2021

Generation Operations - Capital - Karn 3&4 Early Retirement Case

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Karn 3&4 5/31/2023					**Retire Karn 3 & 4 5/31/2025**			
Line No.	Year	Karn 3&4 Total	Karn 1&2 ariance to Base Ca:	Karn 3&4 Variance to Base Case	Karn 3 & 4 Separation Variance to Base Case	Year	Karn 3&4 Total	Karn 1&2 ariance to Base Ca:	Karn 3&4 Variance to Base Case	Karn 3 & 4 Separation Variance to Base Case
1	2020	5,500	-	(3,179)	-	2020	8,679	-	-	-
2	2021	750	-	(3,422)	-	2021	6,012	-	1,840	(667)
3	2022	500	-	(14,916)	(13,675)	2022	2,370	-	(13,046)	(7,204)
4	2023	200	-	(9,872)	(1,790)	2023	1,850	-	(8,222)	(1,290)
5	2024	-	-	(9,775)	-	2024	500	-	(9,275)	-
6	2025	-	-	(10,134)	-	2025	200	-	(9,934)	-
7	2026	-	-	(9,900)	-	2026	-	-	(9,900)	-
8	2027	-	-	(8,950)	-	2027	-	-	(8,950)	-
9	2028	-	-	(2,000)	-	2028	-	-	(2,000)	-
10	2029	-	-	(2,000)	-	2029	-	-	(2,000)	-
11	2030	-	-	(1,000)	-	2030	-	-	(1,000)	-
12	2031	-	-	(500)	-	2031	-	-	(500)	-
13	Total	$ 6,950	$ -	$ (75,648)	$ (15,465)	Total	$ 19,611	$ -	$ (62,987)	$ (9,161)

Note:
1. Cost of removal has not been included.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
Exhibit No.: A-51 (NJK-2)

Witness: NJKapala
Date: June 2021

Generation Operations - Capital - Campbell 3 Early Retirement Cases

Retire Campbell 3 5/31/2025

Line No.	(a) Year	(b) Campbell 3 Total	(c) Campbell 3 Variance to Base Case	(d) Campbell Unit 3 Separation Variance to Base Case
1	2020	12,860	0	-
2	2021	18,397	(1,179)	-
3	2022	12,885	(4,240)	-
4	2023	8,993	(11,774)	-
5	2024	6,039	(29,742)	-
6	2025	467	(29,712)	-
7	2026	-	(29,053)	-
8	2027	-	(30,563)	-
9	2028	-	(4,400)	(6,780)
10	2029	-	(11,750)	(14,341)
11	2030	-	(4,650)	(28,683)
12	2031	-	(2,400)	(14,341)
13	2032	-	(2,750)	-
14	2033	-	(11,750)	-
15	2034	-	(5,400)	-
16	2035	-	(3,650)	-
17	2036	-	(4,650)	-
18	2037	-	(2,400)	-
19	2038	-	(550)	-
20	2039	-	-	-
21	Total	$ 59,641	$ (190,613)	$ (64,146)

Retire Campbell 3 5/31/2032

(e) Year	(f) Campbell 3 Total	(g) Campbell 3 Variance to Base Case	(h) Campbell Unit 3 Separation Variance to Base Case
2020	12,860	0	-
2021	19,576	-	-
2022	17,125	-	-
2023	20,767	-	-
2024	35,781	-	-
2025	30,179	-	-
2026	29,053	-	-
2027	30,563	-	-
2028	4,400	-	(6,780)
2029	8,750	(3,000)	(14,341)
2030	4,650	-	(28,683)
2031	2,400	-	(14,341)
2032	2,750	-	-
2033	-	(11,750)	-
2034	-	(5,400)	-
2035	-	(3,650)	-
2036	-	(4,650)	-
2037	-	(2,400)	-
2038	-	(550)	-
2039	-	-	-
Total	$ 218,854	$ (31,400)	$ (64,146)

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
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($000)

Case No.: U-21090
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Witness: NJKapala
Date: June 2021

Generation Operations - Capital - Campbell 1 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Campbell 1 5/31/2024					**Retire Campbell 1 5/31/2025**			
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
1	2020	9,644	9,268	(381)	-	2020	9,989	9,268	(36)	-
2	2021	3,293	13,541	(200)	29	2021	3,293	13,512	(200)	-
3	2022	1,050	5,257	(6,250)	-	2022	3,810	5,257	(3,490)	-
4	2023	800	9,696	(6,415)	224	2023	3,784	9,472	(3,431)	-
5	2024	250	11,252	(9,503)	-	2024	800	11,252	(8,953)	-
6	2025	-	7,800	(2,550)	-	2025	250	7,800	(2,300)	-
7	2026	-	4,420	(3,300)	-	2026	-	4,420	(3,300)	-
8	2027	-	6,845	(4,050)	-	2027	-	6,845	(4,050)	-
9	2028	-	7,394	(3,500)	-	2028	-	7,394	(3,500)	-
10	2029	-	2,500	(3,879)	-	2029	-	2,500	(3,879)	-
11	2030	-	1,050	(2,564)	-	2030	-	1,050	(2,564)	-
12	2031	-	250	(250)	-	2031	-	250	(250)	-
13	Total	$ 15,037	$ 79,273	$ (42,840)	$ 253	Total	$ 21,926	$ 79,020	$ (35,951)	$ -

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Campbell 1 5/31/2026					**Retire Campbell 1 5/31/2028**			
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
14	2020	9,989	9,268	(36)	-	2020	10,025	9,268	-	-
15	2021	3,293	13,512	(200)	-	2021	3,493	13,512	-	-
16	2022	3,810	5,257	(3,490)	-	2022	7,300	5,257	-	-
17	2023	4,073	9,472	(3,141)	-	2023	7,215	9,472	-	-
18	2024	1,616	11,252	(8,137)	-	2024	9,753	11,252	-	-
19	2025	800	7,800	(1,750)	-	2025	2,550	7,800	-	-
20	2026	250	4,420	(3,050)	-	2026	2,050	4,420	(1,250)	-
21	2027	-	6,845	(4,050)	-	2027	800	6,845	(3,250)	-
22	2028	-	7,394	(3,500)	-	2028	250	7,394	(3,250)	-
23	2029	-	2,500	(3,879)	-	2029	-	2,500	(3,879)	-
24	2030	-	1,050	(2,564)	-	2030	-	1,050	(2,564)	-
25	2031	-	250	(250)	-	2031	-	250	(250)	-
26	Total	$ 23,831	$ 79,020	$ (34,046)	$ -	Total	$ 43,436	$ 79,020	$ (14,442)	$ -

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
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($000)

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Generation Operations - Capital - Campbell 2 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Campbell 2 5/31/2024					**Retire Campbell 2 5/31/2025**			
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
1	2020	10,025	8,861	-	(407)	2020	10,025	9,219	-	(49)
2	2021	3,530	11,739	37	(1,773)	2021	3,493	13,271	-	(241)
3	2022	7,300	1,300	-	(3,957)	2022	7,300	5,107	-	(150)
4	2023	7,500	800	285	(8,672)	2023	7,215	3,800	-	(5,672)
5	2024	9,753	250	-	(11,002)	2024	9,753	800	-	(10,452)
6	2025	2,550	-	-	(7,800)	2025	2,550	250	-	(7,550)
7	2026	3,300	-	-	(4,420)	2026	3,300	-	-	(4,420)
8	2027	4,050	-	-	(6,845)	2027	4,050	-	-	(6,845)
9	2028	3,500	-	-	(7,394)	2028	3,500	-	-	(7,394)
10	2029	3,879	-	-	(2,500)	2029	3,879	-	-	(2,500)
11	2030	2,564	-	-	(1,050)	2030	2,564	-	-	(1,050)
12	2031	250	-	-	(250)	2031	250	-	-	(250)
13	Total	$ 58,200	$ 22,950	$ 322	$ (56,070)	Total	$ 57,878	$ 32,446	$ -	$ (46,573)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Campbell 2 5/31/2026					**Retire Campbell 2 5/31/2028**			
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to Base Case	Campbell 2 Variance to Base Case
14	2020	10,025	9,219	-	(49)	2020	10,025	9,268	-	-
15	2021	3,493	13,271	-	(241)	2021	3,493	13,512	-	-
16	2022	7,300	5,107	-	(150)	2022	7,300	5,257	-	-
17	2023	7,215	3,800	-	(5,672)	2023	7,215	9,472	-	-
18	2024	9,753	1,300	-	(9,952)	2024	9,753	11,252	-	-
19	2025	2,550	800	-	(7,000)	2025	2,550	4,800	-	(3,000)
20	2026	3,300	250	-	(4,170)	2026	3,300	3,170	-	(1,250)
21	2027	4,050	-	-	(6,845)	2027	4,050	3,706	-	(3,139)
22	2028	3,500	-	-	(7,394)	2028	3,500	250	-	(7,144)
23	2029	3,879	-	-	(2,500)	2029	3,879	-	-	(2,500)
24	2030	2,564	-	-	(1,050)	2030	2,564	-	-	(1,050)
25	2031	250	-	-	(250)	2031	250	-	-	(250)
26	Total	$ 57,878	$ 33,746	$ -	$ (45,273)	Total	$ 57,878	$ 60,687	$ -	$ (18,333)

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
Exhibit No.: A-51 (NJK-2)

Witness: NJKapala
Date: June 2021

Generation Operations - Capital - Campbell 1 & 2 Early Retirement Cases

Retire Campbell 1&2 5/31/2024

Line No.	Year (a)	Campbell 1 Total (b)	Campbell 2 Total (c)	Campbell 1 Variance to Base Case (d)	Campbell 2 Variance to Base Case (e)
1	2020	9,644	8,861	(381)	(407)
2	2021	3,293	11,739	(200)	(1,773)
3	2022	1,050	1,300	(6,250)	(3,957)
4	2023	800	800	(6,415)	(8,672)
5	2024	250	250	(9,503)	(11,002)
6	2025	-	-	(2,550)	(7,800)
7	2026	-	-	(3,300)	(4,420)
8	2027	-	-	(4,050)	(6,845)
9	2028	-	-	(3,500)	(7,394)
10	2029	-	-	(3,879)	(2,500)
11	2030	-	-	(2,564)	(1,050)
12	2031	-	-	(250)	(250)
13	Total	$ 15,037	$ 22,950	$ (42,840)	$ (56,070)

Retire Campbell 1&2 5/31/2025

Year (f)	Campbell 1 Total (g)	Campbell 2 Total (h)	Campbell 1 Variance to Base Case (i)	Campbell 2 Variance to Base Case (j)
2020	9,989	9,219	(36)	(49)
2021	3,293	13,271	(200)	(241)
2022	3,810	5,107	(3,490)	(150)
2023	3,784	3,800	(3,431)	(5,672)
2024	800	800	(8,953)	(10,452)
2025	250	250	(2,300)	(7,550)
2026	-	-	(3,300)	(4,420)
2027	-	-	(4,050)	(6,845)
2028	-	-	(3,500)	(7,394)
2029	-	-	(3,879)	(2,500)
2030	-	-	(2,564)	(1,050)
2031	-	-	(250)	(250)
Total	$ 21,926	$ 32,446	$ (35,951)	$ (46,573)

Retire Campbell 1&2 5/31/2026

Line No.	Year (a)	Campbell 1 Total (b)	Campbell 2 Total (c)	Campbell 1 Variance to Base Case (d)	Campbell 2 Variance to Base Case (e)
14	2020	9,989	9,219	(36)	(49)
15	2021	3,293	13,271	(200)	(241)
16	2022	3,810	5,107	(3,490)	(150)
17	2023	4,073	3,800	(3,141)	(5,672)
18	2024	1,616	1,300	(8,137)	(9,952)
19	2025	800	800	(1,750)	(7,000)
20	2026	250	250	(3,050)	(4,170)
21	2027	-	-	(4,050)	(6,845)
22	2028	-	-	(3,500)	(7,394)
23	2029	-	-	(3,879)	(2,500)
24	2030	-	-	(2,564)	(1,050)
25	2031	-	-	(250)	(250)
26	Total	$ 23,831	$ 33,746	$ (34,046)	$ (45,273)

Retire Campbell 1&2 5/31/2028

Year (f)	Campbell 1 Total (g)	Campbell 2 Total (h)	Campbell 1 Variance to Base Case (i)	Campbell 2 Variance to Base Case (j)
2020	10,025	9,268	-	-
2021	3,493	13,512	-	-
2022	7,300	5,257	-	-
2023	7,215	9,472	-	-
2024	9,753	11,252	-	-
2025	2,550	4,800	-	(3,000)
2026	2,050	3,170	(1,250)	(1,250)
2027	800	3,706	(3,250)	(3,139)
2028	250	250	(3,250)	(7,144)
2029	-	-	(3,879)	(2,500)
2030	-	-	(2,564)	(1,050)
2031	-	-	(250)	(250)
Total	$ 43,436	$ 60,687	$ (14,442)	$ (18,333)

Notes:
1. Cost of removal has not been included.
2. Excludes environmental costs related to SEEG and 316(b).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Major Maintenance Expenses
January 1, 2020 through May 31, 2039
($000)

Generation Operations - Major Maintenance - Base Retirement Case

Base Case - Retire Karn 1&2 5/31/2023, remaining Units 5/31/2031

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Year	Karn 1/2 Total	Karn 3/4 Total	Campbell 1 Total	Campbell 2 Total	Campbell 3 Total
1	2020	1,576	1,000	10,105	2,393	1,672
2	2021	3,771	1,000	2,342	9,589	5,103
3	2022	3,292	1,000	1,826	1,711	4,208
4	2023	826	1,000	1,401	1,504	2,524
5	2024		1,000	2,397	1,008	12,954
6	2025		1,000	1,669	2,900	3,811
7	2026		1,000	1,780	1,761	1,661
8	2027		1,000	2,082	1,471	2,561
9	2028		1,000	2,303	1,582	1,831
10	2029		1,000	1,905	3,342	3,861
11	2030		800	1,252	1,253	1,911
12	2031		250	300	300	1,961
13	2032					15,331
14	2033					3,861
15	2034					1,711
16	2035					2,261
17	2036					1,851
18	2037					3,961
19	2038					1,361
20	2039					311
21	Total	$ 9,465	$ 11,050	$ 29,361	$ 28,814	$ 74,700

Notes:
1. Excludes environmental costs related to SEEG and 316(b).

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Consumers Energy Company
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Generation Operations - Major Maintenance - Karn 3&4 Early Retirement Case

Retire Karn 3&4 5/31/2023

Line No.	(a) Year	(b) Karn 3&4 Total	(c) Karn 3&4 Variance to base case
1	2020	300	(700)
2	2021	300	(700)
3	2022	300	(700)
4	2023	100	(900)
5	2024	-	(1,000)
6	2025	-	(1,000)
7	2026	-	(1,000)
8	2027	-	(1,000)
9	2028	-	(1,000)
10	2029	-	(1,000)
11	2030	-	(800)
12	2031	-	(250)
13	Total	$ 1,000	$ (10,050)

Retire Karn 3 & 4 5/31/2025

(d) Year	(e) Karn 3&4 Total	(f) Karn 3&4 Variance to base case
2020	1,000	-
2021	1,300	300
2022	1,450	450
2023	1,000	-
2024	450	(550)
2025	150	(850)
2026	-	(1,000)
2027	-	(1,000)
2028	-	(1,000)
2029	-	(1,000)
2030	-	(800)
2031	-	(250)
Total	$ 5,350	$ (5,700)

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Generation Operations - Major Maintenance - Campbell 3 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)	(f)
		Retire Campbell 3 5/31/2025			**Retire Campbell 3 5/31/2032**	
Line No.	Year	Campbell 3 Total	Campbell 3 Variance to base case	Year	Campbell 3 Total	Campbell 3 Variance to base case
1	2020	1,672	(0)	2020	1,672	(0)
2	2021	5,103	-	2021	5,103	-
3	2022	4,115	(93)	2022	4,208	-
4	2023	2,151	(373)	2023	2,524	-
5	2024	3,594	(9,360)	2024	12,954	-
6	2025	511	(3,300)	2025	3,811	-
7	2026	-	(1,661)	2026	1,661	-
8	2027	-	(2,561)	2027	2,561	-
9	2028	-	(1,831)	2028	1,831	-
10	2029	-	(3,861)	2029	3,861	-
11	2030	-	(1,911)	2030	1,911	-
12	2031	-	(1,961)	2031	1,961	-
13	2032	-	(15,331)	2032	661	(14,670)
14	2033	-	(3,861)	2033	-	(3,861)
15	2034	-	(1,711)	2034	-	(1,711)
16	2035	-	(2,261)	2035	-	(2,261)
17	2036	-	(1,851)	2036	-	(1,851)
18	2037	-	(3,961)	2037	-	(3,961)
19	2038	-	(1,361)	2038	-	(1,361)
20	2039	-	(311)	2039	-	(311)
21	Total	$ 17,145	$ (57,555)	Total	$ 44,716	$ (29,984)

Notes:
1. Excludes environmental costs related to SEEG and 316(b).

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Generation Operations - Major Maintenance - Campbell 1 Early Retirement Cases

Retire Campbell 1 5/31/2024

Line No.	(a) Year	(b) Campbell 1 Total	(c) Campbell 2 Total	(d) Campbell 1 Variance to base case	(e) Campbell 2 Variance to base case
1	2020	9,520	2,393	(585)	-
2	2021	2,020	9,589	(322)	-
3	2022	1,759	1,711	(67)	-
4	2023	1,146	1,504	(255)	-
5	2024	400	1,008	(1,997)	-
6	2025	-	2,900	(1,669)	-
7	2026	-	1,761	(1,780)	-
8	2027	-	1,471	(2,082)	-
9	2028	-	1,582	(2,303)	-
10	2029	-	3,342	(1,905)	-
11	2030	-	1,253	(1,252)	-
12	2031	-	300	(300)	-
13	Total	$ 14,845	$ 28,814	$ (14,516)	$ -

Retire Campbell 1 5/31/2025

(f) Year	(g) Campbell 1 Total	(h) Campbell 2 Total	(i) Campbell 1 Variance to base case	(j) Campbell 2 Variance to base case
2020	9,520	2,393	(585)	-
2021	2,020	9,589	(322)	-
2022	1,759	1,711	(67)	-
2023	1,401	1,504	-	-
2024	2,147	1,008	(250)	-
2025	400	2,900	(1,269)	-
2026	-	1,761	(1,780)	-
2027	-	1,471	(2,082)	-
2028	-	1,582	(2,303)	-
2029	-	3,342	(1,905)	-
2030	-	1,253	(1,252)	-
2031	-	300	(300)	-
Total	$ 17,247	$ 28,814	$ (12,114)	$ -

Retire Campbell 1 5/31/2026

Line No.	(a) Year	(b) Campbell 1 Total	(c) Campbell 2 Total	(d) Campbell 1 Variance to base case	(e) Campbell 2 Variance to base case
14	2020	9,520	2,393	(585)	-
15	2021	2,020	9,589	(322)	-
16	2022	1,759	1,711	(67)	-
17	2023	1,401	1,504	-	-
18	2024	2,397	1,008	-	-
19	2025	1,169	2,900	(500)	-
20	2026	400	1,761	(1,380)	-
21	2027	-	1,471	(2,082)	-
22	2028	-	1,582	(2,303)	-
23	2029	-	3,342	(1,905)	-
24	2030	-	1,253	(1,252)	-
25	2031	-	300	(300)	-
26	Total	$ 18,666	$ 28,814	$ (10,696)	$ -

Retire Campbell 1 5/31/2028

(f) Year	(g) Campbell 1 Total	(h) Campbell 2 Total	(i) Campbell 1 Variance to base case	(j) Campbell 2 Variance to base case
2020	10,105	2,393	-	-
2021	2,342	9,589	-	-
2022	1,826	1,711	-	-
2023	1,401	1,504	-	-
2024	2,397	1,008	-	-
2025	1,669	2,900	-	-
2026	1,780	1,761	-	-
2027	1,442	1,471	(640)	-
2028	300	1,582	(2,003)	-
2029	-	3,342	(1,905)	-
2030	-	1,253	(1,252)	-
2031	-	300	(300)	-
Total	$ 23,262	$ 28,814	$ (6,100)	$ -

Notes:
1. Excludes environmental costs related to SEEG and 316(b).

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Generation Operations - Major Maintenance - Campbell 2 Early Retirement Cases

(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Campbell 2 5/31/2024					**Retire Campbell 2 5/31/2025**			
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to base case	Campbell 2 Variance to base case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to base case	Campbell 2 Variance to base case
1	2020	10,105	3,094	-	702	2020	10,105	3,094	-	702
2	2021	2,342	7,960	-	(1,629)	2021	2,342	7,960	-	(1,629)
3	2022	1,826	1,580	-	(131)	2022	1,826	1,580	-	(131)
4	2023	1,401	1,254	-	(250)	2023	1,401	1,504	-	-
5	2024	2,397	300	-	(708)	2024	2,397	990	-	(18)
6	2025	1,669	-	-	(2,900)	2025	1,669	300	-	(2,600)
7	2026	1,780	-	-	(1,761)	2026	1,780	-	-	(1,761)
8	2027	2,082	-	-	(1,471)	2027	2,082	-	-	(1,471)
9	2028	2,303	-	-	(1,582)	2028	2,303	-	-	(1,582)
10	2029	1,905	-	-	(3,342)	2029	1,905	-	-	(3,342)
11	2030	1,252	-	-	(1,253)	2030	1,252	-	-	(1,253)
12	2031	300	-	-	(300)	2031	300	-	-	(300)
13	Total	$ 29,361	$ 14,189	$ -	$ (14,625)	Total	$ 29,361	$ 15,428	$ -	$ (13,385)

(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
		Retire Campbell 2 5/31/2026					**Retire Campbell 2 5/31/2028**			
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to base case	Campbell 2 Variance to base case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to base case	Campbell 2 Variance to base case
14	2020	10,105	3,094	-	702	2020	10,105	3,143	-	750
15	2021	2,342	7,960	-	(1,629)	2021	2,342	8,839	-	(750)
16	2022	1,826	1,580	-	(131)	2022	1,826	1,711	-	-
17	2023	1,401	1,504	-	-	2023	1,401	1,504	-	-
18	2024	2,397	1,240	-	232	2024	2,397	1,008	-	-
19	2025	1,669	950	-	(1,950)	2025	1,669	2,900	-	-
20	2026	1,780	300	-	(1,461)	2026	1,780	1,761	-	-
21	2027	2,082	-	-	(1,471)	2027	2,082	1,221	-	(250)
22	2028	2,303	-	-	(1,582)	2028	2,303	300	-	(1,282)
23	2029	1,905	-	-	(3,342)	2029	1,905	-	-	(3,342)
24	2030	1,252	-	-	(1,253)	2030	1,252	-	-	(1,253)
25	2031	300	-	-	(300)	2031	300	-	-	(300)
26	Total	$ 29,361	$ 16,629	$ -	$ (12,185)	Total	$ 29,361	$ 22,387	$ -	$ (6,427)

Notes:
1. Excludes environmental costs related to SEEG and 316(b).

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Generation Operations - Major Maintenance - Campbell 1 & 2 Early Retirement Cases

Retire Campbell 1&2 5/31/2024

(a) Line No.	Year	(b) Campbell 1 Total	(c) Campbell 2 Total	(d) Campbell 1 Variance to base case	(e) Campbell 2 Variance to base case
1	2020	9,520	3,094	(585)	702
2	2021	2,020	7,960	(322)	(1,629)
3	2022	1,759	1,580	(67)	(131)
4	2023	1,146	1,254	(255)	(250)
5	2024	400	300	(1,997)	(708)
6	2025	-	-	(1,669)	(2,900)
7	2026	-	-	(1,780)	(1,761)
8	2027	-	-	(2,082)	(1,471)
9	2028	-	-	(2,303)	(1,582)
10	2029	-	-	(1,905)	(3,342)
11	2030	-	-	(1,252)	(1,253)
12	2031	-	-	(300)	(300)
13	Total	$ 14,845	$ 14,189	$ (14,516)	$ (14,625)

Retire Campbell 1&2 5/31/2025

(f) Year	(g) Campbell 1 Total	(h) Campbell 2 Total	(i) Campbell 1 Variance to base case	(j) Campbell 2 Variance to base case
2020	9,520	3,094	(585)	702
2021	2,020	7,960	(322)	(1,629)
2022	1,759	1,580	(67)	(131)
2023	1,401	1,504	-	-
2024	2,147	990	(250)	(18)
2025	400	300	(1,269)	(2,600)
2026	-	-	(1,780)	(1,761)
2027	-	-	(2,082)	(1,471)
2028	-	-	(2,303)	(1,582)
2029	-	-	(1,905)	(3,342)
2030	-	-	(1,252)	(1,253)
2031	-	-	(300)	(300)
Total	$ 17,247	$ 15,428	$ (12,114)	$ (13,385)

Retire Campbell 1&2 5/31/2026

(a) Line No.	Year	(b) Campbell 1 Total	(c) Campbell 2 Total	(d) Campbell 1 Variance to base case	(e) Campbell 2 Variance to base case
14	2020	9,520	3,094	(585)	702
15	2021	2,020	7,960	(322)	(1,629)
16	2022	1,759	1,580	(67)	(131)
17	2023	1,401	1,504	-	-
18	2024	2,397	1,240	-	232
19	2025	1,169	950	(500)	(1,950)
20	2026	400	300	(1,380)	(1,461)
21	2027	-	-	(2,082)	(1,471)
22	2028	-	-	(2,303)	(1,582)
23	2029	-	-	(1,905)	(3,342)
24	2030	-	-	(1,252)	(1,253)
25	2031	-	-	(300)	(300)
26	Total	$ 18,666	$ 16,629	$ (10,696)	$ (12,185)

Retire Campbell 1&2 5/31/2028

(f) Year	(g) Campbell 1 Total	(h) Campbell 2 Total	(i) Campbell 1 Variance to base case	(j) Campbell 2 Variance to base case
2020	10,105	3,143	-	750
2021	2,342	8,839	-	(750)
2022	1,826	1,711	-	-
2023	1,401	1,504	-	-
2024	2,397	1,008	-	-
2025	1,669	2,900	-	-
2026	1,780	1,761	-	-
2027	1,442	1,221	(640)	(250)
2028	300	300	(2,003)	(1,282)
2029	-	-	(1,905)	(3,342)
2030	-	-	(1,252)	(1,253)
2031	-	-	(300)	(300)
Total	$ 23,262	$ 22,387	$ (6,100)	$ (6,427)

Notes:
1. Excludes environmental costs related to SEEG and 316(b).

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Date: June 2021

Generation Operations - Base O&M - Base Retirement Case

Base Case - Retire Karn 1&2 5/31/2023, remaining Units 5/31/2031

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Year	Karn 1/2 Total	Karn 3/4 Total	Campbell 1 Total	Campbell 2 Total	Campbell 3 Total
1	2020	23,474	7,492	7,971	11,021	23,362
2	2021	24,883	7,764	8,816	12,050	24,158
3	2022	25,243	7,903	9,027	12,343	25,242
4	2023	13,388	6,504	9,243	12,643	25,842
5	2024		11,267	9,467	12,954	26,463
6	2025		11,492	9,657	13,214	26,993
7	2026		11,722	9,850	13,478	27,532
8	2027		11,957	10,047	13,747	28,083
9	2028		12,196	10,248	14,022	28,645
10	2029		12,440	10,453	14,303	29,218
11	2030		12,688	10,662	14,589	29,802
12	2031		6,471	5,437	7,440	30,398
13	2032					31,006
14	2033					31,626
15	2034					32,259
16	2035					32,904
17	2036					33,562
18	2037					34,233
19	2038					34,918
20	2039					17,808
21	Total	$ 86,987	$ 119,895	$ 110,877	$ 151,804	$ 574,054

Notes:
1. Excludes environmental costs related to SEEG and 316(b).

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Generation Operations - Base O&M - Karn 3&4 Early Retirement Case

	(a)	(b)	(c)	(d)	(e)	(f)
		Retire Karn 3&4 5/31/2023			**Retire Karn 3 & 4 5/31/2025**	
Line No.	Year	Karn 3&4 Total	Karn 3&4 Variance to base case	Year	Karn 3&4 Total	Karn 3&4 Variance to base case
1	2020	8,486	995	2020	7,492	-
2	2021	7,492	(273)	2021	7,764	-
3	2022	7,764	(139)	2022	7,903	-
4	2023	3,951	(2,553)	2023	6,504	-
5	2024	-	(11,267)	2024	11,267	-
6	2025	-	(11,492)	2025	5,746	(5,746)
7	2026	-	(11,722)	2026	-	(11,722)
8	2027	-	(11,957)	2027	-	(11,957)
9	2028	-	(12,196)	2028	-	(12,196)
10	2029	-	(12,440)	2029	-	(12,440)
11	2030	-	(12,688)	2030	-	(12,688)
12	2031	-	(6,471)	2031	-	(6,471)
13	Total	$ 27,693	$ (92,202)	Total	$ 46,675	$ (73,220)

($000)

Generation Operations - Base O&M - Campbell 3 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)	(f)
		Retire Campbell 3 5/31/2025			**Retire Campbell 3 5/31/2032**	
Line No.	Year	Campbell 3 Total	Campbell 3 Variance to base case	Year	Campbell 3 Total	Campbell 3 Variance to base case
1	2020	23,362	-	2020	23,362	-
2	2021	24,158	-	2021	24,158	-
3	2022	25,242	-	2022	25,242	-
4	2023	25,842	-	2023	25,842	-
5	2024	26,463	-	2024	26,463	-
6	2025	16,196	(10,797)	2025	26,993	-
7	2026	-	(27,532)	2026	27,532	-
8	2027	-	(28,083)	2027	28,083	-
9	2028	-	(28,645)	2028	28,645	-
10	2029	-	(29,218)	2029	29,218	-
11	2030	-	(29,802)	2030	29,802	-
12	2031	-	(30,398)	2031	30,398	-
13	2032	-	(31,006)	2032	15,503	(15,503)
14	2033	-	(31,626)	2033	-	(31,626)
15	2034	-	(32,259)	2034	-	(32,259)
16	2035	-	(32,904)	2035	-	(32,904)
17	2036	-	(33,562)	2036	-	(33,562)
18	2037	-	(34,233)	2037	-	(34,233)
19	2038	-	(34,918)	2038	-	(34,918)
20	2039	-	(17,808)	2039	-	(17,808)
21	Total	$ 141,264	$ (432,791)	Total	$ 341,242	$ (232,813)

Notes:
1. Excludes environmental costs related to SEEG and 316(b).

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Generation Operations - Base O&M - Campbell 1 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Retire Campbell 1 5/31/2024						**Retire Campbell 1 5/31/2025**				
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to base case	Campbell 2 Variance to base case	Campbell 3 Variance to base case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to base case	Campbell 2 Variance to base case	Campbell 3 Variance to base case
1	2020	7,971	11,021	(0)	-	$ -	2020	7,971	11,021	(0)	-	$ -
2	2021	8,816	12,050	(0)	-	$ -	2021	8,816	12,050	(0)	-	$ -
3	2022	9,027	12,343	0	-	$ -	2022	9,027	12,343	0	-	$ -
4	2023	9,243	12,643	(0)	-	$ -	2023	9,243	12,643	(0)	-	$ -
5	2024	4,734	12,954	(4,733)	1,166	$ 1,588	2024	9,467	12,954	(0)	-	$ -
6	2025	-	13,214	(9,657)	1,189	$ 1,619	2025	4,829	13,214	(4,828)	1,189	$ 1,620
7	2026	-	13,478	(9,850)	1,213	$ 1,652	2026	-	13,478	(9,850)	1,213	$ 1,653
8	2027	-	13,747	(10,047)	1,237	$ 1,685	2027	-	13,747	(10,047)	1,238	$ 1,686
9	2028	-	14,022	(10,248)	1,262	$ 1,719	2028	-	14,022	(10,248)	1,262	$ 1,720
10	2029	-	14,303	(10,453)	1,287	$ 1,753	2029	-	14,303	(10,453)	1,288	$ 1,754
11	2030	-	14,589	(10,662)	1,313	$ 1,788	2030	-	14,589	(10,662)	1,313	$ 1,789
12	2031	-	7,440	(5,437)	669	$ 1,824	2031	-	7,440	(5,437)	670	$ 1,825
13	2032	-	-	-	-	$ 1,860	2032	-	-	-	-	$ 1,861
14	2033	-	-	-	-	$ 1,897	2033	-	-	-	-	$ 1,899
15	2034	-	-	-	-	$ 1,935	2034	-	-	-	-	$ 1,937
16	2035	-	-	-	-	$ 1,974	2035	-	-	-	-	$ 1,975
17	2036	-	-	-	-	$ 2,014	2036	-	-	-	-	$ 2,015
18	2037	-	-	-	-	$ 2,054	2037	-	-	-	-	$ 2,055
19	2038	-	-	-	-	$ 2,095	2038	-	-	-	-	$ 2,096
20	2039	-	-	-	-	$ 1,068	2039	-	-	-	-	$ 1,069
21	Total	$ 39,791	$ 151,804	$ (71,086)	$ 9,334	$ 28,524	Total	$ 49,353	$ 151,804	$ (61,524)	$ 8,173	$ 26,953

Notes:
1. Excludes environmental costs related to SEEG and 316(b).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Base O&M Expenses
January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
Exhibit No.: A-53 (NJK-4)
Page: 5 of 9
Witness: NJKapala
Date: June 2021

Generation Operations - Base O&M - Campbell 1 Early Retirement Cases

Retire Campbell 1 5/31/2026

Line No.	(a) Year	(b) Campbell 1 Total	(c) Campbell 2 Total	(d) Campbell 1 Variance to base case	(e) Campbell 2 Variance to base case	(f) Campbell 3 Variance to base case
1	2020	7,971	11,021	(0)	-	$ -
2	2021	8,816	12,050	(0)	-	$ -
3	2022	9,027	12,343	0	-	$ -
4	2023	9,243	12,643	(0)	-	$ -
5	2024	9,467	12,954	(0)	-	$ -
6	2025	9,657	13,214	0	-	$ -
7	2026	4,925	13,478	(4,925)	1,213	$ 1,652
8	2027	-	13,747	(10,047)	1,237	$ 1,685
9	2028	-	14,022	(10,248)	1,262	$ 1,718
10	2029	-	14,303	(10,453)	1,287	$ 1,753
11	2030	-	14,589	(10,662)	1,313	$ 1,788
12	2031	-	7,440	(5,437)	670	$ 1,823
13	2032	-	-	-	-	$ 1,860
14	2033	-	-	-	-	$ 1,897
15	2034	-	-	-	-	$ 1,935
16	2035	-	-	-	-	$ 1,974
17	2036	-	-	-	-	$ 2,013
18	2037	-	-	-	-	$ 2,053
19	2038	-	-	-	-	$ 2,095
20	2039	-	-	-	-	$ 1,068
21	Total	$ 59,106	$ 151,804	$ (51,771)	$ 6,983	$ 25,313

Retire Campbell 1 5/31/2028

Line No.	(g) Year	(h) Campbell 1 Total	(i) Campbell 2 Total	(j) Campbell 1 Variance to base case	(k) Campbell 2 Variance to base case	(l) Campbell 3 Variance to base case
1	2020	7,971	11,021	(0)	-	$ -
2	2021	8,816	12,050	(0)	-	$ -
3	2022	9,027	12,343	0	-	$ -
4	2023	9,243	12,643	(0)	-	$ -
5	2024	9,467	12,954	(0)	-	$ -
6	2025	9,657	13,214	0	-	$ -
7	2026	9,850	13,478	0	-	$ -
8	2027	10,047	13,747	0	-	$ -
9	2028	5,124	14,022	(5,124)	1,262	$ 1,719
10	2029	-	14,303	(10,453)	1,287	$ 1,754
11	2030	-	14,589	(10,662)	1,313	$ 1,789
12	2031	-	7,440	(5,437)	669	$ 1,824
13	2032	-	-	-	-	$ 1,861
14	2033	-	-	-	-	$ 1,898
15	2034	-	-	-	-	$ 1,936
16	2035	-	-	-	-	$ 1,975
17	2036	-	-	-	-	$ 2,014
18	2037	-	-	-	-	$ 2,055
19	2038	-	-	-	-	$ 2,096
20	2039	-	-	-	-	$ 1,069
21	Total	$ 79,202	$ 151,804	$ (31,675)	$ 4,531	$ 21,990

Notes:
1. Excludes environmental costs related to SEEG and 316(b).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Base O&M Expenses
January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
Exhibit No.: A-53 (NJK-4)
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Witness: NJKapala
Date: June 2021

Generation Operations - Base O&M - Campbell 2 Early Retirement Cases

Retire Campbell 2 5/31/2024

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to base case	Campbell 2 Variance to base case	Campbell 3 Variance to base case
1	2020	7,971	3,094	-	(7,926)	-
2	2021	8,816	7,960	-	(4,090)	-
3	2022	9,027	1,580	-	(10,763)	-
4	2023	9,243	1,254	-	(11,389)	-
5	2024	9,467	300	1,231	(12,654)	2,117
6	2025	9,657	-	1,255	(13,214)	2,159
7	2026	9,850	-	1,281	(13,478)	2,202
8	2027	10,047	-	1,306	(13,747)	2,246
9	2028	10,248	-	1,332	(14,022)	2,291
10	2029	10,453	-	1,359	(14,303)	2,337
11	2030	10,662	-	1,386	(14,589)	2,384
12	2031	5,437	-	707	(7,440)	2,431
13	2032	-	-	-	-	2,480
14	2033	-	-	-	-	2,530
15	2034	-	-	-	-	2,580
16	2035	-	-	-	-	2,632
17	2036	-	-	-	-	2,684
18	2037	-	-	-	-	2,738
19	2038	-	-	-	-	2,793
20	2039	-	-	-	-	1,424
21	Total	$ 110,877	$ 14,189	$ 9,857	$ (137,616)	$ 38,029

Retire Campbell 2 5/31/2025

	(g)	(h)	(i)	(j)	(k)	(l)
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to base case	Campbell 2 Variance to base case	Campbell 3 Variance to base case
1	2020	7,971	3,094	-	(7,926)	-
2	2021	8,816	7,960	-	(4,090)	-
3	2022	9,027	1,580	-	(10,763)	-
4	2023	9,243	1,504	-	(11,139)	-
5	2024	9,467	990	-	(11,965)	-
6	2025	9,657	300	1,255	(12,914)	2,159
7	2026	9,850	-	1,281	(13,478)	2,203
8	2027	10,047	-	1,306	(13,747)	2,247
9	2028	10,248	-	1,332	(14,022)	2,292
10	2029	10,453	-	1,359	(14,303)	2,337
11	2030	10,662	-	1,386	(14,589)	2,384
12	2031	5,437	-	707	(7,440)	2,432
13	2032	-	-	-	-	2,480
14	2033	-	-	-	-	2,530
15	2034	-	-	-	-	2,581
16	2035	-	-	-	-	2,632
17	2036	-	-	-	-	2,685
18	2037	-	-	-	-	2,739
19	2038	-	-	-	-	2,793
20	2039	-	-	-	-	1,425
21	Total	$ 110,877	$ 15,428	$ 8,626	$ (136,376)	$ 35,919

Notes:
1. Excludes environmental costs related to SEEG and 316(b).

($000)

Generation Operations - Base O&M - Campbell 2 Early Retirement Cases

Retire Campbell 2 5/31/2026

Line No.	(a) Year	(b) Campbell 1 Total	(c) Campbell 2 Total	(d) Campbell 1 Variance to base case	(e) Campbell 2 Variance to base case	(f) Campbell 3 Variance to base case
1	2020	7,971	3,094	-	(7,926)	-
2	2021	8,816	7,960	-	(4,090)	-
3	2022	9,027	1,580	-	(10,763)	-
4	2023	9,243	1,504	-	(11,139)	-
5	2024	9,467	1,240	-	(11,715)	-
6	2025	9,657	950	-	(12,263)	-
7	2026	9,850	300	1,281	(13,178)	2,203
8	2027	10,047	-	1,307	(13,747)	2,247
9	2028	10,248	-	1,333	(14,022)	2,292
10	2029	10,453	-	1,360	(14,303)	2,337
11	2030	10,662	-	1,387	(14,589)	2,384
12	2031	5,437	-	707	(7,440)	2,432
13	2032	-	-	-	-	2,480
14	2033	-	-	-	-	2,530
15	2034	-	-	-	-	2,581
16	2035	-	-	-	-	2,632
17	2036	-	-	-	-	2,685
18	2037	-	-	-	-	2,739
19	2038	-	-	-	-	2,793
20	2039	-	-	-	-	1,425
21	Total	$ 110,877	$ 16,629	$ 7,375	$ (135,176)	$ 33,759

Retire Campbell 2 5/31/2028

(g) Year	(h) Campbell 1 Total	(i) Campbell 2 Total	(j) Campbell 1 Variance to base case	(k) Campbell 2 Variance to base case	(l) Campbell 3 Variance to base case
2020	7,971	3,143	-	(7,878)	-
2021	8,816	8,839	-	(3,212)	-
2022	9,027	1,711	-	(10,632)	-
2023	9,243	1,504	-	(11,139)	-
2024	9,467	1,008	-	(11,946)	-
2025	9,657	2,900	-	(10,313)	-
2026	9,850	1,761	-	(11,717)	-
2027	10,047	1,221	-	(12,526)	-
2028	10,248	300	1,332	(13,722)	2,292
2029	10,453	-	1,359	(14,303)	2,338
2030	10,662	-	1,386	(14,589)	2,385
2031	5,437	-	707	(7,440)	2,433
2032	-	-	-	-	2,481
2033	-	-	-	-	2,531
2034	-	-	-	-	2,581
2035	-	-	-	-	2,633
2036	-	-	-	-	2,686
2037	-	-	-	-	2,739
2038	-	-	-	-	2,794
2039	-	-	-	-	1,425
Total	$ 110,877	$ 22,387	$ 4,785	$ (129,417)	$ 29,319

Notes:
1. Excludes environmental costs related to SEEG and 316(b).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Base O&M Expenses
January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
Exhibit No.: A-53 (NJK-4)

Witness: NJKapala
Date: June 2021

Generation Operations - Base O&M - Campbell 1 & 2 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Retire Campbell 1&2 5/31/2024						**Retire Campbell 1&2 5/31/2025**				
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to base case	Campbell 2 Variance to base case	Campbell 3 Variance to base case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to base case	Campbell 2 Variance to base case	Campbell 3 Variance to base case
1	2020	7,971	11,021	(0)	0	-	2020	7,971	11,021	(0)	0	-
2	2021	8,816	12,050	(0)	(0)	-	2021	8,816	12,050	(0)	(0)	-
3	2022	9,027	12,343	0	0	-	2022	9,027	12,343	0	0	-
4	2023	9,243	12,643	(0)	(0)	-	2023	9,243	12,643	(0)	(0)	-
5	2024	4,734	6,477	(4,733)	(6,477)	529	2024	9,467	12,954	(0)	(0)	-
6	2025	-	-	(9,657)	(13,214)	539	2025	4,829	6,607	(4,828)	(6,607)	540
7	2026	-	-	(9,850)	(13,478)	550	2026	-	-	(9,850)	(13,478)	551
8	2027	-	-	(10,047)	(13,747)	561	2027	-	-	(10,047)	(13,747)	562
9	2028	-	-	(10,248)	(14,022)	572	2028	-	-	(10,248)	(14,022)	573
10	2029	-	-	(10,453)	(14,303)	584	2029	-	-	(10,453)	(14,303)	585
11	2030	-	-	(10,662)	(14,589)	595	2030	-	-	(10,662)	(14,589)	597
12	2031	-	-	(5,437)	(7,440)	607	2031	-	-	(5,437)	(7,440)	609
13	2032	-	-	-	-	619	2032	-	-	-	-	621
14	2033	-	-	-	-	632	2033	-	-	-	-	633
15	2034	-	-	-	-	644	2034	-	-	-	-	646
16	2035	-	-	-	-	657	2035	-	-	-	-	659
17	2036	-	-	-	-	670	2036	-	-	-	-	672
18	2037	-	-	-	-	684	2037	-	-	-	-	685
19	2038	-	-	-	-	698	2038	-	-	-	-	699
20	2039	-	-	-	-	356	2039	-	-	-	-	357
21	Total	$ 39,791	$ 54,534	$ (71,086)	$ (97,270)	$ 9,497	Total	$ 49,353	$ 67,618	$ (61,524)	$ (84,186)	$ 8,989

Notes:
1. Excludes environmental costs related to SEEG and 316(b).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Base O&M Expenses
January 1, 2020 through May 31, 2039
($000)

Case No.: U-21090
Exhibit No.: A-53 (NJK-4)

Witness: NJKapala
Date: June 2021

Generation Operations - Base O&M - Campbell 1 & 2 Early Retirement Cases

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Retire Campbell 1&2 5/31/2026						**Retire Campbell 1&2 5/31/2028**				
Line No.	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to base case	Campbell 2 Variance to base case	Campbell 3 Variance to base case	Year	Campbell 1 Total	Campbell 2 Total	Campbell 1 Variance to base case	Campbell 2 Variance to base case	Campbell 3 Variance to base case
1	2020	7,971	11,021	(0)	0	-	2020	7,971	11,021	(0)	0	-
2	2021	8,816	12,050	(0)	(0)	-	2021	8,816	12,050	(0)	(0)	-
3	2022	9,027	12,343	0	0	-	2022	9,027	12,343	0	0	-
4	2023	9,243	12,643	(0)	(0)	-	2023	9,243	12,643	(0)	(0)	-
5	2024	9,467	12,954	(0)	(0)	-	2024	9,467	12,954	(0)	(0)	-
6	2025	9,657	13,214	0	0	-	2025	9,657	13,214	0	0	-
7	2026	4,925	6,739	(4,925)	(6,739)	551	2026	9,850	13,478	0	0	-
8	2027	-	-	(10,047)	(13,747)	562	2027	10,047	13,747	0	(0)	-
9	2028	-	-	(10,248)	(14,022)	573	2028	5,124	7,011	(5,124)	(7,011)	573
10	2029	-	-	(10,453)	(14,303)	584	2029	-	-	(10,453)	(14,303)	585
11	2030	-	-	(10,662)	(14,589)	596	2030	-	-	(10,662)	(14,589)	596
12	2031	-	-	(5,437)	(7,440)	608	2031	-	-	(5,437)	(7,440)	608
13	2032	-	-	-	-	620	2032	-	-	-	-	620
14	2033	-	-	-	-	632	2033	-	-	-	-	633
15	2034	-	-	-	-	645	2034	-	-	-	-	646
16	2035	-	-	-	-	658	2035	-	-	-	-	658
17	2036	-	-	-	-	671	2036	-	-	-	-	672
18	2037	-	-	-	-	685	2037	-	-	-	-	685
19	2038	-	-	-	-	698	2038	-	-	-	-	699
20	2039	-	-	-	-	356	2039	-	-	-	-	356
21	Total	$ 59,106	$ 80,964	$ (51,771)	$ (70,840)	$ 8,439	Total	$ 79,202	$ 108,461	$ (31,675)	$ (43,343)	$ 7,331

Notes:
1. Excludes environmental costs related to SEEG and 316(b).

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Generation Operations
Summary of Capital Expenditures and Costs of Removal
January 1, 2021 through December 31, 2025

Case No.: U-21090
Exhibit No.: A-54 (NJK-5)
Page: 1 of 1
Witness: NJKapala
Date: June 2021

	(a)	(b)	(c)	(d)	(e)	(f)
	Capital + COR					
Line No.	**Plant**	**2021**	**2022**	**2023**	**2024**	**2025**
1	Zeeland	$ 28,084,400	$ 12,051,000	$ 28,759,533	$ 10,156,533	$ 9,374,333
2	Jackson	$ 22,275,000	$ 11,486,000	$ 13,078,300	$ 14,531,068	$ 9,621,526
3	Hydro	$ 36,203,831	$ 61,973,366	$ 99,535,400	$ 102,404,500	$ 60,577,200
4	Ludington	$ 33,837,718	$ 9,698,104	$ 6,227,496	$ 8,150,559	$ 8,449,375
5	Classic 7	$ 41,631,372	$ 23,107,374	$ 19,749,895	$ 20,460,000	$ 20,460,000
	Capital Only					
	Plant	**2021**	**2022**	**2023**	**2024**	**2025**
6	Zeeland	$ 27,843,600	$ 11,932,000	$ 28,289,533	$ 10,096,833	$ 9,349,333
7	Jackson	$ 22,186,800	$ 11,436,000	$ 12,643,300	$ 14,511,068	$ 9,611,526
8	Hydro	$ 34,877,831	$ 59,937,366	$ 96,050,400	$ 98,104,500	$ 56,890,200
9	Ludington	$ 32,987,718	$ 9,208,104	$ 5,907,496	$ 7,060,559	$ 8,289,375
10	Classic 7	$ 400,000	$ -	$ -	$ -	$ -

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
New Gas Plants
January 1, 2020 through May 31, 2040
($000)

Case No.: U-21090
Exhibit No.: A-55 (NJK-6)

Witness: NJKapala
Date: June 2021

Generation Operations - LTSA Capital

	(a)	(b)	(c)
Line No.	Year	Covert Total	DIG Total
1	2020	-	
2	2021	-	-
3	2022	-	-
4	2023	7,863	-
5	2024	13,798	-
6	2025	14,117	939
7	2026	14,446	2,670
8	2027	14,790	4,554
9	2028	15,143	6,610
10	2029	15,499	8,864
11	2030	15,855	11,347
12	2031	16,212	14,098
13	2032	16,575	17,173
14	2033	16,948	20,651
15	2034	17,323	24,643
16	2035	17,702	29,329
17	2036	4,522	31,293
18	2037	4,623	33,701
19	2038	2,836	36,287
20	2039	773	37,932
21	2040	-	-
22	Total	$ 209,026	$ 280,091

Notes:
1. Cost of removal has not been included.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
New Gas Plants
January 1, 2020 through May 31, 2040
($000)

Case No.: U-21090
Exhibit No.: A-55 (NJK-6)
Page: 2 of 4
Witness: NJKapala
Date: June 2021

Generation Operations - non-LTSA Capital

(a)		(b)	(c)
Line No.	Year	Covert Total	DIG, Kalamazoo, Livingston Total
1	2020	-	
2	2021	-	-
3	2022	-	-
4	2023	3,128	-
5	2024	5,488	-
6	2025	5,615	415
7	2026	5,746	1,181
8	2027	12,942	2,013
9	2028	6,023	2,923
10	2029	6,165	3,919
11	2030	6,307	5,017
12	2031	6,449	6,233
13	2032	6,593	7,593
14	2033	6,741	9,130
15	2034	6,890	10,896
16	2035	7,041	12,968
17	2036	7,195	15,482
18	2037	7,355	18,709
19	2038	7,520	23,312
20	2039	7,688	31,904
21	2040	-	-
22	Total	$ 114,887	$ 151,696

Notes:
1. Cost of removal has not been included.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
New Gas Plants
January 1, 2020 through May 31, 2040
($000)

Case No.: U-21090
Exhibit No.: A-55 (NJK-6)
Page: 3 of 4
Witness: NJKapala
Date: June 2021

Generation Operations - LTSA-related O&M

	(a)	(b)	(c)
Line No.	Year	Covert Total	DIG Total
1	2020		
2	2021	-	-
3	2022	-	-
4	2023	1,966	-
5	2024	3,450	-
6	2025	3,529	1,667
7	2026	3,611	2,924
8	2027	3,697	2,994
9	2028	3,786	3,065
10	2029	3,875	3,137
11	2030	3,964	3,209
12	2031	4,053	3,282
13	2032	4,144	3,355
14	2033	4,237	3,431
15	2034	4,331	3,506
16	2035	4,426	3,583
17	2036	4,522	3,661
18	2037	4,623	3,743
19	2038	4,726	3,827
20	2039	4,832	3,912
21	2040	2,058	1,666
22	Total	$ 69,829	$ 50,964

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Capital Expenditures
New Gas Plants
January 1, 2020 through May 31, 2040
($000)

Case No.: U-21090
Exhibit No.: A-55 (NJK-6)
Page: 4 of 4
Witness: NJKapala
Date: June 2021

Generation Operations - non-LTSA O&M

	(a)	(b)	(c)
Line No.	Year	Covert Total	DIG, Kalamazoo, Livingston Total
1	2020	-	-
2	2021	-	-
3	2022	-	-
4	2023	16,009	-
5	2024	28,393	-
6	2025	29,004	20,774
7	2026	29,289	33,806
8	2027	29,519	33,841
9	2028	28,816	33,773
10	2029	29,300	34,024
11	2030	29,205	34,009
12	2031	29,295	35,178
13	2032	29,120	35,675
14	2033	30,490	35,998
15	2034	30,868	37,078
16	2035	31,444	37,174
17	2036	31,443	37,075
18	2037	31,130	38,790
19	2038	31,793	38,860
20	2039	32,863	40,584
21	2040	13,204	16,619
22	Total	$ 511,184	$ 543,256

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Separation Activity Capital Expenditures
January 1, 2021 through December 31, 2031
($000)

Case No.: U-21090
Exhibit No.: A-56 (NJK-7)
Page: 1 of 1
Witness: NJKapala
Date: June 2021

Projected Unit Separation Activity Costs

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
			IRP Base Case												
Line No.	Plant	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
1	Karn	3 & 4	$ 890	$ 10,296	$ 15,675	$ 1,790	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 28,651
2	Campbell	3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,780	$ 14,341	$ 28,683	$ 14,341	$ 64,146
			IRP 2023 Karn 3&4 Retirement Case												
	Plant	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
3	Karn	3 & 4	$ 890	$ 10,296	$ 2,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,186
			IRP 2024 Campbell 1&2 Retirement Cases												
	Plant	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
4	Campbell	3	$ -	$ 6,780	$ 14,341	$ 28,683	$ 14,341	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 64,146
			IRP 2025 Campbell 1&2 Retirement Cases												
	Plant	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
5	Campbell	3	$ -	$ -	$ 6,780	$ 14,341	$ 28,683	$ 14,341	$ -	$ -	$ -	$ -	$ -	$ -	$ 64,146
			IRP 2026 Campbell 1&2 Retirement Case												
	Plant	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
6	Campbell	3	$ -	$ -	$ -	$ 6,780	$ 14,341	$ 28,683	$ 14,341	$ -	$ -	$ -	$ -	$ -	$ 64,146
			IRP 2025 Campbell Site Retirement Case												
	Plant	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
7	Campbell	3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
			IRP 2028 Campbell 1&2 Retirement Cases												
	Plant	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
8	Campbell	3	$ -	$ -	$ -	$ -	$ -	$ 6,780	$ 14,341	$ 28,683	$ 14,341	$ -	$ -	$ -	$ 64,146
			IRP 2032 Campbell 3 Retirement Case												
	Plant	Units	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Total
9	Campbell	3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Generation Capital Expenditures
AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2023
($000's)

Line No.	(a) Unit	(b) Cost Type	(c) 2020-2031 Total
Karn 3&4 Retirement Scenario			
1	Karn 3&4	Unavoidable	$ 6,950
2	Karn 3&4 - Unit Separation	Unavoidable	$ 13,186
3	Karn 1&2	Unavoidable	$ 13,294
4	Karn 3&4	Avoidable	$ 75,648
5	Karn 3&4 - Unit Separation	Avoidable	$ 15,465
6	Karn 1&2	Avoidable	$ -
7	Karn 3&4	Incremental	$ -
8	Karn 1&2	Incremental	$ -

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Electric Capital Expenditures

Case No.: U-21090
Exhibit No.: A-57 (NJK-8)
Page: 2 of 6
Witness: NJKapala
Date: June 2021

Generation Capital Expenditures
AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2024
($000's)

Line No.	(a) Unit	(b) Cost Type	(c) 2020-2031 Total
Campbell 1 Retirement Scenario			
1	Campbell 1	Unavoidable	$ 15,037
2	Campbell 2	Unavoidable	$ 79,020
3	Campbell 1	Avoidable	$ 42,840
4	Campbell 2	Incremental	$ 253
Campbell 2 Retirement Scenario			
5	Campbell 1	Unavoidable	$ 57,878
6	Campbell 2	Unavoidable	$ 22,950
7	Campbell 2	Avoidable	$ 56,070
8	Campbell 1	Incremental	$ 322
Campbell 1 and 2 Retirement Scenario			
9	Campbell 1	Unavoidable	$ 15,037
10	Campbell 2	Unavoidable	$ 22,950
11	Campbell 1	Avoidable	$ 42,840
12	Campbell 2	Avoidable	$ 56,070
13	Campbell 3	Incremental	$ -

Generation Capital Expenditures
AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2025
($000's)

Line No.	(a) Unit	(b) Cost Type	(c) 2020-2031 Total
Campbell 1 Retirement Scenario			
1	Campbell 1	Unavoidable	$ 21,926
2	Campbell 2	Unavoidable	$ 79,020
3	Campbell 1	Avoidable	$ 35,951
4	Campbell 2	Incremental	$ -
Campbell 2 Retirement Scenario			
5	Campbell 1	Unavoidable	$ 57,878
6	Campbell 2	Unavoidable	$ 32,446
7	Campbell 2	Avoidable	$ 46,573
8	Campbell 1	Incremental	$ -
Campbell 1 and 2 Retirement Scenario			
9	Campbell 1	Unavoidable	$ 21,926
10	Campbell 2	Unavoidable	$ 32,446
11	Campbell 1	Avoidable	$ 35,951
12	Campbell 2	Avoidable	$ 46,573
13	Campbell 3	Incremental	$ -
Campbell 3 Retirement Scenario			
13	Campbell 3	Unavoidable	$ 59,641
14	Campbell 3 - Unit Separation	Unavoidable	$ -
15	Campbell 3	Avoidable	$ 190,613
16	Campbell 3 - Unit Separation	Avoidable	$ (64,146)
17	Campbell 3	Incremental	$ -
Karn 3&4 Retirement Scenario			
18	Karn 3&4	Unavoidable	$ 19,611
19	Karn 3&4 - Unit Separation	Unavoidable	$ 19,490
20	Karn 1&2	Unavoidable	$ 13,294
21	Karn 3&4	Avoidable	$ 62,987
22	Karn 3&4 - Unit Separation	Avoidable	$ 9,161
23	Karn 1&2	Avoidable	$ -
24	Karn 3&4	Incremental	$ -
25	Karn 1&2	Incremental	$ -

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Electric Capital Expenditures

Case No.: U-21090
Exhibit No.: A-57 (NJK-8)
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Date: June 2021

Generation Capital Expenditures
AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2026
($000's)

Line No.	(a) Unit	(b) Cost Type	(c) 2020-2031 Total	
Campbell 1 Retirement Scenario				
1	Campbell 1	Unavoidable	$	23,831
2	Campbell 2	Unavoidable	$	79,020
3	Campbell 1	Avoidable	$	34,046
4	Campbell 2	Incremental	$	-
Campbell 2 Retirement Scenario				
5	Campbell 1	Unavoidable	$	57,878
6	Campbell 2	Unavoidable	$	33,746
7	Campbell 2	Avoidable	$	45,273
8	Campbell 1	Incremental	$	-
Campbell 1 and 2 Retirement Scenario				
9	Campbell 1	Unavoidable	$	23,831
10	Campbell 2	Unavoidable	$	33,746
11	Campbell 1	Avoidable	$	34,046
12	Campbell 2	Avoidable	$	45,273

Generation Capital Expenditures
AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2028
($000's)

Line No.	(a) Unit	(b) Cost Type	(c) 2020-2031 Total
Campbell 1 Retirement Scenario			
1	Campbell 1	Unavoidable	$ 43,436
2	Campbell 2	Unavoidable	$ 79,020
3	Campbell 1	Avoidable	$ 14,442
4	Campbell 2	Incremental	$ -
Campbell 2 Retirement Scenario			
5	Campbell 1	Unavoidable	$ 57,878
6	Campbell 2	Unavoidable	$ 60,687
7	Campbell 2	Avoidable	$ (18,333)
8	Campbell 1	Incremental	$ -
Campbell 1 and 2 Retirement Scenario			
9	Campbell 1	Unavoidable	$ 43,436
10	Campbell 2	Unavoidable	$ 60,687
11	Campbell 1	Avoidable	$ 14,442
12	Campbell 2	Avoidable	$ 18,333
13	Campbell 3	Incremental	$ -

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Electric Capital Expenditures

Case No.: U-21090
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Witness: NJKapala
Date: June 2021

Exhibit No.:

Generation Capital Expenditures
AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2032
($000's)

Line No.	(a) Unit	(b) Cost Type	(c) 2020-2039 Total
Campbell 3 Retirement Scenario			
1	Campbell 3	Unavoidable	$ 218,854
2	Campbell 3 - Unit Separation	Unavoidable	$ -
3	Campbell 3	Avoidable	$ 31,400
4	Campbell 3 - Unit Separation	Avoidable	$ (64,146)
5	Campbell 3	Incremental	$ -

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Electric Major Maintenance Expenses

Case No.: U-21090
Exhibit No.: A-58 (NJK-9)

Witness: NJKapala
Date: June 2021

Generation Major Maintenance Expenses
AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2023
($000's)

Line No.	(a) **Unit**	(b) **Cost Type**		(c) **2020-2031 Total**
Karn 3&4 Retirement Scenario				
1	Karn 3&4	Unavoidable	$	1,000
2	Karn 1&2	Unavoidable	$	9,465
3	Karn 3&4	Avoidable	$	10,050
3	Karn 1&2	Avoidable	$	-
4	Karn 3&4	Incremental	$	-
5	Karn 1&2	Incremental	$	-

Generation Major Maintenance Expenses
AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2024
($000's)

Line No.	(a) Unit	(b) Cost Type	(c) 2020-2031 Total
Campbell 1 Retirement Scenario			
1	Campbell 1	Unavoidable	$ 14,845
2	Campbell 2	Unavoidable	$ 28,814
3	Campbell 1	Avoidable	$ 14,516
4	Campbell 2	Incremental	$ -
Campbell 2 Retirement Scenario			
5	Campbell 1	Unavoidable	$ 29,361
6	Campbell 2	Unavoidable	$ 14,189
7	Campbell 2	Avoidable	$ 14,625
8	Campbell 1	Incremental	$ -
Campbell 1 and 2 Retirement Scenario			
9	Campbell 1	Unavoidable	$ 14,845
10	Campbell 2	Unavoidable	$ 14,189
11	Campbell 1	Avoidable	$ 14,516
12	Campbell 2	Avoidable	$ 14,625

Generation Major Maintenance Expenses
AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2025
($000's)

Line No.	(a) Unit	(b) Cost Type		(c) 2020-2031 Total
Campbell 1 Retirement Scenario				
1	Campbell 1	Unavoidable	$	17,247
2	Campbell 2	Unavoidable	$	28,814
3	Campbell 1	Avoidable	$	12,114
4	Campbell 2	Incremental	$	-
Campbell 2 Retirement Scenario				
5	Campbell 1	Unavoidable	$	29,361
6	Campbell 2	Unavoidable	$	15,428
7	Campbell 2	Avoidable	$	13,385
8	Campbell 1	Incremental	$	-
Campbell 1 and 2 Retirement Scenario				
9	Campbell 1	Unavoidable	$	17,247
10	Campbell 2	Unavoidable	$	15,428
11	Campbell 1	Avoidable	$	12,114
12	Campbell 2	Avoidable	$	13,385
Campbell 3 Retirement Scenario				
13	Campbell 3	Unavoidable	$	17,145
14	Campbell 3	Avoidable	$	57,555
16	Campbell 3	Incremental	$	-
Karn 3&4 Retirement Scenario				
17	Karn 3&4	Unavoidable	$	5,350
18	Karn 1&2	Unavoidable	$	9,465
19	Karn 3&4	Avoidable	$	5,700
20	Karn 1&2	Avoidable	$	-
21	Karn 3&4	Incremental	$	-
22	Karn 1&2	Incremental	$	-

Generation Major Maintenance Expenses
AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2026
($000's)

Line No.	(a) Unit	(b) Cost Type		(c) 2020-2031 Total
Campbell 1 Retirement Scenario				
1	Campbell 1	Unavoidable	$	18,666
2	Campbell 2	Unavoidable	$	28,814
3	Campbell 1	Avoidable	$	10,696
4	Campbell 2	Incremental	$	-
Campbell 2 Retirement Scenario				
5	Campbell 1	Unavoidable	$	29,361
6	Campbell 2	Unavoidable	$	16,629
7	Campbell 2	Avoidable	$	12,185
8	Campbell 1	Incremental	$	-
Campbell 1 and 2 Retirement Scenario				
9	Campbell 1	Unavoidable	$	18,666
10	Campbell 2	Unavoidable	$	16,629
11	Campbell 1	Avoidable	$	10,696
12	Campbell 2	Avoidable	$	12,185

Generation Major Maintenance Expenses
AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2028
($000's)

	(a)	(b)		(c)
Line No.	**Unit**	**Cost Type**		**2020-2031 Total**
Campbell 1 Retirement Scenario				
1	Campbell 1	Unavoidable	$	23,262
2	Campbell 2	Unavoidable	$	28,814
3	Campbell 1	Avoidable	$	6,100
4	Campbell 2	Incremental	$	-
Campbell 2 Retirement Scenario				
5	Campbell 1	Unavoidable	$	29,361
6	Campbell 2	Unavoidable	$	22,387
7	Campbell 2	Avoidable	$	6,427
8	Campbell 1	Incremental	$	-
Campbell 1 and 2 Retirement Scenario				
9	Campbell 1	Unavoidable	$	23,262
10	Campbell 2	Unavoidable	$	22,387
11	Campbell 1	Avoidable	$	6,100
12	Campbell 2	Avoidable	$	6,427

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Electric Major Maintenance Expenses

Case No.: U-21090
Exhibit No.: A-58 (NJK-9)

Witness: NJKapala
Date: June 2021

Generation Major Maintenance Expenses
AVOIDABLE AND INCREMENTAL UNDER AN EARLY RETIREMENT SCENARIO 2032
($000's)

Line No.	(a) Unit	(b) Cost Type		(c) 2020-2039 Total
Campbell 3 Retirement Scenario				
1	Campbell 3	Unavoidable	$	44,716
2	Campbell 3	Avoidable	$	29,984
3	Campbell 3	Incremental	$	-

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Generating Unit Random Outage Rates (ROR)
January 1, 2016 through December 31, 2031

Case No.: U-21090
Exhibit No.: A-59 (NJK-10)

Witness: NJKapala
Date: June 2021

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
Line No.	**Plant**	**Actual ROR 2016-2020**	**Projected ROR 2021**	**Projected ROR 2022**	**Projected ROR 2023**	**Projected ROR 2024**	**Projected ROR 2025**	**Projected ROR 2026**	**Projected ROR 2027**	**Projected ROR 2028**	**Projected ROR 2029**	**Projected ROR 2030**	**Projected ROR 2031**
1	Campbell 1	15.43%	15.5%	15.5%	16.0%	16.0%	16.5%	18.5%	17.0%	17.5%	18.0%	19.0%	20.0%
2	Campbell 2	18.14%	14.0%	14.5%	14.5%	15.0%	15.0%	15.5%	16.0%	16.5%	17.0%	18.0%	19.0%
3	Campbell 3	7.79%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
4	Karn 1	21.52%	20.5%	21.0%	21.5%								
5	Karn 2	14.75%	15.5%	16.0%	16.5%								

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Generating Unit Equivalent Forced Outage Rate Demand ($EFOR_d$)
January 1, 2016 through December 31, 2020

Case No.: U-21090
Exhibit No.: A-59 (NJK-10)

Witness: NJKapala
Date: June 2021

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Plant**	**Actual $EFOR_d$ 2016**	**Actual $EFOR_d$ 2017**	**Actual $EFOR_d$ 2018**	**Actual $EFOR_d$ 2019**	**Actual $EFOR_d$ 2020**
1	Campbell 1	2.56%	0.54%	5.69%	5.69%	12.08%
2	Cambpell 2	0.38%	10.05%	9.68%	7.95%	4.33%
3	Campbell 3	0.17%	0.29%	5.33%	6.06%	4.21%
4	Karn 1	8.71%	1.60%	24.02%	15.18%	2.60%
5	Karn 2	2.87%	0.20%	4.92%	28.17%	4.06%
6	Karn 3	26.52%	14.43%	25.01%	30.30%	28.16%
7	Karn 4	30.80%	33.96%	30.50%	49.88%	19.28%

Note: $EFOR_d = \dfrac{\text{(Forced Outage Hours demand + Equivalent Forced Derate Hours demand)}}{\text{(Service Hours + Forced Outage Hours demand + Equivalent Forced Derate Hours During Reserve Shutdown)}}$

EXHIBIT A-60 (NJK-11)

CONFIDENTIAL
FILED UNDER SEAL WITH THE MPSC

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
______________________________________	)	

EXHIBITS

OF

BRIAN D. GALLAWAY

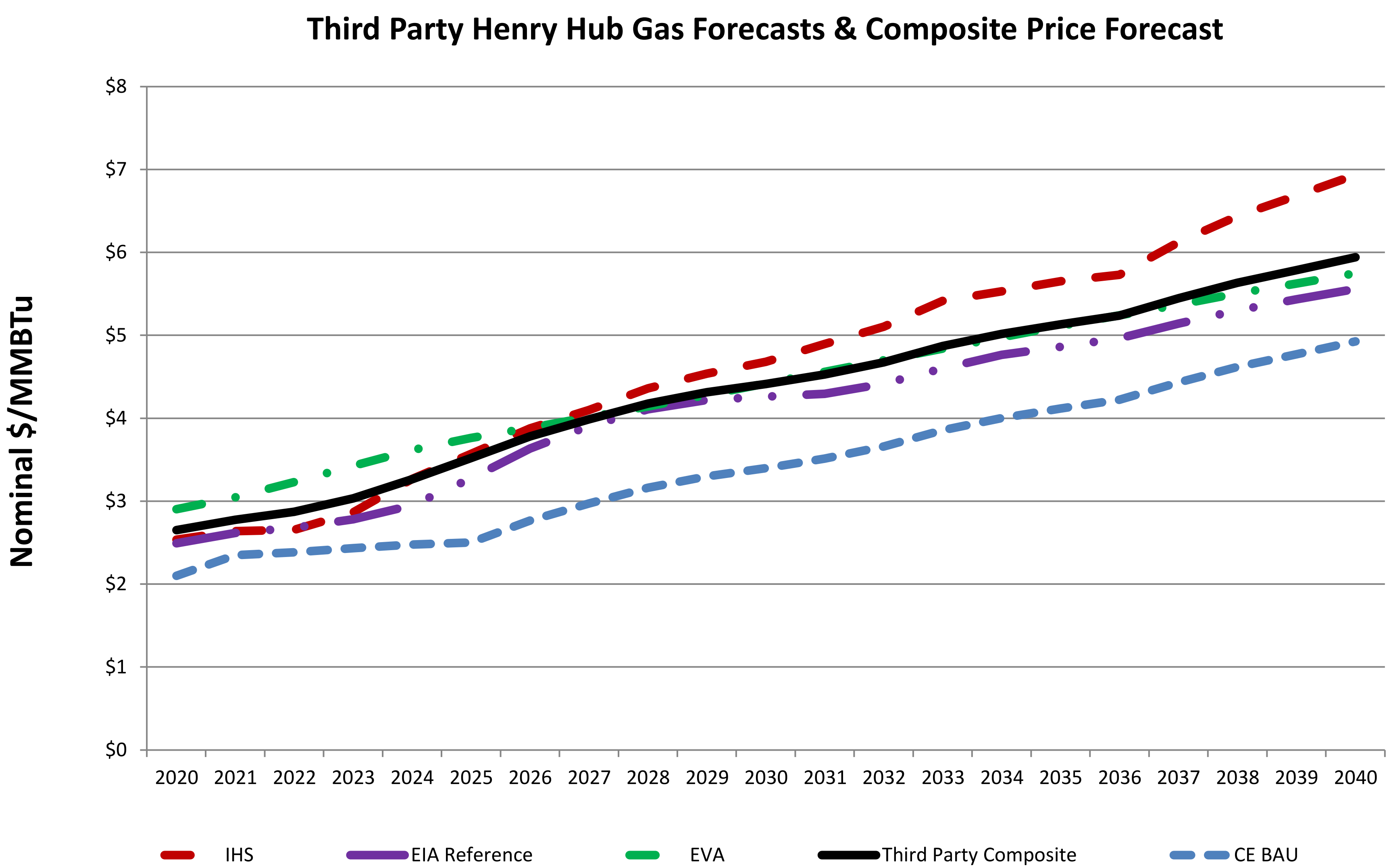
ON BEHALF OF

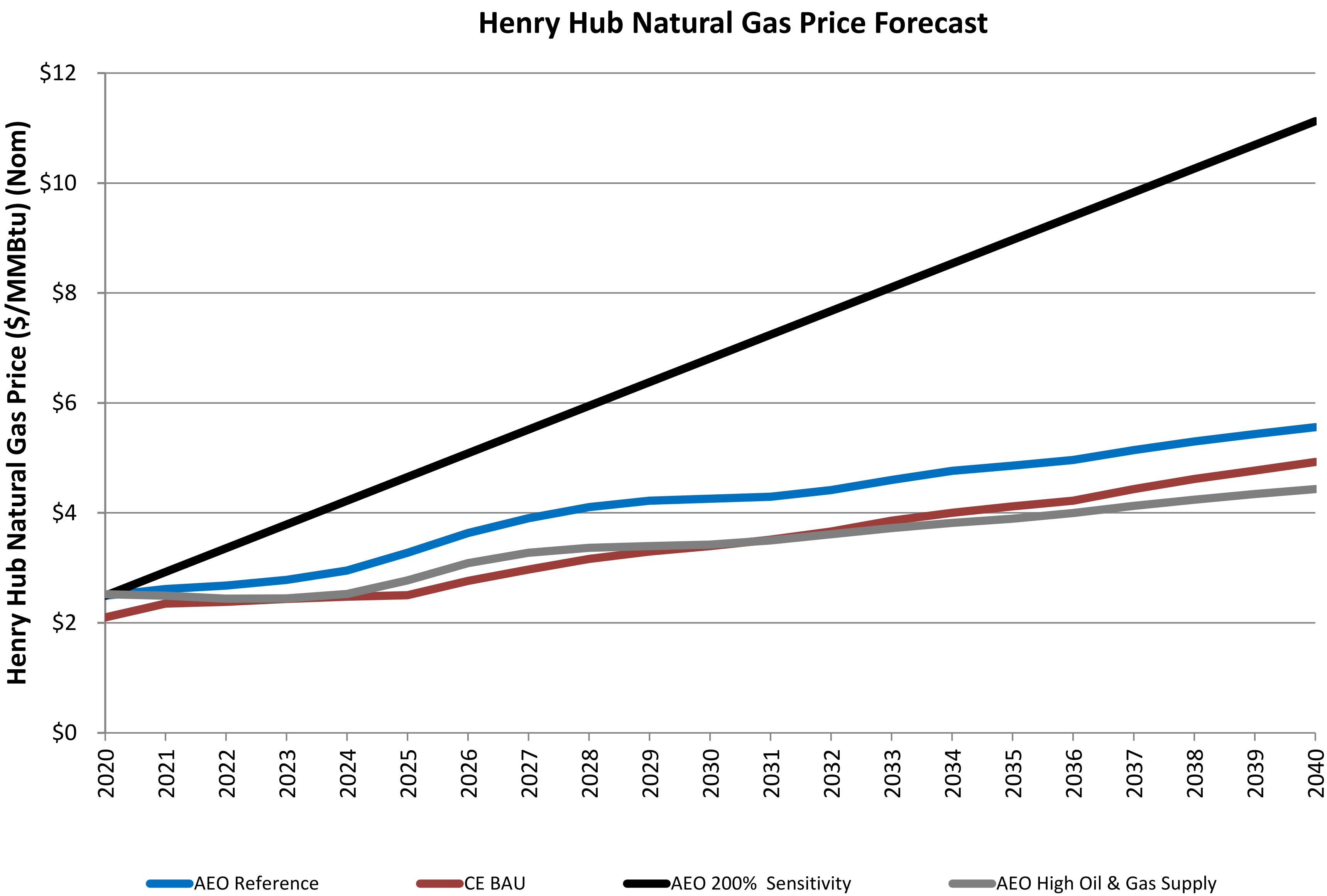
CONSUMERS ENERGY COMPANY

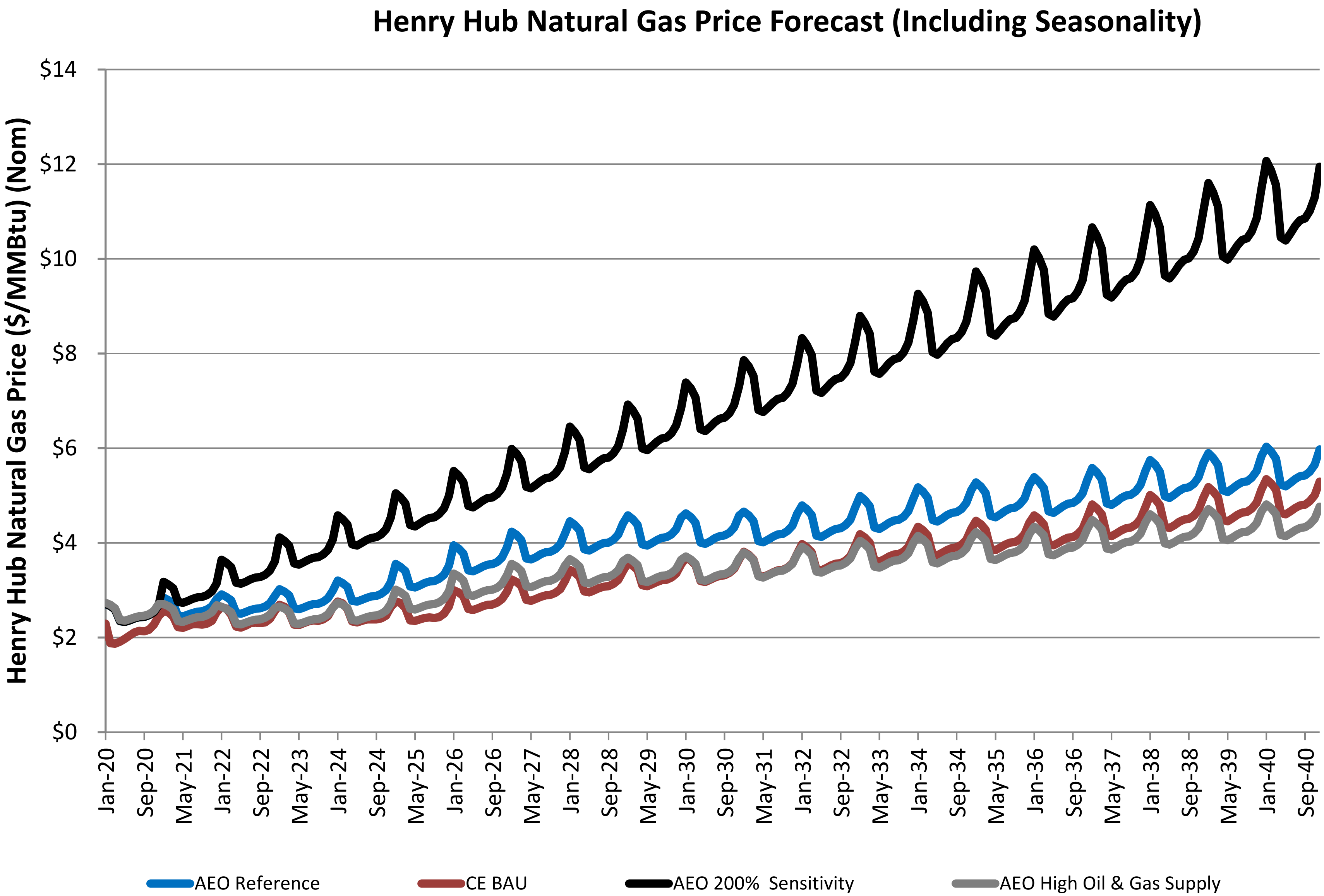
June 2021

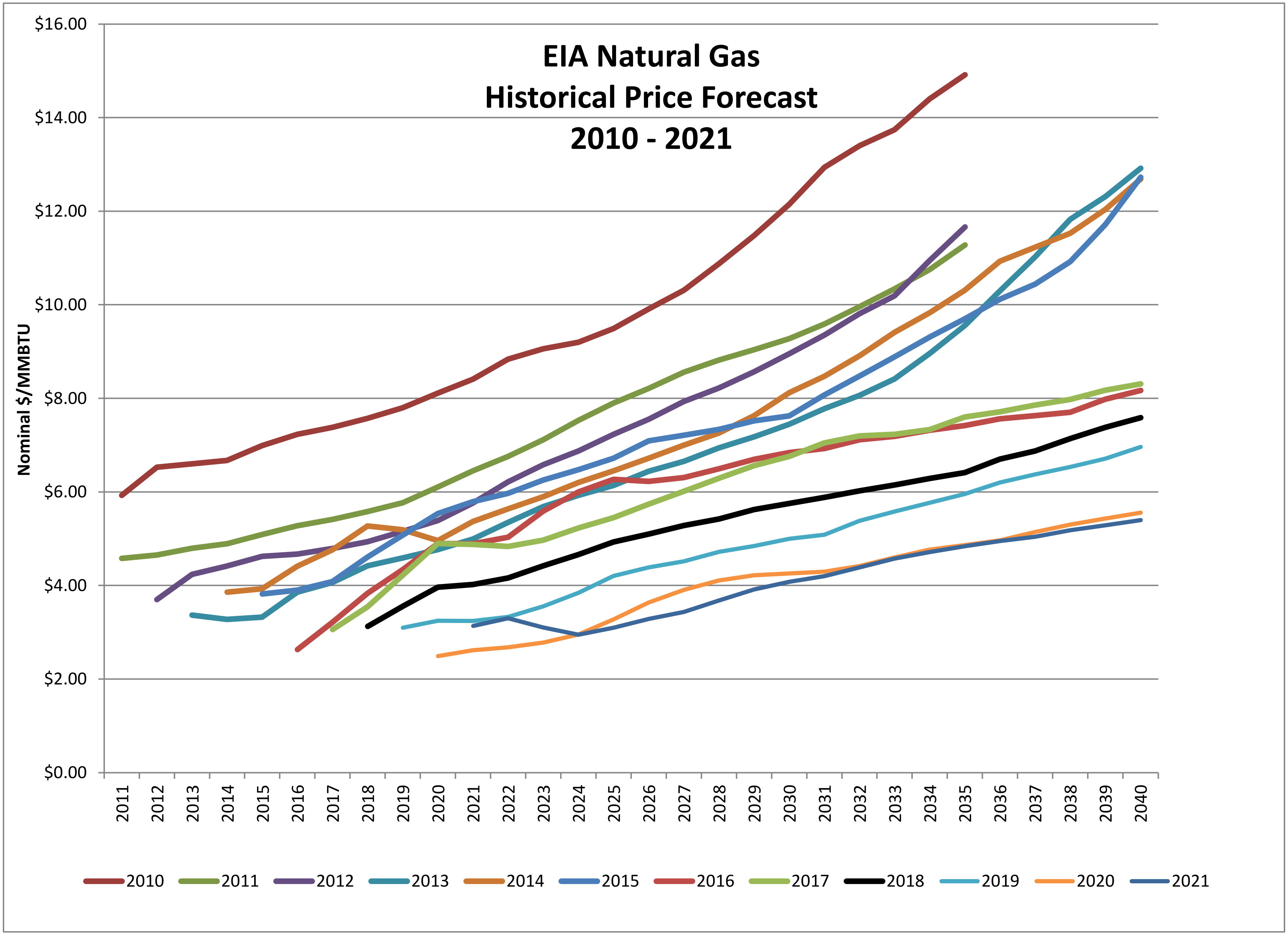
Consumers Energy Company
Existing Fossil Generating Facilities

Line No.	(a) **Facility Name**	(b) **Location**	(c) **Fuel Source**
1	**Steam Plants - Coal Fired**		
2	JHCampbell Units 1-3	West Olive, MI	Coal
3	DEKarn Units 1-2	Essexville, MI	Coal
4	**Steam Plants - Oil/Gas Fired**		
5	DEKarn Units 3-4	Essexville, MI	Natural Gas/Oil
6	Zeeland Units 2A, 2B, 2C	Zeeland, MI	Natual Gas
7	Jackson Plant	Jackson, MI	Natural Gas
8	**Combustion Turbines**		
9	Zeeland 1A & 1B	Zeeland, MI	Natural Gas

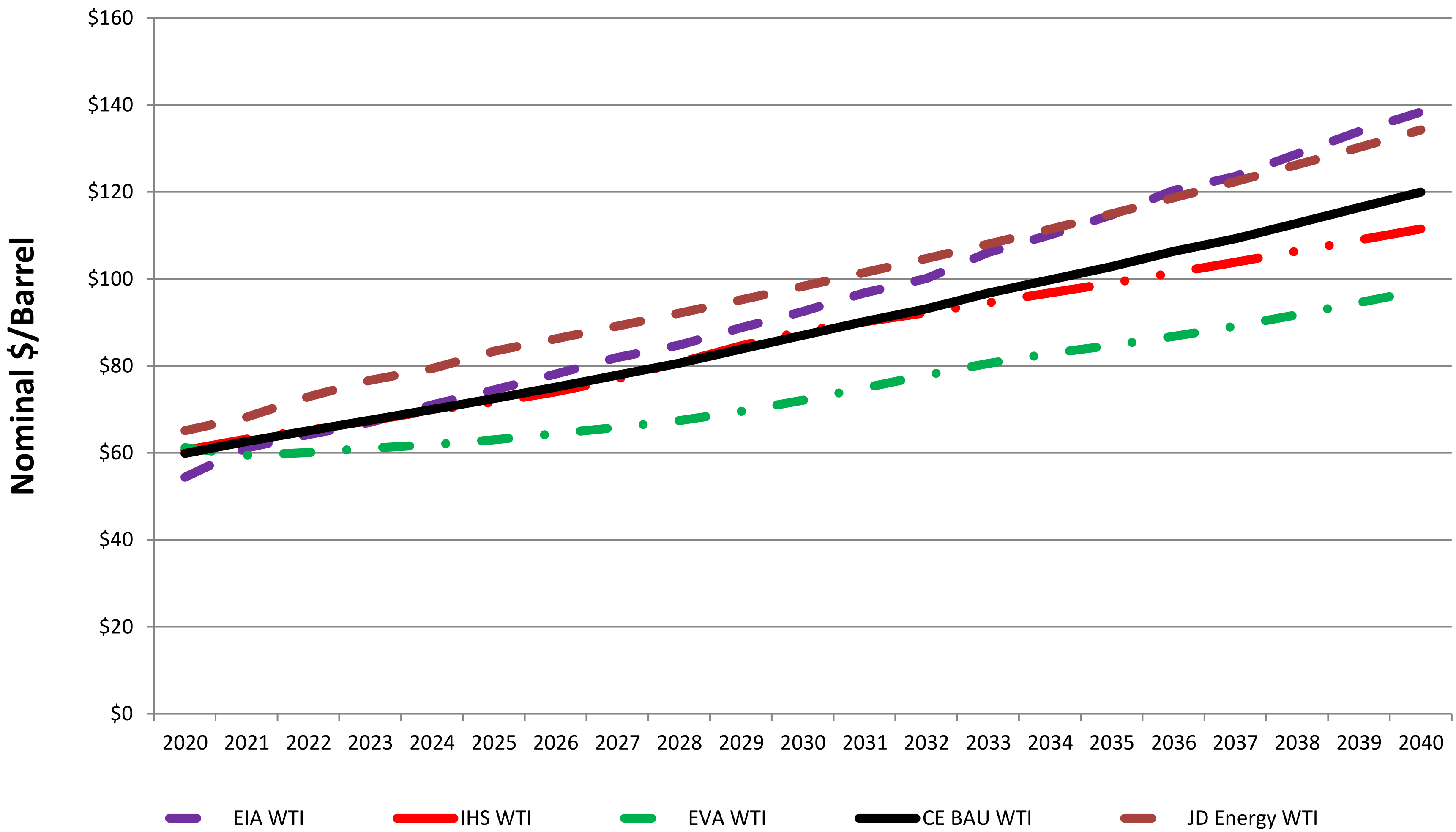

Third Party Henry Hub Gas Forecasts & Composite Price Forecast
Nominal $/MMBTu
$8
$7
$6
$5
$4
$3
$2
$1
$0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
IHS
EIA Reference
EVA
Third Party Composite
CE BAU

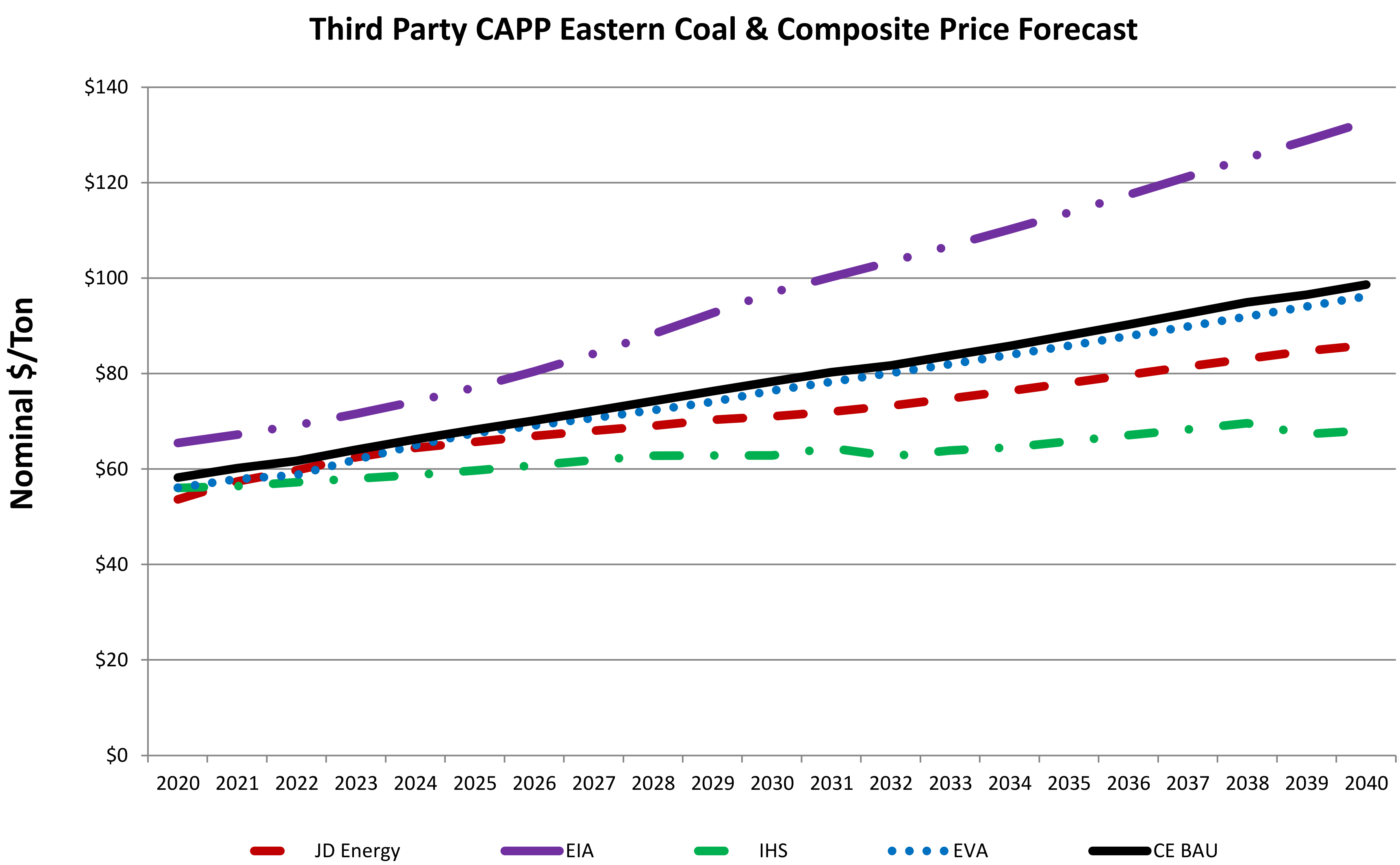

Henry Hub Natural Gas Price Forecast
Henry Hub Natural Gas Price ($/MMBtu) (Nom)
$12
$10
$8
$6
$4
$2
$0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
AEO Reference
CE BAU
AEO 200% Sensitivity
AEO High Oil & Gas Supply

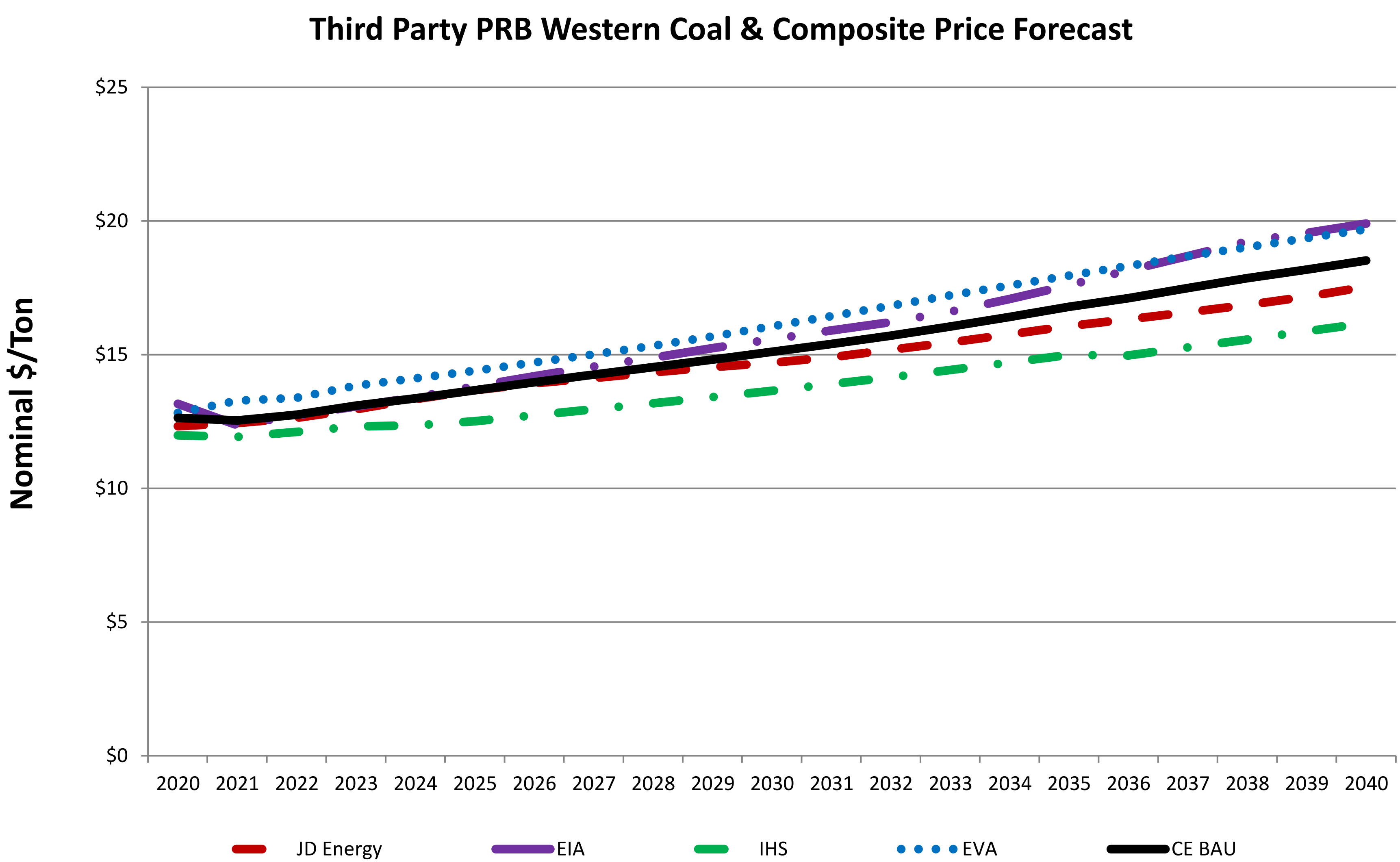

Henry Hub Natural Gas Price Forecast (Including Seasonality)
Henry Hub Natural Gas Price ($/MMBtu) (Nom)
$14
$12
$10
$8
$6
$4
$2
$0
Jan-20
Sep-20
May-21
Jan-22
Sep-22
May-23
Jan-24
Sep-24
May-25
Jan-26
Sep-26
May-27
Jan-28
Sep-28
May-29
Jan-30
Sep-30
May-31
Jan-32
Sep-32
May-33
Jan-34
Sep-34
May-35
Jan-36
Sep-36
May-37
Jan-38
Sep-38
May-39
Jan-40
Sep-40
AEO Reference
CE BAU
AEO 200% Sensitivity
AEO High Oil & Gas Supply


EIA Natural Gas
Historical Price Forecast
2010 - 2021
Nominal $/MMBTU
$16.00
$14.00
$12.00
$10.00
$8.00
$6.00
$4.00
$2.00
$0.00
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021

Third Party Crude Oil Forecasts & Composite Price Forecast




Third Party CAPP Eastern Coal & Composite Price Forecast
Nominal $/Ton
$140
$120
$100
$80
$60
$40
$20
$0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
JD Energy
EIA
IHS
EVA
CE BAU


Third Party PRB Western Coal & Composite Price Forecast
Nominal $/Ton
$25
$20
$15
$10
$5
$0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
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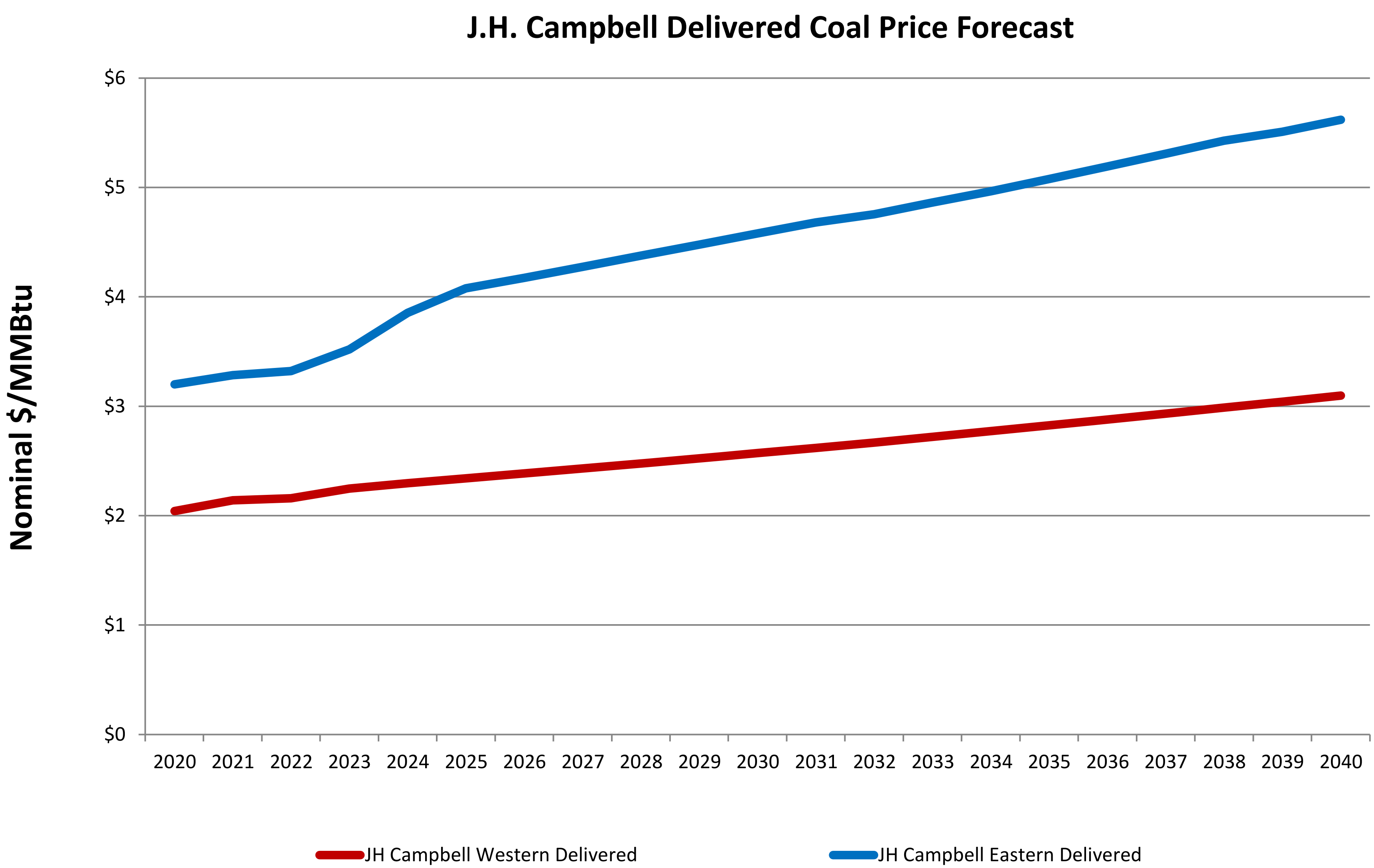
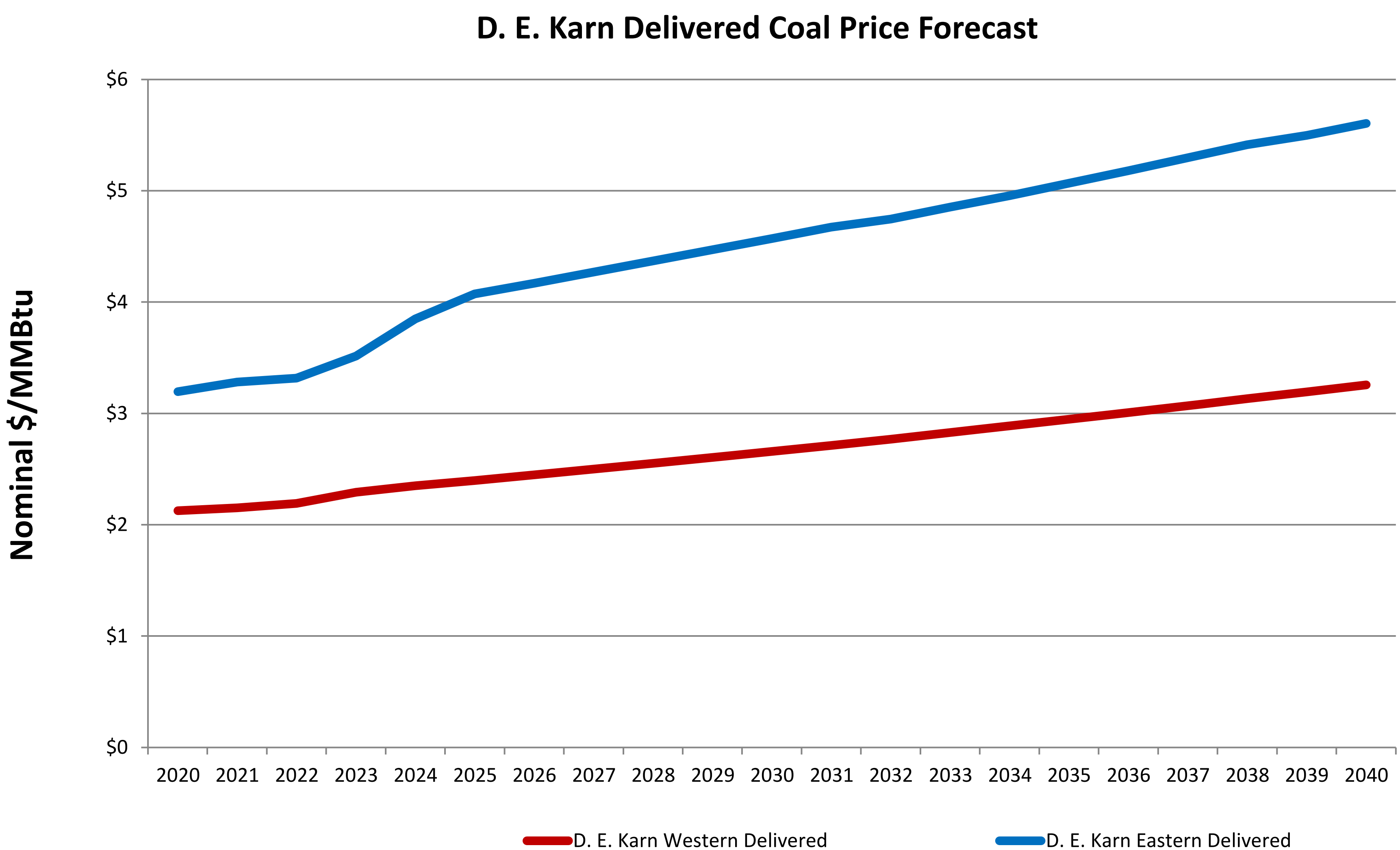
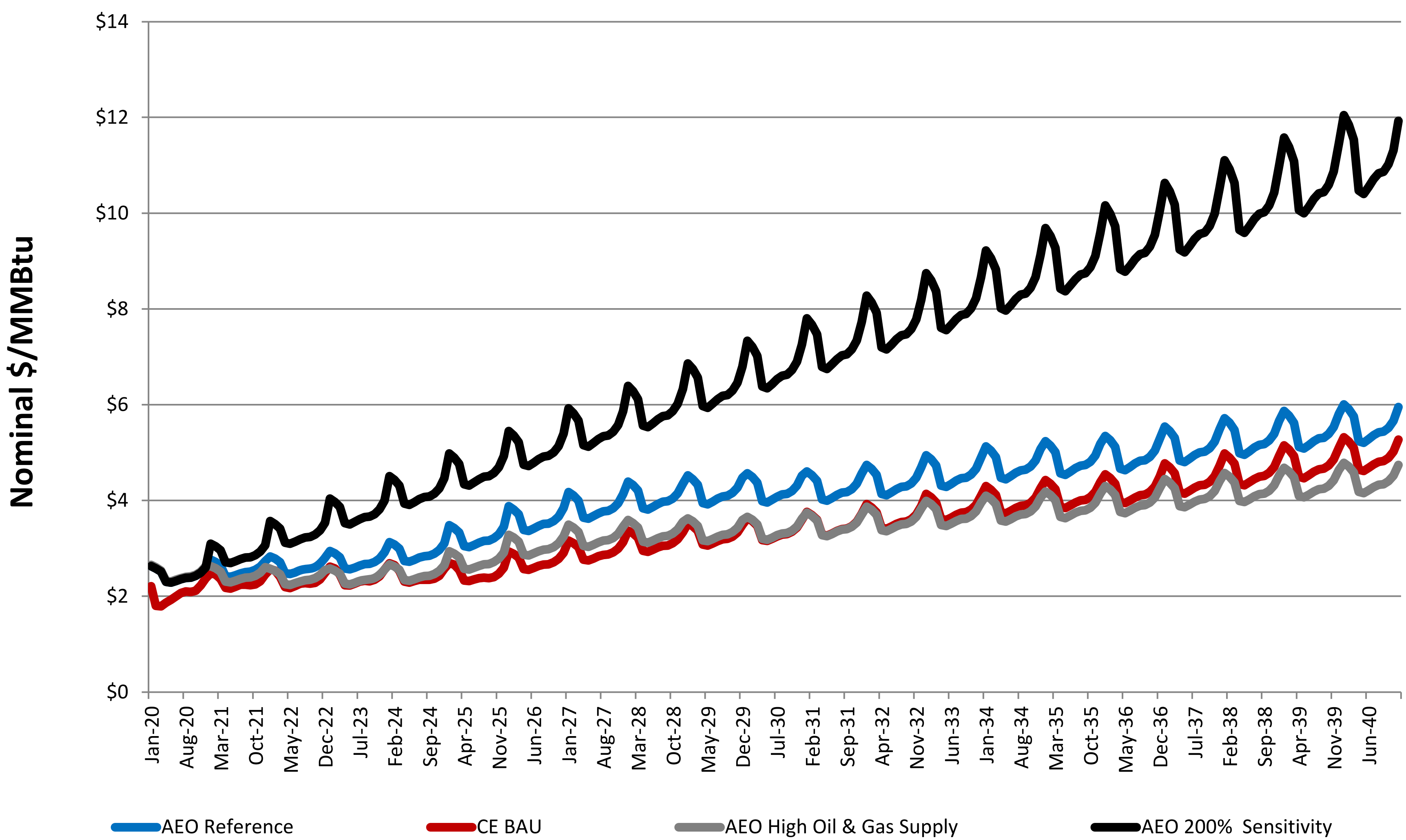
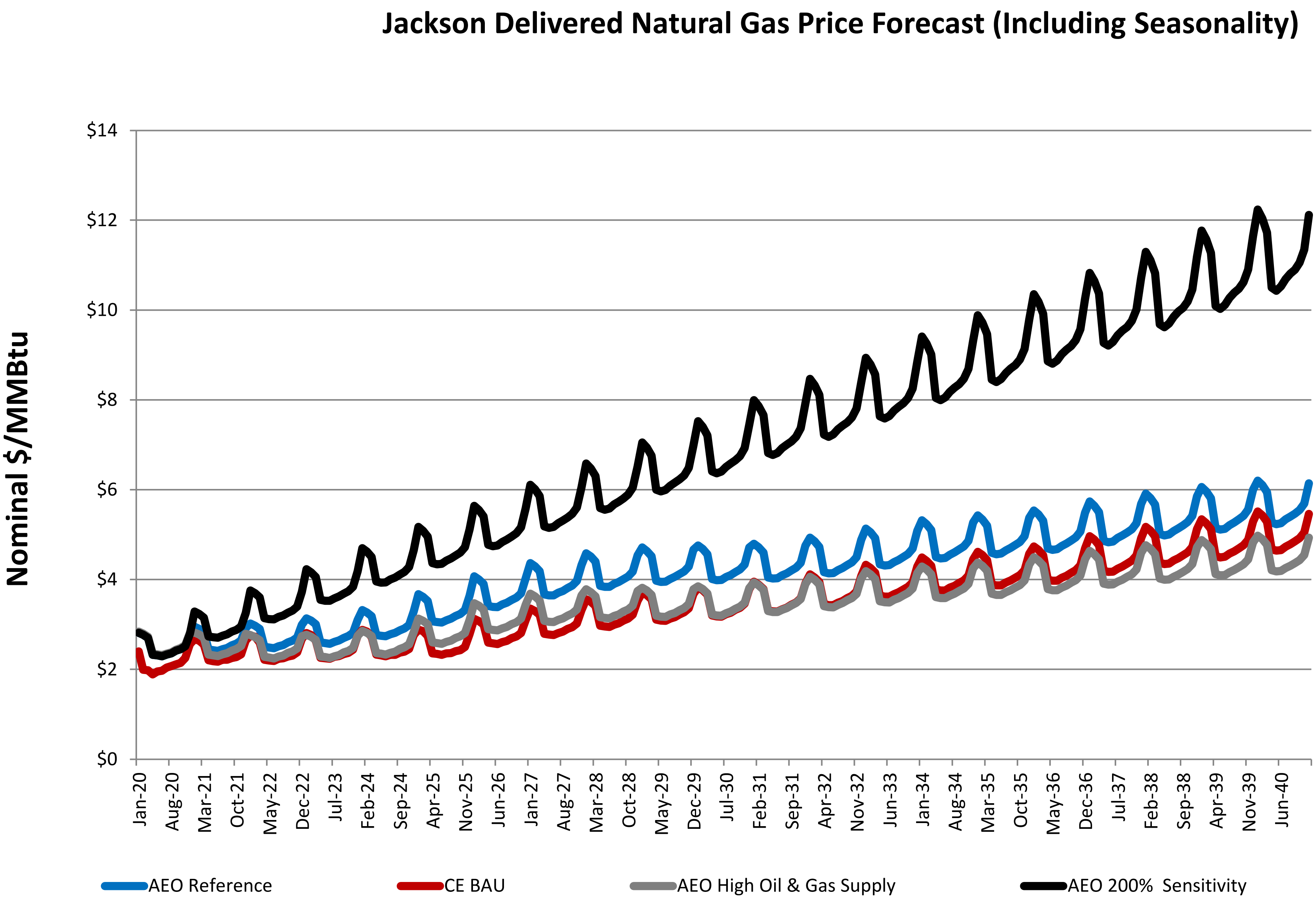
JD Energy
EIA
IHS
EVA
CE BAU

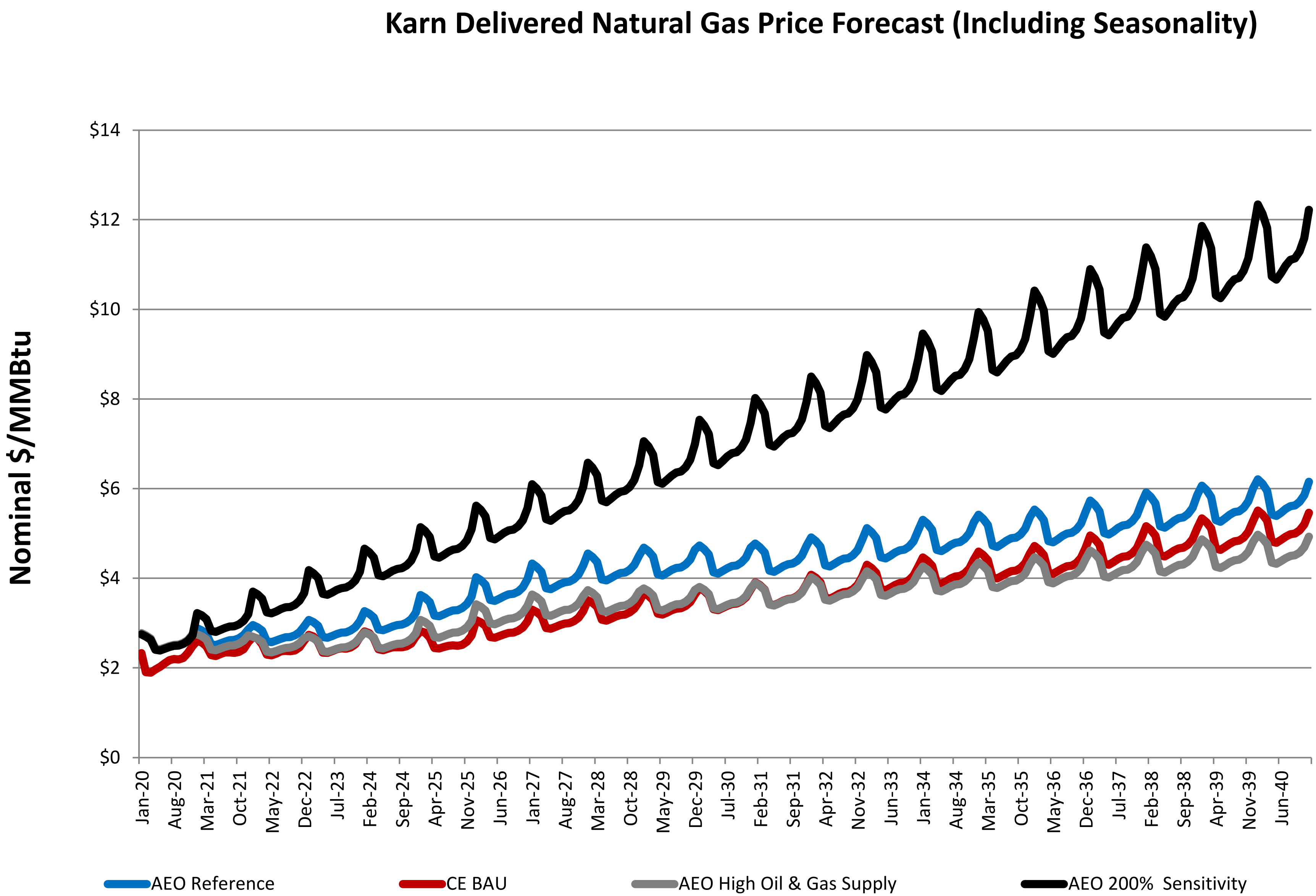

J.H. Campbell Delivered Coal Price Forecast
Nominal $/MMBtu
$6
$5
$4
$3
$2
$1
$0
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
2032
2033
2034
2035
2036
2037
2038
2039
2040
JH Campbell Western Delivered
JH Campbell Eastern Delivered


D. E. Karn Delivered Coal Price Forecast
Nominal $/MMBtu
$6
$5
$4
$3
$2
$1
$0
2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040
D. E. Karn Western Delivered
D. E. Karn Eastern Delivered

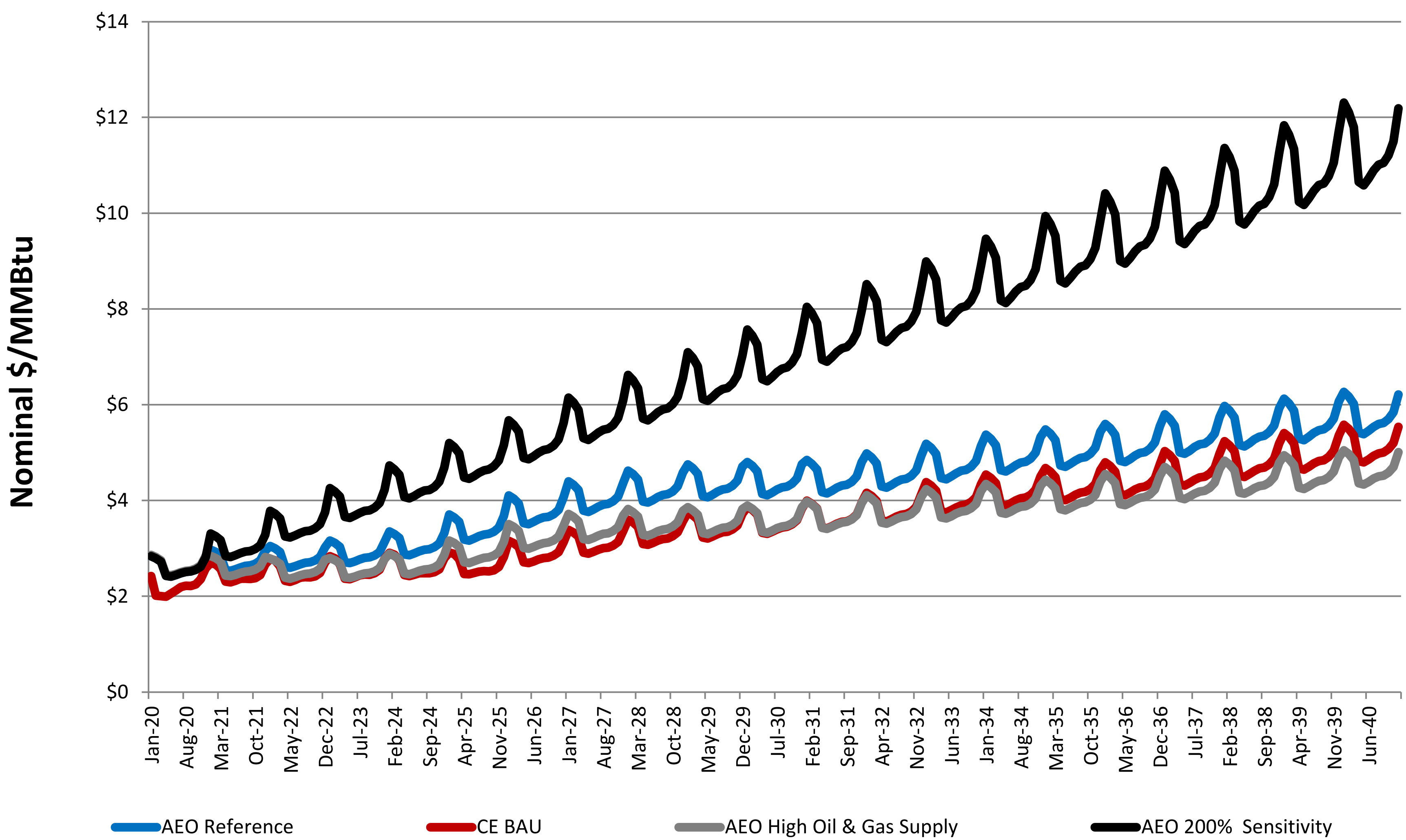
Zeeland Delivered Natural Gas Price Forecast (Including Seasonality)




Jackson Delivered Natural Gas Price Forecast (Including Seasonality)
Nominal $/MMBtu
$14
$12
$10
$8
$6
$4
$2
$0
Jan-20
Aug-20
Mar-21
Oct-21
May-22
Dec-22
Jul-23
Feb-24
Sep-24
Apr-25
Nov-25
Jun-26
Jan-27
Aug-27
Mar-28
Oct-28
May-29
Dec-29
Jul-30
Feb-31
Sep-31
Apr-32
Nov-32
Jun-33
Jan-34
Aug-34
Mar-35
Oct-35
May-36
Dec-36
Jul-37
Feb-38
Sep-38
Apr-39
Nov-39
Jun-40
AEO Reference
CE BAU
AEO High Oil & Gas Supply
AEO 200% Sensitivity


Karn Delivered Natural Gas Price Forecast (Including Seasonality)
Nominal $/MMBtu
$14
$12
$10
$8
$6
$4
$2
$0
Jan-20
Aug-20
Mar-21
Oct-21
May-22
Dec-22
Jul-23
Feb-24
Sep-24
Apr-25
Nov-25
Jun-26
Jan-27
Aug-27
Mar-28
Oct-28
May-29
Dec-29
Jul-30
Feb-31
Sep-31
Apr-32
Nov-32
Jun-33
Jan-34
Aug-34
Mar-35
Oct-35
May-36
Dec-36
Jul-37
Feb-38
Sep-38
Apr-39
Nov-39
Jun-40
AEO Reference
CE BAU
AEO High Oil & Gas Supply
AEO 200% Sensitivity

New Plant Delivered Natural Gas Price Forecast (Including Seasonality)



S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
______________________________________	)	

EXHIBIT

OF

CAROLEE KVORIAK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Summary of Projected Generation Operations Base O&M Expenses
January 1, 2020 through May 31, 2040
($000)

Case No.: U-21090
Exhibit No.: A-75 (CK-1)

Witness: CKvoriak
Date: June 2021

Generation Operations - Property Tax

	(a)	(b)	(c)
Line No.	Year	Covert Total	DIG/Liv./Kal. Total
1	2020	-	
2	2021	-	-
3	2022	-	-
4	2023	8,391	-
5	2024	14,730	-
6	2025	15,069	2,672
7	2026	15,415	4,685
8	2027	15,785	4,798
9	2028	16,164	4,913
10	2029	16,552	5,031
11	2030	16,933	5,146
12	2031	17,322	5,265
13	2032	17,703	5,380
14	2033	18,093	5,499
15	2034	18,491	5,620
16	2035	18,898	5,743
17	2036	19,314	5,870
18	2037	19,738	5,999
19	2038	20,173	6,131
20	2039	20,616	6,266
21	2040	8,779	2,668
22	Total	$ 298,168	$ 81,684

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

EXHIBITS

OF

BENJAMIN T. SCOTT

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

CONSUMERS ENERGY (CE)
2021 INTEGRATED RESOURCE PLAN (IRP)
SECOND MICHIGAN ELECTRIC TRANSMISSION COMPANY (METC) MEETING
208 N. Capitol Ave., Suite 200
JANUARY 16, 2020, 9AM - NOON
AGENDA

Attendees:

Kwafo Adarkwa, Manager of Regulatory Strategy, METC
Teresa Hatcher, Director, Electric Supply Planning, CE
Chuck Marshall, Director, Transmission Planning, METC
Roma Notani, General Engineer I, CE
Ben Scott, Senior Engineer, CE
Thi Tran, Senior Engineer, METC
Kevin Van Oirschot, Electric Transmission & Market Regulation Director, CE
Sara Walz, Senior Engineering Technical Analysis Lead, CE
Jessica Woycehoski, Senior Engineer Lead, CE

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1. Introductions
2. Review CE IRP Project Timeline
3. Proposed Course of Action (PCA)
4. Load Forecast
5. Siting Assumptions
6. Transmission Expense
7. Summary/Action Items
8. Schedule Next Meeting (February 2020)

1. Introductions
   - All invitees were in attendance
   - Two additional personnel from the first meeting were introduced:
     - Roma Notani, Consumers Energy
     - Thi Tran, METC
   - A new agenda topic, Summary/Action Items, was added

2. Review CE IRP Project Timeline
   - CE made an official data request to METC to study the transmission system impact of the Campbell retirement scenarios
   - Discussion of this request made up the majority of the meeting
   - CE indicated that it needs from METC the projected transmission expenses for Campbell Unit Retirement(s) in year 2031 by the end of January
   - CE indicated that it needs from METC the remaining retirement scenarios (years 2024, 2025, 2026, and 2028) by the end of February
   - The feasibility of METC accomplishing these requests by the time requested is discussed below

3. Proposed Course of Action (PCA)
   - CE provided METC with its present PCA to use for the Campbell Retirement Transmission System Impact Study
   - Existing and future generation assets were reviewed
   - At a high level, the PCA contains:
     i. 6,000 MW of solar by 2040
     ii. 1,200 MW of demand response (DR)
     iii. 2.5% energy waste reduction (EWR) savings by 2030
     iv. Conservation voltage reduction (CVR) of 110 – 115 MW
     v. Karn units 1 & 2 retiring 5/31/23
     vi. Palisades Power Purchase Agreement (PPA) terminates 5/31/22

- CE indicated that it has cost recovery pre-approval from the MPSC for the EWR, DR and CVR expansion through June 2022 tied to the energy legislation and that it is locked into the solar expansion through 2024, through the approval of those capacity solicitations.
- CE provided clarification regarding wind in the renewable energy plan:
    i. The renewable energy plan shows 525 MW of wind
    ii. The IRP shows 550 MW of wind – included in this number are two recently MPSC-approved projects

4. Load Forecast
    - CE provided METC with its most current load forecast as of the day of the meeting to use for the Campbell Retirement Transmission System Impact Study
    - METC inquired about the assumptions concerning Electric Vehicles and the effect on the load forecast
    - It contains CE's estimate of MISO's Planning Reserve Margin Requirement (PRMR) for Consumers Energy
    - Consistent with past practice, the forecast represents bundled customers in CE territory only – it does not include Alternative Energy Supplier (AES) customers – assumption should be that the 10% cap remains filled throughout the study period

5. Siting Assumptions
    - CE provided METC with siting information for future renewable generation resources to use for the Campbell Retirement Transmission System Impact Study
    - Distribution is defined as those resources interconnected to the 46kV system and below
    - METC has not historically modelled solar resources connected to Distribution – they will need to think through how/if to model

- The Load Forecast is prior to any PURPA resources – PURPA resources could look like a reduction to the load forecast
- Three categories of projects are presented:
  - Category 1: 584 MW of Solar PURPA contracts
  - Category 2: Remaining PCA Solar Generation, including the 2022 solicitation
  - Category 3: Wind Generation yet to be contracted
- Category 1: It is assumed that 100% will connect to Distribution. There are two tranches – the first tranche is 170 MW of actual known projects with known locations – the second tranche is 414 MW made up of projects not quite finalized – CE provides assumed locations based on its knowledge of the CE queue – METC believes these will be relatively easy to study from a power flow standpoint but won't necessarily be indicative of how things will actually work – METC will initially look at needed transmission assets from a worst case scenario (i.e. solar assets are not available due to clouds/nighttime and therefore needs to be backed up by transmission) – METC will need to think through whether or not this is a realistic worst case scenario – while METC believes that there will probably not be much, if any, impact of PURPA to the transmission system due to its small size and geographic diversity, METC will nonetheless verify this
- Category 2: It is assumed that 30% of this category will connect to Distribution and 70% will connect to Transmission. CE provided assumed siting locations for resources connected to Distribution. METC indicates that the identified distribution locations are helpful. CE is requesting two scenarios for METC to study for the transmission portion:
  - Scenario 1: Site at MISO Definitive Planning Phase (DPP) queue sites of same Regional Resource Forecast (RRF) fuel type without a signed Generator Interconnection Agreement (GIA).

    - Scenario 2: Similar to Scenario 1 above with the exception that in some years, the MISO queue information is replaced with certain sites that CE wants analyzed.

  METC felt that these distinctions might not make much of a difference, but they will verify

- Category 3: CE requested METC to look to the MISO Generation Queue (DPP-2018-APR-MI cycle) for siting guidance – this cycle is far enough down the path (Phase 2) that it provides some level of certainty beyond speculation
- As a general comment, it was recognized that looking to the MISO queue is the best place to look for siting guidance as it is the best information available at any given time

6. Transmission Expense Request
    - CE requested METC to provide the projected transmission expenses associated with the Campbell Unit Retirement scenarios.
    - CE states it is their understanding that METC will take all of the previously discussed assumptions, add a Campbell retirement, then communicate to CE what additional costs would be needed to the transmission system
    - METC suggested it will use a 5-year model as a base case since it incorporates mostly known projects and then amending for retirements and additions from this point
    - METC opined that they may initially look at the 2024 and 2031 Campbell retirement cases first and, if no major upgrade differences between the two years are present, they would likely stop the analysis there indicating that impacts are deminimus or not highly correlated to the PCA
    - CE states that it needs to know retirement costs in isolation (i.e. do not include costs of connecting replacement assets as CE has these assumptions already) – METC states it is unsure as to whether it can provide an accurate retirement costs (i.e. it may be an range) in

isolation because the power flow will change as the generation mix changes in terms of MW and location – see meeting minutes of February meeting (meeting 3) for clarifications on this point

- CE is looking for the revenue requirement needed to support the retirements – METC believes they can do this – their rates group should be able to provide an estimated percentage impact for each year
- CE indicated that it needs from METC the projected transmission expenses for Campbell Unit Retirement(s) in year 2031 by the end of the January– METC indicated that they could not reach this target as it will take time to build a 2031 model with the expected system changes including generation additions/retirements and identifying and incorporating system upgrades to support the topology changes.
- CE provided an estimate of network upgrade costs for generic capacity additions, as assumed in the 2018 IRP as $54,000/MW – METC indicated that they recently estimated an electrically remote project with costs of $150,000/MW – METC stated that a new cost estimate could not be done by the end of the month because legacy costs are not indicative of future costs due to the magnitude of new solar assets – METC indicated that it might make sense for CE to plug in the $150k mentioned above into its models to see if it impacts the PCA (METC suspects not) – this would provide CE with some bookends to work with while METC works out new figures
- CE states that it is concerned about double counting network upgrade costs for new resource additions since CE has this information already but METC may look to consider these as well. METC noted that due to the sequence of events during the first IRP, METC has never provided CE an estimated transmission investment to support its generation buildout in its PCA.
- CE indicated that it needs from METC the remaining retirement scenarios (years 2024, 2025, 2026, and 2028) by the end of February

7. Capacity Import Limit
    - From a capacity perspective, METC sees significant value in increasing the Capacity Import Limit (CIL). METC discussed its recent study to explore options to improve the CIL and its opinion that linking geographically diverse regions can have a significant effect on improving the composite capacity factor. METC indicated it intends to continue to explore the value in geographic diversity for renewable resources.
    - CE inquired if the Campbell retirements could change the CIL – METC will need to review the impacts to the CIL of retiring the Campbell units and adding new resources per the Siting Methodology – this will be done after the more time-sensitive Campbell retirement analysis needs explained above. CE made two requests: (1) What affect does the Campbell retirement have on CIL? If the impacts are negative, what are the alternatives and costs to preserve the CIL? (2) Will METC look at the effect of the CE's PCA on the CIL?
    - METC stated that it is planning to share its overall CIL study at the February 6 MPSC CIL Study meeting

8. Summary/Action Items
    - Retirement Analysis:
        i. Needed information:
            1. METC to perform a Transmission analysis on expenses associated with the retirement of Campbell unit 1, Campbell Unit 2 and both Campbell Units 1 and 2 together
            2. METC will the provide dollar amount and the percentage of revenue requirement by year for the transmission expense (see 1 above)
            3. METC will give context about retirement impacts to transmission system
            4. CE requested METC to do a CIL analysis of the impacts of Campbell retirement scenarios on the CIL

5. METC to provide transmission alternatives per the settlement agreement. In a capacity context, which this study is, METC views transmission alternatives as improvements to the CIL providing access to remote (geographically diverse) resources
6. Action Item: METC to provide feedback on CE's requested deadlines for this information by 1/23/20

- 2021 PCA:
    - i. Needed information:
        1. METC to provide Transmission Network Upgrade costs to support the current PCA (as defined in topics 3, 4, and 5 above).
        2. METC to provide and lead the discussion on the impacts to the CIL in the PCA
        3. CE will provide new 2021 PCA and alternative plan to METC when available
        4. METC to provide Transmission Network Upgrade costs for the transmission investment to support the new 2021 PCA when available.

9. Next Meeting
    - February 18, 2020 at 9am in Lansing
    - To be discussed:
        - i. CIL Study discussion
        - ii. Retirement Study Progress

Agenda to follow

CONSUMERS ENERGY (CE)
2021 INTEGRATED RESOURCE PLAN (IRP)
THIRD MICHIGAN ELECTRIC TRANSMISSION COMPANY (METC) MEETING
208 N. Capitol Ave., Suite 200
February 18, 2020, 10AM – NOON
MEETING MINUTES

Attendees:

Kwafo Adarkwa, Manager of Regulatory Strategy, METC
Teresa Hatcher, Director, Electric Supply Planning, CE
Chuck Marshall, Director, Transmission Planning, METC
Roma Notani, General Engineer I, CE
Ben Scott, Senior Engineer, CE
Thi Tran, Senior Engineer, METC
Kevin Van Oirschot, Electric Transmission & Market Regulation Director, CE
Sara Walz, Senior Engineering Technical Analysis Lead, CE

AGENDA

1. Review of the Last Meeting and Minutes

2. Review IRP Requirements and Timelines

3. Update from METC on Retirement Analysis

4. CIL Study Discussion

5. Monthly MPSC Staff Update Meetings – Joint CE/METC Report

1. Review of the Last Meeting and Minutes
    - Minutes of the last meeting were reviewed and discussed
    - Required amendments were identified
    - An updated version of the 2nd meeting minutes will be distributed prior to the next meeting

2. Review IRP Requirements and Timelines
    - These were reviewed as a reminder

3. Update from METC on Retirement Analysis
    - High-level steps for METC completing the Retirement Analysis were discussed:
        i. create model based on the current PCA provided by CE. METC to develop Corrective Action Plan (CAP) that identifies the transmission network upgrades required to support the current PCA.
        ii. retire Campbell
        iii. METC to develop a second CAP that identifies transmission network upgrades associated with Campbell retirement and develop the revenue requirement of the Campbell retirement CAP– METC is planning to provide a range of costs
        iv. CE will take the above revenue requirement from the Campbell retirement CAP as inputs to its economic retirement analysis
        v. After METC has provided the revenue requirement for the Campbell retirement CAP, METC will develop a revenue requirement associated with the CAP to support the current PCA (Item i. above).
    - CE was asked to determine when they anticipate Ludington to be run differently (i.e. pump during the day, generate at night – exact opposite of how it operates today)
    - METC is still anticipating the or 2nd or 3rd week of March for the Retirement Analysis results

- ACTION ITEM: METC to contemplate if/how an MCV sensitivity could be performed regarding post-2030 – the two cases to consider, per CE, were to assume the CE/MCV PPA expires and either (a) MCV continues to operate or (b) MCV shuts down? – the difference could be significant ~ 1800 MW

4. CIL Study Discussion
    - METC asked CE if they would be interested in their existing CIL study work – is CE interested
    - METC considering if/how to present CIL study in a public forum – METC sees value in increasing the CIL – once the new CE PCA is developed, ways to improve the CIL will be considered

5. MPSC Staff Update Meetings – Joint CE/METC Report
    - METC willing to meet with CE and MPSC on a regular basis to provide updates regarding when the two organizations met and what was talked about
    - Action Item: CE to prepare and provide a high-level bullets one-pager listing what was discussed and what level of engagement/participation CE would need from METC

The next meeting is scheduled for March 18 from 10AM to NOON. The meeting will take place at METC's facility at Wagner and Scio Church in Ann Arbor. This will coincide with a previously scheduled planning meeting for that afternoon. CE is to provide a list of attendees ahead of time in order to expedite security processing.

CONSUMERS ENERGY (CE)
2021 INTEGRATED RESOURCE PLAN (IRP)
FOURTH MICHIGAN ELECTRIC TRANSMISSION COMPANY (METC) MEETING
TELECONFERENCE
MARCH 18, 2020, 10AM - NOON
MINUTES

Invitees:

Kwafo Adarkwa, Manager of Regulatory Strategy, METC
Teresa Hatcher, Director, Electric Supply Planning, CE
Chuck Marshall, Director, Transmission Planning, METC
Roma Notani, General Engineer I, CE
Dwayne Parker, Director, HVD System Planning, CE
Ben Scott, Senior Engineer, CE
Thi Tran, Senior Engineer, METC
Kevin Van Oirschot, Electric Transmission & Market Regulation Director, CE
Sara Walz, Senior Engineering Technical Analysis Lead, CE
Jessica Woycehoski, Senior Engineer Lead, CE

AGENDA

1. Review of the Last Meeting and Minutes
2. Clarification Item from Meeting 2 Minutes
3. Review IRP Requirements and Timelines
4. 2018 Existing IRP Implementation
5. Retirement Analysis Results – METC

The meeting was changed from METC's Scio Church/Wagner Road facility to a conference call owing to COVID-19 work restrictions.

1. Minutes of the last two meetings were reviewed. Minor amendments were required and will be made and distributed by Consumers Energy.

2. See 1. Above.

3. IRP timelines and requirements were reviewed.

4. While the focus of past meetings has been on the 2021 IRP owing to the deadlines required for modelling, the other purpose of the CE-METC meetings is to ensure that the companies work together in implementing the 2018 IRP. It is anticipated that 2018 IRP Implementation will become a larger component of these meetings going forward. It was noted that METC's offer to review and share the results of its CIL/CEL Study with CE is a good starting point for the 2018 IRP implementation collaboration and would satisfy CE's request to examine the CIL/CEL for the 2021 IRP as well, with the understanding that additional analysis will be required as the new PCA becomes known.

5. METC indicated that modelling work for the requested retirement analysis is taking longer than anticipated. METC is now targeting a mid-April date for completion of this work. CE must have this analysis by the end of April at the absolute latest in order to keep the rest of the 2021 IRP project on schedule. If METC is ultimately unable to provide the requested retirement analysis by this time, CE will need to develop and use different model assumptions to start model runs.

   METC also affirmed its desire to assess the affects CE's 2021 IRP would have on the transmission system and provide CE an estimated cost of the corrective action plans.

CONSUMERS ENERGY (CE)
2021 INTEGRATED RESOURCE PLAN (IRP)
FIFTH MICHIGAN ELECTRIC TRANSMISSION COMPANY (METC) MEETING
TELECONFERENCE
APRIL 16, 2020, 9AM – 11AM
AGENDA

Invitees:

Kwafo Adarkwa, Manager of Regulatory Strategy, METC
Teresa Hatcher, Director, Electric Supply Planning, CE
Chuck Marshall, Director, Transmission Planning, METC
Roma Notani, General Engineer I, CE
Ben Scott, Senior Engineer, CE
Thi Tran, Senior Engineer, METC
Kevin Van Oirschot, Electric Transmission & Market Regulation Director, CE
Sara Walz, Senior Engineering Technical Analysis Lead, CE
Jessica Woycehoski, Senior Engineer Lead, CE

AGENDA

1. Retirement Analysis Results – METC

2. Other

Retirement Analysis Results – METC

*METC reviewed the process that they followed in developing the retirement analysis – CE understood the process and found the explanation helpful

*In performing their study, METC encountered violations/overloads as early as 2024 – this resulted in an estimate of not more than $20-million to retire Campbell units 1 and 2 or either as a single unit – the violations tend to be localized to the Campbell area and independent of the solar build out anticipated by CE's Proposed Course of Action (PCA) – more violations/overloads were discovered when attempting to model the PCA – METC will analyze these impacts further in order to develop a cost estimate for network upgrades required to support the PCA

*METC will issue a report detailing the Campbell Units 1 & 2 Retirement and the Network Upgrades for the PCA

>METC is planning to have the revenue requirement for the Campbell Retirement Analysis by the end of April

>METC anticipates having the Network Upgrade analysis in support of the PCA completed by the end of May

>METC did indicate that timing will be tight

*There are a few items that need to be finalized between CE and METC in the near future:

> METC and CE acknowledged that the assumptions regarding how Ludington operates will be important for transmission system studies associated with the IRP – METC evaluated two scenarios which varied the Ludington operations and found that the impacts to Campbell retirement are negligible – the scenarios studied by METC include potential worst case conditions with regard to pumping/generating operations – METC plans to run Ludington operational sensitivities to determine their impact on the PCA

>Discussion regarding operations of MCV occurred – METC indicated that their analysis shows the MCV plant retiring at the expiration of the current CE-MCV Power Purchase Agreement (PPA) in 2030 – CE notes that the plant life is 55 years – with plant operation beginning in 1990, its useful life conclusion in 2045 – ultimately, it is MCV's decision regarding whether or not to operate beyond 2030 – in any event, the assumption around MCV's operational life has a limited impact on the Campbell retirement analysis but could impact the transmission network upgrades required to support the current PCA

Next meeting in May 21, 1:30pm – 3:30pm

CONSUMERS ENERGY (CE)
2021 INTEGRATED RESOURCE PLAN (IRP)
SIXTH MICHIGAN ELECTRIC TRANSMISSION COMPANY (METC) MEETING
TELECONFERENCE
MAY 21, 2020. 130PM – 330PM
AGENDA

Invitees:
Kwafo Adarkwa, Manager of Regulatory Strategy, METC
Teresa Hatcher, Executive Director, Electric Regulatory & Strategy Implementation, CE
Chuck Marshall, Director, Transmission Planning, METC
Roma Notani, General Engineer I, CE
Ben Scott, Senior Engineer, CE
Thi Tran, Senior Engineer, METC
Kevin Van Oirschot, Electric Transmission & Market Regulation Director, CE
Sara Walz, Senior Engineering Technical Analysis Lead, CE
Jessica Woycehoski, Director, Electric Supply Planning, CE

AGENDA

1. Review of Last Meeting and Minutes
    a. Preliminary Approval
    b. METC to review in more detail and advise as to any questions or issues
2.
   Review IRP Requirements and Timelines
    a. Reviewed what is due and when

3. Revenue Requirement Associated with Campbell Retirement Analysis
    a. Provided by METC between meetings 5 and 6

   b. Clarifying questions asked: revenue requirement shown is METC's revenue requirement – CE will be a large percentage of that but not the total – S. Walz to address in the model
   c. Time value of money determined to be de minimus and overly precise – revenue requirement is an estimate at the upper end of estimates derived

4. Network Upgrades Associated with 2018 IRP Proposed Course of Action (PCA)
   a. T. Tran gave a presentation summarizing modeling process and assumptions
   b. The study summarizes the transmission network upgrade and interconnection facility costs for the buildout of 3,430 MW of solar and 234 MW of wind under the 2018 IRP PCA through the year 2031.
   c. Assumptions were made for Steady State, Stability, and Short-Circuit mitigations.
   d. METC determined a cost of $144/kw for both network upgrade and interconnection facility costs
   e. METC to share the presentation for our internal use only – a formal report will follow for public consumption

5. Review of Key Assumptions
   a. Ludington Operations
      i. METC ran sensitivities on Ludington as it operates today and assuming that all six units are pumping at 85% peak (this is different than today's operating guide).
      ii. Results of sensitivities not impactful through 2031.
   b. MCV
      i. METC ran sensitivities with MCV off and on after the PPA with Consumers expires
      ii. Results of sensitivities not impactful through 2031.

6. Other
    a. Outstanding items: formal report, MISO CIL/CEL study, Campbell retirements on CIL and corrective actions
    b. Next meeting scheduled for July 15, 2:30PM-4:30PM

CONSUMERS ENERGY (CE)
2021 INTEGRATED RESOURCE PLAN (IRP)
SEVENTH MICHIGAN ELECTRIC TRANSMISSION COMPANY (METC) MEETING
TELECONFERENCE
JULY 15, 2020. 230PM – 330PM
MINUTES

Attendees:
Ben Abing, Principal Engineer, METC
Kwafo Adarkwa, Manager of Regulatory Strategy, METC
Roma Notani, General Engineer I, CE
Ben Scott, Senior Engineer, CE
Thi Tran, Senior Engineer, METC
Kevin Van Oirschot, Electric Transmission & Market Regulation Director, CE
Sara Walz, Principal Engineering Technical Analyst, CE
Jessica Woycehoski, Director, Electric Supply Planning, CE

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(1) Reviewed and approved minutes of last meeting

(2) CE 2021 IRP Planning Meeting with MPSC Staff Debrief
   a. CE and METC met with the MPSC Staff on July 14 to discuss issues related to transmission
   b. Both CE and METC agreed that the meeting was successful and conveyed to staff that both parties are working together in the spirit of the settlement
   c. No action items were identified for either company as a result of the meeting
   d. CE plans to provide METC with a copy of the presentation given at the meeting by the end of the week – per joint agreement, the presentation will be amended with an ‘as of’ date in order to provide a time stamp to the data provided – this will allow for recognition of future updates as warranted

(3) A discussion regarding the use of MISO's MTEP19 vs MTEP20 data occurred
   a. At issue was whether or not updating the METC Retirement Analysis and the CE Modeling runs for MTEP20 information would be feasible
   b. MTEP cycles are typically approved by MISO in December. Final MTEP models are typically made available around the same time.
   c. Both parties agreed that the timing of the MTEP cycle approval and model availability and the amount of time and resources it takes to run the studies would make it difficult to incorporate MTEP20 information into the IRP analysis
   d. METC articulated that the model used (MTEP19 as of January 2020) was the most up to date and feasible model that can be used given the project timeline – furthermore, there is little meaningful difference in system topology between MTEP19 and MTEP20

(4) A discussion on the next project milestones for the transmission portion of the IRP process ensued
   a. CE stated that the bulk to the data gathering and vetting for the transmission effort was complete and that the next several months would be spent on model runs, leading ultimately to the company's new PCA around December – METC requested a meeting prior to this to review interim results ahead of the official unveiling of the new PCA – CE agreed that a meeting like this would be appropriate in the October time frame
   b. METC noted that the official report regarding the CE IRP and Campbell Retirement analysis will be ready by the end of July
      i. METC agreed to release a copy to CE prior to public dissemination
      ii. METC and CE will discuss this report at the August meeting
      iii. METC will outline process for public dissemination
      iv. Report will be made public well ahead of the next Technical Conference which is to be scheduled but tentatively planned for October

CONSUMERS ENERGY (CE)
2021 INTEGRATED RESOURCE PLAN (IRP)
EIGHTH MICHIGAN ELECTRIC TRANSMISSION COMPANY (METC) MEETING
TELECONFERENCE
August 25, 2020. 230PM – 330PM
MINUTES

Attendees:

Ben Abing, Principal Engineer, METC
Kwafo Adarkwa, Manager of Regulatory Strategy, METC
Anna Munie, IRP Implementation & Strategy Lead, CE
Roma Notani, General Engineer I, CE
Ben Scott, Senior Engineer, CE
Thi Tran, Senior Engineer, METC
Kevin Van Oirschot, Electric Transmission & Market Regulation Director, CE
Jessica Woycehoski, Director, Electric Supply Planning, CE

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(1) Review and approve minutes of last meeting
   a. Minutes were reviewed and amendments were made and agreed upon
   b. Final version to be sent to all parties

(2) Review IRP Requirements and Timelines
   a. Milestones were discussed
   b. Nothing urgent at this time

(3) Review METC's CE IRP and Campbell Retirement Analysis Report
   a. METC presented their near-final report at the meeting
   b. METC noted that there exists a lot of supporting data behind the summary report presented
   c. Discussions ensued regarding how much report detail to disclose – the following timeline was determined to address this issue:

i. Tuesday September 1: METC to submit report to CE
ii. Tuesday September 8: CE to provide comments, questions and/or redline edits back to METC for their consideration
iii. Tuesday September 15: METC to provide responses to the above to CE
iv. Tuesday September 22: METC-CE to meet to discuss all of the above (date approximate, to be scheduled)

(4) Transmission Alternatives

a. CE asks METC what transmission alternatives, if any, would be considered as part of the IRP?
b. METC indicates that any transmission alternatives would be connected to the MPSC mandate to look for ways to increase CIL
c. METC also indicates that the only other transmission alternatives would be the upgrades in the IRP/Retirement Analysis report
d. Although METC did say that they may have transmission alternatives when the new proposed course of action is released by CE
e. CE indicated that it would look to the transmission owner to provide transmission alternatives
f. Both parties conclude that if there were any viable transmission alternatives, other than the ones mentioned above, they would have been identified through the collaborative meeting process that has been ongoing since December 2019

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To: Consumers Energy

From: Michigan Electric Transmission Company

Date: May 6, 2021

Subject: Consumers Energy's Integrated Resource Plan | Transmission Evaluation

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On January 16, 2020, representatives from Michigan Electric Transmission Company, LLC ("METC") and Consumers Energy Company ("Consumers") had a meeting ("January 16 Meeting") to discuss Consumers' 2021 Integrated Resource Plan ("Consumers' 2021 IRP"). The January 16 Meeting was one of several meetings between METC and Consumers regarding Consumers' 2021 IRP. At the January 16 Meeting, Consumers requested METC to perform a study on the transmission system ("Transmission Study") that would model the effects of certain retirements contemplated in Consumers' 2018 Proposed Course of Action ("PCA") with November 2019 Updates. The details of the Consumers' request to METC for the Transmission Study are stated in the minutes of the January 16 Meeting, a copy of which is attached hereto as Exhibit A. METC has completed that Transmission Study, and a summary of the results are contained in this memorandum.

Please note that in completing the Transmission Study, METC made certain estimates and assumptions that may differ from actual numbers and scenarios. For example, in conducting this Transmission Study, the cost estimates developed to mitigate identified system needs were premised upon numerous assumptions, consequently the actual costs will vary depending on the actual generation additions, retirements, and the corresponding system power flows. While METC believes the assumptions made are reasonable for the purposes of this evaluation, no representation is made that the conditions assumed will, in fact, occur.

Consumers Defined Scenarios

1. <u>2031 Generation Additions and Retirements</u>: Transmission system upgrades required to support Consumers' 2018 PCA with November 2019 Updates expressed in $/kW.

2. <u>Campbell Retirements:</u> Transmission system upgrades required to support Campbell retirements for 2024 vs. 2031 (Campbell 1, Campbell 2, and Campbell 1 & 2 scenarios). The study only includes 2024 and 2031 models as there was no material impact between these bookend years.

3. <u>Karn 3 & 4 Retirements:</u> Transmission system upgrades required to support Karn 3 and 4 retirements by 2024.

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4. Campbell 1, 2, & 3 and Karn 3 & 4 Retirements: Transmission system upgrades required to support Campbell 1, Campbell 2, Campbell 3, Karn 3, and Karn 4 retirements by 2025.

Key Assumptions

The studied scenarios were developed by assembling combinations of select generation additions and retirements, as listed below. Additionally, other known in-state generation additions and retirements in accordance with DTE Energy's IRP were included to support the development of the model build.

Table 1: Consumers Retirements & Additions

Retired Units in 2031 Model			**Additions**	
Karn 1	Coal	255 MW	**Solar**	
Karn 2	Coal	260 MW	Transmission	3,430 MW
Karn 3	Natural Gas/Oil	608 MW	Distribution	1,470 MW
Karn 4	Natural Gas/Oil	611 MW	**Wind**	234 MW
Ada Cogeneration LP	Natural Gas	29.4 MW		
Cadillac Renewable Energy, LLC	Biomass	34 MW		
EARP Solar (Original)	Solar	2.02 MW		
Entergy Nuclear Power Marketing, LLC (Palisades)	Nuclear	813 MW		
Genesee Power Station LP	Biomass	35 MW		
Grayling Generating Station LP	Biomass	36.17 MW		
Heritage Stoney Corners Wind Farm I, LLC (Phase 2)	Wind	12.25 MW		
Heritage Stoney Corners Wind Farm I, LLC (Phase 3)	Wind	8.35 MW		
Hillman Power Company LLC	Biomass	18 MW		
Michigan Power LP 1	Natural Gas	123 MW		
Michigan Wind 1, LLC (PPA 2)	Wind	12 MW		
Michigan Wind 2, LLC	Wind	90 MW		
TES Filer City Station LP	Coal	60 MW		
Viking Energy of Lincoln A LP	Biomass	18 MW		
Viking Energy of McBain A LP	Biomass	18 MW		

Scenario 1

To build the year 2031 model, Generation additions for the Transmission Study included solar and wind units connected to the METC system at the projected amount (3664 MW) by 2031. New, distribution-connected solar generators were also added to the model, but they remained offline in all scenarios to allow proper analysis of the transmission network's performance and deliverability at forecasted load. All new solar and wind generators were modeled at preliminary sites as they were proposed in the MISO generator interconnection queue with another alternative considering four pre-selected sites (Weadock, Whiting, Campbell, and Cobb – Four Mile 138 kV). All solar and wind units were dispatched in accordance to MISO's Generator Interconnection Business Practice Manual (BPM-015) – 100% of generator's output capacity for solar and 15.6% for wind at peak, and 50% for solar and 90% for wind in the off-peak condition.

Generation retirements for scenarios analyzed included the removal of all units listed in Consumers Energy's PCA. Table 1 lists all generators anticipated to be retired or added to the METC system by 2031.

The power flow analysis was performed using MTEP19 2029 cases, with all MISO published updates through January 2020 and Consumers' provided load forecast. Adjustments to area interchange, Ludington, IESO imports/exports, generation and load were made to the baseline models as required to reflect the planning conditions in Michigan for each season. The study approach simulated single point of failure outages on the METC system to monitor the impact to the transmission network as a result of the change in generation resources in the METC footprint. P3 and P6 contingencies were not included under the assumption that generation redispatch would be an achievable corrective action plan for the issues identified.

To better present the cause and effect of the generator additions by areas, the METC system was divided into subregions as depicted in Figure 1.

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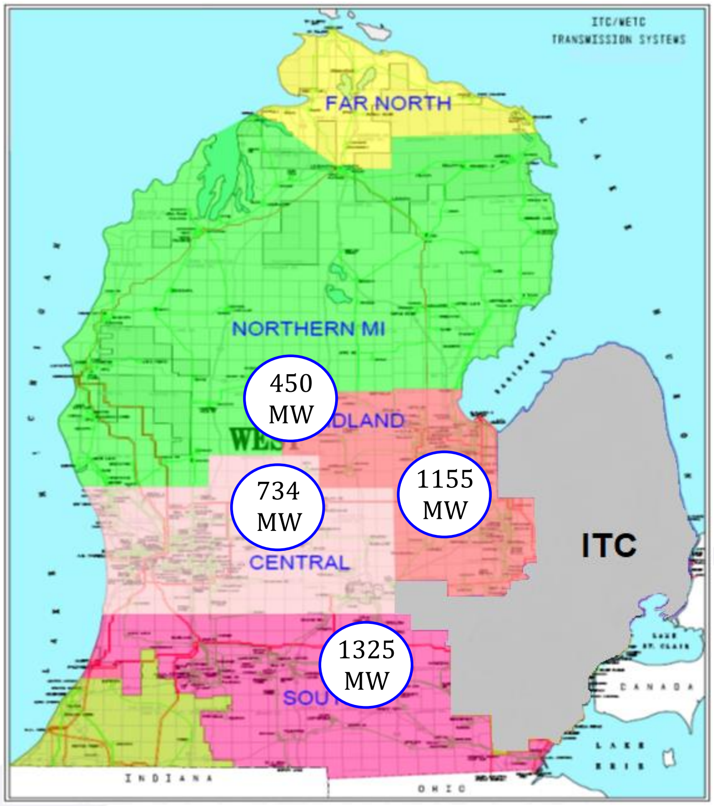
Figure 1: Study Areas with Total Generator Addition



Scenario 2

Two unique and year-specific models were used to assess the transmission system upgrades required to support the Campbell retirements in 2024 vs. 2031. The 2031 Campbell retirement analysis utilized the Transmission Study models with corresponding system upgrades in the 2031 basecase. Any new criteria violation as the result of Campbell units 1 and/or 2 going offline was considered to be a direct impact of the retirement(s). The development of 2024 study cases followed the same approach. The system was built out to 2024 and the associated transmission system upgrades to support the 2024 buildout were included in the basecase. Any new criteria violation as the result of Campbell units 1 and/or 2 going offline was considered to be a direct impact of the retirement(s).

Due to minimal difference in system upgrade needs between the two bookend models, it was unnecessary to perform the same analysis for the intermediate years. Therefore, only 2024 and 2031 study years were analyzed for the proposed Campbell retirements.

Scenario 3

The studied models for scenario 3 derived from the same 2024 basecases with solar buildout and associated transmission upgrades for that year. The models were then redispatched to create two different sets for study and comparison – Karn 3 and 4 units online and offline. With Karn 3 and 4 offline during peak condition, the METC system needed to bring in an additional 220 MW from outside of Michigan to make up for the capacity loss. The study methodology follows the same approach as previous scenarios. Any new criteria violation as the result of Karn units 3 and 4 going offline was considered to be a direct impact of the retirement(s).

Scenario 4

The development of 2025 study models for scenario 4 followed the same approach as the previous scenarios. The system was built out to 2025 and the associated transmission upgrades to support the 2025 were included in the basecase. Two sets of models were created for study and comparison with the main difference being the operating statuses of Campbell 1, Campbell 2, Campbell 3, Karn 3, and Karn 4 units. For the peak models with all of the aforementioned units offline, the METC system needed to import an additional 1,200 MW from outside of Michigan to make up for the capacity loss. The study methodology follows the same approach as previous scenarios. Any new criteria violation as the result of Karn units 3 and 4 going offline was considered to be a direct impact of the retirement(s).

Results

Scenario 1

All thermal and voltage violations were evaluated for mitigation plans. The proposed solutions consisted of replacing or upgrading existing equipment, including the rebuild of overloaded lines to achieve higher capacities. Per the solar sites in the DPP queue, new transmission facilities and ROW were assumed necessary for certain site configurations to maintain system stability. The transmission solution set is currently estimated at approximately $530 million. On a per unit basis, the transmission solution equates to approximately $144 per kilowatt ($/kW) of generation added pursuant to Consumers' PCA. The table below represents a high-level estimate of the types and number of transmission assets that would be needed for the solutions that address the scenario provided to and evaluated by METC.

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Table 2: 2031 System Issues by Areas

AREA	STATION EQUIPMENT	OVERHEAD	OVERHEAD & STATION EQUIPMENT
CENTRAL	1	13	6
FAR NORTH	0	2	0
MIDLAND	4	8	5
NORTHERN MI	2	2	1
SOUTH	0	6	0

Scenario 2

Steady state results showed some local system concerns in both 2024 and 2031 models, which drove the need for transmission upgrades near Campbell generator plant. The preliminary cost estimate to mitigate the projected system issues due to Campbell 1 and 2 retirement is approximately $20 million for a 345/138 kV transformer and overhead line upgrades.

Scenario 3

Steady state results for scenario 3 showed some transmission issues throughout the METC system when Karn 3 and Karn 4 are offline, resulting in the need for system upgrades to accommodate the retirements by 2024[1]. The preliminary cost estimate to mitigate the projected system issues due to Karn 3 and 4 retirements is approximately $12.4 million.

Scenario 4

Steady state analysis for scenario 4 identified a number of issues on the transmission system throughout the METC footprint when Campbell 1, Campbell 2, Campbell 3, Karn 3, and Karn 4 retire in 2025[2]. There is a total of eleven transmission upgrades required to accommodate the retirements, three of which are already in the MTEP21 cycle as target-A projects. The preliminary cost estimate to mitigate the projected system issues due to the aforementioned retirements, excluding MTEP21-submitted projects, is approximately $82.1 million. The system-upgrade cost including MTEP21-submitted projects is approximately $97.2 million.

[1] Consumers Energy requested the study for Karn 3 & 4 retirement by 2025. However, due to time constraints and considering the minimal difference between 2024 and 2025, both parties agreed to perform the analysis using the already-developed 2024 models.
[2] Consumers Energy requested the study for Karn 3 & 4 retirement by 2023 and Campbell 1, 2, and 3 by 2025. Both companies agreed that it made sense to study all the aforementioned generator retirements in one set of 2025 models.

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This analysis was scoped as a high-level evaluation based on available data and assumptions at the time of the study. It should not be treated as a representation of or equivalent to an Attachment Y1 study as performed by MISO due to various factors such as, but not limited to, modeling data, study process, and remedial actions.

Michigan Capacity Import/Export Limit Expansion Study

The Michigan Public Service Commission requested an informational study to determine transmission expansion options to increase the Capacity Import and Export Limits for MISO's Local Resource Zone 7

Contents

Executive Summary

In 2019, the Michigan Public Service Commission requested that MISO conduct a study to evaluate the needs of the Michigan grid under three specific scenarios to determine what transmission or alternative infrastructure could help Michigan enhance the capacity import capability into lower Michigan by specific amounts for each of three scenarios. The study has taken place during a time in which reserve margins in Michigan have tightened, while the speed of transition of the electric generation fleet in Michigan has accelerated.

The Michigan Capacity Import Limit and Capacity Export Limit (MI CIL/CEL) study considers the following three scenarios:

- Scenario 1 is a five-year out study, beginning with MISO's 2019 Transmission Expansion Plan (MTEP) model's 2024 summer peak assessment. Future generation and retirements from the OMS-MISO survey are included, as well as MTEP19 approved developments (including reinforcement projects related to the Bluewater Energy Center). This scenario focuses on near-term means to enhance the lower Michigan import limit by up to 1500MW.
- Scenario 2 is a 10+ year outlook, modeling summer 2032. The model starts with the Scenario 1 model and adds further generation additions and retirements in the ten-year time frame, but no further modifications to load forecasts or transmission. Approximately 9,000 MW of renewables are added, from current-filed IRPs. Resource modeling outside of lower Michigan is augmented based on MISO's "Accelerated Fleet Change" future. This scenario is intended to identify constraints and associated mitigation for a 3,000 MW expansion of the lower Michigan import limit.
- Scenario 3 is a 15-year outlook, modeling summer 2035. The model starts with the base model from scenario 1, additions from scenario 2, as well as additional renewable resources-approximately 27,000 MW of renewables beyond Scenario 1. Renewables were accommodated by downward dispatch of other generation, leading to most other Michigan generation offline, with the exception of the Fermi nuclear plant. This scenario tests robustness and sensitivity of transmission expansion options to generation fleet change uncertainty and seeks to achieve a 3,000 MW expansion of the lower Michigan import limit.

What is the significance of a "CIL/CEL" study? MISO's capacity mechanism (the Planning Resource Auction) incorporates both region-wide and zonal capacity requirements. Each zone (including Zone 7, lower Michigan) has a minimum in-zone requirement, which increases, or decreases based on the zone's ability to import capacity from other zones. To determine lower Michigan's capacity import limit in this study, the system-peak model dispatches generation higher in areas outside of lower Michigan (source region), and dispatches generation lower within lower Michigan (sink region). This creates higher flows into lower Michigan, which highlights transmission constraints that prevent further imports. From this starting point, transmission and alternative projects can be analyzed, with the goal of enhancing import capability to meet the objective of each scenario.

The MI CIL/CEL study resulted in two indicative transmission projects that allowed the CIL to surpass the 6,200MW goal shared in Scenarios 2 and 3. The first project involves a 345kV conductor re-build/upgrade of approximately 17 miles between Monroe and Lallendorf substations at an estimated cost of $53.5M. The second project involves building a new 345 kV substation named Husky, consisting of two four-position sections near the junction of Lemoyne-Majestic, Monroe-Lulu, and Monroe-Lallendorf, tapping all three lines and terminating the new sections. The cost of this project is estimated as $37.8M.

In evaluating the results of this study, it is important to consider three primary limitations to the analysis performed:

1. **The local area constraints identified in the study can be sensitive to the assumed siting of local future generation.** In both Scenario 2 and Scenario 3, assumptions were made regarding the location of up to 27,000MW of new renewable resources in Michigan. Therefore, the actual local area constraints

and associated upgrades could differ from those identified in this study[1]. Further, this study did not contemplate the required system build out needed to support the additional renewables which could also impact the location and magnitudes of future local area constraints.

2. **The study focuses only on dispatch and transfer capability during system peak conditions**. The CIL/CEL study was designed to provide clear inputs into MISO's Planning Resource Auction (PRA), a prompt-year residual market to help market participants fulfill capacity planning obligations. Since the PRA clears capacity against the summer peak, the CIL/CEL studies in the effort have used the same approach. This approach does not necessarily provide a picture of the import needs that Michigan may have for other time periods[2].
3. **MISO stakeholders must confront significant new reliability challenges as portfolio evolution picks up speed.** The issues that MISO stakeholders will need to address are broader than the single-peak view that this methodology captures. MISO's Renewable Integration Impact Assessment (RIIA)[3], which models renewable resources at increasing percentages on the grid, shows that grid complexities increase markedly at higher levels of renewable penetration. With these greatly increased complexities, it is possible that the import capability into Michigan will need to be higher than the 6,200 MW target evaluated for Scenario 3.

This study will inform MISO's broader Reliability Imperative initiative[4]. The Reliability Imperative's Market Redefinition workstream will contemplate changes to market structures to recognize and reflect the reliability needs of a grid in which a single zone, such as lower Michigan, could have surplus energy during one time-period, but scarcity in another. To ensure reliable power delivery in such situations, the Reliability Imperative's Long Range Transmission Planning (LRTP) workstream is focused on ensuring that the regional transmission grid is not a barrier to the rapid transition of resources that is ongoing and projected. While the CIL study began before the initiation of planning analysis on the LRTP; MISO expects that longer term development of the regional resources and grid will require additional strengthening of interstate ties to manage energy flows into and out of Michigan as well as other states. LRTP is a multi-year effort with solution proposals spanning several MTEP cycles. Successful development and implementation of the LRTP requires continuing discussion with stakeholders on both the ability of the transmission system to continue to perform reliably and efficiently, and on approaches to cost allocation for the plan. We encourage Michigan stakeholders to continue to engage with MISO on development of the LRTP in making decisions about how to proceed based upon the MI CIL/CEL study results.

[1] In contrast to regional constraints in moving power to the Michigan border that are less likely to vary after considering alternative sources from the regional pool.
[2] MISO stakeholders through the Resource Adequacy Sub-Committee are currently discussing moving to a seasonal PRA, which may require a seasonal CIL study.
[3] Information about MISO's RIIA can be found here.
[4] Information about MISO's response to the Reliability Imperative can be found here.

Disclaimer

This study is informational and aligns with study methodology similar to the 2021 Planning Resource Auction.

This type of transfer study is sensitive to inputs such as the location of future local generation which may impact study results.

Any and all future projects may require more study beyond the scope of this study to ensure compatibility with other MISO region upgrade plans and compliance with applicable reliability standards.

Additional reliability studies to inform total costs for proposals are outside the scope of this study. Direct comparison of costs between projects should not be undertaken. The projects listed in the table only resolve the CIL/CEL constraints; system impacts studies have not been performed for any of these projects to determine their reliability effect on the MISO Transmission System or impacts to Local Transmission Owner criteria

Study Result Summary

MISO performed analyses for Scenarios 1, 2, and 3 as described in the scope document[5]. Scenario 1 did not require additional transmission build to achieve the desired level. For Scenarios 2 and 3, several traditional transmission lines rebuild projects were considered and alternatives provided by stakeholders. to mitigate the identified constraints.

Table 1 identifies the scenarios that the projects and alternatives resolve.

Table 1: Matrix of Project Alternatives by Scenario

Project Proposals (S#=Scenario)	Project Description	Cost	Scenarios Yes – Desired level was achieved No – Desired level requires further 1	 2	 3
S2-ITC Original Project	1. Rebuild of Monroe-Brownstown 345 kV line 2. Rebuild of Monroe-Wayne 345 kV line	$159.5M	N/A	Yes	No
S2-Alternative Project #1 (LS Power)	Tap the Monroe – Lulu 345 kV and Monroe – Lallendorf 345 kV lines then merge the two tapped buses into one new bus called Pike Swale	$22.8M	N/A	Yes	No
S2-Alternative Project #2 (DTE)	Tap Lemoyne – Majestic 345 kV, build a new ~3 mile 345 kV double circuited line from the tap point to Monroe, add a new row at Monroe 12, terminate line to Lemoyne at Monroe 12, terminate line to Majestic at Monroe 34, and move Coventry line from Monroe 34 to Monroe 12	$26.3M	N/A	Yes	No
S2-Alternative Project #3 (DTE) (same as S3 #1)	Build a new 345 kV substation consisting of two four-position sections near the junction of Lemoyne – Majestic, Monroe – Lulu, and Monroe – Lallendorf. Tap all three of lines and terminate the new sections	$37.8M	N/A	Yes	Yes
S2-Alternative Project #4 (DTE)	Move the 425 MW future solar plant from Monroe 345 kV bus to Brownstone 345 kV bus	No Cost	N/A	Yes	No
S3-ITC Original Projects 20117 and 20116 (ITCT & METC)	Rebuild 16.63 miles of two 954 ACSR conductors on the Monroe – Lallendorf 345 kV circuit with double bundled 1431 ACSR conductor on double circuit steel towers with OPGW	$53.5M	N/A	Yes	Yes
S3-Alternative Project #1 (DTE) (same as S2 #3)	Build a new 345 kV substation named Husky consisting of two four-position sections near the junction of Lemoyne – Majestic, Monroe – Lulu, and Monroe – Lallendorf. Tap all three lines and terminate the new sections	$37.8M	N/A	Yes	Yes
S3-Alternative Project #2 (DTE)	Connect the Lallendorf – Monroe 345 kV and Monroe – Wayne 345 kV lines to form Lallendorf – Wayne 345 kV. This allows power to flow from out of state directly to Wayne. This project cannot be implemented before Monroe suspends or significantly curtails operations.	Not Analyzed	N/A	No	Yes
S3-Alternative Project #3 (DTE)	Site 500 MW capacity of Battery + Solar at Monroe 1	Not Analyzed	N/A	No	Yes

[5] See Appendix 1 for Study Scope

Note that one set of projects (ITC projects 20117 and 20116) resolves both the Scenario 2 and Scenario 3 constraints up to the targeted CIL value and one set of DTE projects (S2 Alternative 3 and S3 Alternative 1) resolves both Scenario 2 and Scenario 3 constraints up to the targeted CIL value. Refer to Appendix 2 for each project designation. The projects listed in the table only resolve the CIL constraints up to the targeted CIL values; system impacts studies have not been performed for any of these projects to determine their reliability effect on the MISO Transmission System or impacts to Local Transmission Owner criteria.

Table 2 presents an overview of results for the study. The table includes the required CIL outcome for each scenario, the CIL that resulted prior to application of any projects or alternatives and the cost estimates. The table also shows Capacity Export Limits (CEL) for each scenario, which were not constrained for any of the scenarios. Finally, Local Clearing Requirements (LCRs), both before and after project application, and for two different outage methods of calculating LCR, are included. The LCR represents the quantity of capacity that must be procured within a zone (in this case Zone 7, or lower Michigan), and is the result of the Local Reliability Requirement less the CIL.[6] LRR analysis took place using the actual resource mix for each scenario; however, any future change in approach to accreditation for any resource type (e.g. solar) would impact the resulting LRR and LCR calculations.[7]

Table 2: Summary of Results by Scenario

		Scenario 1	Scenario 2	Scenario 3
Desired CIL		4,700	6,200	6,200
CIL Prior to Project Additions		5,278	4,097	5,513
Projects added	CIL		6,466	6,491
Alternatives added	CIL		6466	6492
CEL		No Limit (GLT[8] @ 2%)	No Limit (GLT @ 30%)	No Limit (GLT @ 30%)
LCR Optimal Planned Outage	Pre-Upgrade	19,394	19,600	17,860
	Post-Upgrade		17,231	16,882
LCR Realistic Planned Outage	Pre-Upgrade	20,746	20,286	18,635
	Post-Upgrade		17,917	17,657

MISO uses Strategic Energy & Risk Valuation Model (SERVM) tool to determine the LRR for Zone 7 using two different planned outage modeling methods. Under Optimal Planned Outage approach, SERVM creates 30 unique outage schedules that are perfectly optimized for each of the 30 load shapes to avoid high load periods with

[6] More information regarding the Local Clearing Requirements and other parameters included in the Planning Resource Auction can be found by reading Business Practice Manual 011: Resource Adequacy
[7] MISO's Resource Availability and Need effort contains an evaluation of the resource accreditation process that is ongoing at the time of this study.
8 GLT: Generation and load in Tiers 1 and 2 are adjusted up to 50% to increase the capacity available to import into the study LRZ

perfect foresight. Under Realistic Planned Outage methodology, SERVM creates a single outage schedule that is optimized around the average of the 30 load shapes.[9]

Scenario 1: 5-Year Outlook

Scenario 1 is a 2024 five-year outlook utilizing the 2020 Out-Year CIL/CEL Analysis model and study assumptions. The base model includes probable generation added to tiers 1 and 2, the transfer source, to counter probable retirements modeled in those same areas. The study source and sink are defined in Table 3 below. Significant MTEP19 approved topology changes in Michigan (e.g. Blue Water Reinforcement Project and related changes) are also included in the base case. Analysis was performed using MISO's CIL/CEL process defined in BPM-015. This scenario identifies constraints for the local scope options of achieving a CIL +500 MW and +1500 MW above the 3200 MW CIL identified for LRZ 7 in the 2021-22 Planning Year CIL/CEL Analysis.

Sink	Source – Tier-1	Source – Tier-2
218 – METC	217 – NIPS	208 – DEI
219 – ITCT	296 – MIUP	357 – AMIL
		295 – WEC
		696 – WPS
		698 – UPPC

Table 3: LRZ 7 Source (Tier 1 and 2) and Sink

The initial CIL obtained for Scenario 1 was 5,278MW

- Limiting Constraint: *Monroe – Brownstown 345 kV for the loss of Wayne – Monroe 345 kV*
- No voltage violations
- No alternative projects were needed to reach the requested CIL level of 4,700MW

The base case transfer did not produce a valid constraint which resulted in performing a Generator Limited Transfer (GLT). The final limiting constraint and CIL was identified at a GLT of 20%.

CEL = No Limit Found

For the CEL analysis the base case transfer did not produce a valid constraint which resulted in performing a Generation Limited Transfer (GLT). A constraint was identified at a GLT of 2% and a redispatch of 1,321MW was applied to the model. The analysis was rerun, and no valid constraints were identified.

[9] More information regarding planned outage modeling methods can be found in the PY2021-22 LOLE study report via the link: https://cdn.misoenergy.org/PY%202021%2022%20LOLE%20Study%20Report489442.pdf

LRR/LCR Analysis

To perform the Local Reliability Requirement (LRR) analysis, MISO utilized the 2024 LRZ 7 out-year LRR model from the Planning Year 2021–22 LOLE study. The base model was updated according to the assumptions from the CIL/CEL study outlined in the scope. The LRR was evaluated under two different planned outage modeling assumptions to provide an upper and lower bound for the results. The lower bound was calculated by assuming perfectly optimized planned outages while the upper bound assumed realistically optimized planned outages. In each case evaluated under scenario 1 the total UCAP is greater than the LCR indicating sufficient capacity to meet the requirement. A summary of the Scenario 1 LRR/LCR results is shown in Table 4 below.

Local Resource Zone (LRZ 7)	Scenario 1 (2024)		Formula Key
	Optimal Planned Outage	Realistic Planned Outage	
Unforced Capacity (UCAP) (MW)	23,005	23,005	[A]
Adjustment to UCAP {1d in 10yr} (MW)	1,667	3,019	[B]
Local Reliability Requirement (LRR) UCAP (MW)	24,672	26,024	[C]=[A]+[B]
Peak Demand (MW)	20,360	20,360	[D]
LRR UCAP per-unit of LRZ Peak Demand	**121.2%**	**127.8%**	[E]=[C]/[D]
CIL	5,278	5,278	[F]
LCR	**19,394**	**20,746**	[G]=[C]-[F]

Table 4: Scenario 1 LRR/LCR Results

Scenario 2: 12-Year Outlook

Scenario 2 is a 2032 12-year outlook that builds upon Scenario 1 by adding Integrated Resource Plan (IRP) additions and retirements to LRZ 7. The list of generation and retirements requested by MI PSC and stakeholders can be found in the study scope in Appendix 1. Analysis was performed using MISO's CIL process with the source and sink remaining the same as Scenario 1 listed in Table 3. This scenario identifies constraints and associated mitigation for regional scope options of achieving a CIL +3,000 MW above the 3,200 MW CIL identified for LRZ 7 in the Planning Year 2021-22 CIL/CEL Analysis.

Initial CIL without ITC/alternative projects = 4,097MW

- Limiting Constraint: *Monroe – Brownstown 345 kV for the loss of Wayne – Monroe 345 kV*
- No voltage violations
- Projects, provided by ITC and stakeholders, were needed to reach the requested CIL level of 6,200MW

CIL with ITC projects = 6,466MW

- Limiting Constraint: *Racine Bus 7 – Mt. Pleasant 345 kV for the loss of Racine Bus 5 – Mt. Pleasant 345 kV*
- ITC project proposal 1: Rebuild approximately 7.3 miles of Monroe – Brownstone 345 kV
- ITC project proposal 2: Rebuild approximately 25.7 miles of Monroe – Wayne 345 kV
- Estimated cost of ITC projects 1 and 2 by MISO: $159.5M

The initial transfer case did not produce a valid constraint. As a result, a Generation Limited Transfer (GLT) analysis was performed. A GLT of 20% identified a CIL of 4,097MW with a limiting constraint of Monroe – Brownstone 345 kV for the loss of Wayne – Monroe 345 kV. This is the initial CIL without any applied projects as mentioned above.

The ITC project that rebuilds approximately 7.3 miles of Brownstone – Monroe #1 345 kV was applied to the model, the analysis was rerun, and a CIL of 4,404 MW was identified with a limiting constraint of Monroe – Wayne 345 kV for the loss of Wayne to Brownstone 345 kV. Since the CIL did not reach the requested level of 6,200 MW with the single ITC project applied, an additional ITC project was applied. This ITC project which rebuilds approximately 25.7 miles of Monroe – Wayne #1 345 kV was applied to the model with the initial project and analysis was rerun. The final limiting constraint and CIL was identified at a GLT of 25%. The total cost of both ITC projects as estimated by MISO is $159.5M. MISO's cost estimation guide for year 2020 was used with the cost estimation assumptions detailed in Appendix 3 to determine the project's cost. The locations of the ITC projects are shown on the Michigan maps in Appendix 2.

Mitigation identified for Scenario 3 was also tested against the Scenario 2 solution and was found to be adequate to achieve the desired CIL of 6,200MW.

CEL = No Limit Found

For the CEL analysis the initial transfer case did not produce a valid constraint. As a result, a Generation Limited Transfer (GLT) analysis was performed. No constraints were found up to a GLT of 30%.

LRR/LCR Analysis

As in Scenario 1, the LRR for Scenario 2 was evaluated with two different planned outage assumptions to determine an upper and lower bound. Furthermore, the LCR for Scenario 2 was evaluated both with and without the ITC upgrades identified from the CIL study. In each case evaluated under scenario 2 the total UCAP within the zone is greater than the LCR indicating sufficient capacity to meet the requirement. The results for Scenario 2 are shown in Table 5 below.

Local Resource Zone (LRZ 7)	Scenario 2 (2032)				Formula Key
	Optimal Planned Outage		Realistic Planned Outage		
	Pre-Upgrade	Post Upgrade	Pre-Upgrade	Post-Upgrade	
Unforced Capacity (UCAP) (MW)	23,917	23,917	23,917	23,917	[A]
Adjustment to UCAP {1d in 10yr} (MW)	-220	-220	467	467	[B]
Local Reliability Requirement (LRR) UCAP (MW)	23,697	23,697	24,383	24,383	[C]=[A]+[B]
Peak Demand (MW)	19,591	19,591	19,591	19,591	[D]
LRR UCAP per-unit of LRZ Peak Demand	**121.0%**	**121.0%**	**124.5%**	**124.5%**	[E]=[C]/[D]
CIL	4,097	6,466	4,097	6,466	[F]
LCR	**19,600**	**17,231**	**20,286**	**17,917**	[G]=[C]-[F]

Table 5: Scenario 2 LRR/LCR Results

Alternative Project Proposals for Scenario 2

This section describes the project proposals submitted by stakeholders as alternatives to the projects described above. The locations of the projects are shown on the Michigan maps in Appendix 2. The cost of projects, as determined by MISO, are limited to facility cost. A full reliability impact analysis has not been completed for the projects and alternatives due to the informational nature of this study. This cost was determined using MISO's cost estimation guide for year 2020 and the cost estimation assumptions detailed in Appendix 3.

Alternative 1: CIL with LS Power project = 6,462MW

- Limiting Constraint: *Racine Bus 7 – Mt. Pleasant 345 kV for the loss of Racine Bus 5 – Mt. Pleasant 345 kV*
- LS Power project proposal: Tap the Monroe – Lulu 345 kV and Monroe – Lallendorf 345 kV lines then merge the two tapped buses into one new bus called Pike Swale
- Estimated cost of LS Power project by MISO: $22.8M
- Exceeds requested CIL level of 6,200MW

The initial transfer case did not produce a valid constraint. As a result, a Generation Limited Transfer (GLT) analysis was performed. An initial limiting constraint of Monroe- Brownstown circuit 2 for the loss of Monroe-Brownstown circuit 1 at a CIL of 6,246MW was identified at a GLT of 25%. A dispatch of 1,920MW (960MW x2) was performed and the analysis rerun resulting in the final CIL and limiting constraint listed above.

Alternative 2: CIL with DTE project = 6,465MW

- Limiting Constraint: *Racine Bus 7 – Mt. Pleasant 345 kV for the loss of Racine Bus 5 – Mt. Pleasant 345 kV*
- DTE project proposal: Tap Lemoyne – Majestic 345 kV, build a new ~3 mile 345 kV double circuited line from the tap point to Monroe, add a new row at Monroe 12, terminate line to Lemoyne at Monroe 12, terminate line to Majestic at Monroe 34, and move Coventry line from Monroe 34 to Monroe 12
- Estimated cost of DTE project by MISO: $26.3M

- Exceeds requested CIL level of 6,200MW

The initial transfer case did not produce a valid constraint. As a result, a Generation Limited Transfer (GLT) analysis was performed. The final limiting constraint and CIL listed above was identified at a GLT of 25%.

Alternative 3: CIL with DTE project = 6,466MW

- Limiting Constraint: *Racine Bus 7 – Mt. Pleasant 345 kV for the loss of Racine Bus 5 – Mt. Pleasant 345 kV*
- DTE project proposal: Build a new 345 kV substation consisting of two four-position sections near the junction of Lemoyne – Majestic, Monroe – Lulu, and Monroe – Lallendorf. Tap all three of lines and terminate the new sections as follows: (1) at substation section #1, terminate lines to Monroe12, Majestic, and Lallendorf and (2) at substation section #2, terminate lines to Monroe34, Lemoyne, and Lulu
- Estimated cost of DTE project by MISO: $37.8M
- Exceeds requested CIL level of 6,200MW
- MISO has determined that the scope of this project is similar to Scenario 3 Alternative 1 project and, therefore, this project also resolves the Scenario 3 constraint.

The initial transfer case did not produce a valid constraint. As a result, a Generation Limited Transfer (GLT) analysis was performed. The final limiting constraint and CIL listed above was identified at a GLT of 25%.

Alternative 4: CIL with DTE project = No Limit Found

- Limiting Constraint: *No Limit Found*
- DTE project proposal: Move the 425 MW future solar plant from Monroe 345 kV bus to Brownstown 345 kV bus
- Estimated cost of DTE project by MISO: No cost
- Exceeds requested CIL level of 6,200MW

The initial transfer case did not produce a valid constraint. As a result, a Generation Limited Transfer (GLT) analysis was performed An initial limiting constraint of Elm Road – Racine Bus 6 345 kV for the loss of Cypress – Arcadian – Zion Station 345 kV + Arcadian 138/345 kV transformer at a CIL of 6,002MW was identified at a GLT of 25%. A dispatch of 686 MW was performed, and the analysis rerun resulting in no valid constraints identified.

Scenario 3: High Renewables as of May 31, 2035

Scenario 3 is a 2035 high renewable outlook that builds upon Scenarios 1 and 2 by doubling all renewable (wind and solar) nameplate capacity. Battery storage was modeled at 25% of the total MW of the project for combined solar + battery storage projects. Generation and retirements applied to the model are in Tables 3 and 4 of Appendix 1. Some of this generation was redistributed base on stakeholder feedback to avoid large system overloads and unrealistic interconnection points. Analysis was performed using MISO's CIL process with the source and sink remaining the same as Scenarios 1 and 2 listed in Table 3. This scenario identifies constraints and associated mitigation for regional, high renewable scope options of achieving a CIL +3000 MW above the 3200 MW CIL identified for LRZ 7 in the Planning Year 2021-22 CIL/CEL Analysis.

Initial CIL without ITC/alternative projects = 5,513MW

- Limiting Constraint: *Lallendorf – Monroe 345 kV for the loss of Fermi + Nuclear Plant Interface Requirement (NPIR) for proper cooldown*
- No voltage violations
- Alternative ITC projects needed to reach the requested CIL level of 6,200MW

CIL with ITC and METC project = 6,491MW

- Limiting Constraint: *Racine Bus 7 – Mt. Pleasant 345 kV for the loss of Racine Bus 5 – Mt. Pleasant 345 kV*
- ITC and METC project proposal: Rebuild 16.63 miles of two 954 ACSR conductors on the Monroe – Lallendorf 345 kV circuit with double bundled 1431 ACSR conductor on double circuit steel towers with OPGW
- Estimated cost of ITC (MTEP21 Target A Project 20117) project by MISO: $7.8M
- Estimated cost of METC (MTEP21 Target A Project 20116) project by MISO: $45.7M
- These two set of ITCT/METC projects also resolve the Scenario #2 constraints

The initial transfer case did not produce a valid constraint. As a result, a Generation Limited Transfer (GLT) analysis was performed A GLT of 25% identified a CIL of 5513 MW with a limiting constraint of Lallendorf – Monroe 345 kV for the loss of Fermi plus additional actions to insure proper cooldown via NERC Nuclear Plant Interface Requirements (NPIRs). This is the initial CIL without any applied projects as mentioned above.

An ITC project to rebuild 16.63 miles of Monroe-Lallendorf 345 kV was applied to the model and analysis was rerun. The final limiting constraint and CIL was identified at a GLT of 25%. As this portion of the 345 kV line is owned both by ITCT and METC (both ITC companies) for cost allocation purposes the project has been divided into two by ITC as ITCT Project 20117 and METC Project 20116. The total cost of the ITCT portion of the project as estimated by ITC is $7.8M. The total cost of the METC portion of the project as estimated by ITC is $45.7M. Note that for Scenario 3 the cost of the ITC projects were estimated using ITC's cost estimation methodology instead of MISO's cost estimation guide and assumptions, the reason being that ITC has submitted these projects into MTEP21 as Target A projects to resolve identified baseline reliability issue. The locations of the ITC projects are shown on the Michigan maps in Appendix 2.

CEL = No Limit Found

For the CEL analysis for Scenario 3 the initial transfer case did not produce a valid constraint. As a result, a GLT analysis was performed. No constraints were found up to a GLT of 30%.

LRR/LCR Analysis

The LRR model from Scenario 2 was modified according to Scenario 3 assumptions outlined in the scope to produce the Scenario 3 LRR model. As in Scenario 2, Scenario 3 evaluated the LCR with the two planned outage options as well as with and without the ITC upgrades identified via the CIL study. In each case evaluated under scenario 3 the total UCAP within the zone is greater than the LCR indicating sufficient capacity to meet the requirement. The results for Scenario 3 are shown in Table 6 below. The decrease of LRR between Scenario 2 and Scenario 3 could have several drivers, including demand reduction from Scenario 2 to Scenario 3, and different resource mix assumed in the scenarios, such as the availability of additional resources that remain unretired in the model and additional renewable resources added.

Local Resource Zone (LRZ 7)	Scenario 3 (2035)				Formula Key
	Optimal Planned Outage		Realistic Planned Outage		
	Pre-Upgrade	Post Upgrade	Pre-Upgrade	Post Upgrade	
Unforced Capacity (UCAP) (MW)	34,598	34,598	34,598	34,598	[A]
Adjustment to UCAP {1d in 10yr} (MW)	-11,225	-11,225	-10,450	-10,450	[B]
Local Reliability Requirement (LRR) UCAP (MW)	23,373	23,373	24,148	24,148	[C]=[A]+[B]
Peak Demand (MW)	19,310	19,310	19,310	19,310	[D]
LRR UCAP per-unit of LRZ Peak Demand	**121.0%**	**121.0%**	**125.1%**	**125.1%**	[E]=[C]/[D]
CIL	5,513	6,491	5,513	6,491	[F]
LCR	**17,860**	**16,882**	**18,635**	**17,657**	[G]=[C]-[F]

Table 3: Scenario 6 LRR/LCR Results

Alternative Project Proposals for Scenario 3

This section describes the project proposals submitted by stakeholders as alternatives to the ITC projects described above. The locations of the projects are shown on the Michigan maps in Appendix 2. The cost of the projects, as determined by MISO, is also included. This cost was determined using MISO's cost estimation guide for year 2020 and the cost estimation assumptions detailed in Appendix 3.

Alternative 1: CIL with DTE project = 6,453MW

- Limiting Constraint: *Husky – Monroe 345 kV for the loss of Fermi + Nuclear Plant Interface Requirement (NPIR) for proper cooldown*
- DTE project proposal: Build a new 345 kV substation named Husky consisting of two four-position sections near the junction of Lemoyne – Majestic, Monroe – Lulu, and Monroe – Lallendorf. Tap all three lines and terminate the new sections as follows: (1) at substation section #1, terminate lines to Monroe12, Majestic, and Lallendorf and (2) at substation section #2, terminate lines to Monroe 34, Lemoyne, and Lulu. Change line rating between new Husky substation to Monroe to 1440/1660/1660 MW.
- Estimated cost of DTE project by MISO: $37.8M
- Exceeds requested CIL level of 6,200MW
- MISO has determined that the scope of this project is the same as Scenario 2 Alternative 3 project and, therefore, this project also resolves the Scenario 2 constraint.

The initial transfer case did not produce a valid constraint. As a result, a Generation Limited Transfer (GLT) analysis was performed. The final limiting constraint and CIL was identified at a GLT of 25%.

Alternative 2: CIL with DTE project = 6,492MW

- Limiting Constraint: *Racine Bus 7 – Mt. Pleasant 345 kV for the loss of Racine Bus 5 – Mt. Pleasant 345 kV*
- DTE project proposal: Connect the Lallendorf – Monroe 345 kV and Monroe – Wayne 345 kV lines to form Lallendorf – Wayne 345 kV. Impedance on the new Lallendorf – Wayne 345 kV line is based on the

sum of the two existing lines. This allows power to flow from out of state directly to Wayne. This project cannot be implemented before Monroe suspends or significantly curtails operations.

- Estimated cost of DTE project: The costs associated with this alternative have not been estimated, but this alternative will require station and line work to bypass and decommission the Monroe station and tie the two lines together.
- Exceeds requested CIL level of 6,200MW

The initial transfer case did not produce a valid constraint. As a result, a Generation Limited Transfer (GLT) analysis was performed. The final limiting constraint and CIL was identified at a GLT of 25%.

Alternative 3: CIL with DTE Generation Project = 6489 MW

- This alternative sites 500 MW capacity of Battery + Solar at Monroe 1
- Limiting Constraint: *Racine Bus X – Mt. Pleasant #2 345 kV for the loss of Racine Bus X – Mt. Pleasant #5 345 kV*
- Estimated cost: MISO does not estimate the cost of generation projects
- Exceeds requested CIL level of 6200 MW

Conclusions

The Michigan Capacity Import Limit and Capacity Export Limit (MI CIL/CEL) study was an opportunity for Michigan stakeholders to envision how future portfolio change could impact the parameters in use for the Planning Resource Auction. Both Transmission Owning and non-Transmission Owning members submitted project alternatives to achieve desired increases to Capacity Import Limits, across three scenarios. The study resulted in several possible transmission and non-transmission projects options that surpassed the 6,200MW CIL goal shared in Scenarios 2 and 3.

Informational studies are important starting points, but it is also important to note how they could be improved by further analysis. Three limitations of note to this study methodology are:

- Local area constraints, such as the ones identified in this report, can be sensitive to the location of new resources modeled in each scenario.
- The study represents a model of a single point in time, under system peak conditions. Import capabilities could be different during other times and system conditions and may not reflect the import needs of lower Michigan.
- The Renewable Integration Impact Assessment and other future projections show a need for stakeholders to consider a broader set of risks and challenges than are currently considered in the CIL/CEL analysis.

Moving forward, MISO looks forward to working with stakeholders on further developing the outcomes of this study in the MTEP process, as well as understanding how these results work together with the LRTP effort that is now underway. While the CIL study began before the initiation of planning analysis on the LRTP, MISO expects that longer term development of the regional resources and grid will require both local strengthening of the grid within lower Michigan, as identified in this study, as well as strengthening of interstate ties to manage energy flows into and out of Michigan. One benefit of the LRTP, as a broader-scope planning process, will be to provide further enhancement of the import and export capabilities of each zone, including lower Michigan, along with other benefits that will serve to maintain and increase the reliability of the MISO grid as the generation fleet transformation continues.

MISO would like to thank the Michigan Public Service Commission for this opportunity to provide information as they work to provide reliable electric service to their consumers. MISO would also like to thank all of the Michigan stakeholders for participating in this study through scope design, model review and improvement, project and alternative submissions, and stakeholder meetings.

Appendices

Appendix 1: Final Scope Document

Background

In the MISO region, the responsibility for ensuring that enough resources will be available to meet the demand for electricity while also maintaining an adequate supply of reserves rests with individual Load Serving Entities, with oversight from state regulatory agencies where applicable. MISO's role is to provide transparency and establish planning reserve margin requirements to meet the utility industry's benchmark for reliability, a "1-day-in-10-years" loss-of-load expectation. Reserve margins requirements include both a regional requirement (i.e. the total amount of capacity needed to meet the reliability standard) and a local requirement (i.e. the amount of that total capacity which must be sourced locally within that zone). The local resource adequacy requirement (i.e. "Local Clearing Requirement") is driven by zonal generation and load characteristics as well as the transmission system's ability to reliably import capacity from other MISO Local Resource Zones (i.e. the "Capacity Import Limit").

For the 2019-2020 Planning Year, Local Resource Zone 7's Capacity Import Limit is 3,211 MW. When comparing the Local Clearing Requirements (LCR) to regional requirements, Local Resource Zone 7 must source nearly their entire resource adequacy requirement from within Local Resource Zone 7. As Michigan is experiencing a significant number of planned and future power plant retirements, additional import capacity may help Michigan access diverse and economical supplies of power, assist with reliability and resiliency during emergency conditions, and meet MISO's annual resource adequacy requirements, particularly with respect to LRZ 7's ability to meet the MISO Local Clearing Requirement.

In the Michigan State Energy Assessment report issued on September 11, 2019, the Michigan Public Service Commission (MPSC) recommended that the value of resilience should be incorporated in future electric infrastructure planning and investment decisions. On November 7, 2019, the Governor of Michigan and the MPSC, respectively, requested MISO to conduct analysis on the impacts of increasing Capacity Import Limits (CIL) and Capacity Export Limits (CEL) for MISO's Local Resource Zone 7 (LRZ 7). LRZ 7 geographically covers the majority of Michigan's Lower Peninsula (LP).

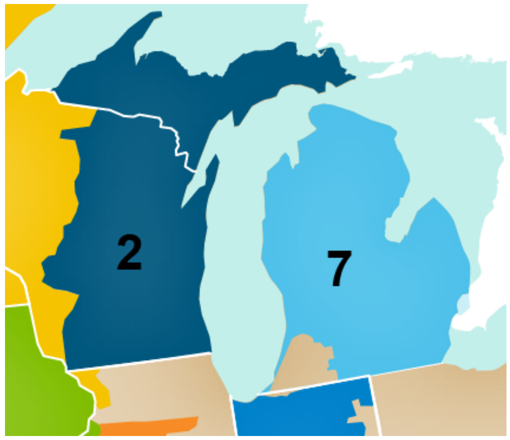


Figure 1: Local Resource Zone 7

Specifically, the MPSC seeks to better understand transmission and non-transmission solution options available to increase the limits into and out of LRZ 7 in the near and long term (e.g., the possibility of considering additional high voltage infrastructure coming into LRZ7), as well as an estimate of the corresponding costs and benefits.

The MPSC requested from MISO to first analyze increasing the CIL in the near term at increments such as 500 MW and 1,500 MW. The goal is to determine the infrastructure needed to accommodate cost-effective increases in the near term, with corresponding costs and benefits to LRZ 7 and other LRZs as applicable.

The MPSC's second request from MISO is to determine what types of projects could facilitate an increase in the CIL in LRZ 7 by larger increments over the next decade to accommodate additional renewable energy and other changes in the generation mix.

Study Methodology

The Michigan Capacity Import/Export Limit Expansion Study is an informational-only study to determine transmission expansion and non-transmission options to increase the capacity import and export limits for MISO's Local Resource Zone 7 (Lower Michigan). As this is an informational study, MTEP Appendix A project recommendations will not be made as a direct result of this study – any further action would be that of the MPSC or MISO stakeholders.

To determine an LRZ's capacity import or export limit, a generation to generation transfer is modeled by ramping generation up in the source subsystem and ramping generation down the sink subsystem. For import limit analysis, the sink subsystem is the study LRZ while the adjacent MISO areas are the source subsystem. For export limit analysis, the source subsystem is the study LRZ while the rest of MISO is the sink subsystem. After the transfer is run, limited redispatch is applied to mitigate constraints and produce the largest CIL or CEL. Redispatch ensures constraints are not caused by the base dispatch and aligns with potential actions that can be implemented for the constraint in MISO operations.

Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred is determined through First Contingency Total Transfer Capability (FCITC) analysis, which identify the total amount of transferrable power before a reliability constraint is identified. Reliability constraints consider steady-state thermal and voltage stability issues based on the NERC Transmission Planning Reliability Standards.

The voltage limited transfer analysis utilizes a generation to generation transfer that decreases generation in the study LRZ while increasing generation in Tiers 1 and 2 using proportional generation dispatch to initiate the transfer in TARA. There is no scaling of reactive output. Generators will try to maintain their voltage schedule with generation changing based on the powerflow solution. This method is more appropriate for peak hour transfer evaluation and respects summer peak projections for each LBA. It simulates real-time drivers for transfer across the system at peak hours and is also more reflective of system capability at peak hour.

The Michigan Capacity Import/Export Limit Expansion study will focus on identifying multiple potential transmission expansion scenarios:

- **Local Smaller-Scope:** Approximately 500 MW incremental increase in capacity import limit
- **Local Larger-Scope:** Approximately 1,500 MW incremental increase in capacity import limit
- **Regional:** 3,000 MW+ incremental increase in capacity import limit

Transmission expansions will be optimized to provide the highest capacity import limit increase to capital cost of the project ratio, while considering the targeted scope ranges. Capacity export limits will be calculated on final transmission expansion options. Additionally, final transmission expansions will be qualitatively evaluated in the context of broader regional needs (i.e. determination of how options fit with additional topology changes being considered through concurrent MTEP20 studies).

As the Michigan Capacity Import/Export Limit Expansion Study is focused on increasing the capacity import limit (decreasing the Local Clearing Requirement) which is MISO intra-zonal, transmission options will be primarily focused inside the MISO footprint or those which increase the LRZ7 CIL. The study will look at transmission expansion and non-transmission options both inside and outside of Michigan.

Study Tools

- Siemens PSS®E Version 33.12 - modeling
- PowerGEM TARA Version 1902.2 – transfer and voltage stability analysis

Scenarios

The Michigan Capacity Import/Export Limit Expansion Study will use a scenario-based approach to bookend out-year uncertainty in an effort to increase certainty in results. Thus, the associated capacity import limit increases for each option will be presented as a range that consider potential changes in the future generation mix (additions and retirements) as submitted by the Michigan PSC. Additional sensitivities beyond these scenarios will be considered on an as-needed basis.

Scenario 1: 5-year outlook

- Model: LOLE20 Out-Year transfer analysis model - built from the MTEP19 2024 Summer Peak base case
    - Same model used for 2020 MISO Out-Year CIL/CEL Analysis which includes future generation and retirements from the MISO-OMS Survey
    - Model updated with significant MTEP19 approved topology changes in Michigan and surrounding areas (e.g. Blue Water Reinforcement Project & related changes)
- Scenario will be used as the primary means to identify constraints and associated mitigation for the local scope options (+500 MW and +1,500 MW using MISO's CIL process)

Scenario 2: 10+ year outlook as of May 31, 2032

- Model: Base model from "Scenario 1" plus:
    - Integrated Resource Plan (IRP) additions and retirements in the 10+ year timeframe (2032) to LRZ 7 made (see Tables 1 and 2); no modifications to load or transmission
    - IRP generator locations based on the general location of the Point of Interconnection (POI) listed in the MISO Generation Interconnection Queue or by county

- First and Second Tier Local Resource Zone generation mix augmented based on the year 2032 expansion in the MTEP20 Accelerated Fleet Change Future, which is most comparable to the Michigan IRP – additional information on the Accelerated Fleet Change Future: https://cdn.misoenergy.org/MTEP19%20Futures%20Summary291183.pdf
- Offset the increase in additional MWs by turning down generation based on Merit/Tier Order in the same LRZ
- Will utilize a .95 power factor (pf) for inverters.
- Will assume the MISO standard of 50% for solar output.
- Will assume 100% output for Battery Storage.

- Scenario will be used as the primary means to identify constraints and associated mitigation for the regional scope options (3,000 MW+ using MISO's CIL process)

Name	Category	MW	Commission
Crescent Wind	Wind	166	December 2020
Cross Winds Phase 3	Wind	76	January 2020
Gratiot Farms Wind Project	Wind	150	December 2020
Ludington 3	Pumped Storage	72	October 2020
Cadillac Solar Garden	Solar	0.5	September 2020
PCA DR	DR	15	May 2020
PURPA PPA	Solar	150	September 2020
REP-IRP Wind Project	Wind	234	December 2021
PCA DR	DR	80	May 2021
PCA Solar	Solar	100	January 2021
PURPA PPA	Solar	150	May 2022
150 MW 2022 Solar - Build	Solar	150	May 2022
PCA DR	DR	75	May 2022
150 MW - PPA	Solar	150	December 2022
PURPA PPA	Solar	150	May 2023
150 MW 2023 Solar - Build	Solar	150	May 2023
PCA DR	DR	75	May 2023
PCA Solar - PPA	Solar	150	May 2023
PURPA PPA	Solar	134	May 2024
PCA DR	DR	80	May 2024
PCA Solar	Solar	500	May 2024
PCA DR	DR	80	May 2025
PCA Solar	Solar	500	May 2025
Solar	Solar	72.33333	May 2025
PCA DR	DR	80	May 2026
PCA Solar	Solar	500	May 2026
Solar	Solar	72.33333	May 2026
PCA DR	DR	80	May 2027
PCA Solar	Solar	500	May 2027
Solar	Solar	72.33333	May 2027
PCA DR	DR	80	May 2028
PCA Solar	Solar	500	May 2028
Solar	Solar	72.33333	May 2028
PCA DR	DR	80	May 2029
PCA Solar	Solar	600	May 2029
Solar	Solar	72.33333	May 2029
PCA DR	DR	83	May 2030
PCA Solar	Solar	600	May 2030
Solar	Solar	72.33333	May 2030
PCA Solar	Solar	600	May 2031
PCA Solar	Solar	150	May 2032
PCA Battery	Battery	50	May 2032
PCA Solar	Solar	150	May 2033
PCA Battery	Battery	50	May 2033
PCA Solar	Solar	150	May 2034
PCA Battery	Battery	50	May 2034
PCA Solar	Solar	150	May 2035
PCA Battery	Battery	50	May 2035
Polaris Wind	Wind	168	April 2020
Solar + Storage Pilot	Solar & Storage	0.75	December 2020
Dearborn CHP	CHP	34	May 2020
Demand Response	DR	16	May 2020
Isabella I and II (Wind VGP)	Wind	383.5	December 2020
Fairbanks (Wind VGP)	Wind	72.45	December 2020
Solar + Storage Pilot	Solar & Storage	10	December 2021

Name	Category	MW	Commission
Demand Response	DR	28	May 2021
2021 RPS Wind	Wind	225	December 2021
2021 Build Solar (VGP)	Solar	100	December 2021
2021 Build/PPA RPS Solar	Solar	79	December 2021
BWEC	NG CC	1150	May 2022
Demand Response	DR	46	May 2022
2022 Build Solar (VGP)	Solar	135	December 2022
2022 Build/PPA RPS Solar	Solar	49	December 2022
2023 Build Solar (VGP)	Solar	100	December 2023
Demand Response	DR	36	May 2023
2024 Build Solar (VGP)	Solar	100	December 2024
Demand Response	DR	5	May 2024
2025 Build Solar (VGP)	Solar	100	December 2025
2026 Build Solar (VGP)	Solar	100	December 2026
2027 Build Solar (VGP)	Solar	100	December 2027
2028 Build Solar (VGP)	Solar	100	December 2028
2029 Build Solar (VGP)	Solar	100	December 2029

Table 1: Scenario 2 LRZ7 Generator Addition Assumptions (provided by MI PSC)

Name	MW	Retirement
Eckert Station	80	January 2020
Eckert Station	80	January 2020
Eckert Station	80	January 2020
Eckert Station	44	January 2020
Eckert Station	47	January 2020
J B Sims	80	June 2020
River Rouge	85	May 2022
St Clair	160	May 2022
St Clair	165	May 2022
St Clair	319	May 2022
St Clair	452	May 2022
Trenton Channel	485	May 2022
Palisades	811.8	April 2022
Dan E Karn	136	May 2023
Dan E Karn	136	May 2023
Dan E Karn	130	May 2023
Dan E Karn	130	May 2023
Filer City Power Plant	73	May 2025
Erickson Station	154.7	December 2025
Belle River	527	May 2029
Belle River	529	May 2030
J H Campbell	259	May 2031
J H Campbell	348	May 2031
Dan E Karn	600	May 2031
Dan E Karn	608	May 2031
J H Campbell	780.1	December 2039

Table 2: Scenario 2 LRZ7 Generator Retirement Assumptions (provided by MI PSC)

Scenario 3: High renewables as of May 31, 2035

Model: Base model from "Scenario 1" with "Scenario 2" generation additions and retirements plus:

- All renewables (wind and solar) nameplate capacity doubled in Tables 3 and 4
  - 19,040 MW of renewables added beyond Scenario 2
- Assume battery storage modeled at 25% of the total MW of the project for combined solar + battery storage projects
- Fermi online
- Redistribute future generation based off stakeholder feedback to avoid large system overloads and unrealistic interconnection points
- Offset the increase in additional MWs by turning down generation based on Merit/Tier Order in the same LRZ

- Scenario will be used to test robustness and sensitivity of transmission expansion option's sensitivity to generation fleet change uncertainty
  - Target Capacity Import Limit = 6200 MW

Name	Category	MW	Commission
Crescent Wind	Wind	166	December 2020
Cross Winds Phase 3	Wind	76	January 2020
Gratiot Farms Wind Project	Wind	150	December 2020
Ludington 3	Pumped Storage	72	October 2020
Cadillac Solar Garden	Solar	0.5	September 2020
PCA DR	DR	15	May 2020
PURPA PPA	Solar	150	May 2021
REP-IRP Wind Project	Wind	234	December 2021
PCA DR	DR	80	May 2021
PCA Solar	Solar	100	January 2021
PURPA PPA	Solar	150	May 2022
150 MW 2022 Solar - Build	Solar	150	May 2022
PCA DR	DR	75	May 2022
150 MW - PPA	Solar	150	December 2022
PURPA PPA	Solar	150	May 2023
150 MW 2023 Solar - Build	Solar	150	May 2023
PCA DR	DR	75	May 2023
PCA Solar - PPA	Solar	150	May 2023
PURPA PPA	Solar	134	May 2024

Name	Category	MW	Commission
PCA DR	DR	80	May 2024
PCA Solar	Solar	500	May 2024
PCA DR	DR	80	May 2025
PCA Solar	Solar	500	May 2025
Solar	Solar	72.33333	May 2025
PCA DR	DR	80	May 2026
PCA Solar	Solar	500	May 2026
Solar	Solar	72	May 2026
PCA DR	DR	80	May 2027
PCA Solar	Solar	500	May 2027
Solar	Solar	72	May 2027
PCA DR	DR	80	May 2028
PCA Solar	Solar	500	May 2028
Solar	Solar	72	May 2028
PCA DR	DR	80	May 2029
PCA Solar	Solar	600	May 2029
Solar	Solar	72	May 2029
PCA DR	DR	83	May 2030
PCA Solar	Solar	600	May 2030
Solar	Solar	72	May 2030
PCA Solar	Solar	600	May 2031
PCA Solar	Solar	150	May 2032
PCA Battery	Battery	50	May 2032
PCA Solar	Solar	150	May 2033
PCA Battery	Battery	50	May 2033
PCA Solar	Solar	150	May 2034
PCA Battery	Battery	50	May 2034
PCA Solar	Solar	150	May 2035
PCA Battery	Battery	50	May 2035
Polaris Wind	Wind	168	April 2020
Solar + Storage Pilot	Solar & Storage	0.75	December 2020
Dearborn CHP	CHP	34	May 2020
Demand Response	DR	16	May 2020
Isabella I and II (Wind VGP)	Wind	383.5	December 2020
Fairbanks (Wind VGP)	Wind	72.45	December 2020
Solar + Storage Pilot	Solar & Storage	10	December 2021
Demand Response	DR	28	May 2021
2021 RPS Wind	Wind	225	December 2021

10

Name	Category	MW	Commission
2021 Build Solar (VGP)	Solar	100	December 2021
2021 Build/PPA RPS Solar	Solar	79	December 2021
BWEC	NG CC	1150	May 2022
Demand Response	DR	46	May 2022
2022 Build Solar (VGP)	Solar	135	December 2022
2022 Build/PPA RPS Solar	Solar	49	December 2022
2023 Build Solar (VGP)	Solar	100	December 2023
Demand Response	DR	36	May 2023
2024 Build Solar (VGP)	Solar	100	December 2024
Demand Response	DR	5	May 2024
2025 Build Solar (VGP)	Solar	100	December 2025
2026 Build Solar (VGP)	Solar	100	December 2026
2027 Build Solar (VGP)	Solar	100	December 2027
2028 Build Solar (VGP)	Solar	100	December 2028
2029 Build Solar (VGP)	Solar	100	December 2029

Table 3: Scenario 3 LRZ7 Generator Addition Assumptions (provided by MI PSC)

County	Category	MW	Commission
Oakland	Solar	200	May 2022
Macomb	Solar	155	May 2022
Midland	Solar	50	May 2022
Eaton	Solar	75	May 2023
Huron	Solar	20	May 2023
Clinton	Solar	50	May 2023
Oakland	Solar	200	May 2024
Van Buren	Solar	50	May 2024
Macomb	Solar	155	May 2025
Isabella	Solar	50	May 2025
Genesee	Solar + Storage	400	May 2025
Shiawassee	Solar	40	May 2025
Macomb	Solar	165	May 2026
Ionia	Solar	40	May 2026
Montcalm	Solar	40	May 2026
Barry	Solar	40	May 2026
1. Kent	Solar	130	May 2027
St. Joseph	Solar	40	May 2027

County	Category	MW	Commission
Tuscola	Solar	40	May 2027
Cass	Solar	40	May 2027
Kent	Solar	130	May 2028
Newaygo	Solar	40	May 2028
Hillsdale	Solar	40	May 2028
Branch	Solar	40	May 2028
Kent	Solar	130	May 2029
Mecosta	Solar	40	May 2029
Sanilac	Solar	30	May 2029
Gratiot	Solar	30	May 2029
Washtenaw	Solar	75	May 2030
Allegan	Solar	75	May 2030
Bay	Solar	75	May 2030
Lenawee	Solar	65	May 2030
Jackson	Solar + Storage	400	May 2030
Grand Traverse	Solar	60	May 2030
Lapeer	Solar	60	May 2030
Wexford	Solar	20	May 2030
Emmet	Solar	20	May 2030
Washtenaw	Solar	75	May 2031
Clare	Solar	20	May 2031
Mason	Solar	20	May 2031
Alpena	Solar	20	May 2031
Manistee	Solar	20	May 2031
Genesee	Solar	90	May 2032
Washtenaw	Solar	75	May 2032
Oceana	Solar	20	May 2032
Charlevoix	Solar	20	May 2032
Cheboygan	Solar	20	May 2032
Ingham	Solar	60	May 2033
Ottawa	Solar	60	May 2033
Livingston	Solar	40	May 2033
Saginaw	Solar	40	May 2033
Muskegon	Solar	40	May 2033
Calhoun	Solar	85	May 2033
Gladwin	Solar	20	May 2033
Iosco	Solar	20	May 2033
Otsego	Solar	20	May 2033

County	Category	MW	Commission
Kalamazoo	Solar	50	May 2034
Livingston	Solar	40	May 2034
Saginaw	Solar	40	May 2034
Muskegon	Solar	40	May 2034
Roscommon	Solar	20	May 2034
Antrim	Solar	20	May 2034
Osceola	Solar	20	May 2034
Leelanau	Solar	10	May 2034
Ingham	Solar	60	May 2035
Ottawa	Solar	60	May 2035
Kalamazoo	Solar	50	May 2035
Saginaw	Solar	40	May 2035
Ogemaw	Solar	10	May 2035
Monroe	Solar + Storage	400	May 2035
Kalkaska	Solar	10	May 2035
Benzie	Solar	10	May 2035
Missaukee	Solar	10	May 2035
Arenac	Solar	10	May 2035

Table 4: Scenario 3 LRZ7 Solar Additional Assumptions (provided by MI PSC)

Name	Category	Retirement
Eckert Station	80	January 2020
Eckert Station	80	January 2020
Eckert Station	80	January 2020
Eckert Station	44	January 2020
Eckert Station	47	January 2020
J B Sims	80	June 2020
River Rouge	85	May 2022
St Clair	160	May 2022
St Clair	165	May 2022
St Clair	319	May 2022
St Clair	452	May 2022
Trenton Channel	485	May 2022
Palisades	811.8	April 2022
Dan E Karn	136	May 2023
Dan E Karn	136	May 2023
Dan E Karn	130	May 2023
Dan E Karn	130	May 2023
Filer City Power Plant	73	May 2025
Erickson Station	154.7	December 2025
Belle River	527	May 2029
Belle River	529	May 2030
J H Campbell	259	May 2031
J H Campbell	348	May 2031
Dan E Karn	130	May 2031
Dan E Karn	130	May 2031

J H Campbell	780.1	December 2039

Table 5: Scenario 3 LRZ7 Generator Retirement Assumptions (provided by MI PSC)

Coordination

The Michigan Capacity Import/Export Limit Expansion Study will be conducted through an open and transparent study process. MISO stakeholders are encouraged to identify and submit potential solutions to the study. MISO will validate capacity import limits for any potential solutions using MISO's current capacity import limit analysis under the defined scenarios.

MISO and the incumbent Transmission Owner(s) ("TO") will collaborate to determine the most suitable transmission infrastructure recommendations for the identified issues. MISO and the incumbent TO may determine it more cost-effective to consider the long-term recommendations to address the near-term issues.

The primary forum for the Michigan Capacity Import/Export Limit Expansion study will be a stand-alone Technical Study Task Force (TSTF). When possible existing Michigan TSTF (MI TSTF) and Planning Advisory Committee (PAC) Meetings will be used to share results. Study initiation and conclusion will occur through the Planning Advisory Committee MISO will also take into consideration the non-transmission alternatives that may be offered from interested stakeholders at the TSTF meetings.

Additional meetings with the Michigan PSC and Governor's office will be scheduled by MISO as needed.

Tentative Timeline

Date	Venue	Purpose
February 6, 2020	MI PSC	Kick Off & Assumptions
February 12, 2020	PAC	Kick Off & Assumptions
May 20, 2020	MI TSTF	Initial Results Update
September 18, 2020	MI TSTF	Scenarios 1 and 2 Preliminary Results and Solution Submission
November 17, 2020	MI TSTF	Scenario 2 Alternative Project Results
February 12, 2021	MI TSTF	Scenario 3 Preliminary Results and Solution Submission
March 2021	MI TSTF	Scenario 3 Alternative Project Results
March 2021	MI PSC	Review results with Commission
April 2021	PAC	Final results

Table 5: Tentative tasks and targeted completion dates*

*Subject to change based on study scope and needs. Regional options may require additional time to study for coordination with concurrent MTEP20 studies.

Deliverables

At the conclusion of the study, MISO will provide the following deliverables:

- Final report
- Summary presentation

Deliverables will detail study results as well as study process and assumptions. Study results will include transmission expansion options (facilities, scope, and voltages), estimated cost for each transmission expansion option, the associated increase in capacity import and export limits under each scenario, and qualitative benefits as applicable.

To frame results in terms of resource adequacy requirements, year 2020 Loss of Load Expectation Results will be used – further information can be found: https://cdn.misoenergy.org/2020%20LOLE%20Study%20Report397064.pdf. Additionally, local reliability requirements (LRR) and local clearing requirements (LCR) for LRZ7 will be calculated using the generation fleet in Scenario 2 and Scenario 3.

As this study is an informational study to increase the capacity import limit, MISO will not make any project recommendations to MTEP Appendix A based on the outcome from this study.

Disclaimer

This analysis that is upon the request of the State of Michigan and the MPSC focuses on increasing the CIL into LRZ 7 with a primary focus on identifying transmission expansion options. While a scenario-based approach is used to increase confidence in study results, no guarantee should be assumed on future CIL/CEL values, which would be based on actual system topology and conditions. All CIL/CEL studies conducted using the processes and policies in place at the time of study.

With the retirement of a significant number of conventional generation resources, there is potential to reduce the inertia (the rotating mass) inside the LP, which would affect frequency response performance during islanding conditions. The reliance mainly on static VAR compensators and capacitor banks as options to increase the CIL to provide reactive power may not be practical under severe disturbances, which are not considered as part of this analysis.

Appendix 2: Projects and Alternatives

S2-Original Project (ITC): Rebuilding the Monroe-Brownstown and Monroe-Wayne 345 kV lines

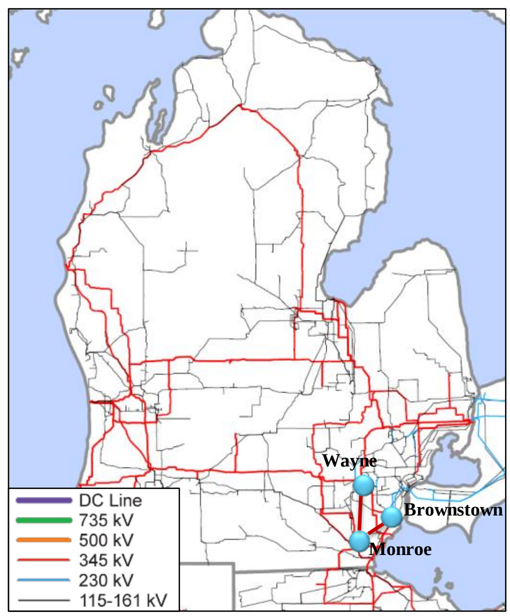
Cost Estimate = $159.5M

Monroe – Brownstown = ~18.2 miles

Monroe – Wayne = ~34.7 miles

Line added/rebuilt by alternative

Existing Substation



2

S2-Alternative Project #1 (LSPOWER): Tap the Monroe to Lulu 345 kV line at 86.86% from Lulu. Tap the Monroe to Lallendorf 345 kV line at 91.5% from Lallendorf. Merge the two tap buses into one. The retained new bus is the Pike Swale

Cost Estimate = $22.8M

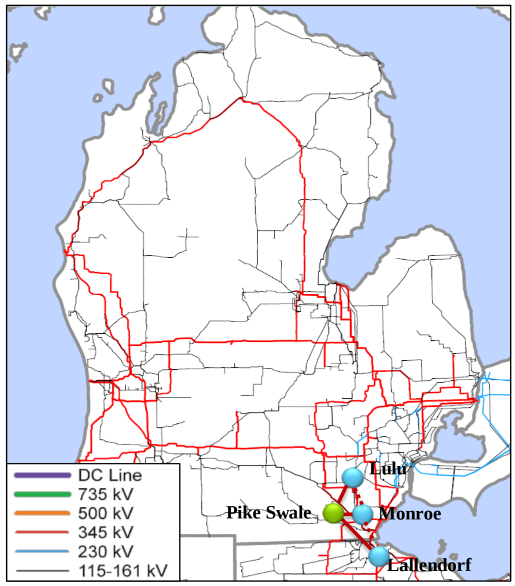
Pike Swale – Monroe = ~2 miles
Pike Swale – Lulu = ~13.2 miles
Pike Swale – Lallendorf = ~21.4 miles

Existing line deleted by alternative

Line added/rebuilt by alternative

Existing Substation

New Substation



MISO

S2-Alternative Project #2 (DTE): Tap Lemoyne – Majestic 345 kV, build a new ~3-mile 345 kV double circuited line from tap point to Monroe, add new row at Monroe 12, terminate line to Lemoyne at Monroe 12, terminate line to Majestic at Monroe 34, move Coventry line from Monroe 34 to Monroe 12.

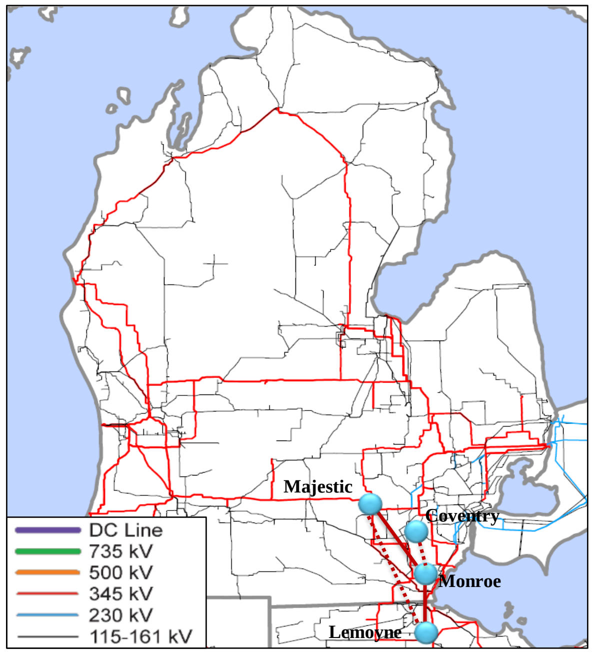
Cost Estimate = $26.3M

Monroe – Lemoyne = ~35 miles
Monroe – Majestic = ~67 miles

Existing line deleted by alternative

Line added/rebuilt by alternative

Existing Substation



MISO

S2-Alternative Project #3 (DTE): Build a new 345 kV substation consisting of two four-position sections near the junction of Lemoyne – Majestic, Monroe – Lulu, and Monroe – Lallendorf. Tap all three of these lines and terminate the new sections as follows: (1) at substation section #1, terminate lines to Monroe12, Majestic, and Lallendorf and (2) at substation section #2, terminate lines to Monroe34, Lemoyne, and Lulu.

Cost Estimate = $37.8M

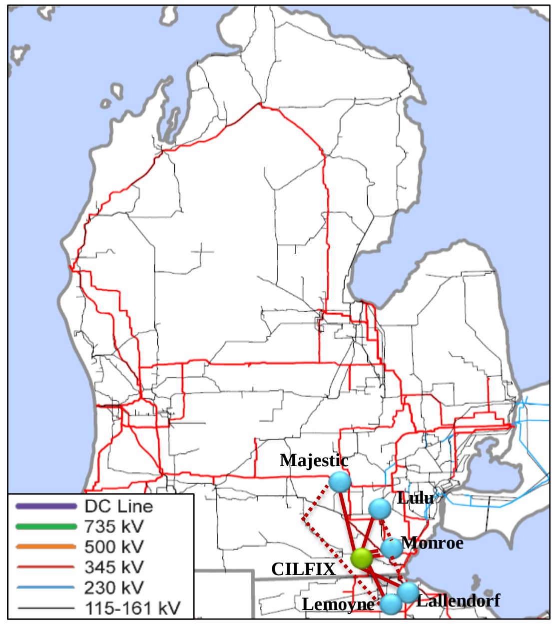
CILFIX1 – Monroe = ~3.4 miles
CILFIX1 – Lallendorf = ~20 miles
CILFIX1 – Majestic = ~64 miles
CILFIX2 – Monroe = ~3.4 miles
CILFIX2 – Lemoyne = ~32 miles
CILFIX2 – Lulu = ~11.8 miles

Existing line deleted by alternative

Line added/rebuilt by alternative

Existing Substation

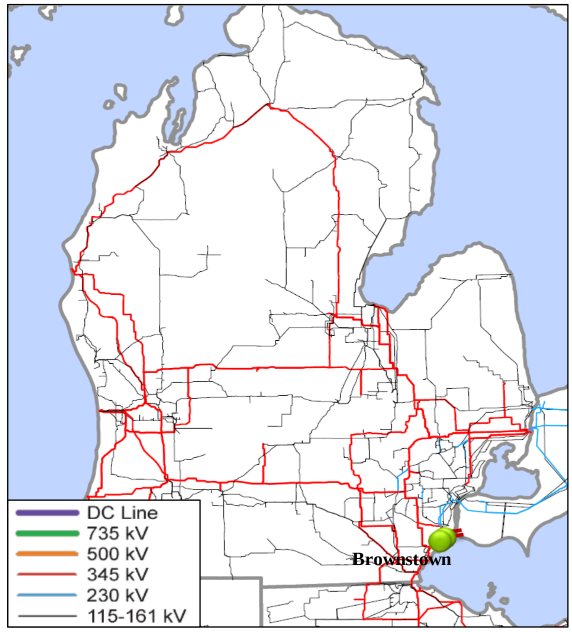
New Substation



S2-Alternative Project #4 (DTE): Relocate 425 MW future solar plant from Monroe to Brownstown 345 kV bus

Cost Estimate = No Cost

New Generation



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MISO

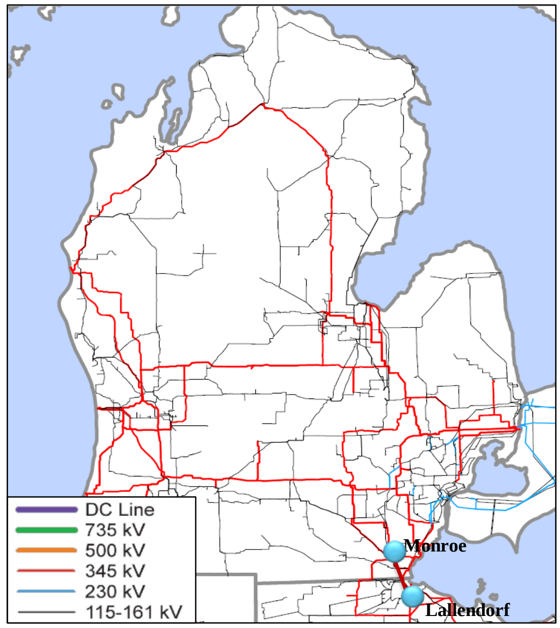
S3-ITC Original Project: MTEP21Target Appendix A Project 20116 Monroe – Lallendorf 345 kV Rebuild (ITCT Portion) - Rebuild 16.63 miles of the 2-954 ACSR conductor on the Monroe – Lallendorf 345 kV circuit to double bundled 1431 ACSR conductor on double circuit steel towers built to 345 kV construction with OPGW.

Cost Estimate = $7.8M

Monroe – Lallendorf = ~23.4 miles

Line added/rebuilt by alternative

Existing Substation



MISO

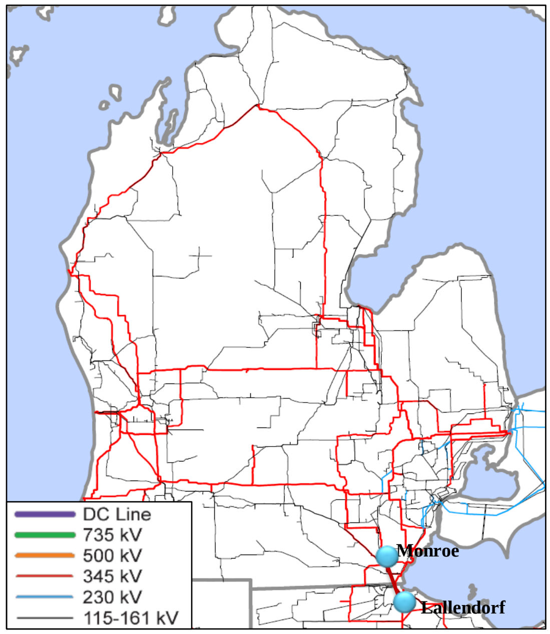
S3-ITC Original Project: MTEP21Target Appendix A Project 20117 Monroe – Lallendorf 345 kV Rebuild (METC Portion) - Rebuild 16.63 miles of the 2-954 ACSR conductor on the Monroe – Lallendorf 345 kV circuit to double bundled 1431 ACSR conductor on double circuit steel towers built to 345 kV construction with OPGW.

Cost Estimate = $45.7M

Monroe – Lallendorf = ~23.4 miles

Line added/rebuilt by alternative

Existing Substation



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MISO

S3-Alternative Project #1 (DTE): Build a new 345 kV substation named Husky consisting of two four-position sections near the junction of Lemoyne – Majestic, Monroe – Lulu, and Monroe – Lallendorf. Tap all three of lines and terminate the new sections as follows: (1) at substation section #1, terminate lines to Monroe12, Majestic, and Lallendorf and (2) at substation section #2, terminate lines to Monroe34, Lemoyne, and Lulu. Change line rating between new Husky substation to Monroe to 1440/1660/1660 MW

Cost Estimate = 37.8M

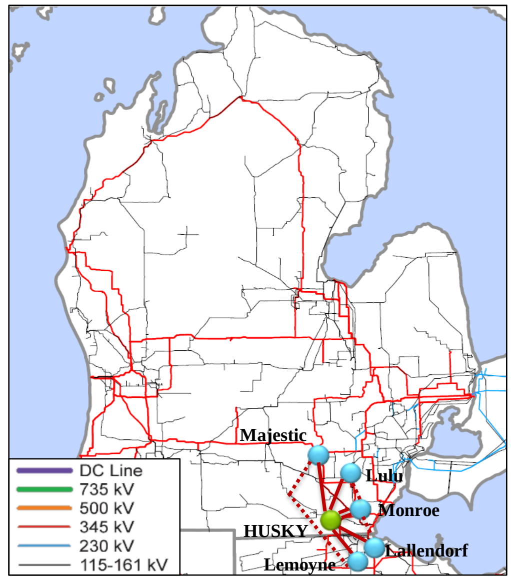
Husky1 – Monroe12 = ~ 3.4 miles
Husky1 – Majestic = ~ 63.8 miles
Husky1 – Lallendorf = ~ 20 miles
Husky2 – Monroe34 = ~ 3.4 miles
Husky2 – Lulu = ~11.8 miles
Husky2 – Lemoyne = ~ 32 miles

Existing line deleted by alternative

Line added/rebuilt by alternative

Existing Substation

New Substation



S3-Alternative Project #2 (DTE): DTE project proposal: Connect the Lallendorf – Monroe 345 kV and Monroe – Wayne 345 kV lines to form Lallendorf – Wayne 345 kV. Impedance on the new Lallendorf – Wayne 345 kV line is based on the sum of the two existing lines. This allows power to flow from out of state directly to Wayne. This project cannot be implemented before Monroe suspends or significantly curtails operations

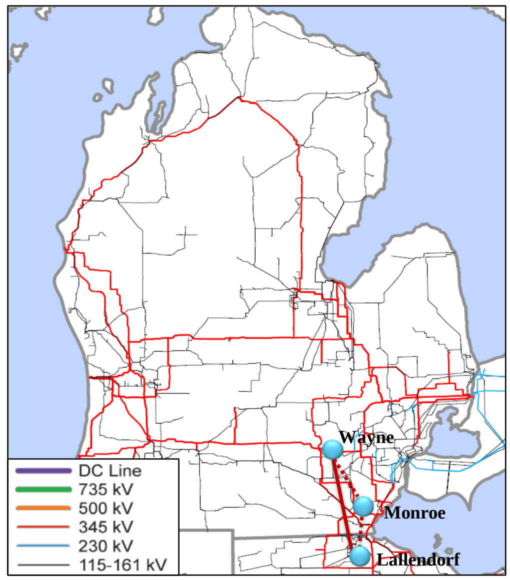
Lallendorf - Wayne = ~ 58.1 miles

Cost Estimate = No cost since project involves opening/closing circuit breakers to achieve the desired result

Existing line deleted by alternative

Line added/rebuilt by alternative

Existing Substation

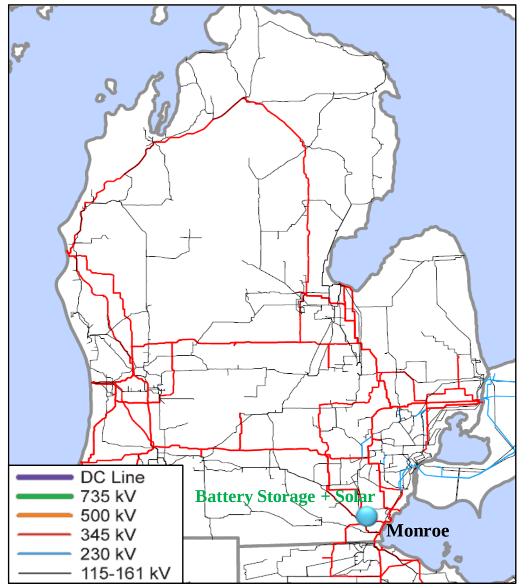


S3-Alternative Project #3 (DTE): Site 500 MW of Battery Storage + Solar at Monroe Substation

Cost Estimate: MISO does not estimate the cost of generation projects

Battery Storage + Solar at Monroe 1 substation
Capacity = 500 MW

Existing Substation



MISO

Appendix 3: Cost Estimation

Scenario 2 Project

MISO planning cost estimates
Michigan Capacity Import/Export Limit Expansion Study

Project	Transmission line scope of work	Substation scope of work	State location	Upfront Project Implementation Cost Estimate ($ nominal) - includes 20% contingency & 7.5% AFUDC adders
Rebuild Brownstown - Monroe	Rebuild Brownstown - Monroe 345kV double circuit line Line length: ~7.3 miles Replacing existing structures - assuming double circuit steel tower structures Replacing existing conductor - assuming 2-1431kcmil ACSR	None.	Michigan	$34.0M
Rebuild Monroe - Wayne	Rebuild Monroe - Wayne 345kV double circuit line Line length: ~24.7 miles Replacing existing structures - assuming double circuit steel tower structures Replacing existing conductor - assuming 2-1431kcmil ACSR	Wayne Substation: Replace 2 345kV circuit breakers, switches, bus work, relay panels, and control cable Monroe Substation: Replace 1 relay panel and control cable	Michigan	$125.5M

Cost estimates are planning cost estimate - see MISO's cost estimation guide for MTEP20 for overview of MISO's cost estimate assumptions (https://www.misoenergy.org/planning/transmission-planning/). If a project was identified for further analysis, a more refined scoping cost estimate would be completed in consultation with local Transmission Owner - if a project would be known to be developed by the local Transmission Owner, they would provide the cost estimate.

Scenario 2 Alternatives

Project	Transmission line scope of work	Substation scope of work	State location	Upfront Project Implementation Cost Estimate ($ nominal) - includes 20% contingency & 7.5% AFUDC adders
Alternative 1	Estimated 2 miles of new single circuit 345kV transmission to account for routing transmission lines into new substation.	Build one new 4-position, ring bus, 345kV substation.	Michigan	$22.8M
Alternative 2	Estimated 3 miles of new double circuit 345kV transmission from Tap Point to Monroe 12 and Monroe 34.	Add two line positions in existing substation in breaker-and-half configuration.	Michigan	$26.3M
Alternative 3	Estimated 2 miles of new single circuit 345kV transmission to account for routing transmission lines into two new substations.	Build two new 4-position, ring bus, 345kV substations. Substation #1: terminate lines to Monroe12, Majestic, Lallendorf, and new Substation #2. Substation #2: terminate lines to Monroe34, Lemoyne, Lulu, and new Substation #1.	Michigan	$37.8M

Cost estimates are planning cost estimate - see MISO's cost estimation guide for MTEP20 for overview of MISO's cost estimate assumptions (https://www.misoenergy.org/planning/transmission-planning/). If a project was identified for further analysis, a more refined scoping cost estimate would be completed in consultation with local Transmission Owner - if a project would be known to be developed by the local Transmission Owner, they would provide the cost estimate.

Scenario 3 Projects

Scenario 3 projects' cost were estimated by ITC since project has been submitted into MTEP21 to resolve identified baseline reliability issue

Scenario 3 Alternatives

<table>
<tr><th>Project</th><th>Transmission line scope of work</th><th>Substation scope of work</th><th>State location</th><th>Upfront Project Implementation Cost Estimate ($ nominal) - includes 20% contingency & 7.5% AFUDC adders</th></tr>
<tr><td rowspan="2">Alternative 1</td><td colspan="2">Assumed same project scope of work as Scenario 2, Alternative 3.</td><td rowspan="2">Michigan</td><td rowspan="2">$37.8M</td></tr>
<tr><td>Estimated 2 miles of new single circuit 345kV transmission to account for routing transmission lines into two new substations.

Assumed all existing transmission lines are rated sufficiently for this alternative - i.e., no existing transmission lines need to be reconductored or rebuilt.</td><td>Build two new 4-position, ring bus, 345kV substations.

Substation #1: terminate lines to Monroe12, Majestic, Lallendorf, and new Substation #2.

Substation #2: terminate lines to Monroe34, Lemoyne, Lulu, and new Substation #1.</td></tr>
<tr><td colspan="5">Cost estimates are planning cost estimate - see MISO's cost estimation guide for MTEP20 for overview of MISO's cost estimate assumptions (https://www.misoenergy.org/planning/transmission-planning/). If a project was identified for further analysis, a more refined scoping cost estimate would be completed in consultation with local Transmission Owner - if a project would be known to be developed by the local Transmission Owner, they would provide the cost estimate.</td></tr>
</table>

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21090
Exhibit No.: A-79 (BTS-4)
Page: 1 of 1
Witness: BTScott
Date: June 2021

Planning Resource Auction (PRA) Results for Local Resource Zone 7

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Planning Year (PY)	**2014-2015**	**2015-2016**	**2016-2017**	**2017-2018**	**2018-2019**	**2019-2020**	**2020-2021**	**2021-2022**	**Equation**
2	Planning Reserve Margin Requirement (PRMR)	22,998	22,678	22,406	22,295	22,121	21,976.0	21,945.3	21,459.2	**[A]**
3	Offer Cleared + Fixed Resource Adequacy Plan (FRAP)	22,627	23,515	21,534	21,956	21,801	21,811.6	21,727.5	21,549.4	
4	Local Clearing Requirement (LCR)	21,293	21,442	20,851	21,109	20,628	21,811.6	21,850.7	19,710.1	**[B]**
5	Capacity Import Limit (CIL)	3,884	3,813	3,521	3,320	3,785	3,211	3,200	4,888	**[C]**
6	Capacity Export Limit (CEL)	4,517	4,804	4,541	2,519	2,578	1,358	NLF	NLF	
7	"NLF" = No Limit Found									
8	**Portion of the CIL that could be used to meet PRMR**	**1,705**	**1,236**	**1,555**	**1,186**	**1,493**	**164**	**95**	**1,749**	**[D] = [A] - [B]**
9	**Portion of the CIL unutilized in PRMR**	**2,179**	**2,577**	**1,966**	**2,134**	**2,292**	**3,047**	**3,105**	**3,139**	**[E] = [C] - [D]**
10	**Percentage of CIL unutilized in PRMR**	**56%**	**68%**	**56%**	**64%**	**61%**	**95%**	**97%**	**64%**	**=[E]/[C]**

Reference to Public Data:

MISO-Home>Planning>Resource Adequacy>PRA Document
2014/2015 PRA Results: https://cdn.misoenergy.org/2014-2015%20PRA%20Results89073.pdf, p. 2;
2015/2016 PRA Results: https://cdn.misoenergy.org/2015-2016%20PRA%20Results87078.pdf, p. 6;
2016/2017 PRA Results: https://cdn.misoenergy.org/2016-2017%20PRA%20Results87167.pdf; p. 8;
2017/2018 PRA Results: https://cdn.misoenergy.org/2017-2018%20Planning%20Resource%20Adequacy%20Results87196.pdf, p. 9
2018/2019 PRA Results: https://cdn.misoenergy.org/2018-19%20PRA%20Results173180.pdf, p. 10.
2019-2020 PRA Results: https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf, p. 7
2020-2021 PRA Results: https://cdn.misoenergy.org/2020-2021%20PRA%20Results442333.pdf, p. 7
2021-2022 PRA Results : https://cdn.misoenergy.org/PY21-22%20Planning%20Resource%20Auction%20Results541166.pdf, p.7

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

EXHIBIT

OF

STEVEN Q. MCLEAN

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Annual Energy Waste Reduction Savings and Investments

Case No.: U-21090
Exhibit No.: A-80 (SQM-1)

Witness: SQMcLean
Date: June 2021

Line No.	Description	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	Consumers Energy IRP											
	Annual Energy Savings (MWh) [a]											
1	Base Outlook Savings	137,178	232,295	332,841	385,331	431,227	385,082	258,048	332,771	521,023	545,123	528,367
2	Prototype Incremental Savings	-	-	-	-	-	-	-	-	-	-	-
3	Total Savings	137,178	232,295	332,841	385,331	431,227	385,082	258,048	332,771	521,023	545,123	528,367
4	Annual % Savings	0.3%	0.7%	1.0%	1.1%	1.3%	1.2%	0.8%	1.0%	1.5%	1.7%	1.6%
	Summer Coincident Peak Demand Savings (MWs)											
5	Base Outlook Savings	16	44	84	130	182	228	274	336	383	430	509
6	Prototype Incremental Savings	-	-	-	-	-	-	-	-	-	-	-
7	Total Savings	16	44	84	130	182	228	274	336	383	430	509
	Annual Investments ($M) [b]											
8	Base Outlook Investments	$ 22.2	$ 33.8	$ 48.5	$ 67.4	$ 69.1	$ 74.9	$ 76.2	$ 77.2	$ 113.5	$ 117.8	$ 116.0
9	Prototype Incremental Investments	-	-	-	-	-	-	-	-	-	-	-
10	Financial Incentive	3.3	5.1	7.3	10.1	10.4	11.2	11.4	11.6	20.9	23.8	23.1
11	Total Investments	$ 25.5	$ 38.9	$ 55.8	$ 77.5	$ 79.5	$ 86.1	$ 87.6	$ 88.8	$ 134.4	$ 141.6	$ 139.1
12	Cost of Conserved Energy ($/kWh)	$ 0.0261	$ 0.0150	$ 0.0126	$ 0.0145	$ 0.0216	$ 0.0181	$ 0.0228	$ 0.0178	$ 0.0228	$ 0.0225	$ 0.0234

Notes:
(a) Excludes savings from Pilots, Education & Awareness, and market transformation adjustments.
(b) Includes investment from Pilots, Education & Awareness and Utility Financial Incentive.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Annual Energy Waste Reduction Savings and Investments

Case No.: U-21090
Exhibit No.: A-80 (SQM-1)
Page: 2 of 3
Witness: SQMcLean
Date: June 2021

Line No.	Description	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	Consumers Energy IRP											
	Annual Energy Savings (MWh) [a]											
1	Base Outlook Savings	593,173	657,200	654,300	653,160	323,250	324,042	325,967	328,686	332,072	343,692	356,094
2	Prototype Incremental Savings	-	-	-	-	246,449	221,263	204,235	211,688	211,977	181,406	184,203
3	Total Savings	593,173	657,200	654,300	653,160	569,699	545,305	530,202	540,374	544,048	525,098	540,297
4	Annual % Savings	1.8%	2.0%	2.0%	2.0%	1.8%	1.7%	1.7%	1.7%	1.7%	1.7%	1.7%
	Summer Coincident Peak Demand Savings (MWs)											
5	Base Outlook Savings	597	646	700	738	784	829	843	836	856	822	843
6	Prototype Incremental Savings	-	-	-	-	18	51	81	110	140	167	193
7	Total Savings	597	646	700	738	802	879	924	947	997	989	1,036
	Annual Investments ($M) [b]											
8	Base Outlook Investments	$ 141.7	$ 164.9	$ 166.4	$ 162.1	$ 68.7	$ 77.1	$ 77.2	$ 79.0	$ 80.7	$ 80.1	$ 83.1
9	Prototype Incremental Investments	-	-	-	-	75.4	88.2	85.6	92.6	96.0	84.5	90.6
10	Financial Incentive	28.3	33.0	33.3	32.4	28.8	33.0	32.6	34.3	35.3	32.9	34.7
11	Total Investments	$ 170.1	$ 197.9	$ 199.7	$ 194.5	$ 172.9	$ 198.3	$ 195.3	$ 206.0	$ 212.0	$ 197.5	$ 208.4
12	Cost of Conserved Energy ($/kWh)	$ 0.0251	$ 0.0252	$ 0.0263	$ 0.0275	$ 0.0273	$ 0.0326	$ 0.0330	$ 0.0338	$ 0.0348	$ 0.0335	$ 0.0368

(a) Excludes savings from Pilots, Education & Awareness, and market transformation adjustments.
(b) Includes investment from Pilots, Education & Awareness and Utility Financial Incentive.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Annual Energy Waste Reduction Savings and Investments

Case No.: U-21090
Exhibit No.: A-80 (SQM-1)
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Witness: SQMcLean
Date: June 2021

Line No.	Description	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Consumers Energy IRP										
	Annual Energy Savings (MWh) [a]										
1	Base Outlook Savings	401,559	427,395	468,198	578,444	587,788	731,651	651,883	633,147	647,610	633,530
2	Prototype Incremental Savings	35,304	14,664	21,378	49,435	49,138	78,427	55,091	49,603	51,658	46,486
3	Total Savings	436,864	442,059	489,576	627,879	636,926	810,078	706,973	682,750	699,268	680,017
4	Annual % Savings	1.4%	1.4%	1.5%	1.9%	1.9%	2.5%	2.2%	2.1%	2.2%	2.1%
	Summer Coincident Peak Demand Savings (MWs)										
5	Base Outlook Savings	751	774	726	777	827	877	924	974	1,022	1,070
6	Prototype Incremental Savings	207	207	205	203	201	198	196	194	192	190
7	Total Savings	958	981	931	980	1,028	1,075	1,120	1,169	1,214	1,261
	Annual Investments ($M) [b]										
8	Base Outlook Investments	$ 144.2	$ 162.5	$ 174.8	$ 175.7	$ 175.8	$ 192.9	$ 200.3	$ 202.3	$ 207.2	$ 217.5
9	Prototype Incremental Investments	15.7	-	6.2	7.7	10.0	22.0	25.8	27.4	32.1	39.7
10	Financial Incentive	32.0	32.5	36.2	36.7	37.2	43.0	45.2	45.9	47.9	51.4
11	Total Investments	$ 191.9	$ 195.0	$ 217.2	$ 220.1	$ 222.9	$ 257.9	$ 271.3	$ 275.6	$ 287.1	$ 308.7
12	Cost of Conserved Energy ($/kWh)	$ 0.0392	$ 0.0355	$ 0.0402	$ 0.0304	$ 0.0307	$ 0.0295	$ 0.0376	$ 0.0388	$ 0.0388	$ 0.0428

Notes:
(a) Excludes savings from Pilots, Education & Awareness, and market transformation adjustments.
(b) Includes investment from Pilots, Education & Awareness and Utility Financial Incentive.

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

EXHIBIT

OF

LAKIN H. GARTH

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

Electric Energy Waste Reduction Potential Study

2021-2040

June 10, 2021

Presented to:

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This report is a deliverable submitted to Consumers Energy as part of a multiyear, independent evaluation contract to conduct impact, process, and market assessment studies of residential energy waste reduction and demand response programs administered by Consumers Energy. The independent evaluation team includes the following firms:

Cadmus, Contract Lead

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Table of Contents

Tables

Figures

Acronyms and Abbreviations

Acronym	Definition
CBECS	Commercial Building Energy Consumption Survey
CEE	Consortium for Energy Efficiency
DEER	California Database of Energy Efficient Resources
DOE	U.S. Department of Energy
EERE	Office of Energy Efficiency and Renewable Technology (U.S. Department of Energy)
EIA	U.S. Energy Information Administration
EISA	Energy Independence and Security Act
EUL	Effective useful life
EWR	Energy waste reduction
IRP	Integrated resource plan
MEMD	*Michigan Energy Measures Database*
MPSC	Michigan Public Service Commission
NPV	Net present value
RECS	Residential Energy Consumption Survey
TLED	Tubular LED
TRM	Technical reference manual
UCT	Utility cost test

Executive Summary

Consumers Energy contracted with an independent evaluation firm, Cadmus, to conduct electric energy waste reduction (EWR) and demand response market potential studies. Cadmus and subcontractor Demand Side Analytics (collectively known as the Cadmus team) completed the two studies in parallel, incorporating a high degree of coordination with Consumers Energy program staff and system planners. This report presents the results of the electric EWR potential study; the results of the demand response potential study are presented in a separate companion report.

The Cadmus team designed the EWR potential study to provide a foundation for continuing utility-administered electric EWR programs in the Consumers Energy service area and for determining the remaining opportunities for cost-effective electric EWR in the residential and business sectors. This study presents the technical, economic, maximum achievable, and program achievable potential for each sector, as well as annual costs comprised of different EWR measures for the Consumers Energy Resource Planning team to use in its *2021 Integrated Resource Plan* (IRP). Figure 1 describes these types of potential in more detail.

Figure 1. Types of Potential Estimates

Technical Potential includes all technically feasible EWR measures, regardless of costs and market barriers, that are commercially available at the time of the study. The Cadmus team used a hybrid top-down, bottom-up approach to analyze energy waste reduction measures.

Economic Potential represents a subset of technical potential and consists of all EWR measures meeting the study's cost-effectiveness criteria using the Utility Cost Test, consistent with the Michigan's Clean and Renewable Energy and Waste Reduction Act (PA 342).

Achievable Potential represents the portion of economic potential that might be reasonably achievable, after accounting for market barriers that may impede customer adoption, including limitations in customers' willingness to adopt EWR measures. For this study, the Cadmus team considered two achievable potential scenarios:

- Maximum achievable includes estimates of gross savings potential including EWR measures not currently offered by Consumers Energy and an expanded distribution of home energy reports.
- Program achievable includes estimates of net savings potential for EWR measures that are offered or have potential to be offered by Consumers Energy over the 20-year study horizon.

Research Objectives

This report addresses three primary research objectives:

- Using the most recent, updated, and available market data, develop annual estimates of EWR electric potential for Consumers Energy to incorporate into its 2021 IRP.
- Using detailed measure-level incentives and program-level administrative costs, develop the most realistic estimates of the annual EWR potential acquisition costs for Consumers Energy to use in its 2021 IRP.

- Using forward-looking (emerging) technologies to examine savings potential to determine the potential for a transformational technology scenario to meet Consumers Energy's long-term EWR goals.

Research Approach

To address the research objectives, the Cadmus team conducted several distinct research activities for the 2020 Consumers Energy EWR potential study:

- Created a baseline end-use energy forecast that assumed no future, planned EWR, based on Consumers Energy customer data and forecasts
- Characterized a comprehensive set of electric EWR measures for the potential study, drawing primarily from the 2020 *Michigan Energy Measures Database* (MEMD)[1]
- Incorporated impacts from federal codes and standards into the modeling framework
- Modeled four levels of EWR potential: technical, economic, maximum achievable, and program achievable
- Developed detailed, annual acquisition costs of EWR for the maximum achievable and program achievable potentials
- Compiled and characterized a transformational technology scenario that includes an expansive set of emerging technologies, based on nascent commercially available technologies as well as technologies under research and development

The Cadmus team prepared 20-year forecasts of electric EWR and peak demand reduction potential for each measure. The team considered various building sectors and multiple vintages (new and existing), distinguished between lost opportunity and retrofit measures, and accounted for building energy codes and future federal equipment standards. Figure 2 outlines the three sectors analyzed in this study.

Figure 2. Study Sectors

1 Michigan Public Service Commission (supplied by Morgan Marketing Partners). Accessed 2020 version. "Michigan Energy Measures Database." https://www.michigan.gov/mpsc/0,9535,7-395-93309_94801_94808_94811---,00.html

Summary of Potential Study Results

For this potential study, the Cadmus team quantified the amount of electric EWR and demand reduction from EWR achievable within Consumers Energy's service territory from 2021 to 2040. Table 1 lists the cumulative electric resources of technical, economic, maximum achievable, and program achievable potential identified for five- and 20-year horizons. Electric EWR potential, representing nearly 6,714 GWh of maximum achievable potential and 5,740 GWh of program achievable potential, could produce approximately 1,374 MW and 1,027 MW of coincident summer peak demand reduction, respectively. All electric potential estimates in this report are presented at the customer site, meaning they do not include line losses that occur from the point of generation.

Table 1. Summary of Electric Energy Savings and Demand Reduction Potential: Cumulative 2025 and 2040

Electric Resource	Technical Potential	Economic Potential	Maximum Achievable Potential	Program Achievable Potential
2025				
Energy (MWh)	4,599,596	4,542,218	2,770,694	2,394,909
Peak Demand (MW)	1,064	1,058	485	383
2040				
Energy (MWh)	10,527,202	10,333,188	6,714,807	5,739,614
Peak Demand (MW)	2,481	2,462	1,374	1,027

Table 2 lists the sector-level cumulative electric technical, economic, maximum achievable, and program achievable potential estimated through the study. As shown in the table, there is over 10,527 GWh of cumulative technically feasible electric EWR potential by 2040, with cost-effective measures producing approximately 10,333 GWh of economic potential. Of Consumers Energy's forecasted 2040 sales, technical and economic potential each represent approximately 26%, equating to 1.5% of forecasted sales on an annual basis. As a percentage of total technical potential, the economic potential represents 98%.

For the 20-year maximum achievable potential, the residential sector accounted for 27% of the residential sector sales forecast, followed by the commercial sector (19%) and the industrial sector (15%). The maximum achievable and program achievable potential equated to 16.5% and 14.1% of forecasted annual electric sales in 2040, respectively.

Table 2. Electric Energy Waste Reduction Potential by Sector—Energy: Cumulative 2040

Sector	Baseline Sales (MWh)	Technical Potential		Economic Potential		Maximum Achievable Potential		Program Achievable Potential	
		MWh	% [a]	MWh	% [a]	MWh	% [a]	MWh	% [a]
Residential	14,861,197	5,515,726	37.1%	5,429,686	36.5%	2,262,348	15.2%	1,737,912	11.7%
Commercial	14,528,160	3,112,498	21.4%	3,061,027	21.1%	2,765,511	19.0%	2,483,449	17.1%
Industrial	11,204,888	1,898,978	16.9%	1,842,475	16.4%	1,686,948	15.1%	1,518,253	13.5%
Total [b]	**40,594,246**	**10,527,202**	**25.9%**	**10,333,188**	**25.5%**	**6,714,807**	**16.5%**	**5,739,614**	**14.1%**

[a] These columns are a percentage of baseline sales.

[b] May not equal sum of rows due to rounding.

The study identified electric EWR maximum achievable potential on both a cumulative and incremental basis, as shown in Table 3.

Table 3. Electric Energy Waste Reduction Potential by Sector—Energy: Cumulative and Incremental Maximum Achievable Potential 2040

Sector	Baseline Sales (MWh)	Maximum Achievable Potential – Total Cumulative Potential		Maximum Achievable Potential – Total Annual Incremental Potential	
		MWh	% [a]	MWh	% [a]
Residential	14,861,197	2,262,348	15.2%	4,723,600	31.8%
Commercial	14,528,160	2,765,511	19.0%	4,421,914	30.4%
Industrial	11,204,888	1,686,948	15.1%	2,359,759	21.1%
Total [b]	**40,594,246**	**6,714,807**	**16.5%**	**11,505,273**	**28.3%**

[a] These columns are a percentage of baseline sales.

[b] May not equal sum of rows due to rounding.

Cumulative potential accounts for measures that are converted during early years of the analysis but reach the end of their effective useful life before the end of the 20-year study timeframe. Cumulative potential assumes these measures are re-installed with a like-for-like technology and accumulated no additional savings compared to the baseline forecast. The cumulative savings are consistent with the EWR savings modeled by Consumers Energy for its Integrated Resource Plan as these represent the expected reduction in the baseline forecast.

Incremental potential assumes that, for measures that are converted during early years of the analysis and are re-installed with a like-for-like technology before the end of the study timeframe, the re-installation savings accumulate using the same per-unit savings as the original installation. Unlike cumulative savings, incremental savings serve as the basis for Consumers Energy's EWR Plan filings and targets, consistent with industry best practices and the recommendations of the National Action Plan for Energy Efficiency.[2]

Figure 3 illustrates the cumulative annual maximum achievable potential available in each sector. The slight change in slope depends on the rate in which discretionary resources and lost opportunity resources are acquired. Discretionary resources represent savings from measures that affect existing buildings or equipment that can be retrofitted at any time. Lost opportunity resources are savings from new buildings or equipment where, if energy efficiency is not incorporated upfront, it may not be available until the buildings undergo renovation or the equipment is replaced. For example, most discretionary resources will be acquired within the first 10 years (2021 and 2030), and the majority of the remaining potential after 2030 will be achieved through lost opportunity resources.

[2] Environmental Protection Agency. November 2007. *Guide for Conducting Energy Efficiency Potential Studies: A Resource of the National Action Plan for Energy Efficiency.* https://www.epa.gov/sites/production/files/2015-08/documents/potential_guide_0.pdf

Figure 3. Electric Energy Waste Reduction Potential by Year-Energy: Cumulative

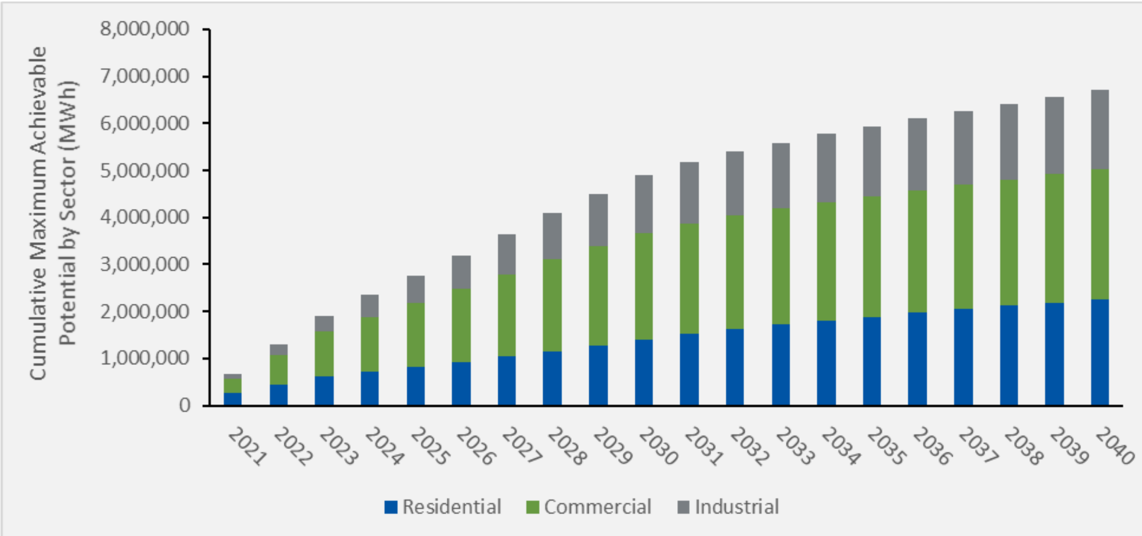


Table 4 shows the cumulative technical, economic, maximum achievable, and program achievable electric coincident peak demand reduction potential for Consumers Energy from 2021 through 2040. Over 99% of the technical electric coincident peak demand reduction is cost-effective. EWR measures provide substantial coincident peak demand reduction from EWR, with maximum achievable and program achievable potential equivalent to approximately 17% and 13% of forecast peak demand in 2040, respectively.[3]

Table 4. Electric Energy Waste Reduction Potential by Sector—Demand: Cumulative 2021 through 2040

Sector	Technical Potential (MW)	Economic Potential (MW) MW	Maximum Achievable Potential (MW)	Program Achievable Potential (MW)
Residential	1,661	1,654	672	397
Commercial	517	515	434	388
Industrial	304	294	269	242
Total [a]	**2,481**	**2,462**	**1,374**	**1,027**

The maximum and program achievable EWR potential estimated by the study provides considerable net economic benefits across the 20-year study horizon. Table 5 shows the net present value (NPV) of the 20-year maximum and program achievable potential benefits and costs, respectively, and the resulting utility cost test (UCT) benefit/cost ratios. The benefits shown in Table 5 include adjusted lifetime savings for residential and commercial screw-based lighting, consistent with the current policy in Michigan and

[3] The Cadmus team developed a peak load forecast for the companion demand response report that subtracted peak load impacts from existing EWR, conservation voltage reduction, retail open access customers, and the effects of a planned transition to default residential summer time-of-use rates from a base, unadjusted peak load forecast provided by Consumers Energy. The peak load forecast we developed equates to approximately 8,000 MW in 2040.

with the MEMD. The commercial and industrial sectors are combined into a single business sector in Table 5 because some Consumers Energy programmatic costs cannot be allocated directly to industrial and commercial customers.

Table 5. Maximum and Program Achievable Potential Utility Cost Test Benefits and Costs

Sector	Maximum Achievable Potential			Program Achievable Potential		
	NPV Benefits	NPV Costs	Benefit/ Cost Ratio	NPV Benefits	NPV Costs	Benefit/ Cost Ratio
Residential	$1,557,936,171	$813,573,354	1.91	$1,077,603,284	$629,154,475	1.71
Business	$3,468,808,813	$839,706,101	4.13	$3,115,968,648	$735,624,244	4.24
Total [a]	**$5,026,744,984**	**$1,653,279,455**	**3.04**	**$4,193,571,932**	**$1,364,778,719**	**3.07**

[a] May not equal sum of rows due to rounding.

Cadmus also calculated the customer electric bill savings across the study horizon associated with the maximum achievable potential results. The bill savings also incorporate a forecast of retail rates at the sector level.[4] Table 6 shows the customer bill savings associated with the maximum achievable potential, in 2040 in nominal dollars.

Table 6. Maximum Achievable Potential Customer Bill Savings, in 2040

Sector	Maximum Achievable Potential Customer Bill Savings
Residential	$576,600,156
Business	$809,272,244
Total	**$1,385,872,400**

In support of Consumers Energy's aggressive goals, Cadmus developed a transformational technology scenario that looked at expanded EWR potential that includes new and emerging technologies. The transformation technology scenario shows increased savings opportunities if key actions to further develop and demonstrate technologies, engage trade allies and consumers, and facilitate regulatory review and acceptance.

Table 7 shows the cumulative technical, economic, and maximum achievable potential when transformational technology measures are included in the potential estimation process. Overall, the transformational technology scenario represents a 63% increase over the initial estimate of maximum achievable potential.

[4] The forecast of retail rates by sector is included in Appendix B.

Table 7. Transformational Technology Scenario Electric Energy Waste Reduction Potential by Sector—Energy: Cumulative 2040

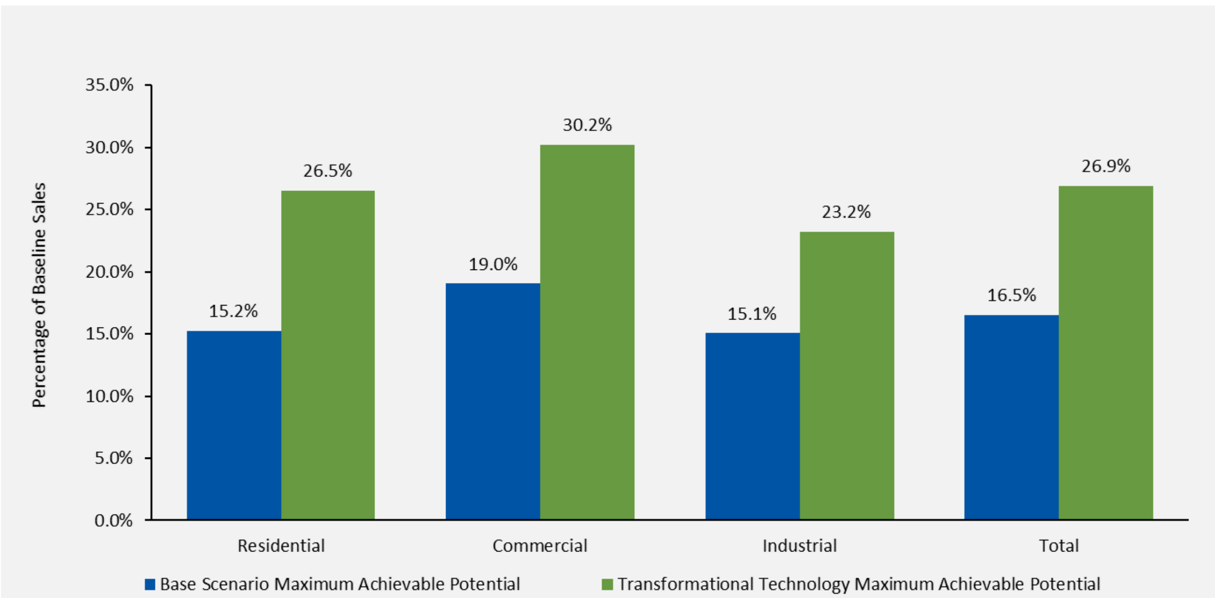
Sector	Baseline Sales (MWh)	Technical Potential		Economic Potential		Maximum Achievable Potential	
		MWh	% [a]	MWh	% [a]	MWh	% [a]
Residential	14,861,197	9,808,564	66.0%	6,943,146	46.7%	3,938,701	26.5%
Commercial	14,528,160	4,827,870	33.2%	4,773,253	32.9%	4,387,185	30.2%
Industrial	11,204,888	2,799,606	25.0%	2,754,011	24.6%	2,599,612	23.2%
Total [b]	**40,594,246**	**17,436,040**	**43.0%**	**14,470,410**	**35.6%**	**10,925,499**	**26.9%**

[a] These percentages are of baseline sales.

[b] May not equal sum of rows due to rounding.

Figure 4 compares the 2040 cumulative maximum achievable potential by sector, as a percentage of baseline sales, to the transformational technology scenario.

Figure 4. Comparison of Percentage of Baseline Sales for Maximum Achievable Potential in Transformational Scenario and Base Scenario – Electric Energy: Cumulative 2040



Conclusions

There are several key conclusions for Consumers Energy to consider in translating this study's estimates of EWR potential into its 2021 IRP:

- ***LED standard screw-based lighting represents significant EWR potential savings in the residential and commercial sectors in 2021, 2022, and 2023.*** Despite the U.S. Department of Energy's (DOE) December 27, 2019, final rule and determination that effectively rescinded the Energy Independence and Security Act (EISA) 2020 backstop standard, substantial uncertainty remains regarding the future of that standard and the effect of DOE's final rule on energy savings potential for LEDs within EWR programs. The general service LED lighting potential savings account for approximately 8% of the total 20-year electric maximum achievable potential for residential homes.

- ***Specialty LED lighting, including lamps that are exempt from the EISA 2020 backstop standard, represent significant EWR savings potential.*** For this study, the Cadmus team assumed a market shift to LED specialty lamps as a baseline technology, starting by the end of 2024. These lamps account for almost 8% of the total 20-year electric maximum achievable potential for residential homes.
- ***Advanced and emerging residential measures offer substantial long-run, cost-effective EWR potential.*** Advanced Tier 4 central air conditioners, with a SEER rating of 21, demonstrate cost-effective EWR and peak demand potential in the early years of the study and after the 2023 central air conditioning federal standard takes effect. One emerging technology measure included in the study, heat pump dryers, represents a significant savings opportunity for this ubiquitous residential end use, as nearly 96% of single family homes have an electric dryer. Combined, these two measures account for approximately 6% of the total 20-year electric maximum achievable potential for residential homes.
- ***Appliance recycling measures contribute significant, cost-effective EWR potential.*** The refrigerator and freezer recycling measures combined account for 46% of the total, 20-year maximum achievable electric EWR potential. With nearly 1.4 refrigerators and 0.6 stand-alone freezers per single family home, 1.2 refrigerators and 0.6 stand-alone freezers per manufactured home, and 1.2 refrigerators and 0.1 stand-alone freezers per multifamily home, appliance recycling measures contribute meaningful, cost-effective electric EWR potential in Consumers Energy service territory. Two additional appliance recycling measures—room air conditioners and dehumidifiers—contribute approximately 0.1% of the total 20-year maximum achievable potential for residential homes.
- ***Residential behavioral energy measures—including home energy reports—offer opportunities and substantial energy savings potential.*** The potential study revealed that home energy report measures will offer substantial savings opportunities in the future, but only after lifting program participation caps. Home energy reports could contribute up to 4% of the total, 20-year maximum achievable electric EWR potential in the residential sector.
- ***Commercial and industrial lighting opportunities contribute significant, cost-effective EWR potential.*** While the data collected by TRC (formerly EMI Consulting) for Consumers Energy's 2019 *Commercial and Industrial Market Assessment* revealed dramatically increased LED penetration across all commercial segments compared with data collected in 2015, there is still a large potential across all LED applications (linear, high-bay, screw-base, and exterior). Combined, commercial and industrial lighting end-use savings account for approximately 48% of the total 20-year nonresidential maximum achievable potential.
- ***Commercial lighting controls contribute significant, cost-effective EWR potential.*** The potential study revealed that lighting controls represent 18% of commercial maximum achievable potential from control technologies such as occupancy sensors, dimming controls, bi-level controls, and advanced network occupancy and daylighting controls.

- ***Industrial process measures contribute significant, cost-effective EWR potential.*** The industrial sector, which represents 28% of 2040 forecasted baseline sales, represents significant cost-effective EWR potential, led by a wide range of process measures across all manufacturing facilities. Process measures account for 39% of the total, 20-year industrial maximum achievable potential and 15% of total nonresidential savings.

To achieve long-term EWR goals, there are several key conclusions for Consumers Energy to consider when pursuing potential identified in the transformational technology scenario:

- ***Transformational technology potential provides a pathway to achievable long-term EWR goals.*** By incorporating dozens of emerging and innovative technologies in various stages of development, Consumers Energy can begin strategically planning initiatives through demonstration projects, pilots, outreach, and regulatory collaboration.
  - **Technology development and demonstration.** This may include investment in research and development, lab testing, or engagement of early adopters to install and use new technologies and to provide feedback that will help further development and determine applicability.
  - **Delivery strategy optimization.** Determination of the most effective market interventions to encourage adoption of emerging technologies at scale; this may include pilots and market forecasting to assess changes in cost as technologies are commercialized.
  - **Customer and trade ally outreach.** Lack of awareness and knowledge are significant barriers to adoption of a new technology; outreach to and education of consumers helps to build interest and demand while trade ally engagement ensures that there is a qualified workforce to install and service new technologies.
  - **Regulatory review and acceptance.** Educating Michigan Public Service Commission (MPSC) staff about emerging technologies and working collaboratively to demonstrate energy saving potential and path to market adoption.
- ***Transformational technology potential requires key actions to achieve long-term potential.*** While this study conducted aggressive research and outreach to industry experts on promising emerging technologies, limited data exists regarding the long-term viability of some of these technologies. This will require Consumers Energy to continue to research, pursue, and promote viable technologies as more data becomes available in coordination with industry partners.
- ***Many of the most impactful transformational technology measures exhibit more long-run potential; however, several provide savings in the study's first five years.*** Advanced commercial HVAC and refrigeration equipment, industrial processes and refrigeration, and expanded residential web portal offerings, advanced furnace fans, radiant panels, and smart vents represent technologies which Consumers Energy should begin monitoring and tracking.

Report Organization

We organized this report as follows:

- Comparison of this study's results to the EWR projections in Consumers Energy's 2018 IRP
- Summary of Consumers Energy electric EWR transformational technology scenario potential results
- General approach and methodology overview
- Detailed findings from several activities:
  - Baseline forecast
  - Electric EWR technical and economic potential
  - Electric EWR maximum achievable potential
  - Electric EWR program achievable potential
- Summary of methodologies
- Consumers Energy electric EWR transformational technology scenario potential
- Appendix A. Baseline forecast data
- Appendix B. Economic Inputs
- Appendix C. Emerging technology descriptions

Comparison to Consumers Energy's 2018 Integrated Resource Plan

The EWR potential values adopted in the Consumers Energy 2018 IRP were based on a statewide EWR potential study for 2017 through 2036, prepared by GDS Associates,[5] which was later adapted for Consumers Energy's service territory.

Table 8 shows a comparison of the 20-year cumulative maximum achievable and program achievable potential identified in this 2020 EWR market potential study, expressed as a percentage of baseline sales, compared to the achievable and constrained achievable potential identified in the 2017 GDS study. Overall, for this 2020 potential study, the Cadmus team identified lower levels of residential, commercial, and industrial potential, for maximum achievable potential compared to the 2017 GDS study's achievable potential, but higher levels of program achievable potential when program budgets are not limited to 2% of revenue.

Table 8. Maximum Achievable and Program Achievable Potential Comparison to 2017 GDS Study: Cumulative 20-Year Potential

Study	2020 Maximum Achievable Potential and 2017 Achievable Potential				2020 Program Achievable Potential and 2017 Constrained Achievable Potential			
	Percentage of Baseline Sales			MWh	Percentage of Baseline Sales			MWh
	Residential	Commercial	Industrial	Total	Residential	Commercial	Industrial	Total
2020 Cadmus	15.2%	19.0%	15.1%	6,714,807	11.7%	17.1%	13.5%	5,739,614
2017 GDS	19.2%	25.0%	17.6%	7,684,742	10.7%	10.5%	10.1%	3,934,680

For this study, the Cadmus team incorporated several changes compared to the 2018 IRP and to the 2017 GDS study:

- Developed a baseline end-use energy forecast, relying on Consumers Energy's most recent electric energy and customer forecasts.
- Estimated both incremental and cumulative EWR potential; however, whereas the 2018 IRP relied on the 2017 GDS study's approach of incorporating incremental potential, the Cadmus team provided cumulative potential for Consumers Energy's 2021 IRP in order to better account for EWR's effect on Consumers Energy's grid and forecasted loads. Whereas the incremental approach is applicable to setting program and portfolio targets—as these more accurately characterize how programs count savings—applying incremental potential to forecast loads in an IRP context overstates the effect on the grid by double-counting savings from EWR measure re-installations at the end of their useful lifetimes. Figure 5 shows a comparison of the 2017 GDS study incremental and cumulative achievable potential to the cumulative maximum achievable potential from this study.
- Used updated market data collected from site visits in 2019, showing the acceleration of LED adoption by Consumers Energy's commercial and industrial customers.

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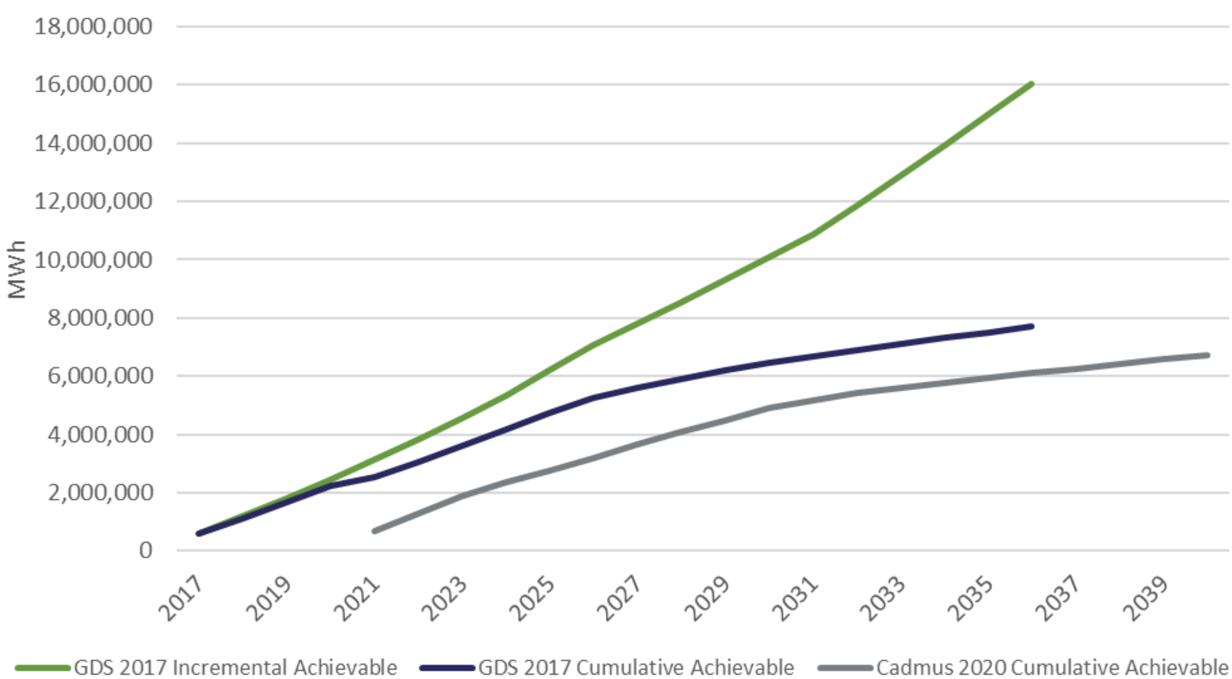
5 GDS Associates. March 20, 2017. *Consumers Energy Electric Energy Efficiency Potential Study.* Prepared for Consumers Energy.

- Employed updated information on changes in federal appliance standards and regulatory treatment of screw-based LED lighting that gradually phases out general service lamp savings from 2021 through 2024.
- This study provides estimates of maximum achievable and program achievable potential. The key outputs of the 2017 GDS study were "Achievable Potential UCT" and "Constrained Achievable Potential UCT." The proposed course of action in Consumers Energy's 2018 IRP was based on the Achievable Potential UCT. A key difference between this study and the 2017 GDS study is that the Cadmus team included both variable program administration and incentive costs. The 2017 GDS study assumed flat rates for administrative and incentive costs, whereas the Cadmus team employed measure-level incentive assumptions and applied administrative costs at the program level, consistent with values from Consumers Energy's most recent EWR plan filing.

Figure 5. Comparison of 2017 GDS Incremental and Cumulative Achievable Potential to 2020 Study Cumulative Maximum Achievable Potential



Summary of Consumers Energy Electric EWR Transformational Technology Potential Results

Per Consumers Energy's request (and as a supplement to the primary EWR potential study), the Cadmus team examined savings potential using a more aggressive set of assumptions to determine the transformational technology potential specific to Consumers Energy. The research had three primary analysis objectives:

- Identify an expanded estimate of EWR potential that could support Consumers Energy's ambitious EWR goals
- Investigate forward-looking technology and market scenarios that are the most likely to support Consumers Energy's longer-term EWR goals, particularly from 2031 to 2040 (the second half of the electric potential study time horizon)
- Provide insights on actions that may be required to fully capture the available potential from emerging measures, which could include investing in technology research and providing demonstrations, educating and building awareness of new and emerging measures, and building regulatory support with the Michigan Public Service Commission (MPSC)

Table 9 summarizes the 20-year transformational cumulative technical, economic, and maximum achievable potential in each sector. Of the total technical potential (17,436 GWh), 83% is considered economic (14,470 GWh). The maximum achievable potential is 10,925 GWh, which is 24% lower than the economic potential.

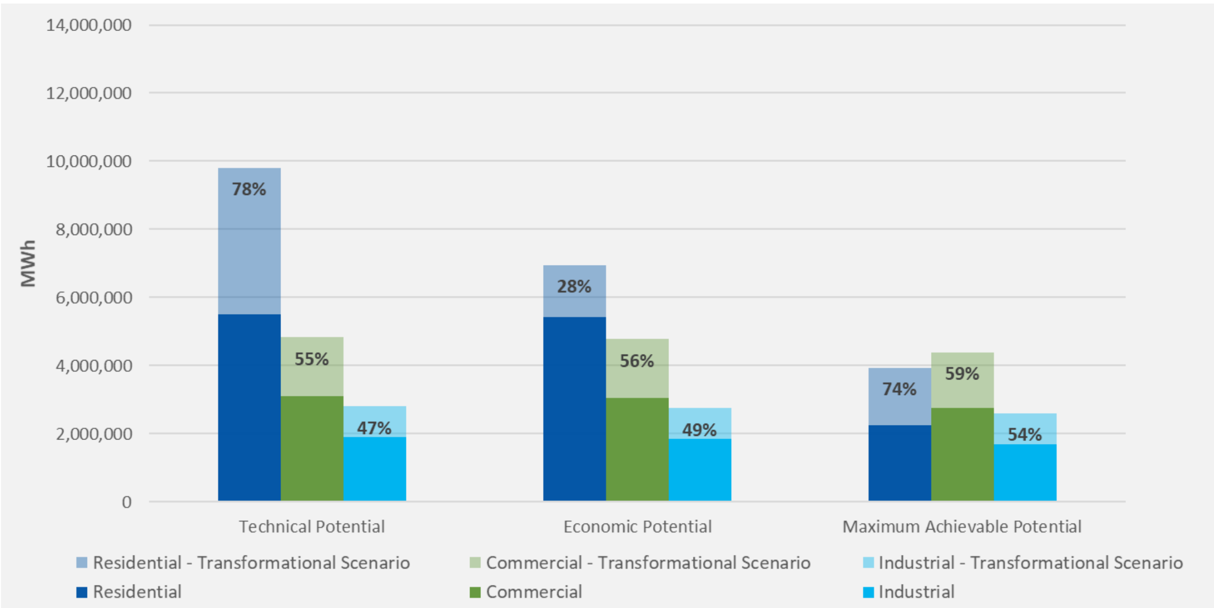
Table 9. Transformational Electric Energy Waste Reduction Potential by Sector—Energy: Cumulative 2040

Sector	Baseline Sales (MWh)	Technical Potential		Economic Potential		Maximum Achievable Potential	
		MWh	% [a]	MWh	% [a]	MWh	% [a]
Residential	14,861,197	9,808,564	66.0%	6,943,146	46.7%	3,938,701	26.5%
Commercial	14,528,160	4,827,870	33.2%	4,773,253	32.9%	4,387,185	30.2%
Industrial	11,204,888	2,799,606	25.0%	2,754,011	24.6%	2,599,612	23.2%
Total [b]	**40,594,246**	**17,436,040**	**43.0%**	**14,470,410**	**35.6%**	**10,925,499**	**26.9%**

[a] These percentages are of baseline sales.
[b] May not equal sum of rows due to rounding.

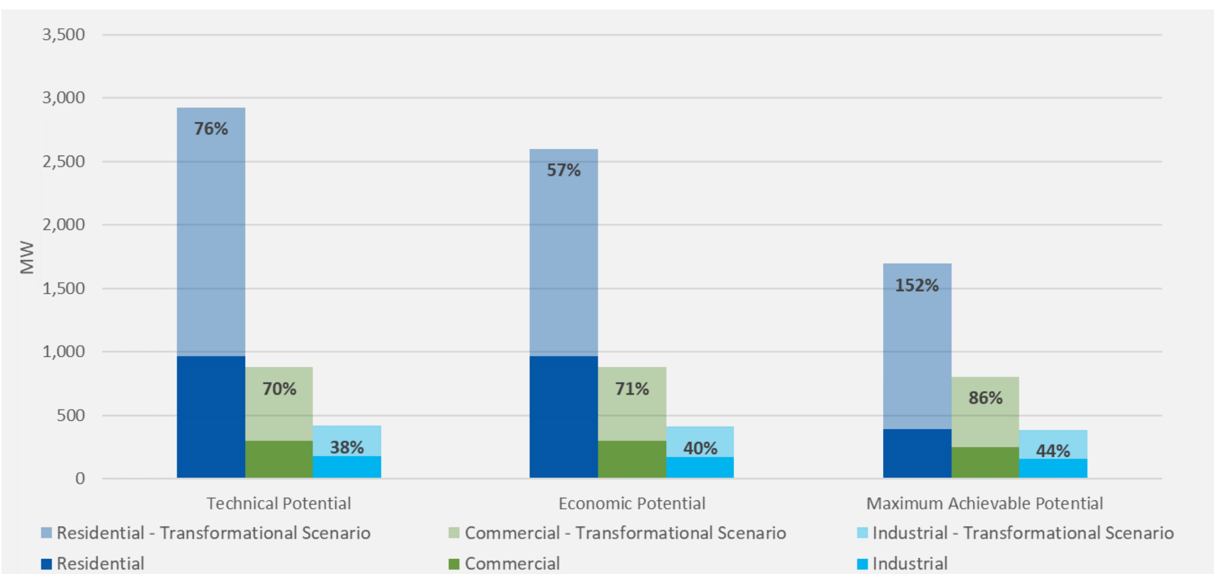
Figure 6 shows the 20-year cumulative transformational potential relative to the primary study results. The percentages represent the increase in cumulative 20-year potential in the transformational technology scenario for each sector. The total, cumulative maximum achievable potential increases by 63% when including transformational measures. Most of the additional savings potential comes from the residential sector, which increases by 74%, followed by the commercial (59%) and industrial (54%) sectors. Figure 7 shows the different peak demand values from the transformational potential and the primary results, with the percentage values representing the percentage increase in peak demand within a sector from the primary potential results to the transformational potential results. The transformational residential and commercial sector peak demand potential increases at a higher rate than the energy savings potential because many of the transformational technology measures incorporate HVAC efficiency improvements that are coincident to Consumers Energy's summer system peak demand.

Figure 6. Transformational Scenario Electric EWR Potential-Energy: Cumulative 2040



The percentages represent the increase in cumulative 20-year potential in the transformational technology scenario for each sector.

Figure 7. Transformational Scenario Electric EWR Potential—Demand: Cumulative 2040



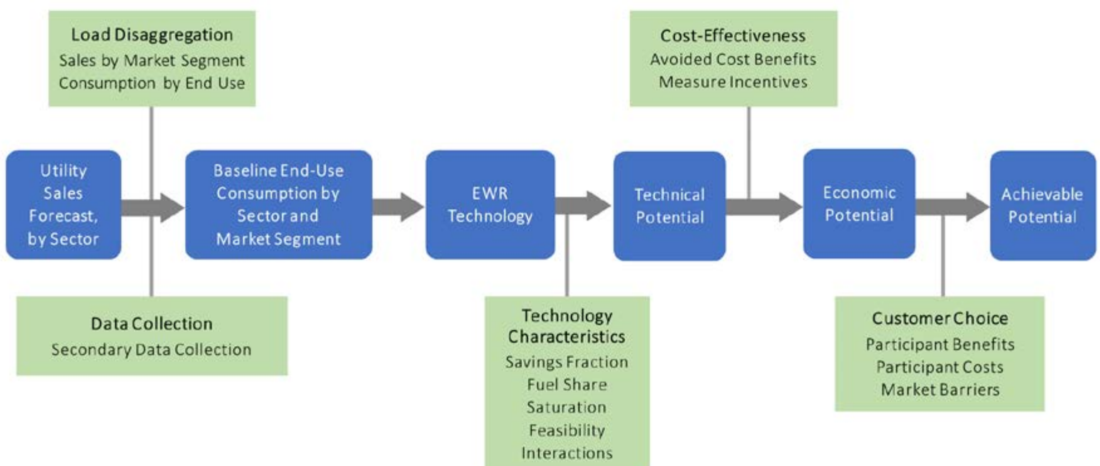
The percentages represent the increase in cumulative 20-year potential in the transformational technology scenario for each sector.

General Approach: Methodology Overview

The Cadmus team's general methodology was a combined top-down/bottom-up approach. For the top-down component, the team began with the most current sales forecasts—excluding future, planned EWR savings and adjusting for building codes, equipment efficiency standards, and market trends that the forecast did not account for—and disaggregated this information into customer sectors, customer segments, and end-use components. For the bottom-up component, the team considered the potential technical impacts of various EWR measures on each end use, then estimated impacts based on engineering calculations and accounting for fuel shares, current market saturations, technical feasibility, and costs.

The Cadmus team followed specific primary steps to model EWR: (1) created a baseline forecast of energy use by end use, (2) conducted measure research to understand where, how, and at what cost EWR potential can be achieved, and (3) modeled EWR based on the defined set of measures. Figure 8 illustrates the process we used to estimate the technical, economic, and achievable potential.

Figure 8. General Methodology for Assessing Energy Waste Reduction Potential



The Cadmus team developed a baseline forecast by determining 20-year future energy use by sector, market segment, and end use. The team calibrated the base year (2020) to Consumers Energy's forecasted sector loads. Baseline forecasts in this report include estimates of naturally occurring potential (such as energy savings due to building energy codes and federal equipment standards); therefore, the EWR potential estimates presented in the report represent only additional savings achievable through programs.

As part of this study, the team leveraged recently collected primary data in the nonresidential sectors (commercial and industrial building stock) within Consumers Energy's service territory, using 255 site visits across all nonresidential building types.[6] The collected data provide Consumers Energy-specific baseline data on building characteristics, demographics, and energy-consuming end uses (such as fuel type, equipment type, and estimated equipment age). For the residential sector, the Cadmus team primarily relied on data collected for the Consumers Energy *Residential Appliance Saturation and Home Characteristics Study*, dated October 2018.

Next, the Cadmus team developed a comprehensive measure database of technical and market data that applied to all end uses in various market segments, as well as the estimated costs, savings, and applicability for a comprehensive set of EWR measures. The primary measure data source was the Michigan Energy Measures Database (MEMD), as well as Consumers Energy workpapers and regional technical reference manuals (TRMs). The *Measure Characterization* section in the *Summary of Methodologies* chapter details the data sources we used for this study.

The Cadmus team assessed four types of potential:

- ***Technical potential*** assumes that all technically feasible EWR measures generally available at the time of the study will be implemented, regardless of their cost or other market barriers. We estimated this theoretical upper bound of available conservation potential after accounting for technical constraints. For EWR resources, there are three classes of technical potential:
  - Retrofit opportunities in existing buildings
  - Equipment replacements in existing buildings
  - New construction

  Customers can theoretically implement retrofits in the current building stock at any point in the planning horizon. Examples of retrofit measures, which reduce the use of end-use equipment without modifying or replacing that equipment, include insulation, faucet aerators, and lighting controls. However, end-use equipment turnover rates and new construction rates dictate the timing of equipment replacements and new construction. The *Baseline End-Use Forecast* section in the *Summary of Methodologies* chapter details the data sources we used to estimate these technical constraints for individual measures.
- ***Economic potential*** represents a subset of technical potential and consists only of measures meeting the cost-effectiveness criteria, set to be consistent with the primary cost-effectiveness test adopted under Michigan Public Acts 295 and 342. Michigan set requirements for Consumers Energy where the primary benefit/cost test includes benefits and cost from the viewpoint of the utility, referred as the UCT. For each EWR measure, the Cadmus team structured the benefit/cost test as the ratio of NPVs for the measure's benefits and costs, using the benefit and cost inputs from Consumers Energy. We identified only measures with a benefit/cost ratio of 1.0 or greater as cost-effective. The *Economic Potential* section in the *Summary of Methodologies* chapter details the benefits and costs considered.

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[6] These data were collected by EMI Consulting in 2019 as part of a Consumers Energy commercial and industrial market assessment.

- ***Maximum achievable potential*** represents the portion of economic potential that might be achieved after accounting for market barriers that impede customer adoption, including limitations in customers' willingness to adopt EWR measures. The maximum achievable potential does not consider any limits to savings achievement that currently constrain home energy report programs; to determine the maximum achievable potential, we assumed that 60% of eligible single family electric service customers would receive home energy reports. A comprehensive set of EWR measures—including technologies not currently offered by Consumers Energy programs spanning the residential, commercial, and industrial sectors—comprised the maximum achievable potential. This report expresses gross maximum achievable savings potential at the meter.
- ***Program achievable potential*** consists of the subset of economic potential for measures currently offered and measures that have potential to be offered during the study horizon by Consumers Energy. This report expresses program achievable potential in net savings, accounting for the most current net-to-gross factors used to determine Consumers Energy program cost-effectiveness.

The Cadmus team did not attempt to predict or incorporate new, non-commercially available technologies that may emerge in future years in the core estimate of potential but did include those in the transformational technology scenario. The team did make assumptions regarding future market conditions and federal and state policies based on informed projections, which may or may not precisely match actual conditions. Therefore, these study results should not serve as the final word on savings that can be achieved by Consumers Energy; rather, they should help to guide future program planning, design, funding, and goal setting. The following sections detail study considerations and limitations of the potential study.

Additional Study Methodological Considerations

The Cadmus team took special considerations in reporting results within this study.

Incremental and Cumulative Potential

EWR potential studies of this type typically produce two sets of savings potential outputs—incremental and cumulative—for each type of potential (technical, economic, maximum achievable, and program achievable). Except where noted, tables within this report present potential estimates on a cumulative basis. EWR measures converted during early analysis years (but reaching the end of their effective useful life [EUL] during the 20-year study horizon) remain eligible for future installations.

Incremental savings include additional savings at the end of these measures' EULs—consistent with EWR program practices—while cumulative savings do not. Cumulative potential includes savings from new measure installations only during the 20-year study horizon and assumes like-for-like replacement of efficient measures when EWR measure lifetimes expire.

Screw-Based Lighting

Despite the DOE's December 27, 2019 final rule and determination that effectively rescinded the EISA 2020 backstop standard,[7] the screw-based LED lighting market continues to transform. To address this transformation within the potential study, the Cadmus team followed Consumers Energy's adopted assumptions (accepted by the MPSC) for screw-based LED lighting program design. This included adjusting the measure life of LED standard and specialty bulbs to coincide with the transformed market (standard LED in 2023 and specialty LED in 2024) projections.

Maximum achievable potential and program achievable potential include savings potential from standard and specialty LED screw-based lamps; however, the baselines for standard LED and specialty LED screw-based lamps will change in 2024 and 2025, respectively, from an incandescent/halogen mix to a market LED baseline, significantly reducing the per-unit savings potential for these lamps. Any remaining potential for screw-based LEDs after these baseline changes is due to the difference between the market LED baseline per-unit energy use assumption and Consortium for Energy Efficiency (CEE) Tier 2 LEDs.

Home Energy Reports

The Cadmus team relied on the *Michigan Behavior Resource Manual* to provide the basis for energy savings, as well as on Consumers Energy's existing EWR behavioral program.[8] The team applied similar savings percentage estimates from the *Michigan Behavior Resource Manual* to single family customers with electric service from Consumers Energy. Generally, the manual calculated savings as a percentage of total home load values, which vary based on the level of total home energy use and the year. These savings percentages ranged from 0.77% for a home with annual use less than 7,000 kWh in the first year a customer receives a report to 2.27% for a home with annual energy use between 7,000 kWh and 8,999 kWh in in the third year a customer receives a report.

Beginning in 2026 and continuing through the end of the study, the Cadmus team deviated from the *Michigan Behavior Resource Manual* by lowering the savings percentages from 2.73% and 2.20% (for single family homes with annual energy use greater than and less than 9,000 kWh, respectively) to 1.5%, after consulting with Consumers Energy's home energy report program vendor, who recommended the lower level of savings based on their experience implementing home energy report programs for utilities across the United States.

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[7] U.S. Department of Energy. December 27, 2019. "Energy Conservation Program: Energy Conservation Standards for General Incandescent Service Lamps." https://federalregister.gov/documents/2019/12/27/2019-27515/energy-conservation-program-energy-conservation-standards-for-general-service-incandescent-lamps

[8] Michigan Public Service Commission. December 17, 2018. *Michigan Behavior Resource Manual.* https://michigan.gov/mpsc/0,9535,7-395-93309_94801_94808_94812---,00.html

In developing estimates of maximum achievable and program achievable potential, the Cadmus team assumed a significant expansion of the home energy report program to 60% of the eligible single family electric customer population.

To support these assumptions, the Cadmus team reviewed secondary data (including program evaluations and the E Source tracking database) to determine which other, vertically integrated investor-owned utilities in the United States achieved similarly high levels of home energy report customer participation. The research showed that several utilities, including Baltimore Gas and Electric and Pepco in Maryland, both exceeded the 60% customer participation threshold in 2019, with Baltimore Gas and Electric reaching approximately 80% of its residential customer population, based on values in its 2019 fourth-quarter evaluation report and U.S. Energy Information Administration (EIA) Form 861 data.

Michigan Energy Measures Database

The Cadmus team used the MEMD as the primary source of measure data to estimate the savings potential. The MEMD includes measure-level deemed or modeled (nominal) savings that the team used to inform its end-use potential study model.[9] It may not be appropriate to apply nominal saving calculations across all building types and vintages due to differences in baseline use when compared to the baseline use of the prototypical building type; therefore, where possible, the Cadmus team adjusted underlying generic assumptions, e.g., number of people per home, to reflect building and occupancy characteristics collected from primary data (specifically, from the Consumers Energy 2018 *Residential Appliance Saturation and Home Characteristics Study* and the Consumers Energy's 2019 *Commercial and Industrial Market Assessment*).[10]

In addition, nominal savings within the MEMD in some cases exceed the Cadmus team's prototypical baseline end-use consumptions. This may be due to multiple factors, but typically reflects the nominal savings baseline being far less efficient than the prototypical baseline. For example, an MEMD measure of residential attic insulation may represent savings from R-0 to R-49, but the team's prototypical home (representing all insulated and non-insulated homes) has an R-19 value. Since the MEMD savings would overestimate potential within the Cadmus team's calibrated end-use model, the team adjusted the MEMD values by embedding applicability and feasibility constraints or by applying the MEMD's underlining percentage savings assumptions (instead of the nominal saving values).

Industrial Measures

While our residential and commercial methodology represents a bottom-up/top-down approach, the Cadmus team assessed the industrial sector primarily using top-down approach due to the diverse nature of industrial facilities. The unique processes and variations within industrial facilities make it

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9 The MEMD consists of a "Deemed Database" and a "Weighting Tool" of measure-level deemed savings, measure incremental costs, and measure lifetimes.

10 TRC (EMI Consulting). Summer 2020. *2019 Commercial and Industrial Market Assessment.* Prepared for Consumers Energy.

infeasible to develop bottom-up end-use loads; therefore, the team estimated EWR potential for this sector using a wide range of measures culled from multiple sources, including Consumers Energy's industrial sales and customer databases, combined with the EIA *Manufacturing Energy Consumption Survey*[11] and DOE *Industrial Assessment Center Database*,[12] as well as lighting data collected from Consumers Energy's 2019 *Commercial and Industrial Market Assessment*.

While the process end-use potential accounts for the largest end-use category in terms of savings, the characterized process improvements may be underestimated because they are often specialized custom improvements and difficult to estimate across an entire industry. As a result, this study may not reflect the total maximum achievable potential, as it does not account for Consumers Energy's experience with developing process measures for highly specialized, specific industrial applications on a facility-by-facility basis.

Limitations for Program Design

This study provides insights into which measures Consumers Energy can offer in future programs by informing future load reduction from EWR in an IRP context. Several considerations regarding the potential study design may cause future program plans to differ from the study results:

- ***Potential study estimates account for interactions between cost-effective measures.*** When installing two interactive measures (such as ceiling insulation and windows), the combined interactive savings are lower than the sum of stand-alone savings for the two measures. Sometimes called measure stacking, such interactive effects can produce lower savings than what is estimated, and program plans may not include all measures considered within the potential study.
- ***The potential study uses broad assumptions about the adoption of EWR measures with different incentive levels.*** Different market potential estimates are meant to be directional (where, given a certain increase or decrease in incentives, there is a corresponding increase or decrease in measure adoption and resulting savings). This approach provides a realistic range of estimates given a range of incentive levels. Program design, however, requires a more detailed examination of historical participation and incentive levels on a measure-by-measure basis. The potential study can be used to inform planning for measures that Consumers Energy has not historically offered.
- ***The potential study cannot accurately predict all market changes over time, whereas programs are able to address market changes dynamically, in real time.*** While this study accounts for planned changes in codes and standards, the Cadmus team cannot predict upcoming changes in policies, pending codes and standards, and new technologies that will become commercially available during the 20-year study horizon. For example, past potential

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11 U.S. Energy Information Administration. 2014. *Manufacturing Energy Consumption Survey.* https://eia.gov/consumption/manufacturing/data/2014/

12 U.S. Department of Energy. 2019. *Industrial Assessment Center Database.* https://energy.gov/eere/amo/industrial-assessment-centers-iacs

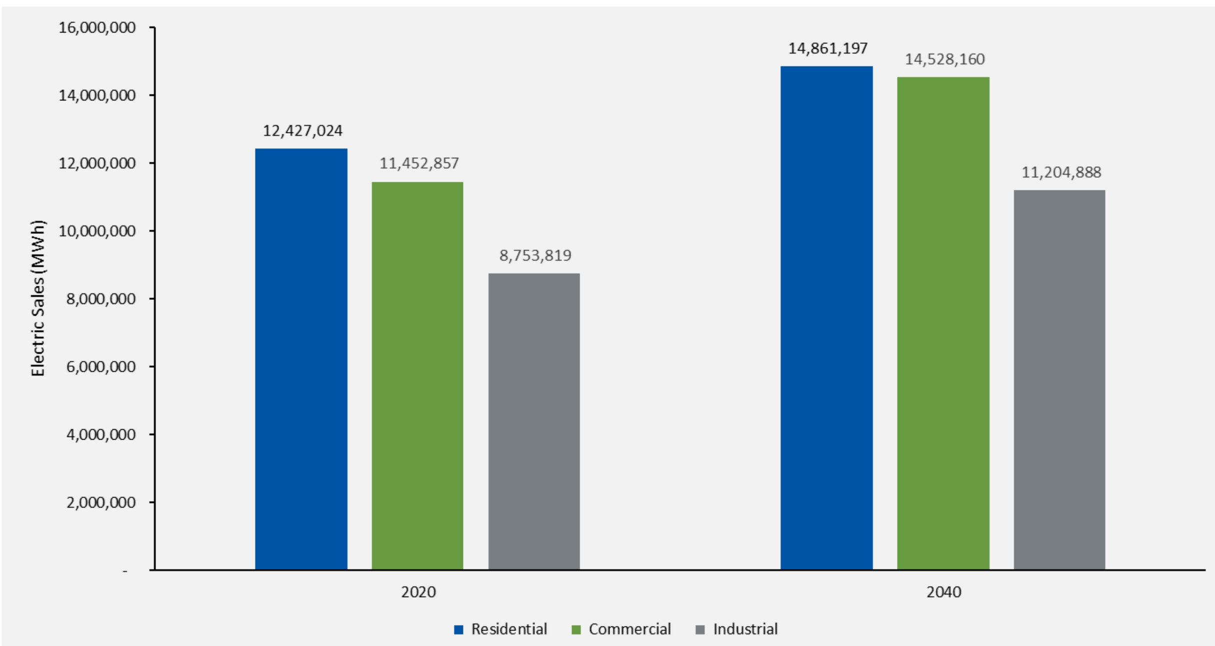
studies may not have accurately predicted the speed and magnitude of recent LED technology adoption. Consumers Energy's programs are not static, providing the flexibility to rapidly address changes in the marketplace. This flexibility was demonstrated in 2020 as Consumers Energy responded to the COVID-19 pandemic with program modifications and innovative measure offerings.

- ***The potential study does not attempt to forecast or otherwise predict future changes in EWR measure costs.*** Although this study includes a thorough estimate of incremental EWR measure costs, including for equipment and labor, it does not attempt to forecast changes to these costs during the study timeline. As a result, incremental costs for some emerging technologies, which may decrease with increased adoption, could be overstated relative to actual costs in later study years.
- ***The potential study incorporated primary data collected within the commercial sector, with findings that provide a probable view of the current commercial stock but may not fully represent Consumers Energy's diverse customer base.*** The commercial baseline market characterization study provided critical inputs for the potential study, such as building characteristics and equipment saturations for each building type. While the baseline study limited the uncertainty through weighting strategies and sample design, all data collection and recruitment efforts produce some level of uncertainty. As a result, the potential study represents the best available data but does not provide a complete and conclusive estimate.
- ***The potential study relies on specified measures and may not include highly customized program measures.*** While this study includes a large variety of EWR measures, it is difficult to characterize highly customized measures that may be designed specifically for a single project or building. For example, while the Cadmus team reviewed a number of measures related to defined technologies used in industrial facilities, we did not capture all the potential from industrial facility custom-process measures specific to *individual* manufacturing processes or facility designs.
- ***The transformational potential relies on technologies in various stages of development to estimate the magnitude, timing, and costs of savings potential with limited data to support measure inputs.*** While this study conducted aggressive research and outreach to identify and characterize promising technologies, limited data are available surrounding these emerging technologies. Significant expert judgement had to be applied when technologies will be commercially available, likely cost trajectories, and estimated savings potential.

Detailed Findings: Baseline Forecast

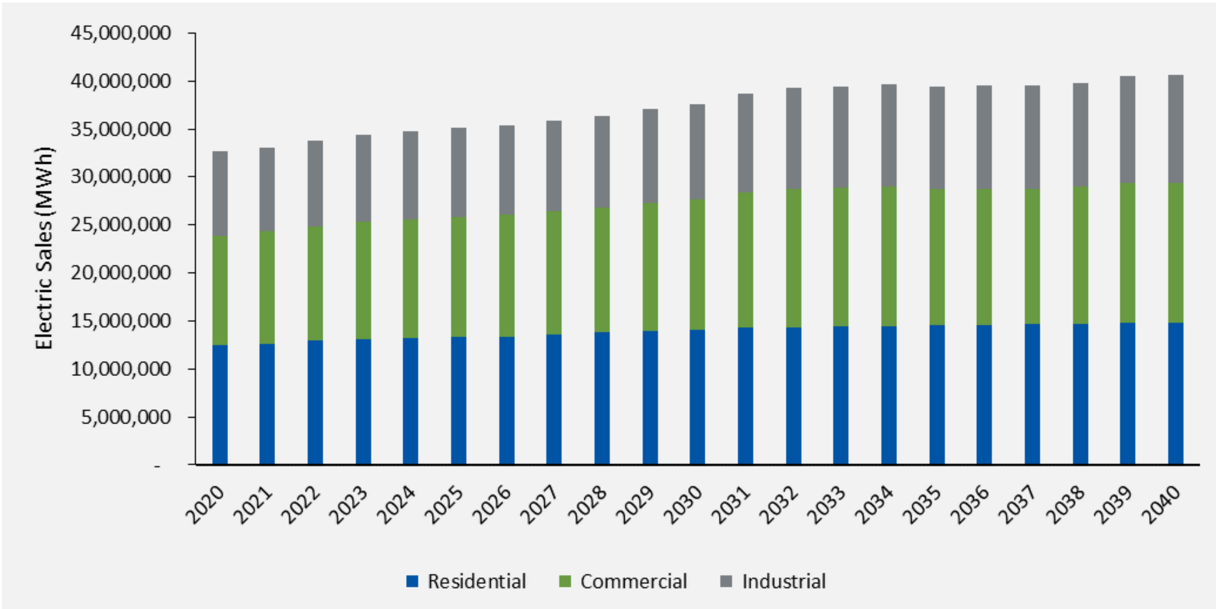
The annual electricity sales in 2020 for the Consumers Energy residential, commercial, and industrial sectors totaled approximately 32,634 GWh. As shown in Figure 9, in 2020 the residential sector accounts for approximately 38% of annual energy sales, while the commercial and industrial sectors combined account for 62% of total sales. The figure also shows the projected 2040 baseline sales of electricity by sector, representing approximately 40,594 GWh. The baseline accounts for naturally occurring potential (such as for changes in codes and standards), as well as for changes in Consumers Energy's customer forecast. *Appendix A* contains additional baseline characterization assumptions for each sector.

Figure 9. Electric Sales by Sector: 2020 and 2040



The baseline forecast in Figure 10 represents the likely future sales in absence of planned efficiency programs. All EWR potentials characterized in this report are referenced and compared to this baseline forecast.

Figure 10. Electricity Baseline Forecast by Sector



Residential Baseline Forecast

For the residential sector, Figure 11 represents the 2020 baseline and 2040 projected baseline sales by segment. Single family baseline sales contribute to approximately 87% in 2020 and 86% in 2040 (all incomes) of the residential electric sales and 33% and 31%, respectively, of all Consumers Energy electricity sales. Overall, low income segments represent 27% of residential sales in 2020 and 2040, while the single family low income segment contributes the majority of low-income sales (82%).

Figure 11. Residential Baseline Electric Sales by Segment: 2020 and 2040

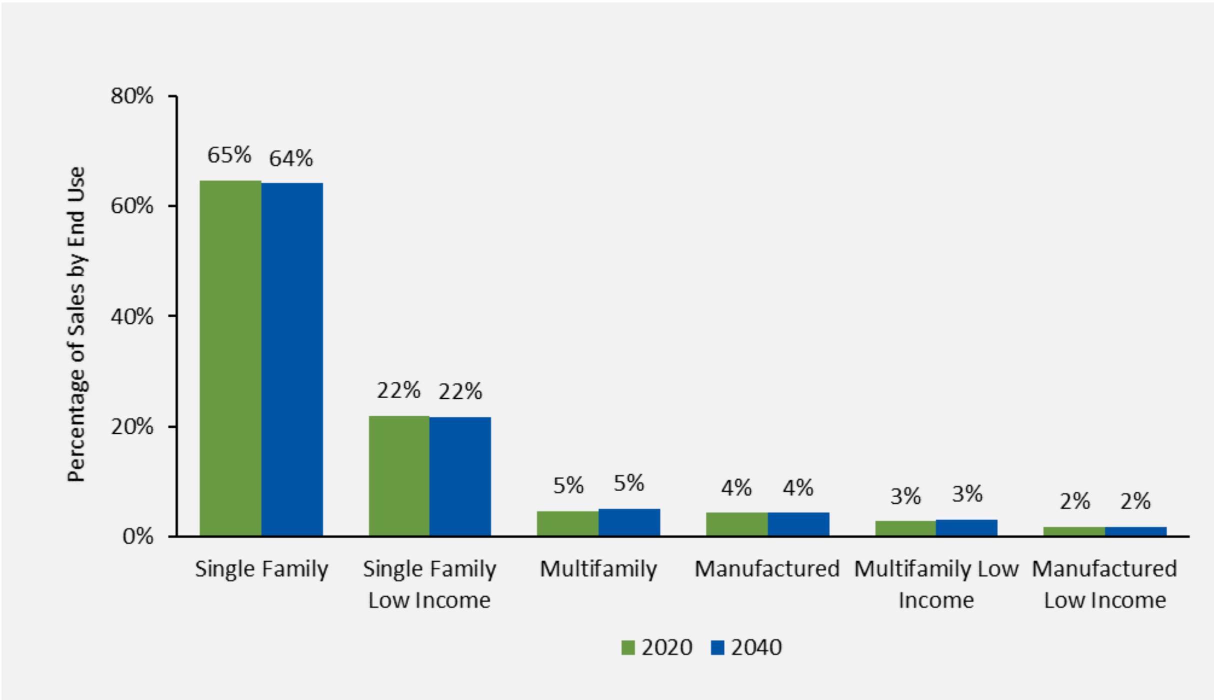


Figure 12 shows the residential baseline forecast by primary end use for 2020 and 2040 as a percentage of baseline sales. Residential lighting represents the predominant end use in 2020 (18% of all residential sales) but reduces to 11% in 2040 due to assumptions regarding changes in lighting market baselines.

Figure 12. Residential Baseline Electric Forecast by End Use: 2020 and 2040

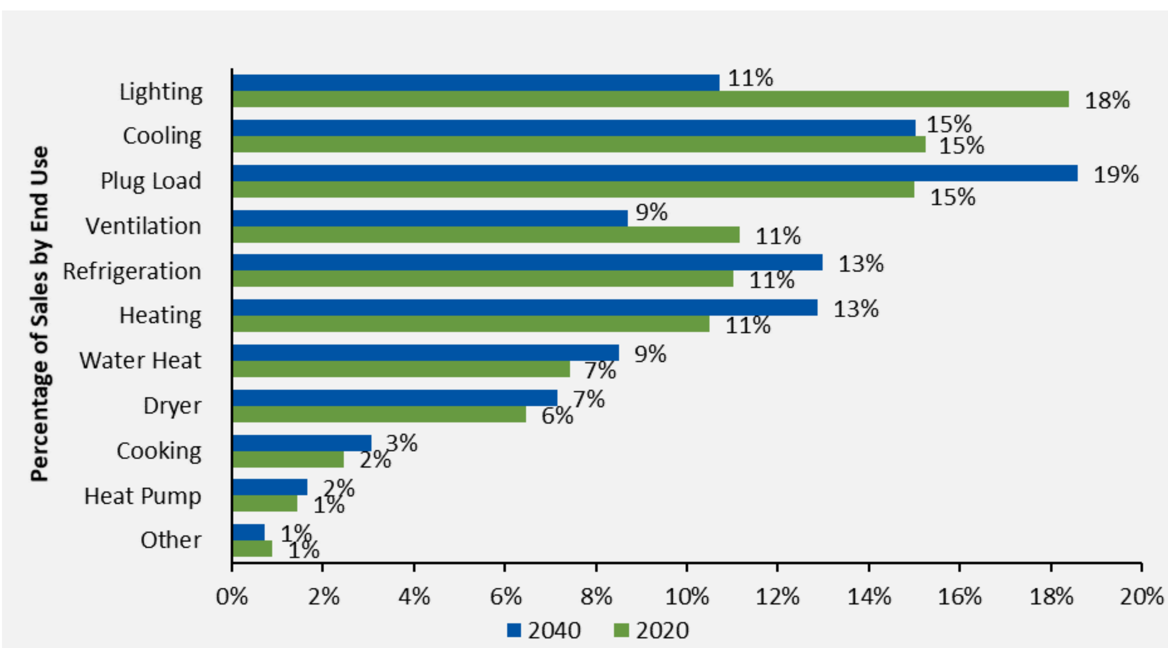


Table 10 shows the 2040 baseline sales by segment and end use.

Table 10. Residential Baseline Electric Sales by Segment and End Use: 2040 (MWh)

End Use Group	Single Family	Single Family Low Income	Multifamily	Multifamily Low Income	Manufactured	Manufactured Low Income	Total [a]
Lighting	1,118,630	335,507	30,594	15,548	66,189	25,432	**1,591,901**
Cooling	1,753,054	317,321	71,510	29,073	46,352	14,514	**2,231,824**
Plug Load	1,879,135	574,285	101,636	46,623	120,043	41,834	**2,763,556**
Ventilation	792,590	322,938	50,064	23,266	73,892	30,497	**1,293,248**
Refrigeration	1,253,519	438,664	79,861	33,349	90,680	34,440	**1,930,514**
Heating	767,530	437,308	306,863	266,464	94,481	39,603	**1,912,250**
Water Heat	649,182	412,053	56,460	25,709	69,962	52,500	**1,265,866**
Dryer	707,948	246,479	23,184	4,693	58,272	21,697	**1,062,274**
Cooking	277,528	111,044	25,796	12,033	21,095	6,676	**454,172**
Heat Pump	213,879	26,414	-	6,605	-	-	**246,898**
Other	108,695	-	-	-	-	-	**108,695**
Total [a]	**9,521,692**	**3,222,014**	**745,967**	**463,363**	**640,968**	**267,194**	**14,861,197**

[a] May not equal sum of rows/columns due to rounding.

Commercial Baseline Forecast

Figure 13 shows the commercial sector 2020 and 2040 projected baseline sales by segment. In 2040 the office building type represents the largest segment, at 23% of the commercial electric sales, followed by retail (19%), other (14%), warehouse (12%), and education (10%). The remaining 21% of commercial electric sales in 2040 contain building segments with less than 10% each: health (8%), restaurant (6%), grocery (4%), and lodging (2%).

Figure 13. Commercial Baseline Electric Sales by Segment: 2020 and 2040

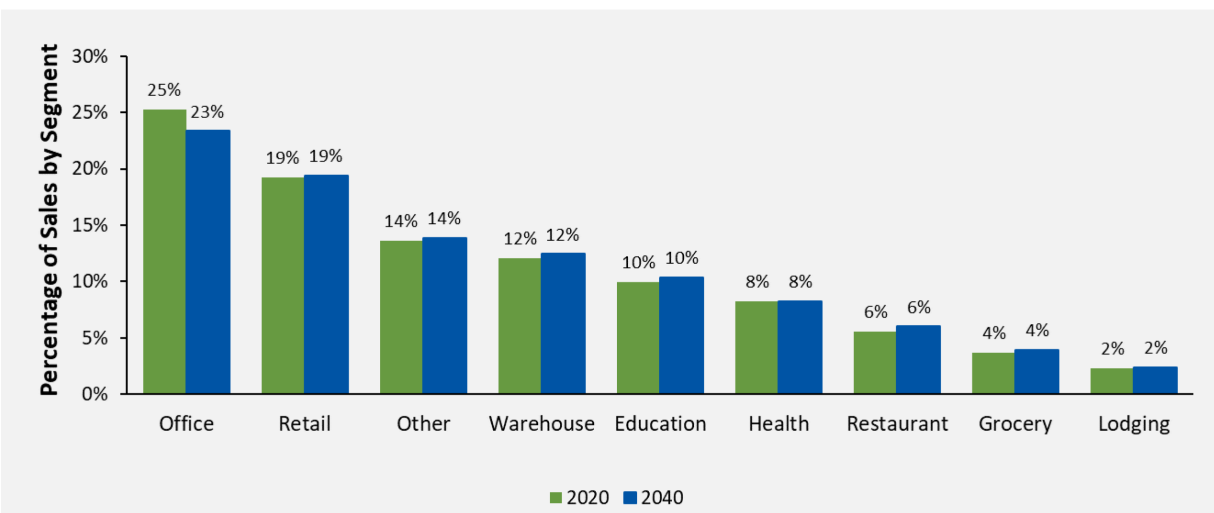


Figure 14 shows the commercial baseline forecast by primary end use for 2020 and 2040 as a percentage of baseline sales. Lighting represents the largest end use in 2020 (41% of all commercial sales) and in 2040 (36% of all commercial sales).

Figure 14. Commercial Baseline Electric Forecast by End Use: 2020 and 2040

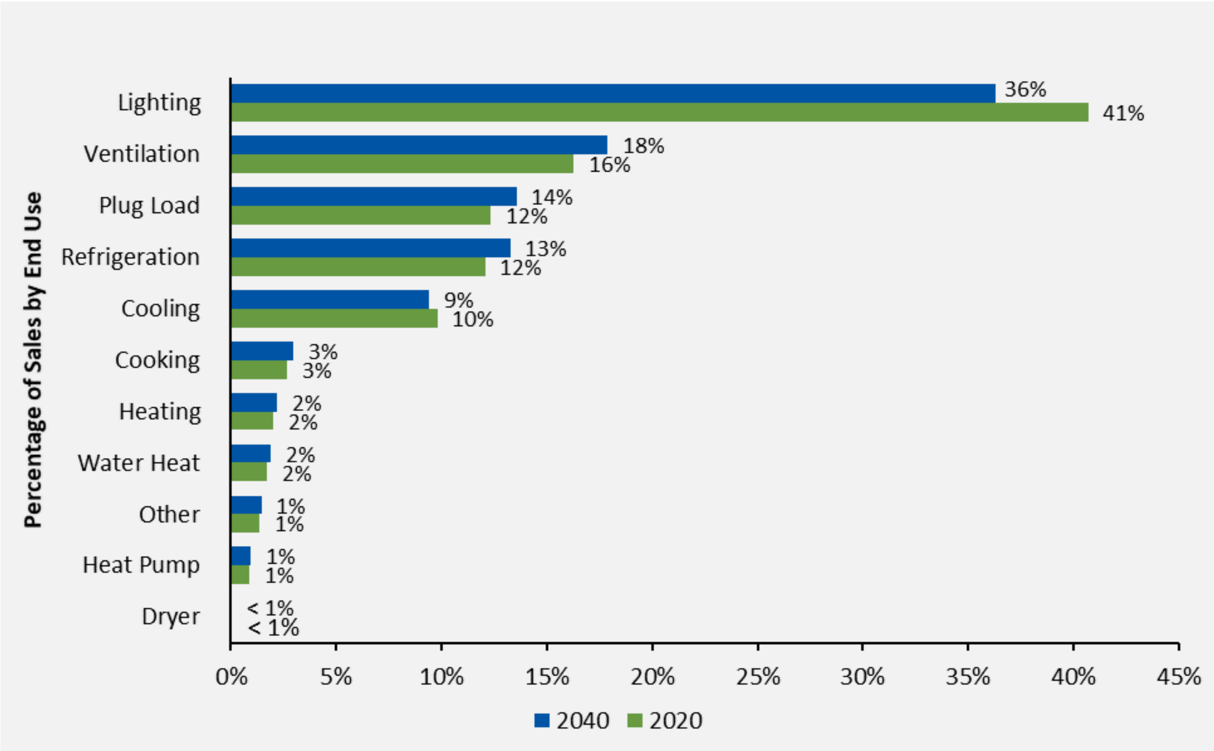


Table 11 shows the 2020 baseline sales by segment and end use.

Table 11. Commercial Baseline Electric Sales by Segment and End Use: 2020 (MWh)

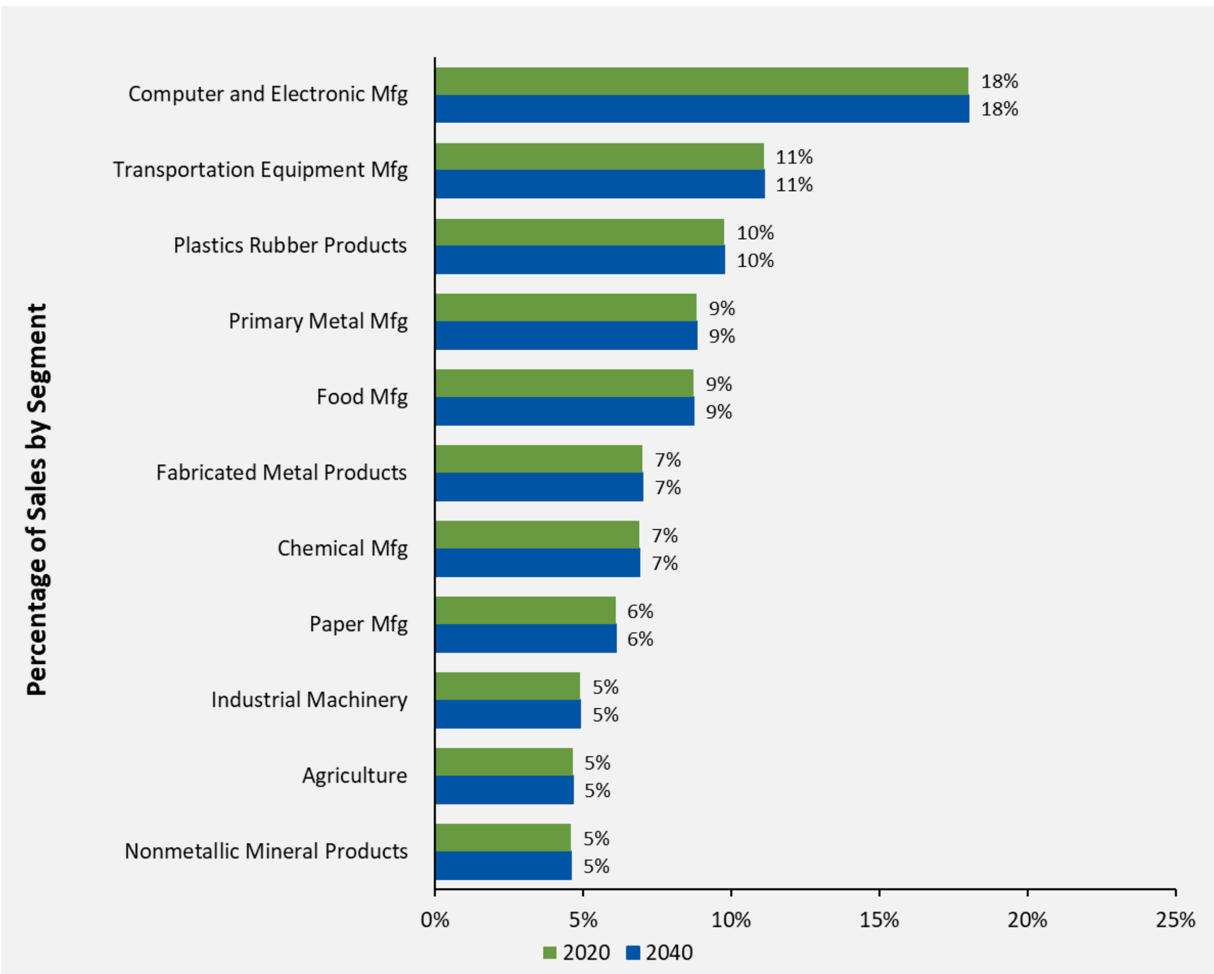
	Education	Grocery	Health	Lodging	Office	Other	Restaurant	Retail	Warehouse	Total [a]
Lighting	440,721	58,765	300,462	47,533	1,258,099	676,161	92,338	900,950	885,146	**4,660,177**
Ventilation	171,958	26,566	194,412	34,024	705,771	174,416	74,464	393,251	88,072	**1,862,935**
Plug Load	188,242	15,492	170,481	74,970	438,646	283,976	51,756	138,990	51,991	**1,414,544**
Refrigeration	107,310	294,380	57,076	19,970	76,055	125,885	226,884	422,399	52,452	**1,382,409**
Cooling	166,269	6,711	120,713	10,705	312,710	213,386	34,868	167,331	92,280	**1,124,972**
Cooking	16,377	16,289	27,887	24,768	624	27,462	146,903	48,138	-	**308,448**
Heating	10,644	957	2,155	39,382	8,771	20,776	5,676	35,419	106,049	**229,831**
Water Heat	21,153	417	47,956	7,436	34,503	20,556	3,943	41,628	22,341	**199,934**
Other	1,738	358	619	558	7,739	16,912	196	44,623	84,335	**157,078**
Heat Pump	14,838	2,498	19,467	1,614	50,329	-	3,323	12,346	-	**104,415**
Dryer	2,627	-	2,160	586	-	2,741	-	-	-	**8,114**
Total [a]	**1,141,878**	**422,432**	**943,389**	**261,547**	**2,893,248**	**1,562,272**	**640,351**	**2,205,075**	**1,382,665**	**11,452,857**

[a] May not equal sum of rows/columns due to rounding.

Industrial Baseline Forecast

Figure 15 shows the industrial sector 2020 and 2040 projected baseline sales by segment. Computer and electronic manufacturing (18%), transportation equipment manufacturing (11%), plastics rubber products manufacturing (10%), primary metal manufacturing (9%), food manufacturing (9%), fabricated metal products manufacturing (7%), and chemical manufacturing (7%) represent 70% of all industrial electric sales. The agriculture sector, included within the industrial sector, represents 5% of the 2040 industrial sales (approximating 1% of sales across all sectors). Whereas changes to the end-use allocation of forecasted electric energy use in the residential and commercial sectors considers both codes and standards and the natural replacement of old, inefficient equipment, the unique characteristics of the industrial sector and the top-down method employed to disaggregate sector-level loads to segment and end use loads means that these do not vary over time in the baseline forecast.

Figure 15. Industrial Baseline Electric Sales by Segment: 2020 and 2040



Note: The remaining 10% of 2020 and 2040 baseline electric sales are from wood product manufacturing, furniture manufacturing, electrical equipment manufacturing, printing-related support, miscellaneous manufacturing, mining, wastewater, textile mills, textile product mills, leather manufacturing, petroleum coal products, apparel, and water, beverage, and tobacco manufacturing.

Figure 16 shows the industrial baseline forecast by primary end use for 2020 and 2040 as a percentage of baseline sales. Industrial process represents the largest end use in 2020 and in 2040 (both 37% of all industrial sales).

Figure 16. Industrial Baseline Electric Forecast by End Use: 2020 and 2040

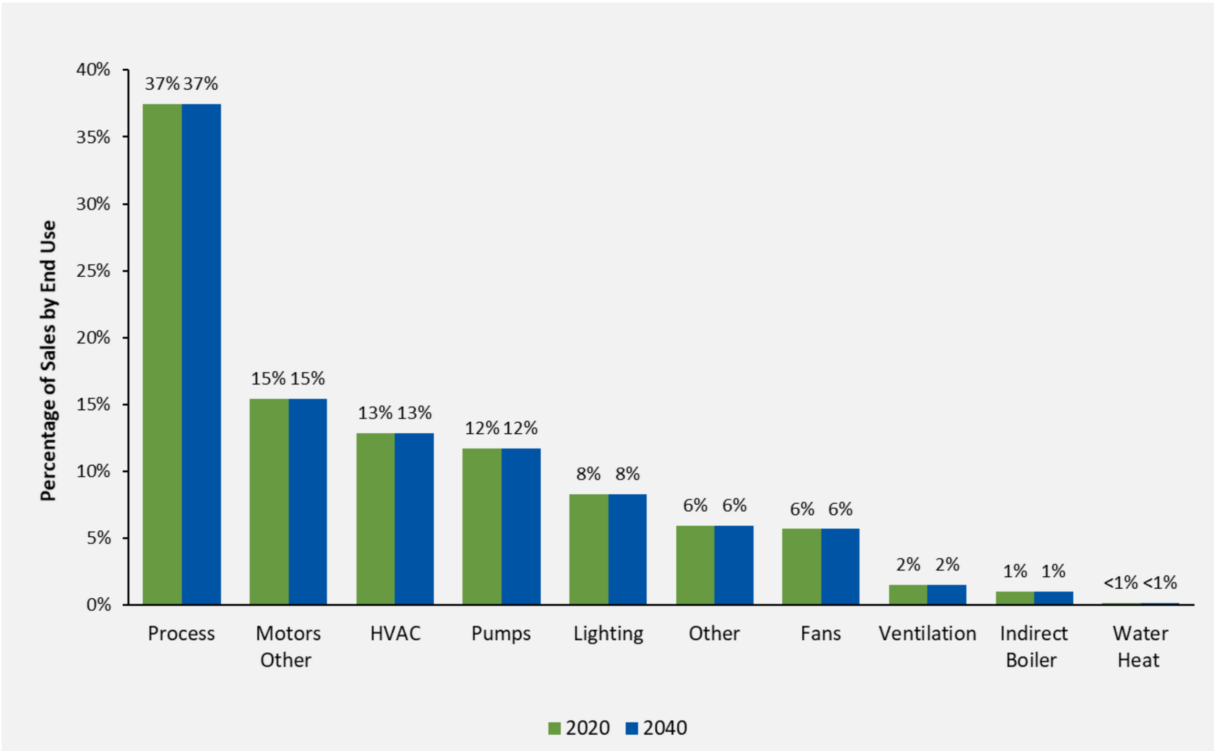


Table 12 shows the 2020 baseline sales by segment and end use.

Table 12. Industrial Baseline Electric Sales by Segment and End Use: 2020 (MWh)

Segment/Type of Manufacturing	Fans	HVAC	Indirect Boiler	Lighting	Motors Other	Other	Process	Pumps	Ventilation	Water Heat	Total [a]
Computer and Electronic	71,148	383,819	14,018	145,990	140,859	147,671	559,313	112,831	-	-	**1,575,651**
Transportation Equipment	44,551	181,056	8,010	120,668	99,958	78,620	340,171	97,337	-	-	**970,371**
Plastics Rubber Products	62,299	86,802	4,136	81,066	177,346	23,214	305,866	112,774	-	-	**853,502**
Primary Metal	31,412	26,728	2,681	25,323	126,468	26,552	515,373	17,862	-	-	**772,398**
Food	24,653	63,243	21,940	56,008	128,194	39,074	377,036	53,907	-	-	**764,056**
Fabricated Metal Products	36,745	95,289	-	58,156	104,604	27,249	223,768	66,517	-	-	**612,328**
Chemical	39,696	43,821	9,567	28,156	89,066	21,495	285,628	86,731	-	-	**604,160**
Paper	78,419	23,452	14,369	21,582	155,254	11,306	104,581	124,361	-	-	**533,325**
Industrial Machinery	25,010	87,525	4,135	59,325	71,197	20,209	115,003	45,274	-	-	**427,677**
Agriculture	-	-	-	38,162	-	44,136	7,028	172,953	131,845	11,596	**405,719**
Nonmetallic Mineral Products	28,938	26,017	3,588	19,864	82,379	8,267	180,850	52,385	-	-	**402,289**
Wood Product	13,744	10,237	1,503	8,112	39,124	4,383	33,164	24,879	-	-	**135,146**
Furniture	8,978	26,482	1,558	21,862	25,558	6,099	23,801	16,252	-	-	**130,589**
Electrical Equipment	3,696	18,350	513	10,865	8,294	3,276	56,228	8,076	-	-	**109,298**
Printing Related Support	8,010	18,405	916	9,171	22,802	4,229	28,534	14,500	-	-	**106,566**
Miscellaneous	5,143	26,341	1,491	15,084	20,708	6,203	28,074	2,925	-	-	**105,969**
Mining	10,706	-	-	-	43,105	9,050	10,006	6,088	-	-	**78,955**
Water	-	-	-	-	-	-	62,042	-	-	-	**62,042**
Beverage and Tobacco	1,722	4,170	537	3,298	4,901	4,717	12,170	3,116	-	-	**34,631**
Wastewater	-	-	-	-	-	33,978	-	-	-	-	**33,978**
Textile Mills	1,040	1,909	264	934	2,960	302	3,503	1,882	-	-	**12,794**
Textile Product Mills	623	1,120	423	912	1,774	426	2,257	1,128	-	-	**8,662**
Leather	742	832	54	885	2,113	215	2,265	1,344	-	-	**8,450**
Petroleum Coal Products	360	111	25	79	1,023	84	750	651	-	-	**3,082**
Apparel	120	638	48	375	343	92	346	218	-	-	**2,180**
Total [a]	**497,755**	**1,126,346**	**89,775**	**725,877**	**1,348,030**	**520,846**	**3,277,755**	**1,023,992**	**131,845**	**11,596**	**8,753,819**

[a] May not equal sum of rows/columns due to rounding.

Detailed Findings: Technical and Economic Potential

This study included a comprehensive set of EWR measures from Consumers Energy's programs and the MEMD, supplemented by additional measures not currently offered by Consumers Energy or included in the MEMD. We began our analysis by assessing the technical potential for hundreds of unique EWR measures. As discussed in the *Measure Characterization* section, we considered measure savings and costs separately for each measure permutation across applicable sector, segment, end use, and construction vintage. As shown in Table 13, the Cadmus team considered 7,314 EWR measure permutations and 471 unique measures across all sectors and fuels.

Table 13. Energy Waste Reduction Measure Counts and Permutations

Sector	Unique Electric Measures	Electric Permutations
Residential	122	2,179
Commercial	230	3,851
Industrial	119	1,284
Total	**471**	**7,314**

The study identified more than 10,527 GWh of cumulative technically feasible electric EWR potential by 2040, with cost-effective measures producing approximately 10,333 GWh. Economic potential represents 26% of forecasted 2040 sales. On an annual basis, the 20-year technical and economic potential savings each correspond to 1.5% of sales. Table 14 summarizes electric technical and economic potential for each sector. The residential sector accounts for 52.6% of the total economic electric potential, followed by commercial and industrial, at 29.6% and 17.8%, respectively.

Table 14. Energy Waste Reduction Technical and Economic Potential by Sector-Energy: Cumulative 2040

Sector	Baseline Sales (MWh)	Technical Potential		Economic Potential		Economic Potential Percentage of Technical Potential
		MWh	Percentage of Baseline Sales	MWh	Percentage of Baseline Sales	
Residential	14,861,197	5,515,726	37.1%	5,429,686	36.5%	98.4%
Commercial	14,528,160	3,112,498	21.4%	3,061,027	21.1%	98.3%
Industrial	11,204,888	1,898,978	16.9%	1,842,475	16.4%	97.0%
Total [a]	**40,594,246**	**10,527,202**	**25.9%**	**10,333,188**	**25.5%**	**98.2%**

[a] May not equal sum of rows due to rounding.

Table 15 provides the corresponding electric peak demand reduction potential.

Table 15. Energy Waste Reduction Technical and Economic Potential by Sector-Demand: Cumulative 2040

Sector	20-Year Technical Potential (MW)	20-Year Economic Potential (MW)	Economic Potential Percentage of Technical Potential
Residential	1,661	1,654	99.6%
Commercial	517	514	99.5%
Industrial	304	294	96.9%
Total [a]	**2,481**	**2,462**	**99.2%**

[a] May not equal sum of rows/columns due to rounding.

Detailed Findings: Maximum Achievable Potential

Estimating technical and economic potentials fundamentally remains an engineering and accounting endeavor, whereas estimating maximum achievable and program achievable potential requires a prediction of customer behavior related to adopting EWR measures. This chapter provides the maximum achievable potential results.

The Cadmus team estimated maximum achievable potential as a subset of economic potential that assumes EWR measure-specific ramp rates, using market research and our recent program experience, as well as using current incentive, implementation, and administration costs for each EWR measure from Consumers Energy programs. The maximum achievable potential also includes EWR measures not currently offered and includes a higher volume of home energy reports than offered through the current program. The Cadmus team closely calibrated our findings to the existing levels of Consumers Energy's incentives (expressed as a percentage of either incremental costs or total measure costs). The Detailed Measure Results workpaper contains additional measure characterization assumptions and potential by measure within each sector.

The savings within the maximum achievable potential also represent gross savings and do not consider savings attribution for any particular program. Maximum achievable potential represents an enhanced portfolio of measures compared to Consumers Energy existing programs, and also accounts for future market impacts such as from codes and standards. The maximum achievable potential spreads discretionary and lost opportunity savings over the study horizon using a ramp-rate selection, based on Consumers Energy's recent measure-level EWR program achievements.

The maximum achievable potential includes energy savings and demand reduction for each measure. Table 16 shows the annual maximum achievable potential EWR program expenditures for incentives and administrative costs, in 2020 dollars. Administrative costs include Consumers Energy's program implementation, marketing, direct install, and administration costs. The year-over-year total expenditures follow market impacts, such as in years 2023 to 2024, when the large drop in expenditures is directly related to the absence of residential LED lighting measures. Another decline starts in 2031, representing when nonresidential LED market adoption has no remaining potential.

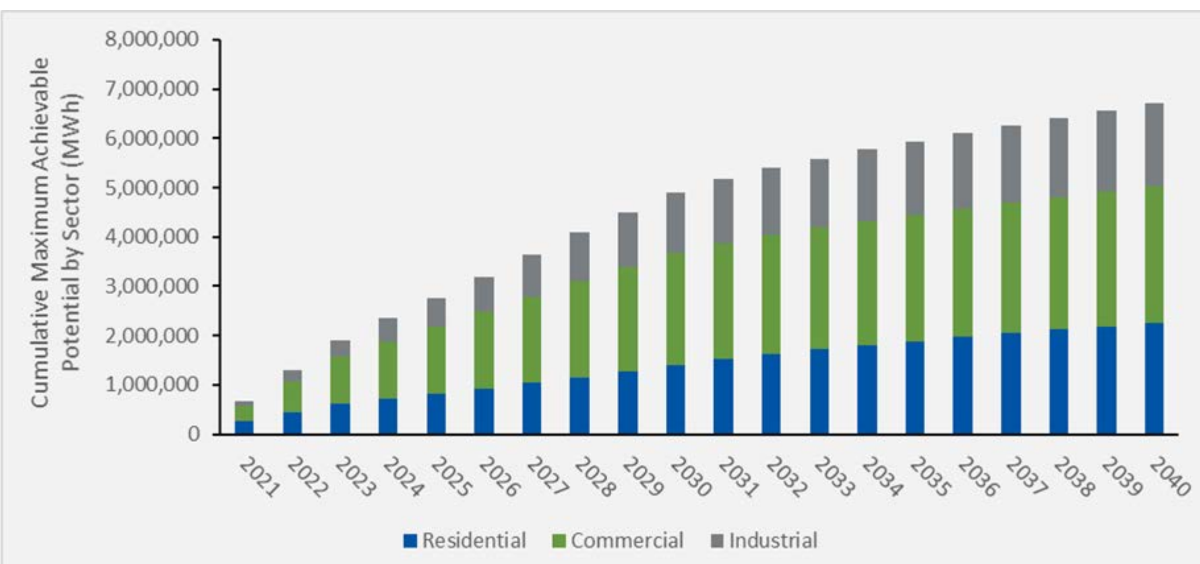
Table 16. Maximum Achievable Potential Energy Waste Reduction Program Expenditures Assumptions

Year	Cost (Million USD)		
	Incentives	Administrative	Total [a]
2021	$73.18	$92.41	**$165.59**
2022	$76.24	$96.95	**$173.19**
2023	$74.85	$96.10	**$170.95**
2024	$61.58	$78.40	**$139.98**
2025	$69.84	$78.63	**$148.47**
2026	$69.85	$79.38	**$149.23**
2027	$71.93	$86.03	**$157.96**
2028	$72.75	$91.82	**$164.56**
2029	$71.12	$92.63	**$163.75**
2030	$74.73	$100.23	**$174.96**
2031	$61.44	$92.50	**$153.95**
2032	$58.86	$89.47	**$148.33**
2033	$54.06	$82.48	**$136.54**
2034	$52.76	$81.07	**$133.83**
2035	$51.98	$80.17	**$132.15**
2036	$66.76	$83.89	**$150.65**
2037	$70.25	$86.91	**$157.16**
2038	$72.52	$87.27	**$159.78**
2039	$70.54	$93.18	**$163.72**
2040	$76.12	$95.34	**$171.46**

[a] May not equal sum of columns due to rounding.

Figure 17 presents the 20-year cumulative maximum achievable EWR potential in megawatt-hours.

Figure 17. Cumulative Maximum Achievable Potential by Sector



Residential

Residential customers in Consumers Energy service territory accounted for 37% of electric baseline forecast sales in 2040—approximately 14,861 GWh. This sector—divided into single family, single family low income, manufactured, manufactured low income, multifamily, and multifamily low income—presents a variety of potential savings sources, including general and specialty LED lighting, air-source and ductless heat pumps, behavior measures, and removing secondary refrigerators.

Based on the resources we assessed, the Cadmus team estimated residential cumulative maximum achievable potential of approximately 2,262,348 MWh over 20 years, corresponding to a 15.2% reduction in residential baseline sales by 2040. This also corresponds to annual savings of 0.8% of sales. Table 17 shows cumulative, 20-year residential electric conservation potential by residential segment.

Table 17. Residential Maximum Achievable Potential by Segment-Energy: Cumulative 2040

Segment	Baseline Sales by Segment	MWh Savings	Percentage of Baseline Sales	MW Savings
Single Family	9,521,692	1,453,901	15.3%	456
Single Family Low Income	3,222,014	551,242	17.1%	145
Manufactured	640,968	86,171	13.4%	26
Multifamily	745,967	79,682	10.7%	23
Multifamily Low Income	463,363	47,333	10.2%	10
Manufactured Low Income	267,194	44,018	16.5%	12
Total or Average [a]	**14,861,197**	**2,262,348**	**15.2%**	**672**

[a] May not equal sum of rows due to rounding.

Table 18 shows cumulative 20-year residential electric conservation potential for the residential segment by end uses and relative to baseline sales. The table shows that the behavior (46%), refrigeration (18%), lighting (16%), heating (5%), and cooling (4%) end uses combined account for 89% of electric residential, cumulative maximum achievable potential. The heating end use only represented 5% because most customers have non-electric heating. The large behavioral savings represents the unconstrained potential from behavior-based changes.

Table 18. Residential Maximum Achievable Potential by End Use-Energy: Cumulative 2040

End Use	Baseline Sales by End Use	MWh Savings	Percentage of Baseline Sales	MW Savings
Refrigeration	1,930,514	731,267	37.9%	86
Lighting	1,591,901	641,698	40.3%	188
Heating	1,912,250	191,430	10.0%	0
Cooling	2,231,824	172,482	7.7%	189
Water Heat	1,265,866	155,823	12.3%	79
Plug Load	2,763,556	123,472	4.5%	66
Dryer	1,062,274	107,848	10.2%	38
Behavior [b]	NA	88,697	NA	10
Heat Pump	246,898	30,783	12.5%	3
Cooking	454,172	18,376	4.0%	11
Other	108,695	473	0.4%	0
Ventilation	1,293,248	0	0.0%	0
Total [a]	**14,861,197**	**2,262,348**	**15.2%**	**672**

[a] May not equal sum of rows due to rounding.
[b] Behavior savings cross all end uses.

Figure 18 shows electric residential cumulative maximum achievable potential by end use in 2025 and 2040.

Figure 18. Residential Maximum Achievable Potential by End Use-Energy: Cumulative

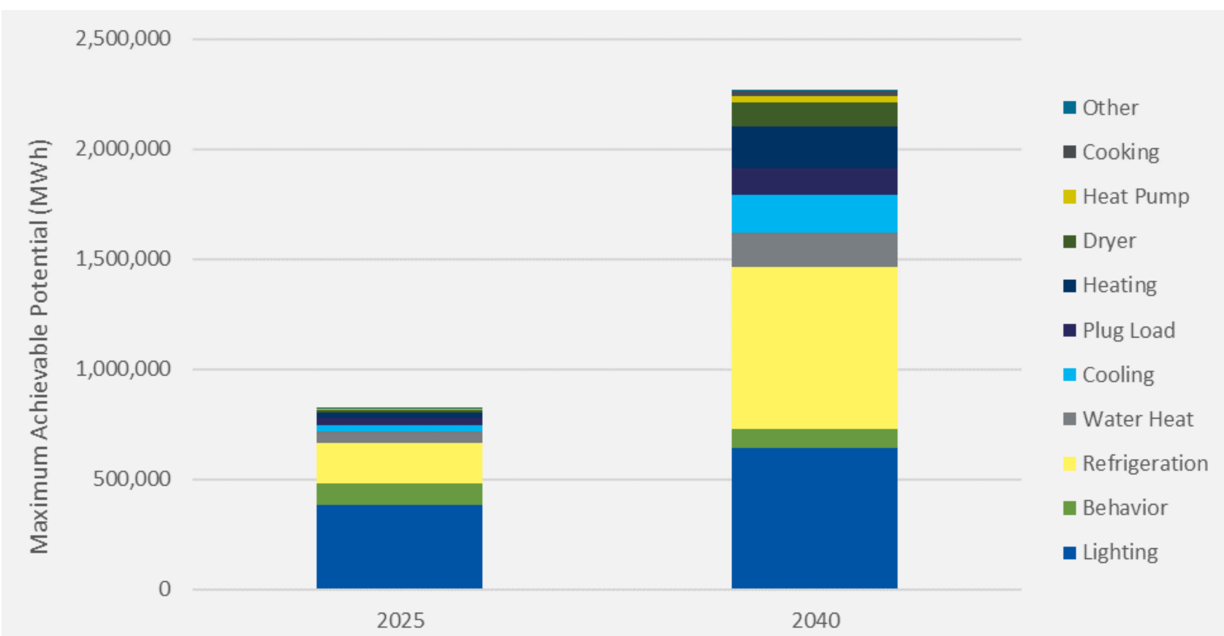


Table 19 lists the top 15 saving electric residential measures that passed the UCT benefit/cost screen. Refrigerator and freezer recycling create the most EWR residential electric maximum achievable potential, LED lighting, home energy reports, windows, heat pump dryers, and lighting controls. Collectively, these top savings measures accounted for 89% of the 20-year residential maximum achievable potential.

Table 19. Top Residential Maximum Achievable Potential Measures: Cumulative 2025 and 2040

Measure Name	Maximum Achievable Potential			
	Cumulative 5-Year (MWh)	Percentage of 5-Year Residential Potential	Cumulative 20-Year (MWh)	Percentage of 20-Year Residential Potential
Home Energy Reports	99,648	12%	88,697	4%
Refrigerator - Removal of Secondary	93,524	11%	726,548	32%
Lighting General Service Lamp - CEE Tier 2	83,360	10%	181,618	8%
Freezer - Removal of Stand-Alone	79,772	10%	319,087	14%
Lighting Specialty Lamp - CEE Tier 2	72,016	9%	173,146	8%
Linear Fluorescent Lamp - TLED	20,088	2%	62,234	3%
Low-Flow Showerhead	17,596	2%	44,937	2%
Interior Lighting Controls	17,025	2%	68,884	3%
Central Air Conditioner - Tier 4	15,755	2%	58,881	3%
Refrigerator - CEE Tier 3	11,289	1%	35,642	2%
Exterior Lighting Controls	9,268	1%	37,498	2%
Dryer - Heat Pump Dryer	9,140	1%	79,168	3%
Ceiling Fan - ENERGY STAR	9,139	1%	37,165	2%
Windows	8,075	1%	85,604	4%
Ceiling / Attic Insulation	2,451	0%	42,157	2%

Commercial

Consumers Energy's commercial sector accounted for 36% of forecasted baseline sales in 2040—approximately 14,528 GWh. The Cadmus team estimated potential for the nine commercial segments listed in Table 20, which summarizes 20-year cumulative maximum achievable potential and the same potentials as a percentage of sales. The available maximum achievable potential for the commercial sector represents 19% of the total 2040 forecasted sales, which corresponds to annual savings of 1.1% of sales. The table shows that offices, retail buildings, warehouses, and other commercial buildings representing 25%, 19%, 16%, and 13%, respectively, of the cumulative 2040 commercial maximum achievable potential.

Table 20. Commercial Maximum Achievable Potential by Segment-Energy: Cumulative 2040

Segment	Baseline Sales by Segment	MWh Savings	Percentage of Baseline Sales	MW Savings
Office	3,392,646	696,975	20.5%	125
Retail	2,817,591	526,321	18.7%	81
Warehouse	1,807,509	445,451	24.6%	64
Other	2,015,616	349,412	17.3%	54
Education	1,503,735	272,055	18.1%	45
Health	1,201,677	204,106	17.0%	33
Restaurant	872,417	133,420	15.3%	17
Grocery	572,090	84,996	14.9%	8
Lodging	344,878	52,777	15.3%	6
Total	**14,528,160**	**2,765,511**	**19.0%**	**434**

[a] May not equal sum of rows due to rounding.

Table 21 shows cumulative 20-year maximum achievable potential for the commercial sector by end use. Lighting (67%), refrigeration (9%), cooling (9%), and ventilation (4%) end uses have the highest 20-year maximum achievable potential in the commercial sector.

Table 21. Commercial Maximum Achievable Potential by End Use-Energy: Cumulative 2040

End Use	Baseline Sales by End Use	MWh Savings	Percentage of Baseline Sales	MW Savings
Lighting	5,276,623	1,852,460	35.1%	285
Refrigeration	1,927,013	259,140	13.4%	20
Cooling	1,366,558	243,037	17.8%	84
Ventilation	2,598,798	120,101	4.6%	12
Heating	320,614	69,817	21.8%	0
Water Heat	278,909	69,253	24.8%	3
Plug Load	1,969,685	41,543	2.1%	4
Heat Pump	138,375	43,422	31.4%	14
Cooking	430,286	41,499	9.6%	7
Other	211,405	24,439	11.6%	4
Dryer	9,895	801	8.1%	0
Total [a]	**14,528,160**	**2,765,511**	**19.0%**	**434**

[a] May not equal sum of rows due to rounding.

Figure 19 shows commercial cumulative maximum achievable potential by end use in 2025 and 2040.

Figure 19. Commercial Maximum Achievable Potential by End Use-Energy: Cumulative

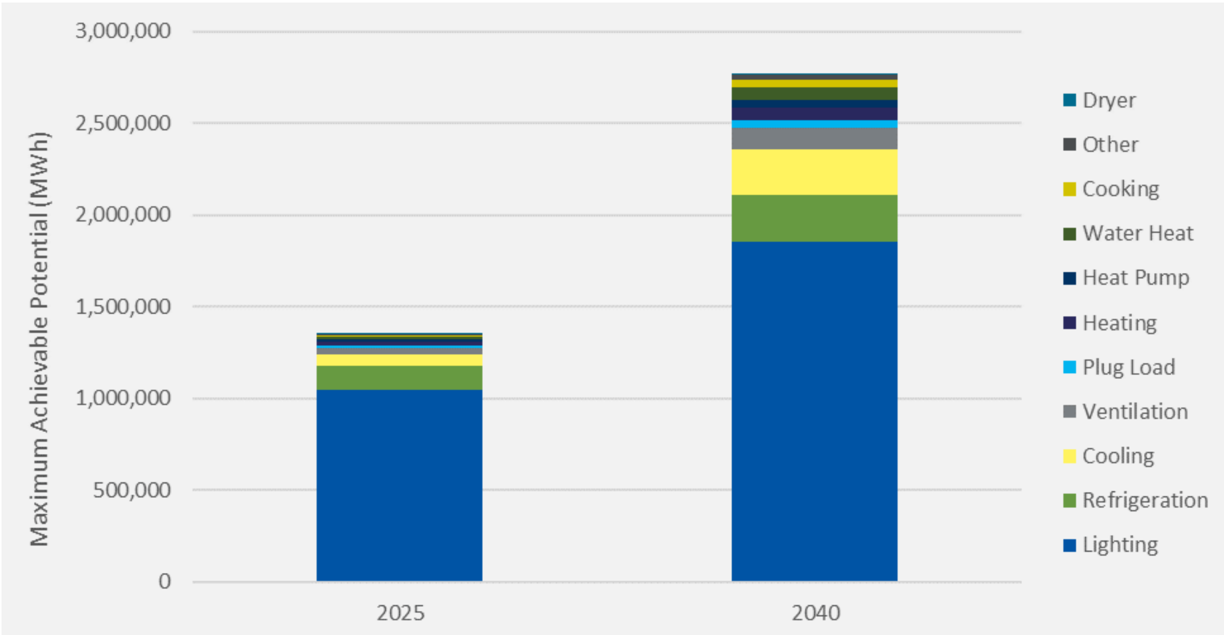


Table 22 lists the top 15 saving commercial measures. The top commercial measures collectively represent 69% of the 20-year commercial maximum achievable potential.

Table 22. Top Commercial Maximum Achievable Potential Measures: Cumulative 2025 and 2040

Measure Name	Maximum Achievable Potential			
	Cumulative 5-Year (MWh)	Percentage of 5-Year Commercial Potential	Cumulative 20-Year (MWh)	Percentage of 20-Year Commercial Potential
Lighting Interior - Screw Base LED - Above Standard	416,107	31%	462,341	17%
Lighting Interior - TLED / LED Panel - Above Standard	204,005	15%	418,602	15%
Occupancy Sensor Control	84,827	6%	212,066	8%
LED Exterior Wall Pack	71,129	5%	115,015	4%
Dimming, Fluorescent Fixtures	54,940	4%	109,879	4%
Advanced Network Occupancy and Daylighting Controls	54,894	4%	109,788	4%
Exterior Occupancy Sensor	43,064	3%	107,660	4%
LED Exterior Flood Lights	37,649	3%	60,878	2%
Bi-Level Control, Stairwell Lighting	29,393	2%	59,196	2%
Walk-in Economizer	29,216	2%	59,184	2%
Lighting Interior - High Bay LED - Above Standard	22,768	2%	46,809	2%
LED Exterior Pole Mount Fixture	21,455	2%	34,692	1%
New Construction Lighting Package - Advanced Efficiency	17,520	1%	43,855	2%
Wall Insulation	10,346	1%	41,384	1%
Direct Digital Control System-Installation	8,699	1%	34,796	1%

Industrial

Consumers Energy's industrial sector accounted for 28% of baseline sales in 2040—approximately 11,205 GWh. The Cadmus team estimated potential for the 25 industrial segments (including agriculture) listed in Table 23, which summarizes 20-year cumulative maximum achievable potential and the same potentials as a percentage of sales. Available maximum achievable potential for the industrial sector represents 15% of the total 2040 forecasted load, which corresponds to annual savings of 0.8% of sales. The table shows that the top five industries represent 59% of cumulative 2040 maximum achievable potential.

Table 23. Industrial Maximum Achievable Potential by Segment-Energy: Cumulative 2040

Segment/Type of Manufacturing	Baseline Sales by Segment	MWh	Percentage of Baseline Sales	MW
Computer and Electronic	2,016,833	331,227	16.4%	48
Transportation Equipment	1,242,074	224,735	18.1%	32
Plastics Rubber Products	1,092,482	172,212	15.8%	25
Food	977,991	145,880	14.9%	21
Fabricated Metal Products	783,780	127,435	16.3%	18
Primary Metal	988,669	118,140	11.9%	17
Chemical	773,325	101,709	13.2%	15
Industrial Machinery	547,426	91,310	16.7%	13
Paper	682,656	77,648	11.4%	11
Nonmetallic Mineral Products	514,930	74,862	14.5%	11
Agriculture	519,321	67,888	13.1%	35
Furniture	167,154	28,467	17.0%	4
Wood Product	172,987	24,612	14.2%	4
Miscellaneous	135,641	24,097	17.8%	3
Electrical Equipment	139,902	23,114	16.5%	3
Printing Related Support	136,405	21,510	15.8%	3
Mining	101,062	8,771	8.7%	1
Beverage and Tobacco	44,328	6,630	15.0%	1
Wastewater	43,491	5,336	12.3%	1
Water	79,414	4,560	5.7%	1
Textile Mills	16,376	2,494	15.2%	0
Textile Product Mills	11,088	1,681	15.2%	0
Leather	10,816	1,629	15.1%	0
Petroleum Coal Products	3,946	501	12.7%	0
Apparel	2,791	498	17.8%	0
Total [a]	**11,204,888**	**1,686,948**	**15.1%**	**269**

[a] May not equal sum of rows due to rounding.

Table 24 shows cumulative 20-year electric conservation potential for the industrial sector by end use. Process load savings represent the highest potential savings (39%) by end use.

Table 24. Industrial Maximum Achievable Potential by End Use-Energy: Cumulative 2040

End Use	Baseline Sales by End Use	MWh	Percentage of Baseline Sales	MW
Process	4,195,527	661,075	15.8%	96
HVAC	1,441,723	312,997	21.7%	45
Lighting	929,122	287,205	30.9%	42
Motors Other	1,725,479	153,934	8.9%	22
Pumps	1,310,710	134,885	10.3%	42
Fans	637,127	63,086	9.9%	9
Other	666,683	36,401	5.5%	5
Ventilation	168,762	31,462	18.6%	7
Indirect Boiler	114,912	5,772	5.0%	1
Water Heat	14,843	132	0.9%	0
Total [a]	**11,204,888**	**1,686,948**	**15.1%**	**269**

[a] May not equal sum of rows due to rounding.

Figure 20 shows the industrial cumulative maximum achievable potential by end use in 2025 and 2040.

Figure 20. Industrial Maximum Achievable Potential by End Use-Energy: Cumulative

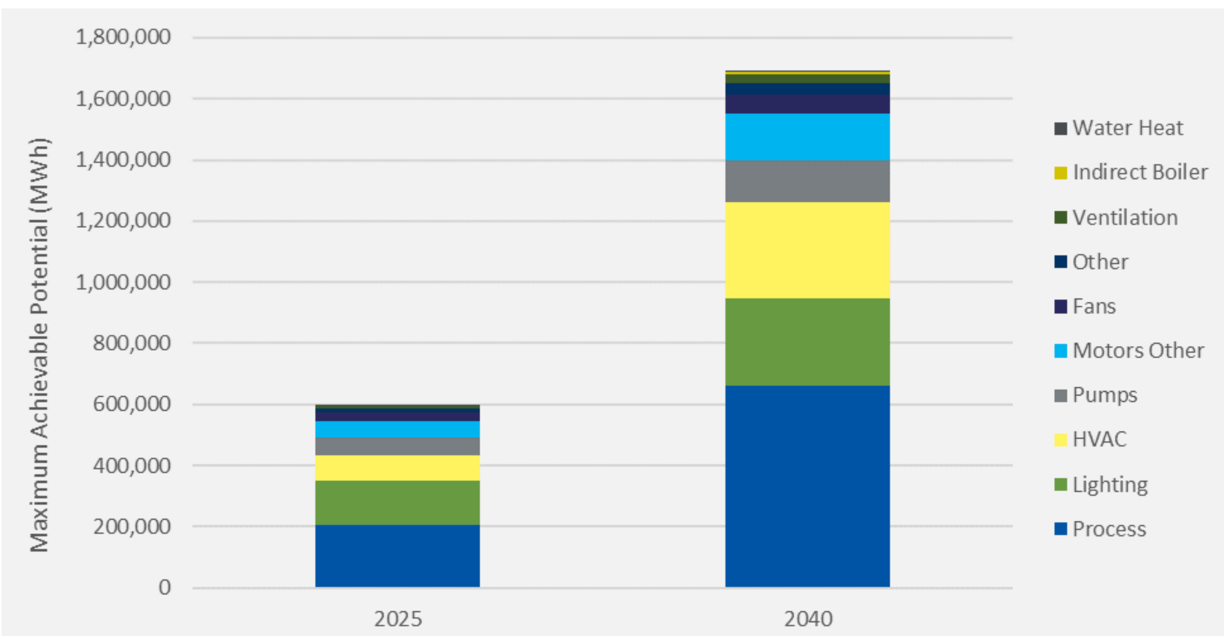


Table 25 lists the top 15 saving electric industrial measures, which collectively represent approximately 54% of the sector's total maximum achievable potential. LED lighting measures accounted for approximately 9% of the industrial electric maximum achievable savings potential.

Table 25. Top Industrial Maximum Achievable Potential Measures: Cumulative 2025 and 2040

Measure Name	Maximum Achievable Potential			
	Cumulative 5-Year (MWh)	Percentage of 5-Year Industrial Potential	Cumulative 20-Year (MWh)	Percentage of 20-Year Industrial Potential
Lighting - Linear LED Packages	51,814	4%	103,629	6%
Optimize Lighting System - Install Skylights And Use Daylighting	27,585	2%	55,170	3%
Equipment Upgrade - Replace Existing Chiller With High Efficiency Model	26,622	2%	66,556	4%
Cooling Tower Operation And Maintenance	25,851	2%	64,627	4%
Lighting - High Bay LED Packages	25,769	2%	51,537	3%
Upgrade Equipment - Replace Existing HVAC Unit With High Efficiency Model	24,687	2%	98,748	6%
Install Adjustable Frequency Drive to Replace Existing System - Pumps	23,686	2%	47,372	3%
Equipment Upgrade - Air Compressor	20,010	2%	50,026	3%
Optimize Chiller and Refrigeration Systems	19,992	2%	49,980	3%
Thermal Systems Recover Heat And Use For Preheating, Space Heating, Power Generation, Steam Generation, Transformers, Exhausts, Engines, Compressors, Dryers, Waste Process Heat, etc.	18,357	2%	73,428	4%
Optimize Motor Systems With Right Sizing	17,967	2%	44,917	3%
Install Compressor Controls	17,909	2%	44,771	3%
Thermal Systems Add Insulation to Equipment	12,958	1%	51,831	3%
Building Envelope Insulation and Window/Door Improvements	12,233	1%	48,932	3%
Building Duct System Improvements	11,392	1%	45,568	3%

Detailed Findings: Program Achievable Potential

The Cadmus team estimated program achievable potential as a subset of maximum achievable potential based on Consumers Energy paying incentive levels (as a percentage of incremental or total measure costs) that are closely calibrated to historical levels, subject to any overall program- or customer class-specific spending constraints. The team mapped program achievable potential incentive levels to those currently offered by Consumers Energy. For instances where we were unable to identify a direct, current incentive for an EWR measure, we used a similar technology and incentive level as a proxy. In addition, the team modeled increased distribution of home energy reports within the residential sector as an expansion to the existing Consumers Energy program.

The savings within the program achievable potential also represent net savings and measures currently offered through Consumers Energy programs and measures with potential to be offered within the study horizon, while also accounting for future market impacts (such as federal standards). The program achievable potential spreads discretionary and lost opportunity savings over the study horizon using a ramp-rate selection based on Consumers Energy's recent, measure-level EWR program achievements.

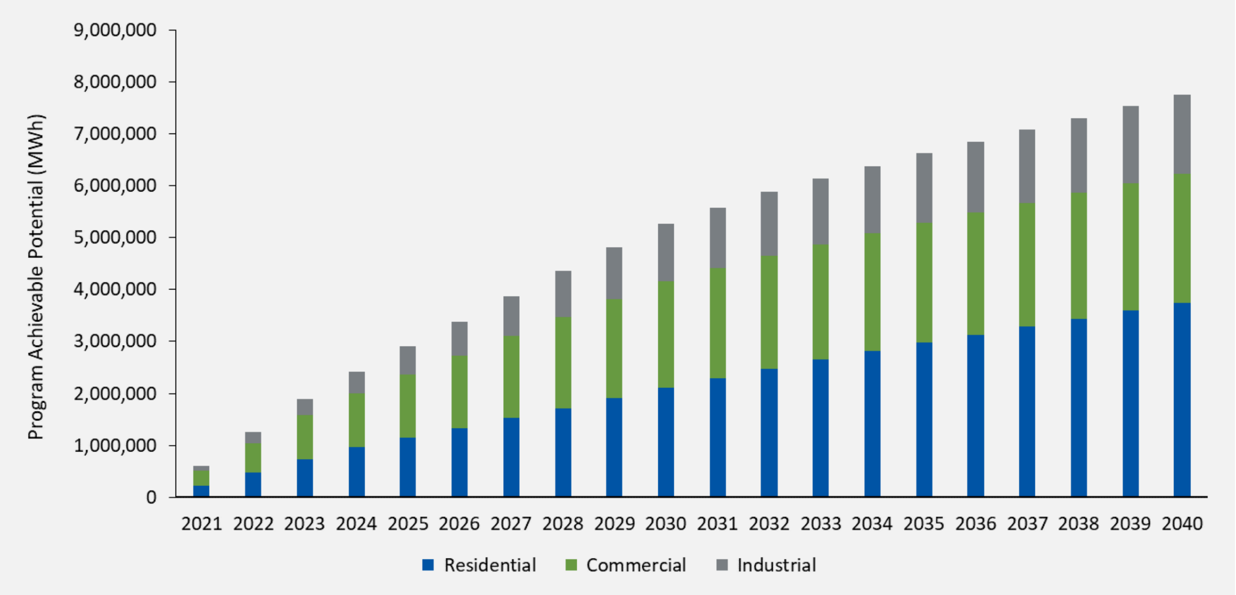
The Cadmus team used various budget assumptions to develop program achievable potential, based on anticipated levels of programmatic spending by Consumers Energy. Table 26 shows the yearly expenditures for administrative and incentive costs. In a pattern similar to that for the estimated maximum achievable potential spending, the budget reflects market impacts from changes such as a decline in spending after 2023, when the LED measures no longer have potential due to changing lighting standards.

Table 26. Program Achievable Potential Energy Waste Reduction Program Expenditures Assumptions

Year	Cost (Million USD)		
	Incentives	Administrative	Total
2021	$60.19	$86.27	**$146.45**
2022	$62.98	$90.57	**$153.55**
2023	$62.04	$90.59	**$152.64**
2024	$53.04	$75.19	**$128.23**
2025	$60.33	$75.18	**$135.50**
2026	$60.55	$76.29	**$136.84**
2027	$62.84	$83.41	**$146.25**
2028	$63.40	$88.75	**$152.14**
2029	$61.82	$89.66	**$151.48**
2030	$64.79	$96.66	**$161.46**
2031	$52.76	$93.90	**$146.66**
2032	$50.78	$91.42	**$142.20**
2033	$47.21	$85.66	**$132.87**
2034	$45.92	$83.44	**$129.36**
2035	$45.02	$81.71	**$126.72**
2036	$58.19	$85.32	**$143.52**
2037	$61.42	$88.14	**$149.56**
2038	$63.75	$88.90	**$152.65**
2039	$60.45	$94.37	**$154.82**
2040	$65.74	$96.62	**$162.36**

Figure 21 presents the 20-year cumulative program achievable EWR potential in megawatt-hours.

Figure 21. Cumulative Program Achievable Potential by Sector



Residential

Based on resources included in this assessment, the Cadmus team estimated residential cumulative program achievable potential of 1,737,9112 MWh over 20 years, corresponding to a 25% reduction in residential baseline sales. Table 27 displays cumulative 20-year residential electric conservation for each segment in the residential sector.

Table 27. Residential Program Achievable Potential by Segment-Energy: Cumulative 2040

Segment	Baseline Sales by Segment	MWh	Percentage of Baseline Sales	MW
Single Family	9,521,692	1,055,697	11%	250
Single Family Low Income	3,222,014	480,932	15%	101
Manufactured	640,968	61,247	10%	16
Multifamily	745,967	57,986	8%	14
Multifamily Low Income	463,363	42,881	9%	7
Manufactured Low Income	267,194	39,169	15%	9
Total [a]	**14,861,197**	**1,737,912**	**12%**	**397**

[a] May not equal sum of rows due to rounding.

Table 28 shows cumulative 20-year residential electric energy waste reduction potential for the residential segment by end uses and relative to baseline sales. The table shows that more than one-third of the available program achievable potential comes from refrigeration (37%). The other end uses with significant amounts of potential are refrigeration (42%), heating (9%), and cooling (7%).

Table 28. Residential Program Achievable Potential by End Use-Energy: Cumulative 2040

End Use	Baseline Sales by End Use	MWh	Percentage of Baseline Sales	MW
Refrigeration	1,930,514	649,187	34%	76
Lighting	1,591,901	423,172	27%	50
Heating	1,912,250	159,482	8%	0
Cooling	2,231,824	138,499	6%	163
Water Heat	1,265,866	126,414	10%	53
Dryer	1,062,274	99,924	9%	36
Behavior	NA	70,957	NA	8
Plug Load	2,763,556	45,607	2%	8
Heat Pump	246,898	24,244	10%	3
Other	108,695	426	0%	0
Cooking	454,172	0	0%	0
Ventilation	1,293,248	0	0%	0
Total [a]	**14,861,197**	**1,737,912**	**12%**	**397**

[a] May not equal sum of rows due to rounding.

Figure 22 shows electric residential cumulative program achievable potential by end use in 2025 and 2040

Figure 22. Residential Program Achievable Potential by End Use-Energy: Cumulative

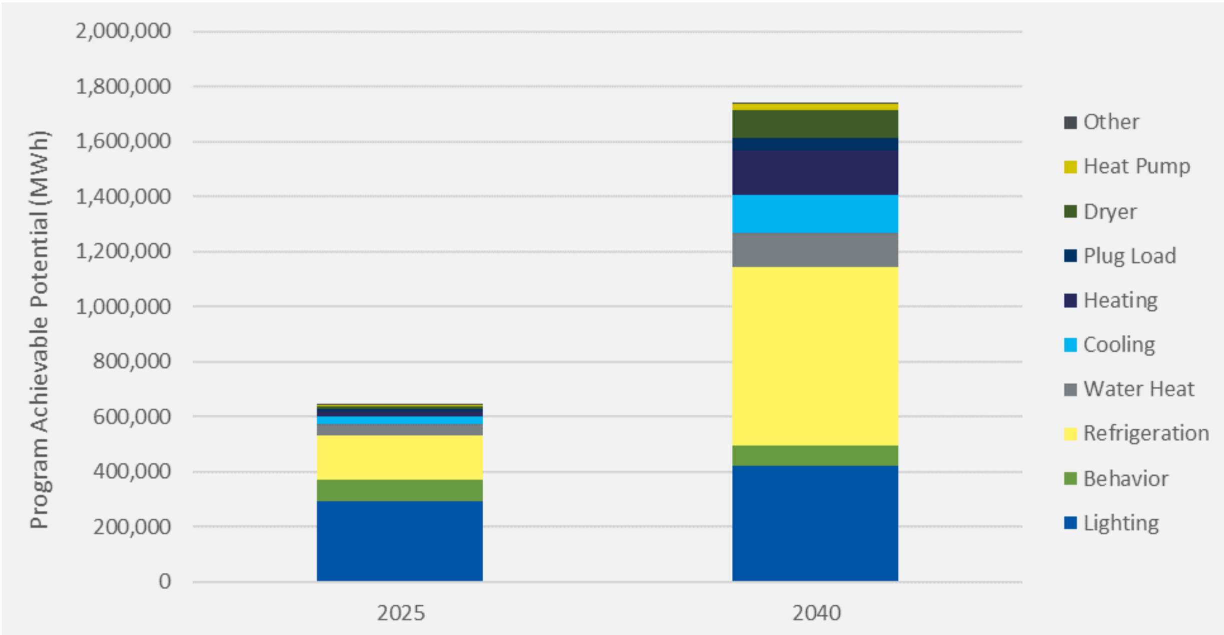


Table 29 lists the top 15 saving electric residential measures that passed the UCT benefit/cost screen. Secondary refrigerator and freezer removal are large contributors, collectively making up 37% of the 20-year residential program achievable potential.

Table 29. Top Residential Program Achievable Potential Measures: Cumulative 2025 and 2040

Measure Name	Program Achievable Potential			
	Cumulative 5-Year (MWh)	Percentage of 5-Year Residential Potential	Cumulative 20-Year (MWh)	Percentage of 20-Year Residential Potential
Refrigerator - Removal of Secondary	85,601	13%	342,402	20%
Home Energy Reports	79,718	12%	70,957	4%
Freezer - Removal of Stand-Alone	73,632	11%	294,527	17%
Lighting General Service Lamp - CEE Tier 2	60,025	9%	124,908	7%
Lighting Specialty Lamp - CEE Tier 2	56,080	9%	124,175	7%
Low-Flow Showerhead	16,739	3%	42,748	2%
Central Air Conditioner - Tier 4	14,432	2%	53,932	3%
Refrigerator - CEE Tier 3	11,289	2%	35,642	2%
Dryer - Heat Pump Dryer	8,469	1%	73,352	4%
Windows	7,518	1%	79,704	5%
Advanced Power Strip - Tier 2	7,293	1%	29,659	2%
Dryer - CEE Advanced Tier	3,414	1%	28,679	2%
Wall Insulation	3,337	1%	35,286	2%
Ceiling / Attic Insulation	2,304	0%	39,611	2%
ENERGY STAR Door	1,453	0%	24,850	1%

Commercial

The Cadmus team estimated potential for the nine commercial segments listed in Table 30, which summarizes 2040 forecast sales, 20-year cumulative program achievable potential, and the same potential as a percentage of sales. The table shows that the commercial sector has 2,483,449 MWh of available program achievable potential and 388 MW of demand reduction. The energy savings for commercial program achievable potential aggregates to 17% of the 2040 commercial baseline sales, with individual segments ranging between 13% and 22%. Offices make up 25% of the energy savings, the greatest proportion, with retail buildings (19%) and warehouses (16%) also making up a sizable amount. This trend is reflected in the demand reduction as well.

Table 30. Commercial Program Achievable Potential by Segment-Energy: Cumulative 2040

Segment	Baseline Sales by Segment	MWh	Percentage of Baseline Sales	MW
Office	3,392,646	625,179	18%	111
Retail	2,817,591	472,770	17%	73
Warehouse	1,807,509	400,217	22%	58
Other	2,015,616	313,834	16%	48
Education	1,503,735	244,237	16%	40
Health	1,201,677	183,344	15%	30
Restaurant	872,417	120,017	14%	16
Grocery	572,090	76,447	13%	7
Lodging	344,878	47,402	14%	5
Total	**14,528,160**	**2,483,449**	**17%**	**388**

[a] May not equal sum of rows due to rounding.

Table 31 shows cumulative 20-year program achievable potential at the end use level for the commercial sector. The table shows the greatest potential for lighting (67%), followed by refrigeration (9%), cooling (9%), and ventilation (4%).

Table 31. Commercial Program Achievable Potential by End Use-Energy: Cumulative 2040

End Use	Baseline Sales by End Use	MWh	Percentage of Baseline Sales	MW
Lighting	5,276,623	1,664,734	32%	256
Refrigeration	1,927,013	233,226	12%	18
Cooling	1,366,558	217,440	16%	74
Ventilation	2,598,798	108,091	4%	10
Water Heat	278,909	62,328	22%	3
Heating	320,614	62,308	19%	0
Plug Load	1,969,685	36,735	2%	4
Heat Pump	138,375	38,523	28%	12
Cooking	430,286	37,349	9%	6
Other	211,405	21,995	10%	4
Dryer	9,895	720	7%	0
Total	**14,528,160**	**2,483,449**	**17%**	**388**

[a] May not equal sum of rows due to rounding.

Figure 23 shows the cumulative program achievable potential by end use for the commercial sector in 2025 and 2040. The figure shows that lighting savings grow significantly in the first few years of the study, then plateau (as LED measures do not obtain potential in the latter half of the study).

Figure 23. Commercial Program Achievable Potential by End Use-Energy: Cumulative

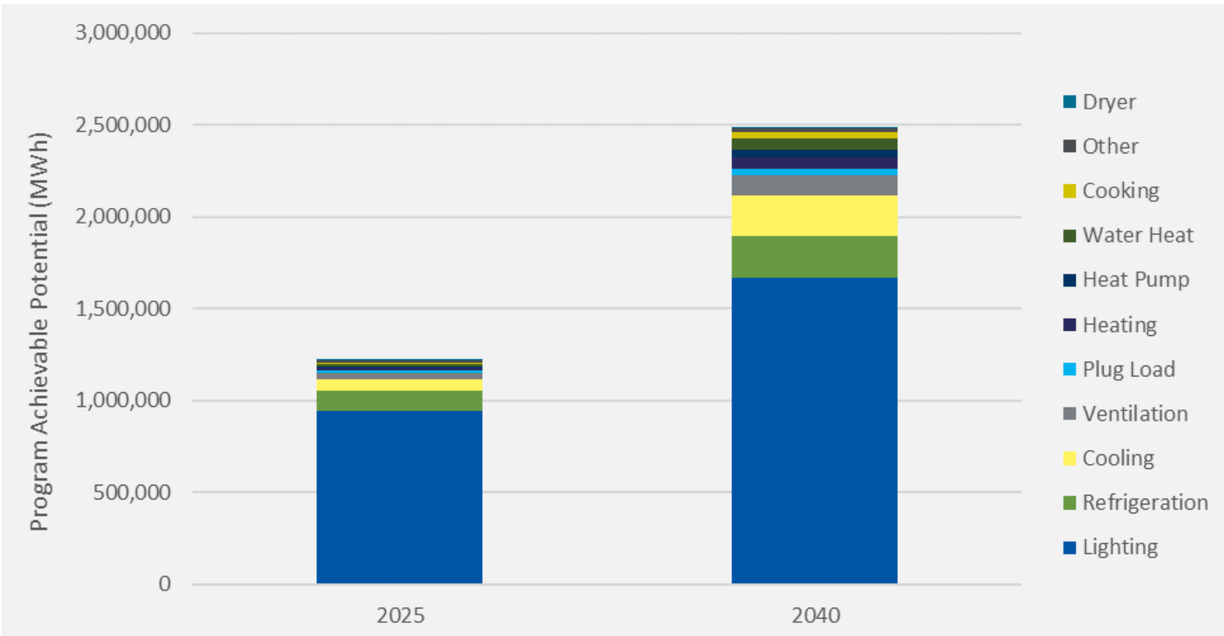


Table 32 lists the top 15 saving commercial measures that passed the UCT benefit/cost screen. Above-standard LED/TLED panel interior lighting accounts for 15% of the 20-year commercial program achievable potential, followed by several other retrofit and equipment lighting measures. Collectively, the top 15 measures make up 67% of the 20-year commercial program achievable potential.

Table 32. Top Commercial Program Achievable Potential Measures: Cumulative 2025 and 2040

Measure Name	Program Achievable Potential			
	Cumulative 5-Year (MWh)	Percentage of 5-Year Commercial Potential	Cumulative 20-Year (MWh)	Percentage of 20-Year Commercial Potential
Lighting Interior - Screw Base LED - Above Standard	182,395	330,990	27%	367,766
Lighting Interior - TLED / LED Panel - Above Standard	330,990	182,395	15%	374,261
Occupancy Sensor Control	76,344	76,344	6%	190,860
LED Exterior Wall Pack	64,016	64,016	5%	103,514
Dimming, Fluorescent Fixtures	49,446	49,446	4%	98,891
Advanced Network Occupancy and Daylighting Controls	49,404	49,404	4%	98,809
Exterior Occupancy Sensor	38,758	38,758	3%	96,894
LED Exterior Flood Lights	33,884	33,884	3%	54,791
Bi-Level Control, Stairwell Lighting	26,453	26,453	2%	53,277
Walk-in Economizer	26,294	26,294	2%	53,265
Lighting Interior - High Bay LED - Above Standard	20,491	20,491	2%	42,128
LED Exterior Pole Mount Fixture	15,768	19,309	2%	31,223
New Construction Lighting Package - Advanced Efficiency	9,311	15,768	1%	39,470
Wall Insulation	7,829	9,311	1%	37,246
Direct Digital Control System-Installation	19,309	7,829	1%	31,317

Industrial

The Cadmus team estimated program achievable potential for the 25 industrial segments listed in Table 33. The table summarizes the 20-year cumulative program achievable potential and the same potential as a percentage of sales. There are 1,518,253 MWh of overall industrial EWR available as a part of the program achievable potential, which is 14% of the 2040 industrial baseline sales. Additionally, there are 242 MW of demand reduction available. Computer and electronic manufacturing provides the greatest opportunity for energy savings and demand reduction based on current Consumers Energy program offerings, followed by transportation equipment manufacturing and plastic rubber product manufacturing.

Table 33. Industrial Program Achievable Potential by Segment-Energy: Cumulative 2040

Segment/Type of Manufacturing	Baseline Sales by Segment	MWh	Percentage of Baseline Sales	MW
Computer and Electronic	2,016,833	298,104	15%	43
Transportation Equipment	1,242,074	202,262	16%	29
Plastics Rubber Products	1,092,482	154,991	14%	22
Food	977,991	131,292	13%	19
Fabricated Metal Products	783,780	114,692	15%	17
Primary Metal	988,669	106,326	11%	15
Chemical	773,325	91,538	12%	13
Industrial Machinery	547,426	82,179	15%	12
Paper	682,656	69,884	10%	10
Nonmetallic Mineral Products	514,930	67,376	13%	10
Agriculture	519,321	61,099	12%	31
Furniture	167,154	25,620	15%	4
Wood Product	172,987	22,151	13%	3
Miscellaneous	135,641	21,688	16%	3
Electrical Equipment	139,902	20,803	15%	3
Printing Related Support	136,405	19,359	14%	3
Mining	101,062	7,894	8%	1
Beverage and Tobacco	44,328	5,967	13%	1
Wastewater	43,491	4,803	11%	1
Water	79,414	4,104	5%	1
Textile Mills	16,376	2,245	14%	< 1
Textile Product Mills	11,088	1,513	14%	< 1
Leather Mfg	10,816	1,466	14%	< 1
Petroleum Coal Products	3,946	451	11%	< 1
Apparel	2,791	448	16%	< 1
Total	**11,204,888**	**1,518,253**	**14%**	**242**

[a] May not equal sum of rows due to rounding.

Table 34 shows cumulative 20-year electric conservation potential for the industrial sector by end use. The table shows that process measures make up the greatest amount of the industrial program achievable potential (39%), followed by HVAC (19%), and lighting (17%).

Table 34. Industrial Program Achievable Potential by End Use-Energy: Cumulative 2040

End Use	Baseline Sales by End Use	MWh	Percentage of Baseline Sales	MW
Process	4,195,527	594,967	14%	86
HVAC	1,441,723	281,698	20%	41
Lighting	929,122	258,484	28%	38
Motors Other	1,725,479	138,540	8%	20
Pumps	1,310,710	121,396	9%	38
Fans	637,127	56,777	9%	8
Other	666,683	32,761	5%	5
Ventilation	168,762	28,316	17%	6
Indirect Boiler	114,912	5,195	5%	1
Water Heat	14,843	118	1%	0
Total [a]	**11,204,888**	**1,518,253**	**14%**	**242**

[a] May not equal sum of rows due to rounding.

Figure 24 shows the annual cumulative program achievable potential by end use for industrial sector in 2025 and 2040.

Figure 24. Industrial Program Achievable Potential by End Use-Energy: Cumulative

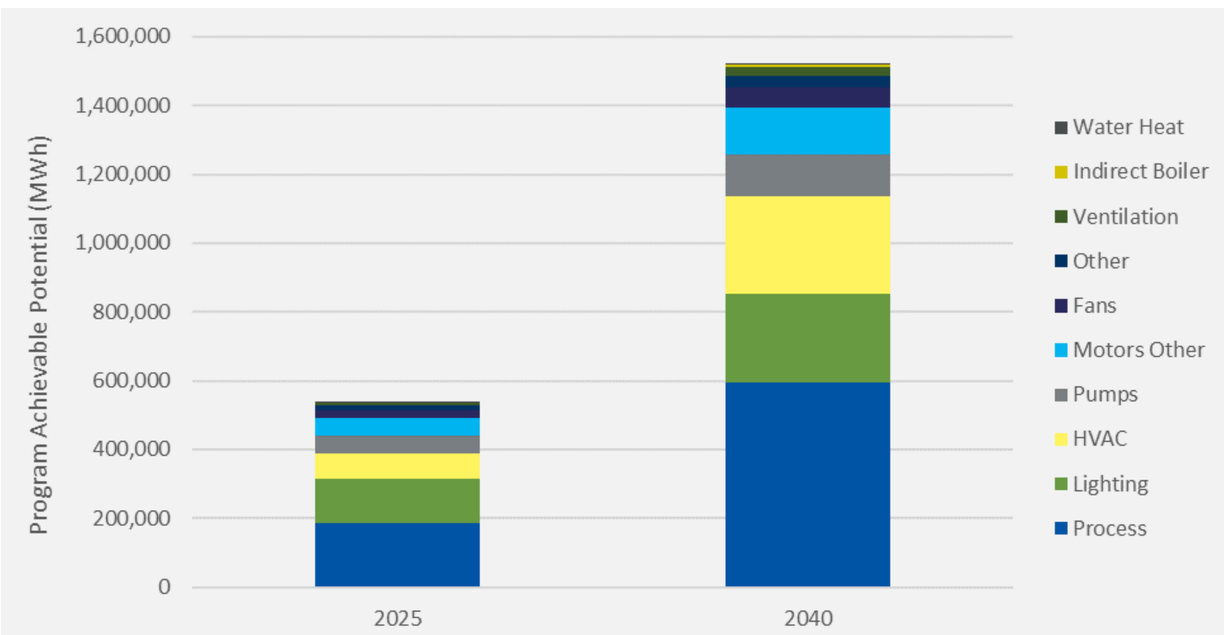


Table 35 lists the top 15 saving electric industrial measures that passed the UCT benefit/cost screen. These top 15 measures collectively accounted for 53% of the 20-year industrial achievable potential. The individual measure with the largest 20-year program achievable potential is the linear lighting LED package, with over 93,000 MWh of program achievable potential.

Table 35. Top Industrial Program Achievable Potential Measures: Cumulative 2025 and 2040

Measure Name	Program Achievable Potential			
	Cumulative 5-Year (MWh)	Percentage of 5-Year Industrial Potential	Cumulative 20-Year (MWh)	Percentage of 20-Year Industrial Potential
Lighting - Linear LED Packages	46,633	4%	93,266	6%
Optimize Lighting System - Install Skylights And Use Daylighting	24,826	2%	49,653	3%
Equipment Upgrade - Replace Existing Chiller With High Efficiency Model	23,960	2%	59,900	4%
Cooling Tower Operation And Maintenance	23,266	2%	58,164	4%
Lighting - High Bay LED Packages	23,192	2%	46,384	3%
Upgrade Equipment - Replace Existing HVAC Unit With High Efficiency Model	22,218	2%	88,874	6%
Install Adjustable Frequency Drive to Replace Existing System - Pumps	21,317	2%	42,635	3%
Equipment Upgrade - Air Compressor	18,009	2%	45,023	3%
Optimize Chiller and Refrigeration Systems	17,993	2%	44,982	3%
Thermal Systems Recover Heat And Use For Preheating, Space Heating, Power Generation, Steam Generation, Transformers, Exhausts, Engines, Compressors, Dryers, Waste Process Heat, etc.	16,521	2%	66,085	4%
Optimize Motor Systems With Right Sizing	16,170	2%	40,425	3%
Install Compressor Controls	16,118	2%	40,294	3%
Thermal Systems Add Insulation to Equipment	11,662	1%	46,648	3%
Building Envelope Insulation and Window/Door Improvements	11,010	1%	44,039	3%
Building Duct System Improvements	10,253	1%	41,011	3%

Summary of Methodologies

The Cadmus team relied on industry best practices, analytic rigor, and flexible and transparent tools to accurately estimate the long-term electric EWR potential for energy savings and peak demand reduction in Consumers Energy's territory from 2021 to 2040. This chapter describes the team's methods for each step in the assessment process.

Baseline End-Use Forecast

To assess EWR, the Cadmus team first determined an accurate and Consumers Energy-specific representation of baseline energy use by sector and segment. We established customer counts and sales, as well as forecasts, and disaggregated the baseline year (2020) sales and customer counts using 2019 sales data, applying primary and secondary data to further disaggregate.

To create a baseline forecast, the team used multiple data inputs to accurately characterize energy use within Consumers Energy's service area:

- Electric energy sales and customer forecasts
- Major customer segments (residential dwelling types, nonresidential business types)
- End-use saturations (the percentage of an end use, such as an air conditioner, present in a building)
- Equipment saturations (average number of units in a building)
- Fuel shares (proportion of units using electricity versus natural gas)
- Efficiency shares (the percentage of equipment below, at, and above standard)
- Annual end-use estimates by efficiency levels

Data specific to Consumers Energy's service territory not only provided the basis for baseline calibration, but also supported the team's estimate of technical potential. Table 36 lists the key data sources used.

Table 36. Baseline Forecast Data Sources

Data	Residential	Commercial	Industrial
Baseline Sales and Customers	Consumers Energy Customer Databases, Actual	Consumers Energy Customer Databases, Actual	Consumers Energy Customer Databases, Actual
Forecasted Sales and Customers	Consumers Energy Load Forecasts	Consumers Energy Load Forecasts	Consumers Energy Load Forecasts
Percentage of Sales by Building Type	Consumers Energy Customer Databases	Consumers Energy Customer Databases	Consumers Energy Customer Databases
End-Use Energy Use	Consumers Energy Load Forecasts, 2020 MEMD, EIA 2015 *Residential Energy Consumption Survey* (RECS), ENERGY STAR, Cadmus team research	Consumers Energy Load Forecasts, Consumers Energy *2019 Commercial and Industrial Market Assessment*, 2020 MEMD, EIA 2012 *Commercial Building Energy Consumption Survey* (CBECS), ENERGY STAR, Cadmus team research	Consumers Energy Load Forecasts, Consumers Energy *2019 Commercial and Industrial Market Assessment* EIA 2018 *Manufacturing Energy Consumption Survey*, 2020 MEMD, Cadmus team research
Saturations and Fuel Shares	Consumers Energy 2018 *Residential Appliance Saturation and Home Characteristics Study*, EIA RECS, Cadmus team research	*2019 Commercial and Industrial Market Assessment*, EIA CBECS, Cadmus team research	*2019 Commercial and Industrial Market Assessment*, DOE *Industrial Assessment Center Database*, EIA *Manufacturing Energy Consumption Survey*, Cadmus team research
Efficiency Shares	Consumers Energy 2018 *Residential Appliance Saturation and Home Characteristics Study*, EIA RECS, ENERGY STAR unit shipment reports, Cadmus team research	*Nonresidential Baseline Study*, EIA CBECS, Cadmus team research	*Nonresidential Baseline Study*, DOE *Industrial Assessment Center Database*, EIA *Manufacturing Energy Consumption Survey*, Cadmus team research

The Cadmus team followed these steps to create the baseline forecast:

- ***Step 1. Establish Utility Sales and Customer Counts.*** The team requested Consumers Energy's residential, commercial, and industrial customer counts and sales data, sales and customer forecasts, and peak demand by sector and segment. These data served as the foundation for establishing the level of EWR potential available in Consumers Energy territory over the 20-year study period. The initial data request included several additional details:
  - The number of customers and weather-normalized actual electric sales for 2019 (as a historical base year) and for a forecast period.
  - Forecast sales absent future, planned EWR (to avoid double-counting savings future potential savings).

  These customer data were intended to represent the number of buildings or dwellings, but the team used accounts and premises as a proxy where available and necessary.
- ***Step 2. Disaggregate Market Results.*** To disaggregate Consumers Energy's customer counts and electric sales, the team reviewed Consumers Energy's electric sales and demand forecasts for a

20-year period (2021 through 2040), along with one full year of customer billing data. After analyzing the customer billing databases, the team determined the distribution of energy use and demand by sector and segment in 2019. Within each segment, the team analyzed two vintages—existing construction and new construction—within the following market-sector and segment classifications:

- ***Sectors:*** residential, commercial, industrial
- ***Segments:*** Residential (single family, single family low income, multifamily, multifamily low income, manufactured, manufactured low income) and commercial and industrial (both based on business type, typically by North American Industry Classification System code, as shown in Table 37).

- ***Step 3: Develop Baseline End-Use Profiles.*** The Cadmus team further divided each market sector into major end-use shares using a combination of primary and secondary data sources.

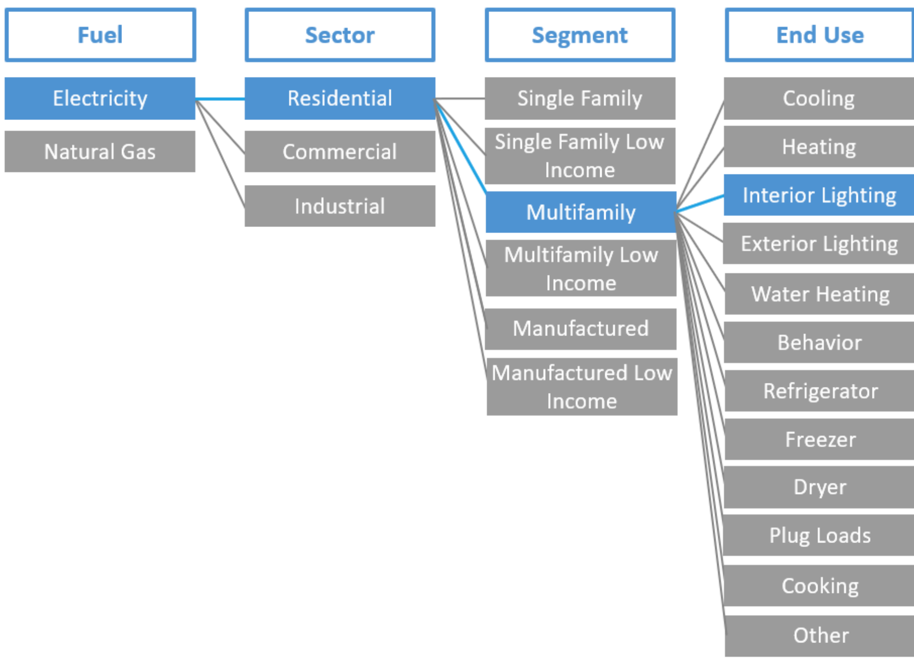
Table 37. Segments Modeled

Residential	Commercial	Industrial
• Single Family • Multifamily • Manufactured • Single Family Low Income • Multifamily Low Income • Manufactured Low Income	• Office • Retail • Education • Grocery • Restaurant • Health • Lodging • Warehouse • Miscellaneous	• Agriculture • Apparel Manufacturing • Beverage and Tobacco Manufacturing • Chemical Manufacturing • Computer Electronics Manufacturing • Electrical Equipment Manufacturing • Fabricated Metal Product Manufacturing • Food Manufacturing • Furniture Manufacturing • Industrial Machinery Manufacturing • Leather Manufacturing • Mining • Miscellaneous Manufacturing • Nonmetallic Mineral Product Manufacturing • Paper Manufacturing • Petroleum and Coal Products • Plastics Rubber Manufacturing • Primary Metal Manufacturing • Printing-Related Support • Textile Mills • Textile Product Mills • Transportation Equipment Manufacturing • Wastewater • Water • Wood Product Manufacturing

Figure 25 illustrates how the team applied this data using an example that pertains to residential lighting. The team used information about end-use saturations (the percentage of homes with lighting) and penetrations (the average number of light bulbs per home), as well as fuel shares (the percentage of homes with electric lighting) and home vintage (the number of existing homes), drawn from primary data provided from Consumers Energy's *2018 Residential Appliance Saturation and Home Characteristics Study* and 2019 *Commercial and Industrial Market Assessment*, supplemented with regional datasets.

Using each dataset, the team estimated average fuel shares and end-use saturations by sector and by segment to develop end-use load profiles. The team identified all relevant end uses by sector including, but not limited to, interior and exterior lighting, HVAC, building shell, refrigeration, cooking, freezer, dryer, water heating, plug loads, processes, data centers, and motors.

Figure 25. Simple Load Disaggregation Example – Residential Lighting



With the disaggregation process complete, the team applied per-unit end-use energy use—sometimes called unit energy use for a residential forecast and energy-use intensity for a commercial forecast—to develop the end-use forecasts. We used an equation to specify the forecast for each end use in the study:

$$EUSE_{ij} = \Sigma_e\, ACCTS_i * UPA_i * SAT_{ij} * FSH_{ij} * ESH_{ije} * EUI_{ije}$$

Where:

$EUSE_{ij}$ = Total energy use for end use 'j' in customer segment 'i'

$ACCTS_i$ = The number of accounts/customers in segment 'i'

UPA_i = The units per account in customer segment 'i'

SAT_{ij} = The share of customers in customer segment 'i' with end use 'j'

FSH_{ij} = The share associated with electric or natural gas in end use 'j' in customer segment 'i'

ESH_{ije} = The market share of efficiency level 'e' equipment for customer segment 'ij'

EUI_{ije} = End-use intensity or unit energy use for the equipment configuration 'ije'

The Cadmus team summed the end-use forecast within each segment, sector, and fuel type combination to determine the overall sales forecast.

Measure Characterization

It was critical to characterize EWR measure impacts specific to Consumers Energy's service territory. To develop an initial list of measures, the Cadmus team used research from both the 2020 MEMD and from the weather-sensitive database for the residential and commercial high-impact measures (such as lighting, HVAC equipment, and insulation). The team also used several additional sources:

- eTracker (to account for measures currently included in Consumers Energy's programs, including the supporting workpaper)
- 2017 GDS electric energy efficiency potential study
- Efficiency tiers from the Consortium for Energy Efficiency (CEE) and ENERGY STAR
- Cadmus' extensive database, including measures in regional or national databases (such as the California *Database of Energy Efficient Resources* [DEER][13] and other TRMs)
- Selected behavioral measures

Upon identifying measures, the team compiled all measure characterization inputs into a master Excel database to estimate potential. We then used this database to populate the potential study model to estimate technical, economic, maximum, and program achievable potential. The database included technical and market data that applied to all end uses in various market segments, as well as estimated costs, savings, and applicability for a comprehensive set of EWR measures. Through this process, the team calculated measure savings as unit energy savings or measure percentage savings to estimate the present end-use savings. These measure end-use percentage savings, when applied to the baseline end-use forecast, produced estimates of EWR potential.

MEMD Methodology

The MEMD includes measure-level deemed or modeled (nominal) savings, which the team used to inform the end-use potential study model. The MEMD includes two databases:

- ***MEMD Master Database.*** This dataset includes measure-level deemed savings, measure costs, and useful life [EUL]assumptions. To understand the underlining deemed assumptions, Consumers Energy provided supporting files of the MEMD's "Deemed Database" that contained Microsoft Word and Excel measure-specific documentation.
- ***MEMD Master with Weather-Sensitive Weighting Tool.*** This dataset includes measure savings that are affected directly by weather, as simulated through building modeling software. The tool weights measure results by segment and region, as well as by equipment characteristics. In

[13] California Public Utilities Commission. 2020. *Database of Energy Efficient Resources.* https://cpuc.ca.gov/general.aspx?id=2017

addition, the Cadmus team used the modeling MEMD “Deemed Database” documentation that contained additional context on model inputs and system efficiencies.

Using the underlying MEMD “Deemed Database” documentation, the team adjusted generic assumptions to better reflect Consumers Energy’s service territory, such as number of people per home. The team used specific characteristics collected from primary data (specifically, from the Consumers Energy 2018 *Residential Appliance Saturation and Home Characteristics Study* and the EMI Consulting 2019 *Commercial and Industrial Market Assessment,* prepared for Consumers Energy).

The MEMD weighting tool provided the flexibility to adjust (weight) the climate zones across Michigan to best represent the Consumers Energy electric service territory. Using residential customer accounts by zip code, the Cadmus team mapped zip codes to MEMD climate zones to create a distribution of Consumers Energy customers across MEMD weather locations. In addition, the team relied on the weighting tool to inform differences between standard and income-qualified residential homes by varying the MEMD vintage age for weatherization measures. This allowed us to characterize income-qualified homes as being less efficient than standard homes.

Considering the very specific measure iterations within the MEMD, the Cadmus team may have combined iterations or only selected certain iterations to avoid complexity. For example, the MEMD may have included various equipment configurations (such as single door, side-by-side, top freezer, and bottom freezer options for ENERGY STAR refrigerators). In a few cases, the Cadmus team found inconsistent results between MEMD HVAC equipment efficiency iterations (which were non-linear across efficiency tiers). After comparing this inconsistency with prior potential study results, other regional TRMs, and the EIA RECS, the team identified the most appropriate MEMD efficiency tier and re-calculated energy use across the other equipment efficiency tiers.

While the MEMD provided a robust measure-level dataset, it can be challenging to incorporate deemed values within a bottom-up calibrated end use. The Cadmus team made best efforts to align with the MEMD, but nominal savings in some cases may have exceeded the team’s prototypical baseline end uses. This may have been due to multiple factors, and typically reflects the nominal savings baseline being far less efficient than the prototypical baseline. For example, an MEMD measure of residential attic insulation may represent savings from R-0 to R-49, but the team’s prototypical home (representing all insulated and non-insulated homes) has an R-19 value. Since the MEMD savings would overestimate potential within the Cadmus team’s end-use model, the team adjusted the MEMD values by embedding applicability and feasibility constraints or by applying the MEMD’s underlining percentage savings assumptions (instead of using the nominal saving values).

Measure Data Sources

Table 38 lists the study’s key EWR measure data sources.

Table 38. Key Measure Data Sources

Input	Residential	Commercial	Industrial
Energy Savings	Consumers Energy 2018 *Residential Appliance Saturation and Home Characteristics Study*, 2020 MEMD, *Michigan Behavior Resource Manual*, Consumers Energy workpapers, Consumers Energy *2020-2023 EWR Plan*, DOE/EERE technical support documents, [a] EIA RECS, ENERGY STAR calculators, state TRMs, Cadmus team research	Consumers Energy 2019 *Commercial and Industrial Market Assessment,* 2020 MEMD, Consumers Energy *2020-2023 EWR Plan*, ENERGY STAR calculators, DOE/EERE technical support documents, [a] EIA CBECS, state TRMs, Cadmus team research	Consumers Energy 2019 *Commercial and Industrial Market Assessment,*2020 MEMD, DOE *Industrial Assessment Center Database*, DOE/EERE technical support documents, [a] state TRMs, Cadmus team research
Equipment and Labor Costs	2020 MEMD, Consumers Energy workpapers, Consumers Energy *2020-2023 EWR Plan*, DOE/EER technical support documents, [a] ENERGY STAR, Northeast Energy Efficiency Partnerships incremental cost reports, RSMeans "Database for Cost Estimation," [c] state TRMs, Cadmus team research	2020 MEMD, Consumers Energy *2020-2023 EWR Plan*, DOE/EERE technical support documents, [a] ENERGY STAR, Northeast Energy Efficiency Partnerships incremental cost reports, RSMeans "Database for Cost Estimation," [c] state TRMs, Cadmus team research	2020 MEMD, Consumers Energy *2020-2023 EWR Plan,* DOE *Industrial Assessment Center Database*, DOE/EERE technical support documents, [a] state TRMs, Cadmus team research
Measure Life	2020 MEMD, Consumers Energy workpapers, Consumers Energy *2020-2023 EWR Plan*, ENERGY STAR, DOE/EERE technical support documents, [a] state TRMs, Cadmus team research	2020 MEMD, ENERGY STAR, DOE/EERE technical support documents, [a] state TRMs, Cadmus team research	2020 MEMD, DOE's Industrial Technologies Program, DOE/EERE technical support documents, [a] state TRMs, Cadmus team research
Technical Feasibility	Consumers Energy 2019 *Residential Appliance Saturation and Home Characteristics Study*, EIA RECS, Cadmus team research	Consumers Energy 2019 *Commercial and Industrial Market Assessment,* 2020 MEMD Commercial Database, Cadmus team research	Consumers Energy 2019 *Commercial and Industrial Market Assessment*, Cadmus team research
Percentage Incomplete	Consumers Energy 2019 *Residential Appliance Saturation and Home Characteristics Study*, ENERGY STAR, Cadmus team research, third-party research	Consumers Energy 2019 *Commercial and Industrial Market Assessment,* ENERGY STAR, Cadmus team research, third-party research	Consumers Energy 2019 *Commercial and Industrial Market Assessment,* Cadmus team research, third-party research

[a] U.S. Department of Energy, Office of Energy Efficiency and Renewable Technology (EERE). n.d. "Standards and Test Procedures."

[b] Regional Technical Forum. 2020. "UES Measures." https://rtf.nwcouncil.org/measures

[c] RSMeans. 2020. "Comprehensive Database for Cost Estimation." https://rsmeans.com/products/online.aspx

Energy Savings

For each EWR measure, the Cadmus team estimated energy savings, both per unit (kilowatt-hours) and as a percentage of end use. These estimates also accounted for savings interactions and results across end uses (for example, upon installing efficient lighting, cooling loads decrease due to the reduction of waste heat). The team relied on several key sources to develop savings estimates:

- ***Consumers Energy 2019 Commercial and Industrial Market Assessment and Consumers Energy 2018 Residential Appliance Saturation and Home Characteristics Study:*** This included data from nonresidential site visits and mail/web residential surveys. Primary data provided comprehensive information on building characteristics, energy-consuming end uses, and equipment efficiencies.
- ***2020 MEMD:*** The primary resource for determining measure savings was the 2020 MEMD that includes deemed and calculated savings values for residential and commercial weather sensitive and non-weather sensitive measures. For every measure in this study where an appropriate MEMD match was available, the team used the MEMD deemed savings values. Otherwise, where possible, the team used MEMD supporting methodologies to match study measure descriptions.
- ***Michigan Behavior Resource Manual:*** A resource for determining behavior energy savings that was used in combination with input from the program vendor.
- **Consumers Energy 2020-2023 EWR Plan and Workpapers:** Measure energy savings data within Consumers Energy's 2020-2023 EWR plan and measure workpapers supporting programs were used for program specific measures not within the MEMD.
- ***DOE/ Office of Energy Efficiency and Renewable Technology (EERE) technical support documents:*** The DOE technical support documents include estimates of equipment energy use for several types of energy-efficient equipment. The team leveraged these documents for input to our savings calculations, when necessary.
- ***U.S. Energy Information Administration (EIA) RECS and EIA CBECS:*** These assessments include building characteristics that the team may have used to inform estimates of energy savings. For example, number of commercial vending machines per building.
- ***Industrial Assessment Center Database:*** The team used U.S. DOE Industrial Assessment Centers' technical assessment data with specific details on energy savings and operational opportunities.
- ***ENERGY STAR calculators:*** The team used U.S. Environmental Protection Agency ENERGY STAR calculators to estimate per-unit savings for several measures, including efficient appliances (refrigerators, freezers, clothes washers) and efficient home electronics (televisions, computers, monitors).
- ***State technical reference manuals (TRMs):*** The team used various state TRMs including those from California, Illinois, Iowa, Minnesota, New York, Vermont, Wisconsin, and the NW Regional Technical Forum[14] for guidance on savings calculations, EULs, costs, and other key potential study inputs for EWR measures not included in the MEMD.

[14] Regional Technical Forum. 2020. "UES Measures." https://rtf.nwcouncil.org/measures

- ***Cadmus team research:*** The team used various third-party measure characterization reports, data conducted within prior potential studies, and online research to inform the energy savings, when applicable.

Equipment and Labor Costs

The Cadmus team estimated equipment and labor costs for each EWR measure and used these costs to calculate benefit/cost ratios and to estimate potential program expenditures. All costs were adjusted to 2020 dollars. The team relied on several key sources to develop cost estimates:

- ***2020 MEMD:*** The primary resource for determining measure costs was the 2020 MEMD that includes cost data for residential and commercial weather sensitive and non-weather sensitive measures . For every measure in this study where an appropriate MEMD match was available, the team used MEMD-listed costs. Otherwise, when possible, we adjusted MEMD supporting document methodologies to match study measure descriptions.
- **Consumers Energy 2020-2023 EWR Plan and Workpapers:** Measure cost data within Consumers Energy's 2020-2023 EWR plan and measure workpapers supporting programs were used for program specific measures not within the MEMD.
- ***DOE/EERE technical support documents:*** The DOE technical support documents include estimates of equipment and labor costs for several types of energy-efficient equipment. The team leveraged these documents for input to our savings calculations, when necessary.
- ***ENERGY STAR:*** The team used U.S. Environmental Protection Agency-provided equipment costs for a number of ENERGY STAR-rated technologies.
- ***RSMeans "Database for Cost Estimation":*** The team used construction cost data from RSMeans Online 2020, the most recent version, including costs for several home and business retrofits (water heater tank wrap, insulation, air sealing, other shell upgrades).
- ***Northeast Energy Efficiency Partnerships incremental cost reports:*** These studies show baseline and efficiency measure costs (labor, equipment) for the measures most commonly offered through utility sponsored EWR programs.
- ***State TRMs:*** The team used various state TRMs for guidance on savings calculations, EULs, costs, and other key potential study inputs for many EWR measures.
- ***Cadmus team research:*** The team continuously reviewed prices listed on manufacturer or retailer websites. While online retailers may not provide estimates of installation (labor) costs, they provide reliable equipment costs.

Measure Life

The Cadmus team used estimates of each measure's EUL to calculate the lifetime NPV benefits and costs for each EWR measure. Many data sources for measure savings and costs (described above) also provided estimates for measure lifetimes. The team relied on several sources to develop measure life estimates:

- ***2020 MEMD:*** The primary resource for determining measure EUL was the 2020 MEMD. For every measure in this study where an appropriate MEMD match was available, the team used MEMD-listed EULs.
- **Consumers Energy 2020-2023 EWR Plan and Workpapers:** EUL data within Consumers Energy's 2020-2023 EWR plan and measure workpapers supporting programs. For example, Consumers Energy's program data and cost-effectiveness assumptions supporting residential lighting EULs to account for the rapid changes within the LED market.
- ***ENERGY STAR:*** The team used U.S. Environmental Protection Agency-provided equipment EULs for a number of ENERGY STAR-rated units.
- ***DOE/EERE technical support documents:*** The DOE technical support documents include estimates of EULs for several types of energy-efficient equipment. The team leveraged these documents for input to our savings calculations, when necessary.
- ***State TRMs:*** The team used various state TRMs for guidance on savings calculations, EULs, costs, and other key potential study inputs for many EWR measures.
- ***Cadmus team research:*** The team used various third-party measure characterization reports, data conducted within prior potential studies, and online research to inform the measure EUL, when applicable.

Technical Feasibility

Technical feasibility represents the percentage of homes or buildings that could feasibly install an EWR measure. Technical limitations include equipment capability or space limitations. For example, geothermal heat pumps could not be feasibly installed in all buildings, as some buildings do not have the required land to drill horizonal or vertical ground loops. The team relied on several key sources to develop feasibility estimates:

- ***Consumers Energy 2019 Commercial and Industrial Market Assessment and Consumers Energy 2018 Residential Appliance Saturation and Home Characteristics Study:*** The collected data provides building characteristics and equipment information that informs measure applicability. The team leveraged these documents for input to our savings calculations, when necessary.
- ***2020 MEMD:*** The MEMD Weather-Sensitive Database informed measure feasibility through classification measures applicable to specific market segments (large office versus small office).
- ***EIA RECS and EIA CBECS:*** These assessments include building characteristics that the team may have used to inform estimates of technical feasibility. For instance, some floor insulation measures require a basement or a crawlspace; using EIA RECS, the team determined the proportion of homes with a basement or crawlspace that could feasibly install this measure.
- ***Cadmus team research; third-party research (including the Federal Energy Management program, DOE, or Toolbase.org):*** The team used various third-party measure characterization reports that identify technical limitations for EWR measures. We used these assessments to

estimate the proportion of homes or businesses that could feasibly install each measure. In some instances, the team used engineering judgment to approximate technical constraints.

Percentage Incomplete

Percentage incomplete factors represent the percentage of remaining homes or businesses that have yet to install an EWR measure and is calculated as the total market size minus the current saturation of EWR measures. To account for Consumers Energy's program accomplishments, building energy codes and standards, and the natural adoption of efficiency measures, the team relied on three key sources to develop percentage incomplete estimates:

- ***Consumers Energy 2019 Commercial and Industrial Market Assessment and Consumers Energy 2018 Residential Appliance Saturation and Home Characteristics Study:*** Using recent primary data, this research informed the percentage of the market that has already achieved EWR technology.
- ***ENERGY STAR:*** National ENERGY STAR shipment data informed the penetration of ENERGY STAR products currently in the market.
- ***Cadmus team research:*** The team used various third-party measure characterization reports, data conducted within prior potential studies, and online research to inform the percentage of the market that already implemented the efficient technology.

Compiling Energy Waste Reduction Technology Measure Database

After creating a list of electric EWR measures applicable to Consumers Energy's service territory, the team classified EWR measures into two categories:

- ***Lost opportunity measures:*** These measures affect new buildings or equipment at the end of its useful life, incorporating energy efficiency at this point is most cost-effective. The lost opportunity measures in any given year are based on stock turnover and normal replacement patterns based on EULs.
- ***Discretionary measures (retrofit):*** These measures affect end uses without replacing end-use equipment (such as insulation). As such, these measures did not include timing constraints from equipment turnover and could be acquired at any point over the planning horizon.

For this study, the Cadmus team assumed that all high-efficiency equipment measures would be installed at the end of the existing equipment's remaining useful life, and therefore we did not assess EWR potential for early replacement.[15] In addition, most measures naturally turn over within the study horizon, and the long-run technical potential from early replacement measures equals savings from replace-on-burnout measures.

[15] The Cadmus team considered refrigerator, freezer, and room air conditioner recycling to estimate savings associated with the removal of below-standard secondary units. These measures, however, could not be considered early replacement, as they do not assume secondary units would be replaced with efficient units.

The team used several relevant inputs for each measure:

- Equipment and non-equipment measures:
    - Technical feasibility—the percentage of buildings where customers could install this measure, accounting for physical constraints
    - Energy savings—average annual savings attributable to installing the measure, in absolute and/or percentage terms
    - Equipment cost—full or incremental equipment cost, depending on the nature of the measure and the application
    - Labor cost—the expense of installing the measure, accounting for differences in labor rates by region and other variables
    - Measure life—the expected life for the equipment
- Non-equipment measures only:
    - Percentage incomplete—the percentage of buildings where customers had not installed the measure, but where it could technically (and feasibly) be installed
    - Measure competition—for mutually exclusive measures, accounting for the percentage of each measure likely installed to avoid double-counting savings (for example, 1.5 gallons per minute (gpm) and 2.0 gpm showerheads cannot both be installed in the same showerhead socket; therefore, only one permutation could possibly be installed, which would depend on technical feasibility for technical potential and would depend on both technical feasibility and cost-effectiveness for economic potential)

Incorporating Codes and Standards

The Cadmus team accounted for changes in codes and standards over the planning horizon. These changes will affect customers' energy-use patterns and behaviors and we used them to determine which EWR measures would continue to produce energy savings over minimum requirements. The team captured current efficiency requirements, including those enacted but not yet in effect.

The team did not, however, attempt to predict how federal standards might change in the future. Rather, we only factored in legislation that has already been enacted. Based on a strict interpretation of each standard, the team assumed that customers would replace affected equipment with more efficient alternatives, and that these alternatives would meet minimum federal standards. In other words, the team assumed complete compliance. Notably, we made one exception, for screw-based LEDs: instead of adhering to the DOE's December 27, 2019, final rule and determination that effectively rescinded the EISA 2020 backstop standard,[16] we followed Consumers Energy's adopted assumptions (accepted by the

[16] U.S. Department of Energy. December 27, 2019. "Energy Conservation Program: Energy Conservation Standards for General Incandescent Service Lamps." https://federalregister.gov/documents/2019/12/27/2019-27515/energy-conservation-program-energy-conservation-standards-for-general-service-incandescent-lamps

MPSC). This included adjusting the measure life of LED standard and specialty bulbs to coincide with the transformed market (standard LED in 2023 and specialty LED in 2024).

The Cadmus team explicitly accounted for several other pending federal standards. Table 39 lists the recently enacted or pending equipment standards the team accounted for in this study's commercial and residential sectors for electric and natural gas end uses. The team also incorporated standards that became effective for equipment prior to 2015 including:

- Commercial boilers (2013)
- Commercial clothes washer (2013)
- Commercial package terminal heat pumps (2012)
- Cooking ovens and ranges (2012)
- Dehumidifier (2013)
- Faucet aerators (1994)
- Pool heaters (2014)
- Residential dishwashers (2014)
- Residential refrigerators and freezers (2015)
- Room air conditioners (2015)
- Showerheads (1994)

For measures where a future standard will have a higher efficiency than a current standard market practice baseline, the team adjusted the baseline to the new federal standard.

Table 39. Current and Pending Electric Standards by End Use

Equipment Electric Type	Existing (Baseline) Standard	New Standard	Sectors Impacted	Study Effective Year
Appliances				
Automatic commercial ice maker	Federal standard 2010	Federal standard 2018	Nonresidential	2019 [a]
Clothes dryer	Federal standard 1994	Federal standard 2015	Residential/Nonresidential	2015
Clothes washer	Federal standard 2015	Federal standard 2018	Residential	2018
Vending machine	Federal standard 2012	Federal standard 2019	Nonresidential	2020 [a]
Cooking				
Microwave	Existing conditions (no federal standard)	Federal standard 2016	Residential	2017 [a]
HVAC				
Central air conditioner	Federal standard 2006	Federal standard 2015 and 2023	Residential	2015-2023
Heat pump (air source)	Federal standard 2006	Federal standard 2015 and 2023	Residential	2015-2023
Package terminal air conditioner	Federal standard 2012	Federal standard 2017	Nonresidential	2017
Small, large, and very large commercial package air conditioner and heat pump	Federal standard 2010	Federal standard 2018 and 2023	Nonresidential	2018-2023

Equipment Electric Type	Existing (Baseline) Standard	New Standard	Sectors Impacted	Study Effective Year
Lighting				
General service fluorescent lamp	Federal standard 2012	Federal standard 2018	Residential/Nonresidential	2019 [a]
Refrigeration				
Commercial display case	Federal standard 2012	Federal standard 2017	Nonresidential	2018 [a]
Commercial freezer	Federal standard 2012	Federal standard 2017	Nonresidential	2018 [a]
Commercial refrigerator	Federal standard 2012	Federal standard 2017	Nonresidential	2018 [a]
Walk-in cooler and freezer	Federal standard 2009	Federal standard 2017	Nonresidential	2018 [a]
Ventilation and Circulation				
Furnace fan	Existing conditions (no prior federal standard)	Federal standard 2019	Residential	2020 [a]
Motor	Federal standard 2010	Federal standard 2016	Nonresidential	2017 [a]
Pool pump	Existing conditions (no federal standard)	Federal standard 2021	Residential/Nonresidential	2021
Water Heat				
Pre-rinse spray valve	Federal standard 2006	Federal standard 2019	Nonresidential	2020 [a]
Water heater ≤55 gallons	Federal standard 2003 and 2004	Federal standard 2015 (test procedure update in 2017)	Residential/Nonresidential	2015-2017
Water heater >55 gallons	Federal standard 2003 and 2004	Federal standard 2015 (test procedure update in 2017)	Residential/Nonresidential	2015-2017

[a] To estimate potential, the Cadmus team assumed that standards taking effect mid-year would start on January 1 of the following year.

Naturally Occurring Conservation

The Cadmus team's baseline forecast included naturally occurring conservation, which refers to the reduction in energy use occurring due to normal market adoption of efficient technologies, improved energy codes and standards, and market transformation efforts. These impacts resulted in updated baseline sales, from which the team could estimate technical and achievable technical potential.

This analysis accounted for naturally occurring conservation in three ways:

- For the potential associated with certain energy-efficient measures, the team assumed a natural adoption rate, net of current saturation. For example, the total potential savings associated with ENERGY STAR appliances accounts for current trends in customer adoption. As such, the baseline energy forecast reflected the total technical savings potential from ENERGY STAR appliances.
- The team assumed gradual increases in efficiency due to retiring older equipment in existing buildings and homes that are replaced with units meeting or exceeding minimum standards at the time of replacement. For example, the existing single family residential building construction stock includes a number of central air conditioning units that do not meet current minimum

federal efficiency standards. As these units are replaced, the baseline forecast assumes replacement with a unit that meets minimum federal efficiency standards.

- The team accounted for pending improvements to equipment efficiency standards that will take effect during the planning horizon, as discussed above in the *Incorporating Codes and Standards* section. The team did not, however, forecast changes to standards yet to be passed.

Energy Waste Reduction Modeling

The Cadmus team used its demand-side management Excel Potential Model to estimate EWR potential using an end-use-based modeling approach. For modeling, the team separated measures into two classes: lost opportunity (equipment and new construction) and retrofit (non-equipment). The team characterized the technical, economic, maximum, and program achievable potential by sector, segment, end use, program, measure, and year for both fuel types in Consumers Energy's territory.

Technical Potential

The Cadmus team incorporated measure-level inputs and disaggregated baseline forecasts into its Excel Potential Model to estimate technical potential over the 20-year planning horizon. We accomplished this by creating an alternate forecast in which energy use is reduced by the installation of all technically feasible EWR measures. For each individual measure, the team estimated savings using a basic relationship:

$$SAVE_{ijm} = UEC_{ije} * PCTSAV_{ijem} * APP_{ijem}$$

Where:

$SAVE_{ijm}$	=	Annual energy savings for measure 'm' for end use 'j' in customer segment 'i'
UEC_{ije}	=	Calibrated annual end-use energy use for equipment 'e' for end use 'j' in customer segment 'i'
$PCTSAV_{ijem}$	=	The percentage savings of measure 'm' relative to the base use of equipment 'e' for end use 'j' in customer segment 'i'
APP_{ijem}	=	Measure applicability fraction that represents a combination of the technical feasibility, existing measure saturation, end-use interaction, and any adjustments to account for competing measures

The Cadmus team then subtracted this forecast from the baseline forecast to estimate the technical potential by sector, segment, building vintage, end use, year, and measure. The team accounted for the portion of load with no energy savings opportunity (for example, miscellaneous non-premise electrical loads such as communication towers, railway installations, and other non-building loads) where the baseline forecast will not have any EWR potential.

The team's goal for our analysis of each market segment and end-use combination was to estimate the cumulative effect of the bundle of eligible measures and incorporate all impacts into the end-use model as a percentage adjustment to the baseline end uses. Capturing all applicable measures requires examining instances in which multiple measures affect a single end use. To avoid overestimating savings, the Cadmus team accounted for the interaction among measures using a technique called stacking. The team's Excel Potential Model conducted this stacking by establishing a rolling, reduced energy use baseline, which it applied iteratively as measures in the stack were assessed. For example, the model reduced central air conditioner savings after the addition of insulation reduced the baseline space cooling energy load.

The model prioritizes measures in the stacking list based on cost-effectiveness (first analyzing measures with the highest UCT results). The team also accounted for interactive effects between measure types by reducing the measure-level savings estimates of relevant measures (such as reduced LED savings because of increased space heating load).

Economic Potential

Economic potential represents a subset of technical potential, consisting only of measures meeting cost-effectiveness criteria. The Cadmus team used the UCT as the primary cost-effectiveness test for determining economic potential, consistent with consistent with the requirements of Michigan's Clean and Renewable Energy and Energy Waste Reduction Act (PA 342).[17] The UCT examines the cost and benefits of an EWR measure or program from the program implementor's perspective. For the purposes of this study, the Cadmus team included only utility incentive cost when screening measures on an individual basis. For determining total maximum achievable and program achievable annual budgets, we included all other non-incentive costs incurred by the utility, including program administration, support services, and marketing costs, consistent with the categories included in Consumers Energy's most recent EWR Plan.

Table 40 lists the inputs included in the calculation of cost-effectiveness, which we used to develop the economic potential, or the savings potential for measures that have benefits greater than zero or have a benefit/cost ratio greater than one. Specific values used in the analysis are listed in Appendix B.

Table 40. Cost-effectiveness Data Summary

Benefit/Cost Data Element	Benefits	Costs
Avoided Electric Energy Cost	X	
Avoided Electric Generation Capacity Cost	X	
Avoided or Deferred Transmission and Distribution Capacity Cost	X	
Supplemental Reserve Margin Adder	X	
Average Electric Transmission and Distribution Line Losses	X	
Avoided Natural Gas Costs	X	
Discount Rate	X	X
Utility Incentives and Program Administration Costs		X

The ***avoided electric and natural gas energy costs*** in the table reflect the direct (primary) and secondary energy savings benefits from installing EWR measures, respectively. The Cadmus team's end-use

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[17] Michigan Legislature. April 20, 2017. "Act No. 342: Public Acts of 2016." http://www.legislature.mi.gov/documents/2015-2016/publicact/pdf/2016-PA-0342.pdf

modeling approach to estimating potential necessitated that each individual measure accounted for primary (electric) and secondary (natural gas) fuel energy savings. An example is the cost of R-60 ceiling insulation for a home with a natural gas furnace and electric cooling system. For the electric cooling system, the team characterized the energy savings that R-60 insulation produced for natural gas furnace, conditioned in the presence of an electric cooling system, as a secondary benefit in the electric EWR modeling.

Avoided energy costs used in the analysis are based on market prices for electricity and natural gas at delivery points within Michigan and forecasts that consider multiple scenarios and historical load and weather variation.

The ***avoided electric generation capacity cost*** and the ***avoided or deferred transmission and distribution capacity cost*** are based on the expected cost of adding new resources to meet increased demand. These are used to value reductions in peak-coincident electric demand from EWR measures. In addition to reductions in the need for new resources to meet demand, peak-coincident savings also reduce the need for ***supplemental reserve margin.***

Line losses represent energy lost from point of generation to the meter. A reduction in energy use in homes or businesses reduce those losses and are reflected in the ***average electric transmission and distribution line losses.***

Finally, the team calculated the NPV of cost and benefits accruing over the planning horizon using a 7.5% ***discount rate*** which represents the weighted average cost of capital, per data provided by Consumers Energy.

Additional Economic Potential Considerations

Economic potential for a given measure can exceed technical potential when a second measure, interacting with that measure, fails a cost-effectiveness screen. For instance, if a homeowner installs an efficient air conditioner that reduces baseline cooling use from 1,000 kWh to 900 kWh, then installs a weatherization measure that saves 10% off the baseline cooling use, this weatherization results in EWR savings, or technical potential, of 90 kWh (900 * 10%).

Had the efficient air conditioner not been installed first, the homeowner’s baseline use would have been 1,000 kWh, and the weatherization measure would have resulted in energy savings, or economic potential, of 100 kWh (1,000 * 10%). In this case, the economic potential (100 kWh) exceeds the technical potential (90 kWh) for the weatherization measure.

Achievable Potential

The Cadmus team assessed EWR achievable potential under maximum achievable and program achievable scenarios. Both scenarios included similar estimates of per-unit measure incentives and programmatic administration costs. We based the maximum achievable potential on current measure offerings, plus an expanded Home Energy Reports program and several EWR measures not presently offered by Consumers Energy. For the program achievable potential, we also included measure-specific net-to-gross values. Table 41 shows key differences between maximum and program achievable potential.

Table 41. Maximum and Program Achievable Potential Considerations

Treatment	Maximum Achievable Potential	Program Achievable Potential
Included measures not currently offered?	Yes	Yes
Home energy report participation eligibility [a]	60%	60%
Reported savings	Gross	Net

[a] This row applies to residential single family customers.

The Cadmus team employed a two-step approach to estimating market potential:

- ***Estimated long-term market penetration for maximum and program achievable potential.*** The team relied on secondary data to establish the long-run percentage of Consumers Energy customers who would adopt an efficient option. We developed unique penetration rates for key end uses and/or technology types as well as for miscellaneous categories.
- ***Apply ramp rates to measures, aligning savings acquisition opportunities with results likely to occur.*** Ramp rates are acquisition curves that indicate how long a measure will take to reach the long-term achievable market penetration rate from the previous step. To develop these ramp rates, the team relied on existing measure-level program data (such as participation counts by technology or end use by year, program, and customer class) from the 2016 through 2019 program years. We assigned shorter ramp rates to specific measures or groups of measures demonstrating significant, recent achievements within Consumers Energy EWR programs. The Cadmus team assigned a longer ramp rate for newer measures to factor in the time required for the technology or measure to reach a steady state of adoption.

For the maximum and program achievable potential scenarios, the team calculated potential as the sum of each measure's annual energy-savings estimate and the expected market saturation for each program year, and over the entire forecast period.

Consumers Energy Electric EWR Transformational Technology Scenario

The Cadmus team had three objectives for determining the transformational potential specific to Consumers Energy:

- Identify an expanded estimate of EWR potential that could support Consumers Energy's ambitious EWR goals (up to 2% of sales)
- Investigate forward-looking technology and market scenarios that are the most likely to support Consumers Energy's longer-term EWR goals, particularly from 2031 to 2040 (during the second half of the potential study horizon)
- Provide insights on actions that may be needed to fully capture the available potential from underused measures, which could include investing in technology and providing demonstrations, educating and building awareness of new and emerging measures, and building regulatory support with the MPSC

We identified the savings potential that Consumers Energy could capture by being even more aggressive and by strategically researching, supporting, and implementing emerging energy-efficiency technologies, alternative delivery strategies, and other new energy-efficiency opportunities. We envision the transformational potential as a countermeasure and initial roadmap of the path needed to fill a gap identified in the Cadmus team's and other firms' recent electric EWR potential studies showing reduced utility program EWR potential over the next 20 years.

The Cadmus team assessed several opportunities including:

- Expanded savings for measures that have historically been underused due to low market awareness or other key barriers, especially in the small and medium commercial customer sectors. We assumed that a concerted action would be required to address underuse issues, such as expanding customer education, conducting targeted outreach and marketing to specific customer segments, or increasing incentive levels.
- Currently available technologies that, to date, have been characterized by high costs and low cost-effectiveness (and therefore we did not include them in our calculation of achievable potential in the initial study). We made reasonable assumptions regarding the time periods during which the costs of identified technologies are likely to decline and market shares to increase.
- Incremental savings from smart, or Tier 3, thermostats for residential homes based on peer-reviewed research in other jurisdictions with broad adoption similar to that in Michigan. Currently the MEMD does not include a unique savings value for this measure because of unclear evaluation results. The MEMD set Tier 3 thermostat savings at the same level as standard programable thermostat savings; however, the MPSC has indicated a willingness to

incorporate this measure into the MEMD as soon as calibration research can be conducted using an industry-accepted evaluation methodology.[18]

- Potential savings opportunities that may be available from expanding behavior-based energy-efficiency programs including (but not limited to) traditional home energy reports programs through increased investment in marketing, alternative outreach strategies, and tools development. The MPSC currently limits savings that can be claimed from home energy report programs; however, Consumers Energy may be able to negotiate a relaxed cap over time through efforts to demonstrate veracity and persistence of savings.
- Sustained savings over a longer period from emphasizing (through increased and targeted marketing, incentives, education, and other efforts) equipment with measure lives of 20 years or more, such as chillers and air compressors.
- Expanded savings from certain measures—specifically commercial variable frequency drives and refrigeration, cooling, and ventilation measures—for which the Cadmus team's potential estimate may have been understated due to the MEMD's assignment of savings values to a subset of potentially viable building types.
- A less restrictive approach to modeling certain measures that could be expected to gain market acceptance and more widespread adoption under future conditions that emphasize decarbonization, a shift toward greater residential energy uses (a potential outcome of the Covid-19 pandemic), and increased proliferation of automation, real-time monitoring, and artificial intelligence-supported building systems. Such technologies may also become more economically feasible under shifting policy environments that emphasize integrated decarbonization over energy efficiency alone.
- Incorporation of additional emerging technology options identified by Consumers Energy staff, vendors, national research teams, and industry experts from across the country. The Cadmus team compiled, reviewed, and prioritized these emerging technologies that may be associated with varying degrees of technical, economic, market, or programmatic uncertainty.

As shown in Table 42, the transformational technology scenario incorporates 170 additional unique emerging technology measures that were assessed across 4,102 different permutations for various building types, vintages, and unique applications. These measures are described in more detail in *Appendix C*.

[18] The Uniform Methods Project, an effort by DOE to provide standard methods for determining energy savings for common measures and programs, is currently working to develop a Smart Thermostat Evaluation Protocol. https://www.nrel.gov/ump/index.html. The Energy Waste Reduction Collaborative will pursue calibration research when the protocol is available.

Table 42. Emerging Technology Measure Counts and Permutations

Sector	Unique Measures	Measure Permutations
Residential	59	1,656
Commercial	60	1,995
Industrial	51	451
Total	**170**	**4,102**

Technical Feasibility Updates

As part of the transformational potential assessment, the Cadmus team reviewed and updated a select set of the commercial sector measure values used to estimate potential in the primary results. This update addressed loosening a strict methodology that incorporated the structure and organization of the MEMD's building application assumptions. Specifically, many commercial measures listed in the MEMD are mapped to 18 individual building types; however not all measures are mapped to every building type. Using this approach to limit the technical feasibility of measure applications within buildings can be considered too rigid within the context of utility programs. Note that, although the update spanned multiple variables in the calculation of potential, technical feasibility changes had the largest impact on potential. We removed the building type weighting applicability (technical constraints) from the MEMD weighting tool and used engineering judgement (that aligns with prior Cadmus potential studies) to make the model inputs more realistic.

As shown in Table 43, the cumulative technical and economic potential both increased by 19% as a result of the technical feasibility updates. The maximum achievable potential increased by 18%.

Table 43. Technical Feasibility Update Impact on Commercial Energy Waste Reduction Potential: Cumulative 2040

Technical Potential			Economic Potential			Maximum Achievable Potential		
Initial Results (MWh)	Technical Feasibility Update (MWh) [a]	Change	Initial Results (MWh)	Technical Feasibility Update (MWh) [a]	Change	Initial Results (MWh)	Technical Feasibility Update (MWh) [a]	Change
3,112,498	3,703,772	19%	3,061,027	3,637,589	19%	2,765,511	3,253,317	18%

[a] This comparison does not include transformational technology measures.

Table 44 provides the end-use-level impacts of the technical feasibility updates. Ventilation, plug load, and refrigeration end uses have the largest percentage increase in maximum achievable potential as a result of the technical feasibility updates. On the other hand, the maximum achievable potential for dryers and water heaters decreased by 20% and 7%, respectively, due to the technical feasibility changes.

Table 44. Technical Feasibility Update 20-Year Commercial Energy Waste Reduction Potential by End Use: Cumulative 2040

End Use	Technical Potential			Economic Potential			Maximum Achievable Potential		
	Initial Results (MWh)	Technical Feasibility Update (MWh) [a]	Percentage Change	Initial Results (MWh)	Technical Feasibility Update (MWh) [a]	Percentage Change	Initial Results (MWh)	Technical Feasibility Update (MWh) [a]	Percentage Change
Lighting	1,852,767	1,831,613	-1%	1,852,767	1,831,613	-1%	1,852,460	1,831,326	-1%
Ventilation	144,319	600,949	316%	142,647	600,949	321%	120,101	509,657	324%
Plug Load	69,634	110,162	58%	56,073	91,416	63%	41,543	71,139	71%
Refrigeration	333,959	421,770	26%	306,570	380,144	24%	259,140	320,608	24%
Cooling	340,950	371,757	9%	338,327	370,993	10%	243,037	273,030	12%
Cooking	49,564	49,564	0%	49,564	49,564	0%	41,499	41,499	0%
Heating	100,044	100,172	0%	96,066	96,066	0%	69,817	69,817	0%
Water Heat	132,768	126,929	-4%	132,195	126,451	-4%	69,253	64,548	-7%
Other	29,696	29,696	0%	29,118	29,118	0%	24,439	24,439	0%
Heat Pump	57,002	59,824	5%	55,908	59,541	6%	43,422	46,366	7%
Dryer	1,794	1,603	-11%	1,794	1,603	-11%	801	644	-20%
Total [b]	**3,112,498**	**3,703,911**	**19%**	**3,061,027**	**3,637,458**	**19%**	**2,765,637**	**3,253,199**	**18%**

[a] This comparison does not include emerging technology measures.
[b] May not equal sum of rows due to rounding.

Technical and Economic Potential

After finalizing the emerging technology measure bundles, the Cadmus team estimated the technically viable savings from emerging technologies and the technologies included in the primary results. Once we finalized the technical potential, we used the UCT to screen for measures that would be economically feasible.

The cumulative, 20-year, sector-level results of this process are summarized in Table 45, showing 17,436 GWh of technically available savings. Of that technical potential, 83% is cost-effective (14,470 GWh) by 2040. On an annual basis, the 20-year technical and economic potential savings correspond to savings of 2.8% and 2.2% of sales, respectively. The residential sector accounts for 48% of the total economic electric potential, followed by commercial (33%) and industrial (19%).

Table 45. Transformational Scenario Energy Waste Reduction Technical and Economic Potential by Sector: Cumulative 2040

Sector	Baseline Sales (MWh)	Technical Potential		Economic Potential	
		MWh	Percentage of Baseline Sales	MWh	Percentage of Baseline Sales
Residential	14,861,197	9,808,564	66.0%	6,943,146	46.7%
Commercial	14,528,160	4,827,870	33.2%	4,773,253	32.9%
Industrial	11,204,888	2,799,606	25.0%	2,754,011	24.6%
Total [a]	**40,594,246**	**17,436,040**	**43.0%**	**14,470,410**	**35.6%**

[a] May not equal sum of rows due to rounding.

Table 46 provides the corresponding electric peak demand reduction potential.

Table 46. Transformational Technology Scenario Energy Waste Reduction Technical and Economic Potential by Sector-Demand: Cumulative 2040

Sector	20-Year Technical Potential (MW)	20-Year Economic Potential (MW)	Economic Potential Percentage of Technical Potential
Residential	2,926	2,600	89%
Commercial	879	878	100%
Industrial	419	412	98%
Total [a]	**4,224**	**3,890**	**92%**

[a] May not equal sum of rows due to rounding.

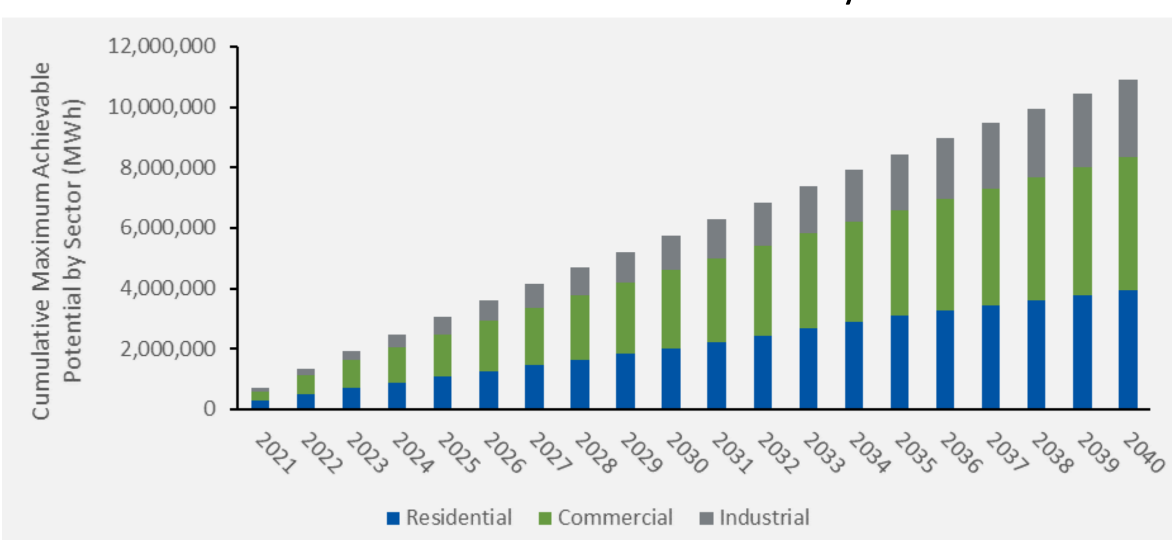
The above findings are based on measure characterizations and financial calculations alone. The following section describes the maximum achievable potential, which accounts for customer behavior such as their willingness to adopt given financial relief or have increased awareness through utility-provided incentives, marketing, and awareness initiatives.

Maximum Achievable Potential

After determining the amount of potential that was economically achievable, the Cadmus team identified the subset these savings that make up the maximum achievable potential assuming EWR measure-specific ramp rates. We used maximum achievable potential assumptions that are consistent with the primary results for non-emerging technology measures, and we used emerging technology measure characterization assumptions based on the research described in Appendix C. The emerging technology measures and certain non-emerging technology measures included in the maximum achievable potential are not currently offered by Consumers Energy's EWR programs.

Figure 26 presents the 20-year cumulative maximum achievable EWR potential in megawatt-hours.

Figure 26. Transformational Technology Scenario Cumulative Maximum Achievable Potential by Sector



Residential

Residential customers represent the largest percentage of 2040 cumulative baseline sales (37%). The Cadmus team and Consumers Energy identified 59 unique, residential emerging technologies that could provide savings within the framework of the 20-year study horizon. The resulting savings increased cumulative 20-year potential by 40%, to 3,939 GWh of maximum achievable potential. This corresponds to annual savings of 1.6% of sales. Behavioral web portal savings are a large driver in this increase, making up 10% of total cumulative 20-year horizon savings.

Table 47 shows cumulative 20-year residential electric conservation potential for the residential segment by end uses and relative to baseline sales. The table shows that cooling (20%), refrigeration (18%), lighting (17%), behavior (17%), and heating 11%) end uses combined account for 83% of residential electric cumulative maximum achievable potential. The large behavioral savings represents the unconstrained potential from behavior-based changes and the added web portal emerging technology measure savings.

Table 47. Transformational Technology Scenario 20-Year Cumulative Maximum Achievable Residential Potential by End Use

End Use	Baseline Sales by End Use	MWh	Percentage of 2040 Total End Use Baseline Sales	MW
Cooling	2,231,824	772,458	35%	831
Refrigeration	1,930,514	717,482	37%	85
Lighting	1,591,901	685,437	43%	283
Behavior	NA	657,213	NA [a]	75
Heating	1,912,250	444,623	23%	0
Water Heat	1,265,866	177,192	14%	131
Ventilation	1,293,248	145,991	11%	15
Plug Load	2,763,556	125,087	5%	68
Dryer	1,062,274	123,902	12%	181
Heat Pump	246,898	72,546	29%	16
Cooking	454,172	16,270	4%	10
Other	108,695	417	0%	0
Electric Vehicle	NA	83	NA [a]	0
Total [b]	**14,861,197**	**3,938,701**	**27%**	**1,695**

[a] The team calculated potential for the behavioral end use based on the aggregate of all other end use baseline sales, so it does not have a corresponding baseline sales value. Additionally, electric vehicles are an emerging technology that does not have a baseline.

[b] May not equal sum of rows due to rounding.

Figure 27 shows electric residential cumulative maximum achievable potential by end use in 2025 and 2040.

Figure 27. Transformational Technology Scenario Residential Maximum Achievable Potential by End Use-Energy: Cumulative

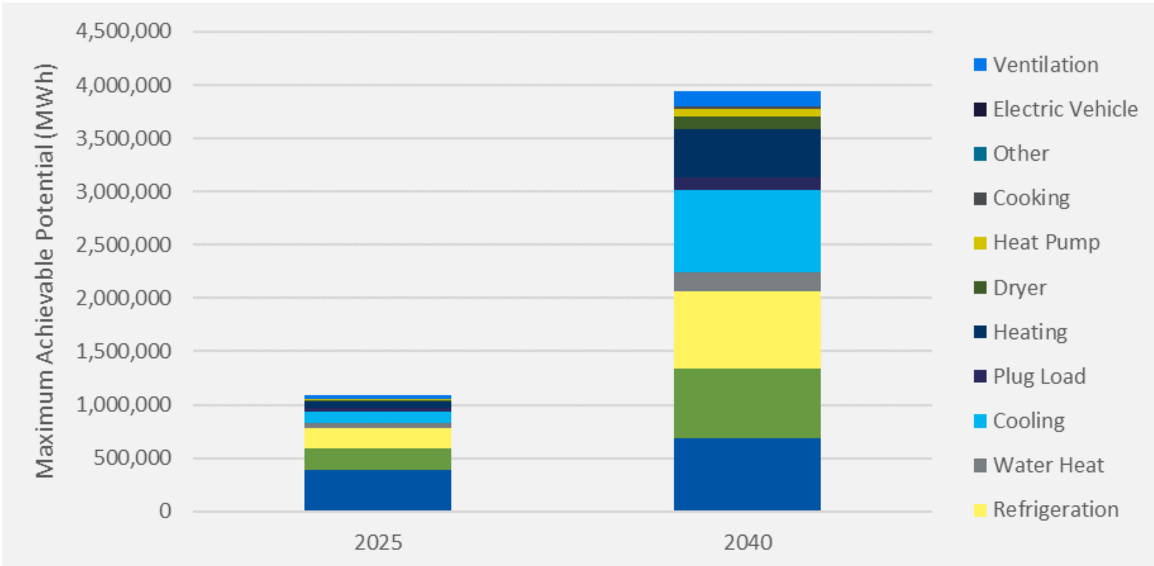


Table 48 provides the top five emerging technology measures based on their contribution to the cumulative maximum achievable potential. Web portal measures offer the largest emerging technology savings, followed by advanced furnace fans, wet bulb chillers, radiant panels, and smart vents. In total, these emerging technology measures account for 26% of the total residential maximum achievable potential. Some measures, like wet bulb chillers, are expected to take longer to develop and gain market acceptance so savings occur later in the planning period.

Table 48. Top Residential Maximum Achievable Potential Emerging Technology Measures: Cumulative 2025 and 2040

Measure Name	Maximum Achievable Potential			
	Cumulative 5-Year (MWh)	Percentage of 5-Year Residential Potential	Cumulative 20-Year (MWh)	Percentage of 20-Year Residential Potential
Emerging Technology - Web Portal	105,176	9%	568,516	14%
Emerging Technology - Advanced Furnace Fan	27,539	2%	142,392	4%
Emerging Technology - Residential-Sized Sub-Wet Bulb Chiller	-	0%	132,393	3%
Emerging Technology - Smart Vents	24,456	2%	130,228	3%
Emerging Technology - Radiant Panels	20,025	2%	106,574	3%

Commercial

Commercial customers represent the second largest percentage of 2040 cumulative baseline sales (36%). Of the 14,528 GWh of cumulative, commercial baseline sales, 30% are achievable (4,387 GWh). This is a 58% increase from the primary results for20-year cumulative commercial maximum achievable potential and corresponds to annual savings of 1.8% of sales. The major contributing emerging technology measures are advanced motors and advanced dedicated outdoor air systems.

Table 49 shows the commercial, cumulative 20-year electric maximum achievable potential by end use and relative to baseline sales. The greatest energy savings category is lighting, with 45% of the total commercial maximum achievable potential. Ventilation and cooling provide a combined 32% of the 4,387 GWh of maximum achievable potential. These three end uses also make up 88% of the total peak demand reduction. Emerging technology measures for advanced motors, advanced dedicated outdoor air systems, and future lighting Perovskite LEDs are primary contributors to these end-use savings.

Table 49. Transformational Scenario 20-Year Cumulative Maximum Achievable Commercial Potential by End Use

End Use	Baseline Sales by End Use	MWh Savings	Percentage of 2040 Total End Use Baseline Sales	MW Savings
Lighting	5,276,623	1,955,500	37%	300
Ventilation	2,598,798	713,230	27%	31
Cooling	1,366,558	681,062	50%	376
Refrigeration	1,927,013	537,750	28%	42
Plug Load	1,969,685	165,244	8%	8
Heating	320,614	99,361	31%	2
Heat Pump	138,375	76,350	55%	25
Water Heat	278,909	71,293	26%	3
Cooking	430,286	55,293	13%	11
Other	211,405	30,703	15%	5
Dryer	9,895	1,399	14%	0
Total [a]	**14,528,160**	**4,387,185**	**30%**	**805**

[a] May not equal sum of rows due to rounding.

Figure 28 shows electric commercial cumulative maximum achievable potential by end use in 2025 and 2040.

Figure 28. Transformational Scenario Commercial Maximum Achievable Potential by End Use-Energy: Cumulative

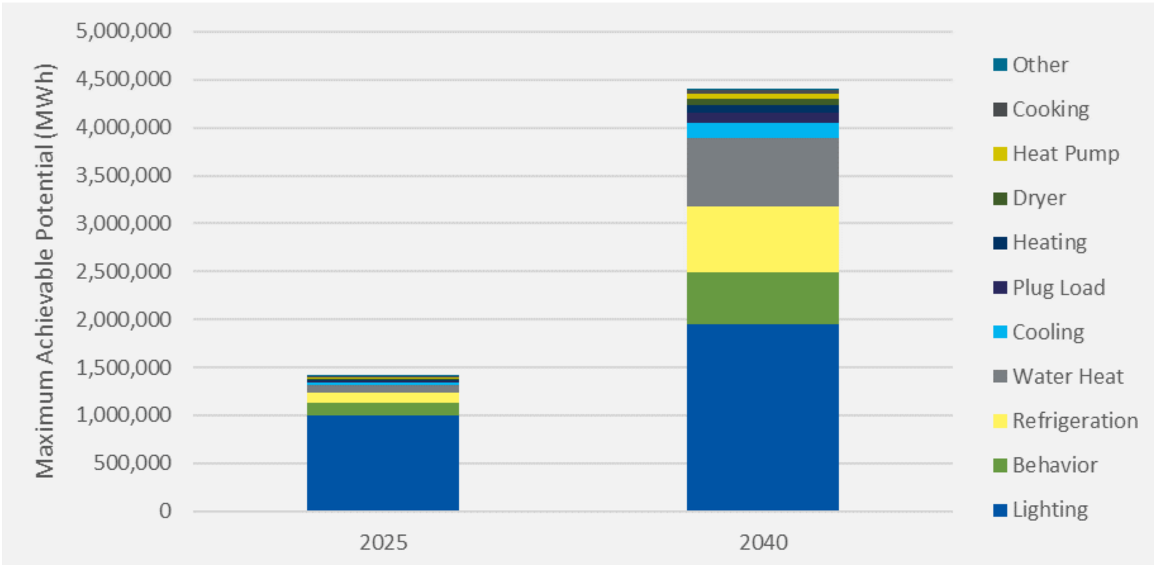


Table 50 lists the top five emerging technology savings measures. These measures all provide savings to the top four saving end uses: lighting, ventilation, cooling, and refrigeration. Combined, advanced motors, advanced dedicated outdoor air systems, aerofoils for open display cases, perovskite LEDs, and advanced refrigeration equipment make up 11% of the total cumulative, 20-year maximum achievable potential for the commercial sector.

Table 50. Top Commercial Maximum Achievable Potential Emerging Technology Measures: Cumulative 2025 and 2040

Measure Name	Maximum Achievable Potential			
	Cumulative 5-Year (MWh)	Percentage of 5-Year Commercial Potential	Cumulative 20-Year (MWh)	Percentage of 20-Year Commercial Potential
Emerging Technology - Advanced Motors	0	0%	128,001	3%
Emerging Technology - Advanced Dedicated Outdoor Air Systems	0	0%	96,684	2%
Emerging Technology - Aerofoils for Open Display Cases	18,150	1%	93,857	2%
Emerging Technology - Future Lighting - Perovskite LEDs	0	0%	89,940	2%
Emerging Technology - Advanced Refrigeration / CO2 Systems	0	0%	67,293	2%

Industrial

Industrial customers represent the smallest percentage of 2040 cumulative baseline sales (28%). Of the 20-year cumulative industrial baseline sales, the maximum achievable potential is 2,607 GWh, or 23% of baseline sales. The Cadmus team and Consumers Energy identified 51 unique, industrial emerging technologies and savings acquisition approaches that could provide savings within the framework of the 20-year study horizon, increasing cumulative 20-year potential by 54%. This corresponds to annual savings of 1.3% of sales. The major contributors to the increase in maximum achievable potential are process improvements for refrigeration and cooling and future proxy process heating improvements. Proxy measure bundles represent unique energy-efficiency improvements in commercial and industrial applications, akin to custom measures, that may be acquired through program strategies such as standard offer or pay-for-performance.

Table 51 shows the industrial end-use distribution of 20-year cumulative maximum achievable potential. The end use with the greatest cumulative savings is process (44%). The emerging technology measures included in this category are for future process improvement. Other end uses with high cumulative achievable values include lighting (16%) and HVAC (14%).

Table 51. Transformational Scenario 20-Year Cumulative Maximum Achievable Industrial Potential by End Use

End Use	Baseline Sales by End Use	MWh	Percentage of 2040 Total End Use Baseline Sales	MW
Process	4,195,527	1,153,055	27%	167
Lighting	929,122	402,969	43%	58
HVAC	1,441,723	353,651	25%	50
Motors Other	1,725,479	257,365	15%	37
Pumps	1,310,710	222,170	17%	47
Fans	637,127	101,174	16%	15
Other	666,683	59,382	9%	8
Ventilation	168,762	38,544	23%	6
Indirect Boiler	114,912	5,772	5%	1
Plug Load [a]	0	4,045	NA [a]	0
Water Heat	14,843	1,486	10%	0
Total [b]	**11,204,888**	**2,599,612**	**23%**	**388**

[a] The plug load end use is made of emerging technology measures for indoor agriculture, which has no baseline.

[b] May not equal sum of rows due to rounding.

Figure 29 shows electric industrial cumulative maximum achievable potential by end use in 2025 and 2040.

Figure 29. Transformational Technology Scenario Industrial Maximum Achievable Potential by End Use-Energy: Cumulative

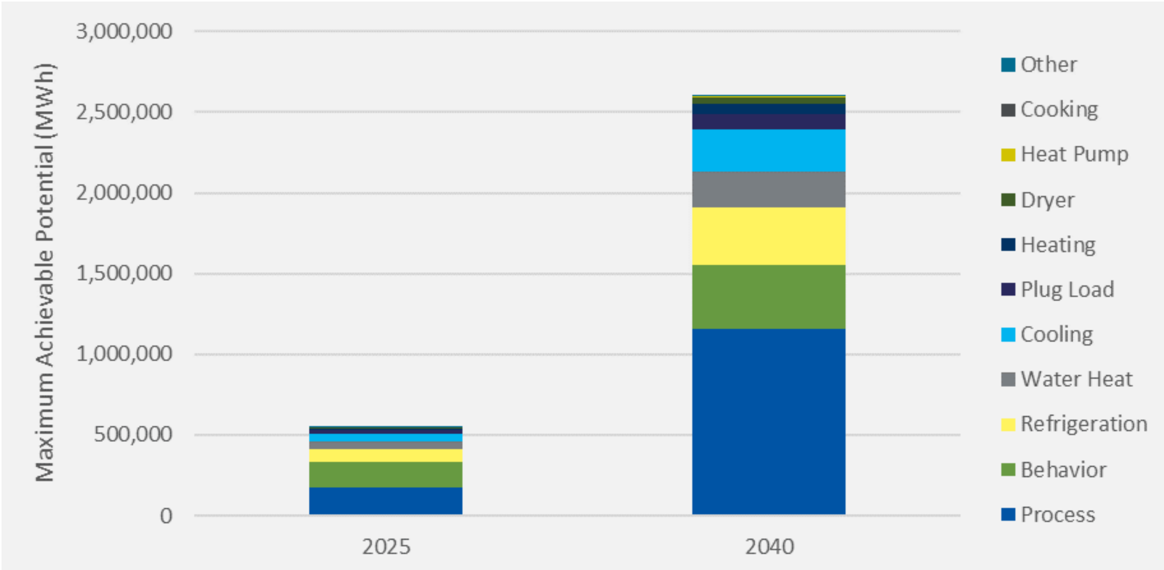


Table 52 provides the top five emerging technology savings measures and their cumulative five-year and 20-year maximum achievable potential, in addition to the percentage of total 20-year industrial maximum achievable potential. For the industrial sector, the emerging technology measures that had the greatest contributions (11% in total) are for process improvements in refrigeration and cooling and in heating. Advanced lighting controls and advanced motors contributed 5% of the industrial cumulative 20-year maximum achievable potential.

Table 52. Top Industrial Maximum Achievable Potential Emerging Technology Measures: Cumulative 2025 and 2040

Measure Name	Maximum Achievable Potential			
	Cumulative 5-Year (MWh)	Percentage of 5-Year Industrial Potential	Cumulative 20-Year (MWh)	Percentage of 20-Year Industrial Potential
Emerging Technology - Process Improvement - Refrigeration and Cooling	20,287	4%	109,659	4%
Emerging Technology - Future Proxy Process Improvement - Heat	0	0%	108,066	4%
Emerging Technology - Future Proxy Process Improvement - Refrigeration and Cooling	0	0%	86,130	3%
Emerging Technology - Advanced Lighting Controls	12,721	2%	68,761	3%
Emerging Technology - Advanced Motor - Motors Other	0	0%	56,893	2%

Appendix A. Baseline Forecast Data

This appendix provides baseline forecast data for the residential (Figure A-1, Figure A-2, and Table A-1), commercial (Figure A-3, Figure A-4, and Table A-2), and industrial (Figure A-5 and Figure A-6) sectors.

Residential Electric

Figure A-1. Residential Baseline Electric Forecast by Segment

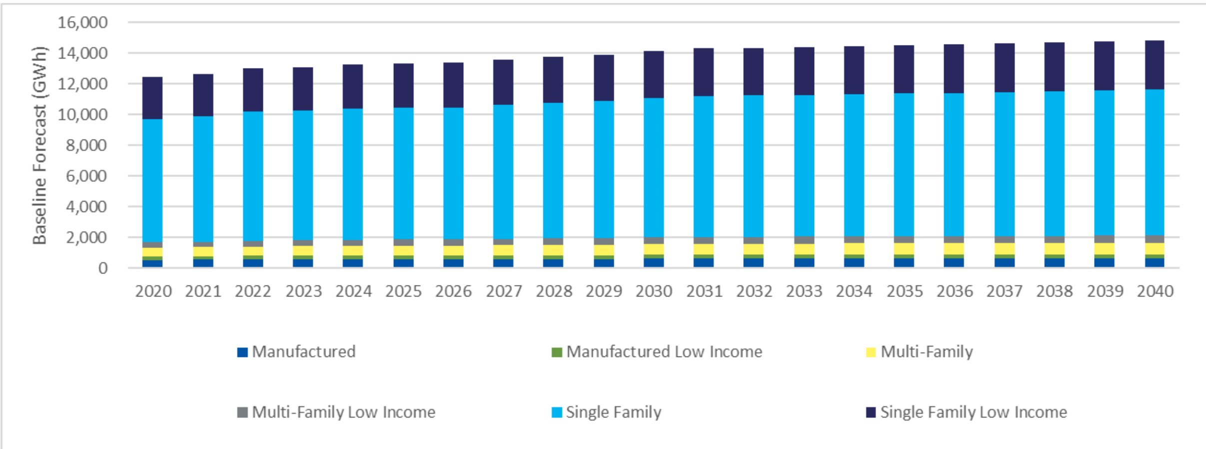


Figure A-2. Residential Baseline Electric Forecast by End Use

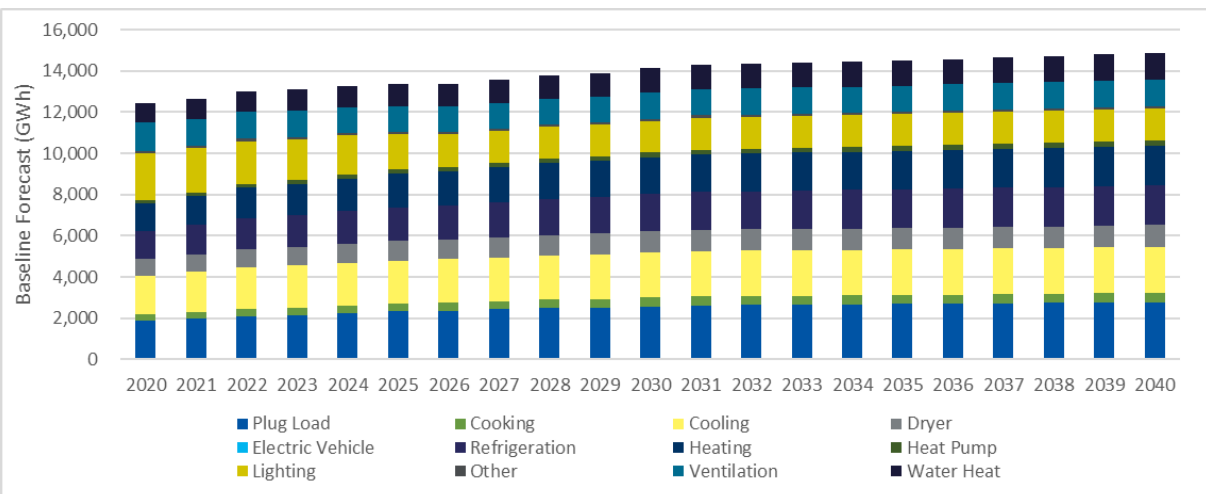


Table A-1. Residential Baseline Forecast Assumptions: Electric Saturations Fuels Shares and Unit Energy Use

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Existing Construction			
Manufactured			
Air Purifier	6%	100%	890.21
Computer	99%	100%	60.68
Cooking Oven	86%	56%	174.17
Cooking Range	96%	96%	124.74
Cool Central	58%	100%	806.74
Cool Room	36%	100%	208.92
Dehumidifier	12%	100%	551.45
Dryer	96%	96%	670.49
Electric Vehicle	0%	100%	2,553.36
Freezer	55%	100%	524.30
Heat Central	5%	100%	17,670.97
Heat Pump	0%	100%	6,775.74
Heat Room	0%	100%	11,507.79
Lighting – Fluorescent	617%	100%	26.57
Lighting – Specialty	2032%	100%	31.42
Lighting – Standard	2818%	100%	20.47
Microwave	88%	100%	130.99
Monitor	40%	100%	28.92
Other	100%	100%	0.00
Plug Load Other	100%	100%	628.75
Refrigerator	116%	100%	527.13
Television	187%	100%	103.39
Ventilation and Circulation	99%	100%	1,118.04
Water Heater GT 55 Gallon	3%	41%	1,716.76
Water Heater LE 55 Gallon	95%	41%	1,710.26
Manufactured Low Income			
Air Purifier	2%	100%	890.21
Computer	82%	100%	60.68
Cooking Oven	100%	24%	174.17
Cooking Range	93%	93%	124.74
Cool Central	44%	100%	749.44
Cool Room	36%	100%	192.42
Dehumidifier	7%	100%	551.45
Dryer	91%	91%	670.49
Electric Vehicle	0%	100%	2,553.36
Freezer	46%	100%	524.30
Heat Central	5%	100%	15,887.25
Heat Pump	0%	100%	6,204.51
Heat Room	2%	100%	10,346.18
Lighting – Fluorescent	568%	100%	26.57
Lighting – Specialty	1872%	100%	34.98

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Lighting – Standard	2595%	100%	23.62
Microwave	79%	100%	130.99
Monitor	34%	100%	28.92
Other	100%	100%	0.00
Plug Load Other	100%	100%	548.56
Refrigerator	110%	100%	527.13
Television	165%	100%	103.39
Ventilation and Circulation	98%	100%	1,118.04
Water Heater GT 55 Gallon	3%	46%	2,808.96
Water Heater LE 55 Gallon	94%	46%	2,803.74
Multifamily			
Air Purifier	3%	100%	890.21
Computer	93%	100%	60.68
Cooking Oven	98%	66%	174.17
Cooking Range	88%	88%	124.74
Cool Central	59%	100%	1,071.31
Cool Room	45%	100%	201.01
Dehumidifier	8%	100%	551.45
Dryer	56%	56%	670.49
Electric Vehicle	0%	100%	2,553.36
Freezer	14%	100%	524.30
Heat Central	9%	100%	12,868.67
Heat Pump	0%	100%	6,159.80
Heat Room	16%	100%	8,380.41
Lighting – Fluorescent	131%	100%	26.57
Lighting – Specialty	202%	100%	27.31
Lighting – Standard	2195%	100%	16.06
Microwave	86%	100%	130.99
Monitor	18%	100%	28.92
Other	100%	100%	0.00
Plug Load Other	100%	100%	461.21
Refrigerator	115%	100%	527.13
Television	120%	100%	103.39
Ventilation and Circulation	58%	100%	1,118.04
Water Heater GT 55 Gallon	45%	46%	1,592.74
Water Heater LE 55 Gallon	45%	46%	1,585.36
Multifamily Low Income			
Air Purifier	8%	100%	890.21
Computer	79%	100%	60.68
Cooking Oven	99%	68%	174.17
Cooking Range	93%	93%	124.74
Cool Central	44%	100%	1,242.81
Cool Room	50%	100%	232.81
Dehumidifier	7%	100%	551.45
Dryer	38%	38%	670.49

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Electric Vehicle	0%	100%	2,553.36
Freezer	18%	100%	524.30
Heat Central	26%	100%	14,505.34
Heat Pump	2%	100%	7,345.66
Heat Room	14%	100%	9,446.25
Lighting – Fluorescent	151%	100%	26.57
Lighting – Specialty	234%	100%	31.24
Lighting – Standard	2543%	100%	17.97
Microwave	64%	100%	130.99
Monitor	15%	100%	28.92
Other	100%	100%	0.00
Plug Load Other	100%	100%	473.03
Refrigerator	106%	100%	527.13
Television	144%	100%	103.39
Ventilation and Circulation	62%	100%	1,118.04
Water Heater GT 55 Gallon	42%	45%	1,780.64
Water Heater LE 55 Gallon	42%	45%	1,776.63
Single Family			
Air Purifier	9%	100%	890.21
Computer	153%	100%	60.68
Cooking Oven	109%	56%	174.17
Cooking Range	98%	98%	124.74
Cool Central	71%	100%	2,455.89
Cool Room	23%	100%	304.09
Dehumidifier	46%	100%	551.45
Dryer	98%	98%	670.49
Electric Vehicle	0%	100%	2,553.36
Freezer	66%	100%	524.30
Heat Central	2%	100%	23,220.98
Heat Pump	2%	100%	10,972.27
Heat Room	1%	100%	15,122.09
Lighting – Fluorescent	898%	100%	26.57
Lighting – Specialty	2958%	100%	21.71
Lighting – Standard	4101%	100%	24.34
Microwave	85%	100%	130.99
Monitor	63%	100%	28.92
Other	100%	100%	0.00
Plug Load Other	100%	100%	750.76
Pool Pump	9%	100%	1,448.34
Refrigerator	137%	100%	527.13
Television	213%	100%	103.39
Ventilation and Circulation	92%	100%	1,118.04
Water Heater GT 55 Gallon	3%	22%	2,533.15
Water Heater LE 55 Gallon	96%	22%	2,526.91

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Single Family Low Income			
Air Purifier	5%	100%	890.21
Computer	96%	100%	60.68
Cooking Oven	110%	54%	174.17
Cooking Range	96%	96%	124.74
Cool Central	39%	100%	1,791.27
Cool Room	37%	100%	221.96
Dehumidifier	28%	100%	551.45
Dryer	90%	90%	670.49
Electric Vehicle	0%	100%	2,553.36
Freezer	55%	100%	524.30
Heat Central	4%	100%	16,832.99
Heat Pump	1%	100%	7,668.32
Heat Room	3%	100%	10,962.07
Lighting – Fluorescent	655%	100%	26.57
Lighting – Specialty	2159%	100%	26.13
Lighting – Standard	2993%	100%	27.32
Microwave	78%	100%	130.99
Monitor	39%	100%	28.92
Other	100%	100%	0.00
Plug Load Other	100%	100%	596.96
Refrigerator	118%	100%	527.13
Television	161%	100%	103.39
Ventilation and Circulation	91%	100%	1,118.04
Water Heater GT 55 Gallon	3%	31%	2,833.12
Water Heater LE 55 Gallon	96%	31%	2,828.28
New Construction			
Manufactured			
Air Purifier	6%	100%	843.03
Computer	99%	100%	60.68
Cooking Oven	86%	56%	174.17
Cooking Range	96%	96%	124.74
Cool Central	58%	100%	526.18
Cool Room	36%	100%	192.79
Dehumidifier	12%	100%	536.46
Dryer	96%	96%	583.43
Electric Vehicle	0%	100%	2,553.36
Freezer	55%	100%	479.17
Heat Central	5%	100%	11,658.21
Heat Pump	0%	100%	5,952.18
Heat Room	0%	100%	7,592.12
Lighting – Fluorescent	421%	100%	26.04
Lighting – Specialty	1386%	100%	31.42
Lighting – Standard	1922%	100%	20.47
Microwave	88%	100%	130.99

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Monitor	40%	100%	28.92
Other	100%	100%	0.00
Plug Load Other	100%	100%	628.75
Refrigerator	116%	100%	507.30
Television	187%	100%	103.39
Ventilation and Circulation	99%	100%	699.39
Water Heater GT 55 Gallon	3%	41%	740.56
Water Heater LE 55 Gallon	95%	41%	1,642.11
Manufactured Low Income			
Air Purifier	2%	100%	843.03
Computer	82%	100%	60.68
Cooking Oven	100%	24%	174.17
Cooking Range	93%	93%	124.74
Cool Central	44%	100%	484.61
Cool Room	36%	100%	177.56
Dehumidifier	7%	100%	536.46
Dryer	91%	91%	583.43
Electric Vehicle	0%	100%	2,553.36
Freezer	46%	100%	479.17
Heat Central	5%	100%	10,737.78
Heat Pump	0%	100%	5,407.19
Heat Room	2%	100%	6,992.71
Lighting – Fluorescent	388%	100%	26.04
Lighting – Specialty	1276%	100%	34.98
Lighting – Standard	1770%	100%	23.62
Microwave	79%	100%	130.99
Monitor	34%	100%	28.92
Other	100%	100%	0.00
Plug Load Other	100%	100%	548.56
Refrigerator	110%	100%	507.30
Television	165%	100%	103.39
Ventilation and Circulation	98%	100%	699.39
Water Heater GT 55 Gallon	3%	46%	1,211.71
Water Heater LE 55 Gallon	94%	46%	2,686.83
Multifamily			
Air Purifier	3%	100%	843.03
Computer	93%	100%	60.68
Cooking Oven	98%	66%	174.17
Cooking Range	88%	88%	124.74
Cool Central	59%	100%	883.65
Cool Room	45%	100%	185.92
Dehumidifier	8%	100%	536.46
Dryer	56%	56%	583.43
Electric Vehicle	0%	100%	2,553.36
Freezer	14%	100%	479.17

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Heat Central	9%	100%	10,504.95
Heat Pump	0%	100%	6,670.53
Heat Room	16%	100%	6,841.09
Lighting – Fluorescent	131%	100%	26.04
Lighting – Specialty	202%	100%	27.31
Lighting – Standard	2195%	100%	16.06
Microwave	86%	100%	130.99
Monitor	18%	100%	28.92
Other	100%	100%	0.00
Plug Load Other	100%	100%	461.21
Refrigerator	115%	100%	507.30
Television	120%	100%	103.39
Ventilation and Circulation	58%	100%	699.39
Water Heater GT 55 Gallon	45%	46%	706.63
Water Heater LE 55 Gallon	45%	46%	1,525.68
Multifamily Low Income			
Air Purifier	8%	100%	843.03
Computer	79%	100%	60.68
Cooking Oven	99%	68%	174.17
Cooking Range	93%	93%	124.74
Cool Central	44%	100%	1,023.46
Cool Room	50%	100%	215.34
Dehumidifier	7%	100%	536.46
Dryer	38%	38%	583.43
Electric Vehicle	0%	100%	2,553.36
Freezer	18%	100%	479.17
Heat Central	26%	100%	12,167.66
Heat Pump	2%	100%	7,930.96
Heat Room	14%	100%	7,923.89
Lighting - Fluorescent	151%	100%	26.04
Lighting - Specialty	234%	100%	31.24
Lighting - Standard	2543%	100%	17.97
Microwave	64%	100%	130.99
Monitor	15%	100%	28.92
Other	100%	100%	0.00
Plug Load Other	100%	100%	473.03
Refrigerator	106%	100%	507.30
Television	144%	100%	103.39
Ventilation and Circulation	62%	100%	699.39
Water Heater GT 55 Gallon	42%	45%	821.85
Water Heater LE 55 Gallon	42%	45%	1,709.22
Single Family			
Air Purifier	9%	100%	843.03
Computer	153%	100%	60.68
Cooking Oven	109%	56%	174.17

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Cooking Range	98%	98%	124.74
Cool Central	71%	100%	1,319.42
Cool Room	23%	100%	280.61
Dehumidifier	46%	100%	536.46
Dryer	98%	98%	583.43
Electric Vehicle	0%	100%	2,553.36
Freezer	66%	100%	479.17
Heat Central	2%	100%	12,672.03
Heat Pump	2%	100%	7,849.14
Heat Room	1%	100%	8,252.35
Lighting - Fluorescent	612%	100%	26.04
Lighting - Specialty	2017%	100%	21.71
Lighting - Standard	2797%	100%	24.34
Microwave	85%	100%	130.99
Monitor	63%	100%	28.92
Other	100%	100%	0.00
Plug Load Other	100%	100%	750.76
Pool Pump	9%	100%	955.26
Refrigerator	137%	100%	507.30
Television	213%	100%	103.39
Ventilation and Circulation	92%	100%	699.39
Water Heater GT 55 Gallon	3%	22%	1,097.41
Water Heater LE 55 Gallon	96%	22%	2,423.53
Single Family Low Income			
Air Purifier	5%	100%	843.03
Computer	96%	100%	60.68
Cooking Oven	110%	54%	174.17
Cooking Range	96%	96%	124.74
Cool Central	39%	100%	963.07
Cool Room	37%	100%	204.82
Dehumidifier	28%	100%	536.46
Dryer	90%	90%	583.43
Electric Vehicle	0%	100%	2,553.36
Freezer	55%	100%	479.17
Heat Central	4%	100%	9,250.11
Heat Pump	1%	100%	5,372.10
Heat Room	3%	100%	6,023.91
Lighting - Fluorescent	447%	100%	26.04
Lighting - Specialty	1472%	100%	26.13
Lighting - Standard	2042%	100%	27.32
Microwave	78%	100%	130.99
Monitor	39%	100%	28.92
Other	100%	100%	0.00
Plug Load Other	100%	100%	596.96
Refrigerator	118%	100%	507.30

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Television	161%	100%	103.39
Ventilation and Circulation	91%	100%	699.39
Water Heater GT 55 Gallon	3%	31%	1,238.55
Water Heater LE 55 Gallon	96%	31%	2,711.77

Commercial Electric

Figure A-3. Commercial Baseline Electric Forecast by Segment

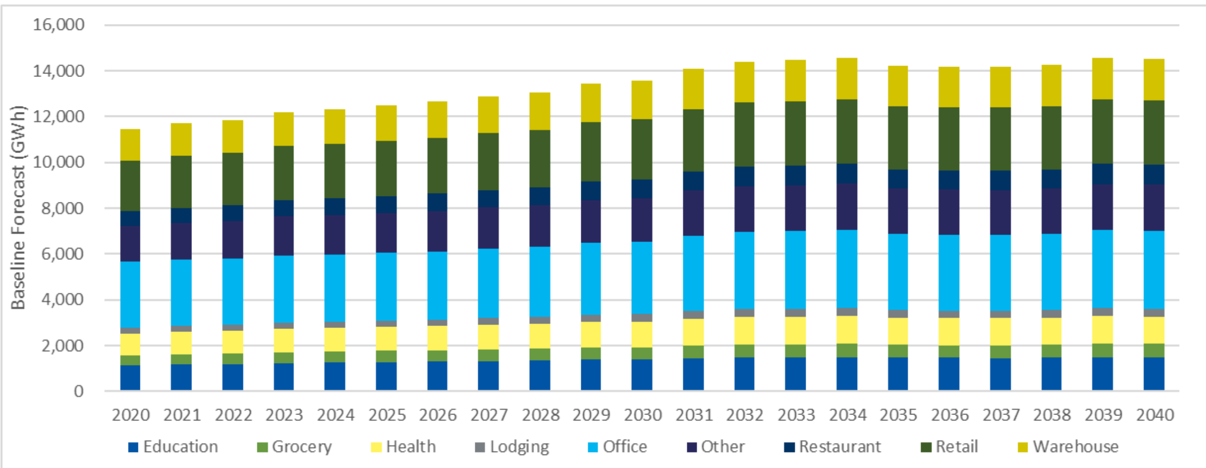


Figure A-4. Commercial Baseline Electric Forecast by End Use

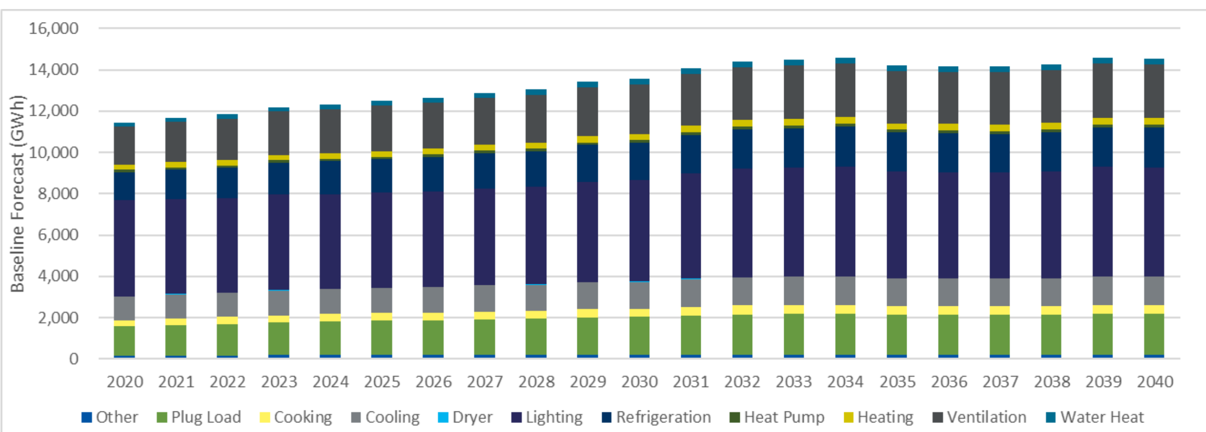


Table A-2. Commercial Baseline Forecast Assumptions: Electric Saturation Fuel Shares and Unit Energy Use

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Existing Construction			
Education			
Compressed Air	100%	100%	0.00
Computer	100%	100%	0.11
Cooking	100%	33%	0.42
Cooling Chillers	29%	100%	0.88
Cooling Direct Expansion	66%	100%	1.70
Dryer	100%	92%	0.02
Extension Lighting	100%	100%	0.46
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.00
Heat Pump	3%	100%	4.51
Lighting Interior Fluorescent	100%	100%	1.27
Lighting Interior HID	100%	100%	0.13
Lighting Interior Other	100%	100%	0.09
Lighting Interior Screw Base	100%	100%	0.15
Monitor	100%	100%	0.07
Other	100%	100%	0.00
Other Plug Load	100%	100%	2.92
Package Terminal Air Conditioner	0%	100%	0.61
Package Terminal Heat Pump	0%	100%	1.47
Photo Copier	100%	100%	0.00
Pool Pump	100%	100%	0.01
Printer	100%	100%	0.02
Refrigeration	100%	100%	0.89
Refrigerator	100%	100%	0.02
Room Cool	4%	100%	0.62
Room Heat	12%	28%	2.76
Server	100%	100%	0.08
Space Heat	86%	0%	8.32
Vending Machine	100%	100%	0.03
Ventilation and Circulation	100%	100%	1.46
Water Heat GT 55 Gallon	50%	20%	0.55
Water Heat LE 55 Gallon	50%	20%	1.22
Grocery			
Compressed Air	100%	100%	0.05
Computer	100%	100%	0.03
Cooking	100%	41%	5.25
Cooling Chillers	0%	100%	0.85
Cooling Direct Expansion	100%	100%	0.88
Dryer	100%	0%	0.02
Extension Lighting	100%	100%	0.95
Fax Machine	100%	100%	0.00

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Freezer	100%	100%	0.01
Heat Pump	10%	100%	3.39
Lighting Interior Fluorescent	100%	100%	5.01
Lighting Interior HID	100%	100%	0.01
Lighting Interior Other	100%	100%	0.09
Lighting Interior Screw Base	100%	100%	1.84
Monitor	100%	100%	0.02
Other	100%	100%	0.00
Other Plug Load	100%	100%	1.69
Package Terminal Air Conditioner	0%	100%	0.69
Package Terminal Heat Pump	0%	100%	2.35
Photo Copier	100%	100%	0.01
Pool Pump	100%	100%	0.00
Printer	100%	100%	0.02
Refrigeration	100%	100%	38.75
Refrigerator	100%	100%	0.05
Room Cool	0%	100%	0.70
Room Heat	8%	0%	5.31
Server	100%	100%	0.11
Space Heat	82%	2%	8.07
Vending Machine	100%	100%	0.03
Ventilation and Circulation	100%	100%	3.50
Water Heat GT 55 Gallon	33%	30%	0.10
Water Heat LE 55 Gallon	67%	30%	0.22
Health			
Compressed Air	100%	100%	0.00
Computer	100%	100%	0.08
Cooking	100%	24%	2.89
Cooling Chillers	13%	100%	1.94
Cooling Direct Expansion	78%	100%	3.38
Dryer	100%	57%	0.10
Extension Lighting	100%	100%	0.70
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.00
Heat Pump	6%	100%	8.30
Lighting Interior Fluorescent	100%	100%	3.07
Lighting Interior HID	100%	100%	0.04
Lighting Interior Other	100%	100%	0.09
Lighting Interior Screw Base	100%	100%	0.68
Monitor	100%	100%	0.07
Other	100%	100%	0.00
Other Plug Load	100%	100%	6.99
Package Terminal Air Conditioner	0%	100%	1.82
Package Terminal Heat Pump	0%	100%	3.95
Photo Copier	100%	100%	0.01
Pool Pump	100%	100%	0.02

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Printer	100%	100%	0.04
Refrigeration	100%	100%	1.40
Refrigerator	100%	100%	0.04
Room Cool	9%	100%	1.83
Room Heat	1%	0%	6.83
Server	100%	100%	0.13
Space Heat	93%	0%	14.70
Vending Machine	100%	100%	0.03
Ventilation and Circulation	100%	100%	4.92
Water Heat GT 55 Gallon	20%	28%	2.22
Water Heat LE 55 Gallon	80%	28%	4.91
Lodging			
Compressed Air	100%	100%	0.01
Computer	100%	100%	0.02
Cooking	100%	53%	3.09
Cooling Chillers	16%	100%	0.52
Cooling Direct Expansion	33%	100%	1.01
Dryer	100%	41%	0.09
Extension Lighting	100%	100%	0.70
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.01
Heat Pump	1%	100%	2.80
Lighting Interior Fluorescent	100%	100%	0.29
Lighting Interior HID	100%	100%	0.01
Lighting Interior Other	100%	100%	0.09
Lighting Interior Screw Base	100%	100%	1.62
Monitor	100%	100%	0.01
Other	100%	100%	0.00
Other Plug Load	100%	100%	5.27
Package Terminal Air Conditioner	3%	100%	0.56
Package Terminal Heat Pump	5%	100%	1.42
Photo Copier	100%	100%	0.00
Pool Pump	100%	100%	0.03
Printer	100%	100%	0.01
Refrigeration	100%	100%	1.21
Refrigerator	100%	100%	0.09
Room Cool	47%	100%	0.57
Room Heat	40%	43%	2.76
Server	100%	100%	0.01
Space Heat	54%	74%	5.35
Vending Machine	100%	100%	0.03
Ventilation and Circulation	100%	100%	2.24
Water Heat GT 55 Gallon	82%	17%	2.42
Water Heat LE 55 Gallon	18%	17%	5.36

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Office			
Compressed Air	100%	100%	0.03
Computer	100%	100%	0.12
Cooking	100%	2%	0.15
Cooling Chillers	10%	100%	1.07
Cooling Direct Expansion	82%	100%	1.87
Dryer	100%	0%	0.03
Extension Lighting	100%	100%	0.70
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.00
Heat Pump	6%	100%	4.30
Lighting Interior Fluorescent	100%	100%	1.55
Lighting Interior HID	100%	100%	0.08
Lighting Interior Other	100%	100%	0.09
Lighting Interior Screw Base	100%	100%	1.72
Monitor	100%	100%	0.09
Other	100%	100%	0.00
Other Plug Load	100%	100%	4.69
Package Terminal Air Conditioner	0%	100%	1.19
Package Terminal Heat Pump	0%	100%	2.44
Photo Copier	100%	100%	0.01
Pool Pump	100%	100%	0.01
Printer	100%	100%	0.05
Refrigeration	100%	100%	0.38
Refrigerator	100%	100%	0.03
Room Cool	8%	100%	1.20
Room Heat	21%	1%	3.98
Server	100%	100%	0.26
Space Heat	72%	1%	7.20
Vending Machine	100%	100%	0.03
Ventilation and Circulation	100%	100%	3.91
Water Heat GT 55 Gallon	26%	63%	0.16
Water Heat LE 55 Gallon	74%	63%	0.35
Other			
Compressed Air	100%	100%	0.11
Computer	100%	100%	0.02
Cooking	100%	43%	0.42
Cooling Chillers	2%	100%	0.83
Cooling Direct Expansion	94%	100%	1.42
Dryer	100%	39%	0.05
Extension Lighting	100%	100%	0.70
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.00
Heat Pump	0%	100%	4.09
Lighting Interior Fluorescent	100%	100%	2.02
Lighting Interior HID	100%	100%	0.45

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Lighting Interior Other	100%	100%	0.09
Lighting Interior Screw Base	100%	100%	0.97
Monitor	100%	100%	0.02
Other	100%	100%	0.00
Other Plug Load	100%	100%	1.87
Package Terminal Air Conditioner	0%	100%	0.88
Package Terminal Heat Pump	0%	100%	2.27
Photo Copier	100%	100%	0.00
Pool Pump	100%	100%	0.00
Printer	100%	100%	0.02
Refrigeration	100%	100%	0.77
Refrigerator	100%	100%	0.04
Room Cool	4%	100%	0.89
Room Heat	42%	0%	4.43
Server	100%	100%	0.05
Space Heat	58%	3%	8.46
Vending Machine	100%	100%	0.03
Ventilation and Circulation	100%	100%	1.13
Water Heat GT 55 Gallon	43%	29%	0.27
Water Heat LE 55 Gallon	57%	29%	0.59
Restaurant			
Compressed Air	100%	100%	0.01
Computer	100%	100%	0.01
Cooking	100%	34%	24.54
Cooling Chillers	0%	100%	1.97
Cooling Direct Expansion	98%	100%	1.97
Dryer	100%	0%	0.49
Extension Lighting	100%	100%	2.30
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.01
Heat Pump	4%	100%	4.95
Lighting Interior Fluorescent	100%	100%	1.10
Lighting Interior HID	100%	100%	0.02
Lighting Interior Other	100%	100%	0.09
Lighting Interior Screw Base	100%	100%	1.60
Monitor	100%	100%	0.01
Other	100%	100%	0.00
Other Plug Load	100%	100%	2.82
Package Terminal Air Conditioner	0%	100%	1.69
Package Terminal Heat Pump	0%	100%	3.26
Photo Copier	100%	100%	0.00
Pool Pump	100%	0%	0.00
Printer	100%	100%	0.01
Refrigeration	100%	100%	12.71
Refrigerator	100%	100%	0.07
Room Cool	2%	100%	1.70

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Room Heat	7%	86%	5.02
Server	100%	100%	0.05
Space Heat	89%	0%	7.28
Vending Machine	100%	100%	0.01
Ventilation and Circulation	100%	100%	4.20
Water Heat GT 55 Gallon	38%	6%	2.15
Water Heat LE 55 Gallon	63%	6%	4.77
Retail			
Compressed Air	100%	100%	0.33
Computer	100%	100%	0.02
Cooking	100%	49%	0.81
Cooling Chillers	0%	100%	1.38
Cooling Direct Expansion	100%	100%	1.38
Dryer	100%	0%	0.04
Extension Lighting	100%	100%	0.95
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.00
Heat Pump	2%	100%	4.64
Lighting Interior Fluorescent	100%	100%	2.96
Lighting Interior HID	100%	100%	0.27
Lighting Interior Other	100%	100%	0.09
Lighting Interior Screw Base	100%	100%	1.53
Monitor	100%	100%	0.02
Other	100%	100%	0.00
Other Plug Load	100%	100%	2.61
Package Terminal Air Conditioner	0%	100%	0.96
Package Terminal Heat Pump	0%	100%	2.36
Photo Copier	100%	100%	0.00
Pool Pump	100%	100%	0.04
Printer	100%	100%	0.02
Refrigeration	100%	100%	3.46
Refrigerator	100%	100%	0.02
Room Cool	0%	100%	0.97
Room Heat	35%	19%	4.47
Server	100%	100%	0.06
Space Heat	63%	0%	7.93
Vending Machine	100%	100%	0.02
Ventilation and Circulation	100%	100%	3.24
Water Heat GT 55 Gallon	18%	69%	0.25
Water Heat LE 55 Gallon	82%	69%	0.55
Warehouse			
Compressed Air	100%	100%	0.35
Computer	100%	100%	0.01
Cooking	100%	0%	0.02
Cooling Chillers	3%	100%	0.39
Cooling Direct Expansion	90%	100%	0.39

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Dryer	100%	0%	0.04
Extension Lighting	100%	100%	0.95
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.00
Heat Pump	0%	100%	2.30
Lighting Interior Fluorescent	100%	100%	0.74
Lighting Interior HID	100%	100%	0.62
Lighting Interior Other	100%	100%	0.09
Lighting Interior Screw Base	100%	100%	0.13
Monitor	100%	100%	0.01
Other	100%	100%	0.00
Other Plug Load	100%	100%	1.28
Package Terminal Air Conditioner	0%	100%	0.24
Package Terminal Heat Pump	0%	100%	0.96
Photo Copier	100%	100%	0.00
Pool Pump	100%	100%	0.00
Printer	100%	100%	0.01
Refrigeration	100%	100%	0.20
Refrigerator	100%	100%	0.01
Room Cool	7%	100%	0.25
Room Heat	56%	34%	2.29
Server	100%	100%	0.04
Space Heat	44%	0%	4.60
Vending Machine	100%	100%	0.02
Ventilation and Circulation	100%	100%	0.37
Water Heat GT 55 Gallon	6%	55%	0.08
Water Heat LE 55 Gallon	94%	55%	0.18
New Construction			
Education			
Compressed Air	100%	100%	0.00
Computer	100%	100%	0.11
Cooking	100%	33%	0.42
Cooling Chillers	29%	100%	0.88
Cooling Direct Expansion	66%	100%	1.57
Dryer	100%	92%	0.02
Extension Lighting	100%	100%	0.46
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.00
Heat Pump	3%	100%	4.51
Lighting Interior Fluorescent	100%	100%	0.00
Lighting Interior HID	100%	100%	0.00
Lighting Interior Other	100%	100%	1.47
Lighting Interior Screw Base	100%	100%	0.00
Monitor	100%	100%	0.07
Other	100%	100%	0.00
Other Plug Load	100%	100%	2.92

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Package Terminal Air Conditioner	0%	100%	0.61
Package Terminal Heat Pump	0%	100%	1.47
Photo Copier	100%	100%	0.00
Pool Pump	100%	100%	0.00
Printer	100%	100%	0.02
Refrigeration	100%	100%	0.89
Refrigerator	100%	100%	0.02
Room Cool	4%	100%	0.62
Room Heat	12%	28%	2.76
Server	100%	100%	0.08
Space Heat	86%	0%	8.32
Vending Machine	100%	100%	0.02
Ventilation and Circulation	100%	100%	1.46
Water Heat GT 55 Gallon	50%	20%	0.55
Water Heat LE 55 Gallon	50%	20%	1.22
Grocery			
Compressed Air	100%	100%	0.05
Computer	100%	100%	0.03
Cooking	100%	41%	5.25
Cooling Chillers	0%	100%	0.85
Cooling Direct Expansion	100%	100%	0.78
Dryer	100%	0%	0.02
Extension Lighting	100%	100%	0.95
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.01
Heat Pump	10%	100%	3.39
Lighting Interior Fluorescent	100%	100%	0.00
Lighting Interior HID	100%	100%	0.00
Lighting Interior Other	100%	100%	5.98
Lighting Interior Screw Base	100%	100%	0.00
Monitor	100%	100%	0.02
Other	100%	100%	0.00
Other Plug Load	100%	100%	1.69
Package Terminal Air Conditioner	0%	100%	0.69
Package Terminal Heat Pump	0%	100%	2.35
Photo Copier	100%	100%	0.01
Pool Pump	100%	100%	0.00
Printer	100%	100%	0.02
Refrigeration	100%	100%	38.75
Refrigerator	100%	100%	0.05
Room Cool	0%	100%	0.70
Room Heat	8%	0%	5.31
Server	100%	100%	0.11
Space Heat	82%	2%	8.07
Vending Machine	100%	100%	0.02
Ventilation and Circulation	100%	100%	3.50

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Water Heat GT 55 Gallon	33%	30%	0.10
Water Heat LE 55 Gallon	67%	30%	0.22
Health			
Compressed Air	100%	100%	0.00
Computer	100%	100%	0.08
Cooking	100%	24%	2.89
Cooling Chillers	13%	100%	1.94
Cooling Direct Expansion	78%	100%	3.02
Dryer	100%	57%	0.08
Extension Lighting	100%	100%	0.70
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.00
Heat Pump	6%	100%	8.30
Lighting Interior Fluorescent	100%	100%	0.00
Lighting Interior HID	100%	100%	0.00
Lighting Interior Other	100%	100%	3.41
Lighting Interior Screw Base	100%	100%	0.00
Monitor	100%	100%	0.07
Other	100%	100%	0.00
Other Plug Load	100%	100%	6.99
Package Terminal Air Conditioner	0%	100%	1.82
Package Terminal Heat Pump	0%	100%	3.95
Photo Copier	100%	100%	0.01
Pool Pump	100%	100%	0.01
Printer	100%	100%	0.04
Refrigeration	100%	100%	1.40
Refrigerator	100%	100%	0.04
Room Cool	9%	100%	1.83
Room Heat	1%	0%	6.83
Server	100%	100%	0.13
Space Heat	93%	0%	14.70
Vending Machine	100%	100%	0.02
Ventilation and Circulation	100%	100%	4.92
Water Heat GT 55 Gallon	20%	28%	2.22
Water Heat LE 55 Gallon	80%	28%	4.91
Lodging			
Compressed Air	100%	100%	0.01
Computer	100%	100%	0.02
Cooking	100%	53%	3.09
Cooling Chillers	16%	100%	0.52
Cooling Direct Expansion	33%	100%	0.93
Dryer	100%	41%	0.08
Extension Lighting	100%	100%	0.70
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.01
Heat Pump	1%	100%	2.80

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Lighting Interior Fluorescent	100%	100%	0.00
Lighting Interior HID	100%	100%	0.00
Lighting Interior Other	100%	100%	1.32
Lighting Interior Screw Base	100%	100%	0.00
Monitor	100%	100%	0.01
Other	100%	100%	0.00
Other Plug Load	100%	100%	5.27
Package Terminal Air Conditioner	3%	100%	0.56
Package Terminal Heat Pump	5%	100%	1.42
Photo Copier	100%	100%	0.00
Pool Pump	100%	100%	0.01
Printer	100%	100%	0.01
Refrigeration	100%	100%	1.21
Refrigerator	100%	100%	0.09
Room Cool	47%	100%	0.57
Room Heat	40%	43%	2.76
Server	100%	100%	0.01
Space Heat	54%	74%	5.35
Vending Machine	100%	100%	0.03
Ventilation and Circulation	100%	100%	2.24
Water Heat GT 55 Gallon	82%	17%	2.42
Water Heat LE 55 Gallon	18%	17%	5.36
Office			
Compressed Air	100%	100%	0.03
Computer	100%	100%	0.12
Cooking	100%	2%	0.15
Cooling Chillers	10%	100%	1.07
Cooling Direct Expansion	82%	100%	1.67
Dryer	100%	0%	0.02
Extension Lighting	100%	100%	0.70
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.00
Heat Pump	6%	100%	4.30
Lighting Interior Fluorescent	100%	100%	0.00
Lighting Interior HID	100%	100%	0.00
Lighting Interior Other	100%	100%	2.51
Lighting Interior Screw Base	100%	100%	0.00
Monitor	100%	100%	0.09
Other	100%	100%	0.00
Other Plug Load	100%	100%	4.69
Package Terminal Air Conditioner	0%	100%	1.19
Package Terminal Heat Pump	0%	100%	2.44
Photo Copier	100%	100%	0.01
Pool Pump	100%	100%	0.00
Printer	100%	100%	0.05
Refrigeration	100%	100%	0.38

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Refrigerator	100%	100%	0.03
Room Cool	8%	100%	1.20
Room Heat	21%	1%	3.98
Server	100%	100%	0.26
Space Heat	72%	1%	7.20
Vending Machine	100%	100%	0.03
Ventilation and Circulation	100%	100%	3.91
Water Heat GT 55 Gallon	26%	63%	0.16
Water Heat LE 55 Gallon	74%	63%	0.35
Other			
Compressed Air	100%	100%	0.11
Computer	100%	100%	0.02
Cooking	100%	43%	0.42
Cooling Chillers	2%	100%	0.83
Cooling Direct Expansion	94%	100%	1.24
Dryer	100%	39%	0.04
Extension Lighting	100%	100%	0.70
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.00
Heat Pump	0%	100%	4.09
Lighting Interior Fluorescent	100%	100%	0.00
Lighting Interior HID	100%	100%	0.00
Lighting Interior Other	100%	100%	2.81
Lighting Interior Screw Base	100%	100%	0.00
Monitor	100%	100%	0.02
Other	100%	100%	0.00
Other Plug Load	100%	100%	1.87
Package Terminal Air Conditioner	0%	100%	0.88
Package Terminal Heat Pump	0%	100%	2.27
Photo Copier	100%	100%	0.00
Pool Pump	100%	100%	0.00
Printer	100%	100%	0.02
Refrigeration	100%	100%	0.77
Refrigerator	100%	100%	0.04
Room Cool	4%	100%	0.89
Room Heat	42%	0%	4.43
Server	100%	100%	0.05
Space Heat	58%	3%	8.46
Vending Machine	100%	100%	0.02
Ventilation and Circulation	100%	100%	1.13
Water Heat GT 55 Gallon	43%	29%	0.27
Water Heat LE 55 Gallon	57%	29%	0.59
Restaurant			
Compressed Air	100%	100%	0.01
Computer	100%	100%	0.01
Cooking	100%	34%	24.54

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Cooling Chillers	0%	100%	1.97
Cooling Direct Expansion	98%	100%	1.76
Dryer	100%	0%	0.42
Extension Lighting	100%	100%	2.30
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.01
Heat Pump	4%	100%	4.95
Lighting Interior Fluorescent	100%	100%	0.00
Lighting Interior HID	100%	100%	0.00
Lighting Interior Other	100%	100%	1.92
Lighting Interior Screw Base	100%	100%	0.00
Monitor	100%	100%	0.01
Other	100%	100%	0.00
Other Plug Load	100%	100%	2.82
Package Terminal Air Conditioner	0%	100%	1.69
Package Terminal Heat Pump	0%	100%	3.26
Photo Copier	100%	100%	0.00
Pool Pump	100%	0%	0.00
Printer	100%	100%	0.01
Refrigeration	100%	100%	12.71
Refrigerator	100%	100%	0.07
Room Cool	2%	100%	1.70
Room Heat	7%	86%	5.02
Server	100%	100%	0.05
Space Heat	89%	0%	7.28
Vending Machine	100%	100%	0.01
Ventilation and Circulation	100%	100%	4.20
Water Heat GT 55 Gallon	38%	6%	2.15
Water Heat LE 55 Gallon	63%	6%	4.77
Retail			
Compressed Air	100%	100%	0.33
Computer	100%	100%	0.02
Cooking	100%	49%	0.81
Cooling Chillers	0%	100%	1.38
Cooling Direct Expansion	100%	100%	1.23
Dryer	100%	0%	0.03
Extension Lighting	100%	100%	0.95
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.00
Heat Pump	2%	100%	4.64
Lighting Interior Fluorescent	100%	100%	0.00
Lighting Interior HID	100%	100%	0.00
Lighting Interior Other	100%	100%	3.92
Lighting Interior Screw Base	100%	100%	0.00
Monitor	100%	100%	0.02
Other	100%	100%	0.00

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Other Plug Load	100%	100%	2.61
Package Terminal Air Conditioner	0%	100%	0.96
Package Terminal Heat Pump	0%	100%	2.36
Photo Copier	100%	100%	0.00
Pool Pump	100%	100%	0.02
Printer	100%	100%	0.02
Refrigeration	100%	100%	3.46
Refrigerator	100%	100%	0.02
Room Cool	0%	100%	0.97
Room Heat	35%	19%	4.47
Server	100%	100%	0.06
Space Heat	63%	0%	7.93
Vending Machine	100%	100%	0.02
Ventilation and Circulation	100%	100%	3.24
Water Heat GT 55 Gallon	18%	69%	0.25
Water Heat LE 55 Gallon	82%	69%	0.55
Warehouse			
Compressed Air	100%	100%	0.35
Computer	100%	100%	0.01
Cooking	100%	0%	0.02
Cooling Chillers	3%	100%	0.39
Cooling Direct Expansion	90%	100%	0.35
Dryer	100%	0%	0.03
Extension Lighting	100%	100%	0.95
Fax Machine	100%	100%	0.00
Freezer	100%	100%	0.00
Heat Pump	0%	100%	2.30
Lighting Interior Fluorescent	100%	100%	0.00
Lighting Interior HID	100%	100%	0.00
Lighting Interior Other	100%	100%	1.40
Lighting Interior Screw Base	100%	100%	0.00
Monitor	100%	100%	0.01
Other	100%	100%	0.00
Other Plug Load	100%	100%	1.28
Package Terminal Air Conditioner	0%	100%	0.24
Package Terminal Heat Pump	0%	100%	0.96
Photo Copier	100%	100%	0.00
Pool Pump	100%	100%	0.00
Printer	100%	100%	0.01
Refrigeration	100%	100%	0.20
Refrigerator	100%	100%	0.01
Room Cool	7%	100%	0.25
Room Heat	56%	34%	2.29
Server	100%	100%	0.04
Space Heat	44%	0%	4.60
Vending Machine	100%	100%	0.01

End Use	Saturation	Fuel Share	Weighted Average Unit Energy Use (kWh/Unit)
Ventilation and Circulation	100%	100%	0.37
Water Heat GT 55 Gallon	6%	55%	0.08
Water Heat LE 55 Gallon	94%	55%	0.18

Industrial Electric

Figure A-5. Industrial Baseline Forecast by Segment - Electric

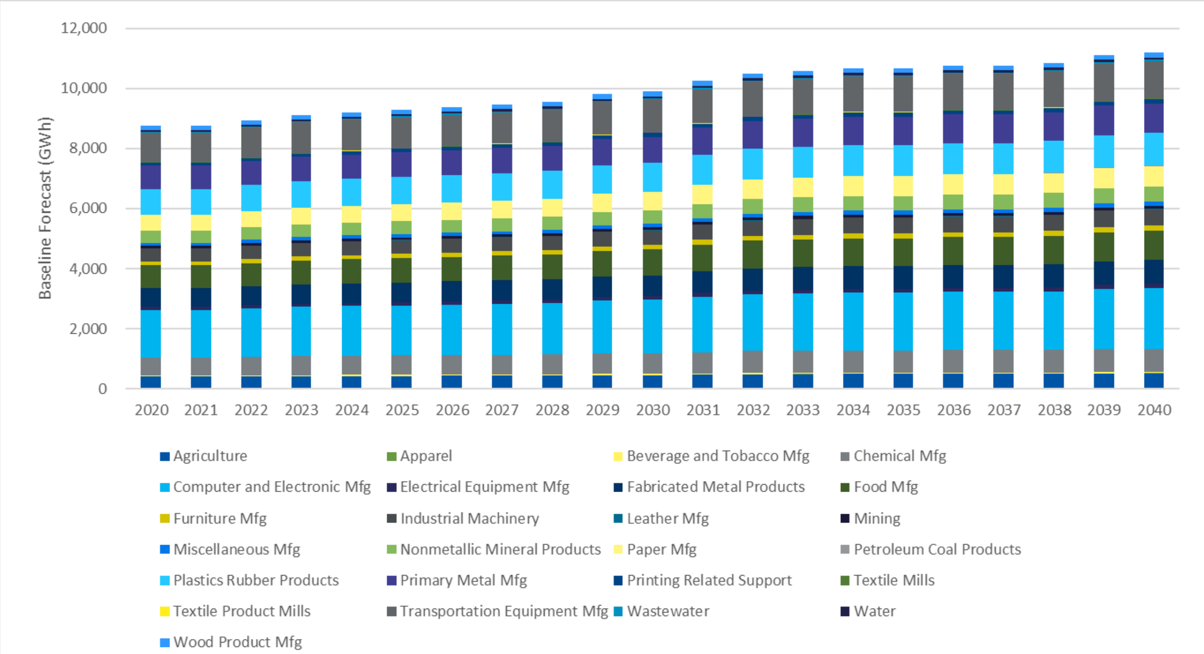
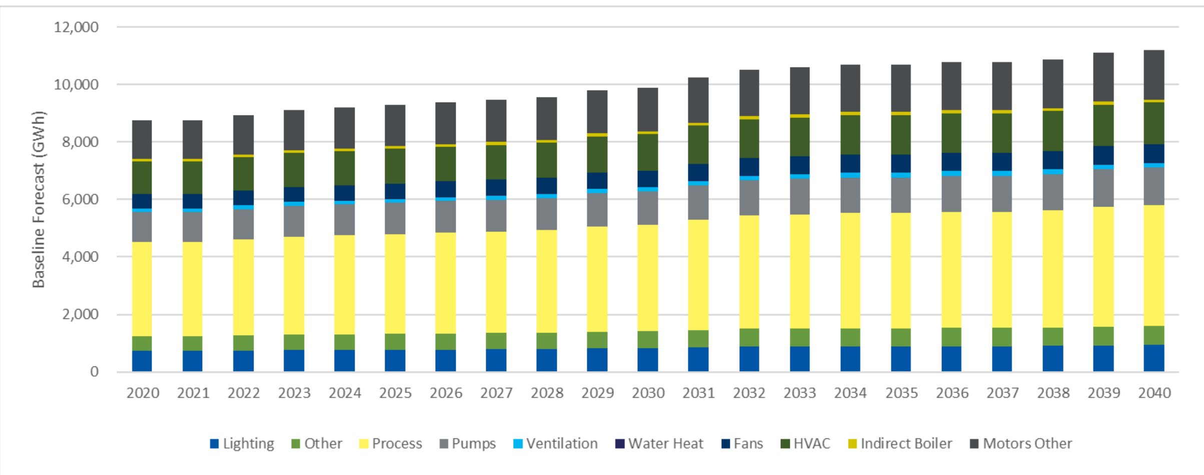


Figure A-6. Industrial Baseline Forecast by End Use - Electric



Appendix B. Economic Inputs

Table B-1 presents the avoided costs used for determining economic potential. These values are provided by Consumers Energy and are consistent with values used to estimate cost-effectiveness in the 2020–2023 EWR Plan.

Table B-1. Avoided Costs

Year	Avoided Electric Energy ($/kWh)	Avoided Generation Capacity ($/kW)	Avoided Transmission & Distribution ($/kW)	Avoided Natural Gas Energy ($/therm)
2021	$0.0370	$75.62	$22.03	$0.3251
2022	$0.0389	$77.44	$22.14	$0.3360
2023	$0.0406	$79.29	$22.68	$0.3555
2024	$0.0444	$81.20	$23.12	$0.3740
2025	$0.0461	$83.15	$23.76	$0.3924
2026	$0.0485	$85.14	$24.09	$0.4014
2027	$0.0501	$87.18	$24.59	$0.4109
2028	$0.0516	$89.28	$25.03	$0.4203
2029	$0.0542	$91.42	$25.45	$0.4301
2030	$0.0560	$93.61	$25.77	$0.4401
2031	$0.0589	$95.86	$26.24	$0.4506
2032	$0.0614	$98.16	$26.61	$0.4613
2033	$0.0639	$100.52	$26.99	$0.4722
2034	$0.0664	$102.93	$27.28	$0.4835
2035	$0.0690	$105.40	$27.76	$0.4949
2036	$0.0717	$107.93	$28.16	$0.5066
2037	$0.0744	$110.52	$28.56	$0.5185
2038	$0.0773	$113.17	$28.88	$0.5308
2039	$0.0801	$115.89	$29.41	$0.5435
2040	$0.0831	$118.67	$29.87	$0.5565

Table B-2 shows additional global economic assumptions.

Table B-2. Global Assumptions

Nominal Discount Rate	7.50%
Inflation Rate	2.10%
Reserve Margin Multiplier	7.84%
Electric Line Losses	7.73%

Table B-3 shows the retail rate forecast used to calculate potential customer bill savings from the maximum achievable potential.

Table B-3. Retail Rate Forecast by Sector

Year	Residential ($/kWh)	Commercial ($/kWh)	Industrial ($/kWh)
2021	$0.172	$0.133	$0.080
2022	$0.175	$0.135	$0.080
2023	$0.178	$0.135	$0.079
2024	$0.183	$0.137	$0.079
2025	$0.190	$0.142	$0.081
2026	$0.199	$0.147	$0.084
2027	$0.208	$0.154	$0.086
2028	$0.218	$0.160	$0.090
2029	$0.228	$0.167	$0.093
2030	$0.237	$0.172	$0.096
2031	$0.247	$0.179	$0.099
2032	$0.255	$0.184	$0.102
2033	$0.266	$0.192	$0.106
2034	$0.275	$0.197	$0.109
2035	$0.284	$0.204	$0.112
2036	$0.292	$0.208	$0.115
2037	$0.300	$0.213	$0.117
2038	$0.308	$0.217	$0.120
2039	$0.316	$0.222	$0.122
2040	$0.324	$0.227	$0.125

Appendix C. Emerging Technology Descriptions

To create the transformational technology scenario, the Cadmus team identified over 200 emerging measures, which we then characterized and incorporated into the energy-efficiency potential model. Ultimately, 170 unique measures were added to create the transformational technology scenario. The team aggregated these measures to create bundles focused on specific end uses. The measure bundles are described in Table C-1.

Table C-1. Emerging Technology Bundles

Residential	Commercial	Industrial
• Emerging HVAC • Online Services • Emerging Building Shell • Emerging Lighting • Emerging Domestic Hot Water • Other	• Emerging HVAC • Emerging Refrigeration • Emerging Lighting • Emerging DHW • Emerging Information Technology (IT) • Other • Proxy Measures (post-2036)	• Emerging Process • Emerging Lighting • Emerging Motors • Emerging Agriculture and Indoor Agriculture • Emerging Pumps and Fans • Other • Proxy Measures (2031-2036) • Proxy Measures (post-2036)

For each measure bundle, this appendix provides a high-level description that includes the identity of specific measures, applicability to segments or building types, measure energy savings and demand reduction, measure cost, EUL; the expected path to commercialization, and key resources used to characterize the measures or measure bundles.

The measure costs shown do not include necessary investments to drive innovation that may be undertaken by Consumers Energy or industry partners. The Cadmus team identified four key paths to realizing savings from emerging technologies, described in Table C-2. One or more paths may be pursued to support the availability and acceptance of a measure either in sequence or in parallel depending on specific barriers to measure development or adoption that may be faced.

Table C-2. Paths to Realizing Transformational Technology Savings

	Technology development and demonstration. This may include investment in research and development, lab testing, or engagement of early adopters to install and use new technologies and to provide feedback that will help further development and determine applicability
	Delivery strategy optimization. Determining the most effective market interventions to encourage the adoption of emerging technologies at-scale; this may include pilots and market forecasting to assess changes in cost as technologies are commercialized
	Customer and trade ally outreach. Lack of awareness and knowledge are significant barriers to adopting a new technology: providing outreach and education to customers helps to build interest and demand while trade ally engagement ensures that there is a qualified workforce to install and service new technologies.
	Regulatory review and acceptance. Educating MPSC staff and others about emerging technologies and working collaboratively to demonstrate energy saving potential and path to market adoption

The measure descriptions also include an estimate of the development timeline or year that measures may be available for widespread use. Generally, measures may be available in the short-term (2021 to 2025), mid-term (2026 to 2030), or long-term (2031 or later).

Finally, specific descriptions of proxy measures are not defined. Proxy measure bundles represent unique energy-efficiency improvements in commercial and industrial applications, akin to custom measures, that may be acquired through program strategies such as standard offer or pay-for-performance. The cost and size of proxy measure bundles varies based on the time period in which they are installed.

Residential Emerging Technology: Domestic Water Heaters

Domestic heat pump hot water heaters make up 1% of the 20-year residential portfolio achievable potential.

Bundle Measure Names and Residential Sector Applicability

Table C-3 shows the four measures in the domestic water heater bundle, as well as the residential sectors in which the measures can be installed.

Table C-3. Domestic Hot Water Heater Measure Names and Applicable Segments

Measure Name	Single Family	Single Family Low Income	Multifamily	Multifamily Low Income	Manufactured	Manufactured Low Income
Emerging Technology - Advanced Heat Pump Water Heater	X	X	X	X	X	X
Emerging Technology - Heat Pump Water Heater - CEE Advanced Tier			X	X		
Emerging Technology - Heat Pump Water Heater - ENERGY STAR Tier 4			X	X		
Emerging Technology - Pool Heat Pump Water Heater	X	X				

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-4 shows several characteristics for each measure: the percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, and measure life. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-4. Percentage Energy Savings over the Baseline Technology

Measure Name	Energy Savings (%)	Energy Savings (kWh)	Demand Reduction (kW)	Incremental Cost Per Home	Incremental Cost (Per Unit)	Units Per Home	Measure Life
Emerging Technology - Advanced Heat Pump Water Heater	1.5% - 3.4%	24 - 48	0.003 - 0.005	$129	$129/water heater	1	10 years
Emerging Technology - Heat Pump Water Heater - CEE Advanced Tier	20% - 46%	322 - 375	0.043	$1,063	$1,063/water heater	1	10 years
Emerging Technology - Heat Pump Water Heater - ENERGY STAR Tier 4	73% - 79%	1,555	0.153	$3,602	$3,602/water heater	1	10 years
Emerging Technology - Pool Heat Pump Water Heater	42% - 53%	283 - 314	0.832	$1,137	$314/pool heater	0.25	10 years

Path to Commercialization

All measures are expected to be commercially available by 2021; however, they face barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Incremental cost

Table C-5 shows the path to commercialization for each domestic water heater measure.

Table C-5. Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Advanced Heat Pump Water Heater	Near-Term 2020-2025			X	
Emerging Technology - Heat Pump Water Heater - CEE Advanced Tier	Near-Term 2020-2025		X	X	
Emerging Technology - Heat Pump Water Heater - ENERGY STAR Tier 4	Near-Term 2020-2025		X	X	
Emerging Technology - Pool Heat Pump Water Heater	Near-Term 2020-2025			X	X

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Residential Emerging Technology: HVAC Cooling, Duct Sealing, and Thermostats

The emerging technology HVAC cooling, duct sealing, and smart thermostat measures make up 31% of the 20-year residential portfolio achievable potential for emerging technology measures. These are a subset of the HVAC measures bundle, which makes up 46% of the of the 20-year residential portfolio achievable potential for emerging technology measures.

Bundle Measure Names and Residential Sector Applicability

Table C-6 shows the 10 measures in the HVAC cooling, duct sealing, and thermostats bundle, as well as the residential sectors in which the measures can be installed.

Table C-6. HVAC Heating Measure Names and Applicable Segments

Measure Name	Single Family	Single Family Low Income	Multifamily	Multifamily Low Income	Manufactured	Manufactured Low Income
Emerging Technology - Aerosol-Based Duct Sealing	X	X	X	X	X	X
Emerging Technology - Communicating Electric Line Voltage Thermostat	X	X	X	X	X	X
Emerging Technology - Eco-Snap Air Conditioning	X	X	X	X	X	X
Emerging Technology - HVAC Economizer	X	X	X	X	X	X
Emerging Technology - Integrated HVAC Controls	X	X	X	X	X	X
Emerging Technology - Optimized Thermostat	X	X	X	X	X	X
Emerging Technology - Residential Indirect-Direct Evaporative Cooler	X	X	X	X	X	X
Emerging Technology - Residential-Sized Sub-Wet Bulb Chiller	X	X	X	X	X	X
Emerging Technology - Smart Vents	X	X	X	X	X	X
Emerging Technology - Solar-Assisted Air Conditioning	X	X	X	X	X	X

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-7 shows several characteristics for each measure: the annual percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, measure life, and commercial availability start year. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-7. Percentage Energy Savings over the Baseline Technology

Measure Name	Energy Savings (%)	Energy Savings (kWh)	Demand Reduction (kW)	Incremental Cost Per Home	Incremental Cost (Per Unit)	Units Per Home	Measure Life
Emerging Technology - Aerosol-Based Duct Sealing - Cool Central	15%	112 - 3,483	0.2 - 0.3	$347 - $617	$333 - $1,000/ building sq ft	1.04 - 1.85	18
Emerging Technology - Aerosol-Based Duct Sealing - Heat Central and Heat Pump	15%	924 - 2,651	0 - 0.2	$347 - $618	$333 - $1,000/ building sq ft	1.04 - 1.86	18
Emerging Technology - Communicating Electric Line Voltage Thermostat	6%	361 - 907	-	$100	$100/ thermostat	1	15
Emerging Technology - Eco-Snap Air Conditioning	22% - 38%	43 - 106	0.04 - 0.06	$80	$80/home	1	15
Emerging Technology - HVAC Economizer	10% - 10%	49 - 246	0.05 - 0.3	$399 - $630	$200/ central AC ton	1.99 - 3.15	20
Emerging Technology - Integrated HVAC Controls (cool room, cool central)	5%	10 - 133	-	$90 - $108	$90 - $108/ thermostat	1	9
Emerging Technology - Integrated HVAC Controls (heat central, heat pump, heat room)	5%	290 - 1,253	0.0 - 0.13	$90 - $109	$90 - $108/ thermostat	1	9
Emerging Technology - Optimized Thermostat	4%	7 - 859	-	$5	$5/ thermostat	1	1
Emerging Technology - Residential Indirect-Direct Evaporative Cooler	44% - 51%	249 - 1,080	0.1 - 0.4	($1,792) - ($1,134)	($1,792) - ($1,134)/ tonnage	1.99 - 3.15	15
Emerging Technology - Residential-Sized Sub-Wet Bulb Chiller	32% - 37%	180 - 782	0.2 - 0.8	$1,511 - $2,388	$1,511 - $2,388/ home	1	20
Emerging Technology - Smart Vents	20% - 20%	97 - 4,645	0.0 - 1.0	$1,219	$1,219/ home	1	10
Emerging Technology - Solar-Assisted Air Conditioning	30% - 30%	146 - 737	0.2 - 0.8	$533	$533/home	1	15

Path to Commercialization

The commercialization dates for the residential emerging HVAC cooling, duct sealing, and thermostats measures range from 2021 to 2031; however, they face barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Incremental cost

Table C-8 shows the path to commercialization for each measure.

Table C-8. Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Aerosol-Based Duct Sealing	Near-Term 2021-2025			X	X
Emerging Technology - Communicating Electric Line Voltage Thermostat	Near-Term 2021-2025			X	X
Emerging Technology - Eco-Snap Air Conditioning	Mid-Term 2026-2030	X		X	X
Emerging Technology - HVAC Economizer	Near-Term 2021-2025		X	X	X
Emerging Technology - Integrated HVAC Controls	Near-Term 2021-2025			X	X
Emerging Technology - Optimized Thermostat	Near-Term 2021-2025			X	X
Emerging Technology - Residential Indirect-Direct Evaporative Cooler	Near-Term 2021-2025			X	X
Emerging Technology - Residential-Sized Sub-Wet Bulb Chiller	Mid-Term 2026-2030	X	X	X	X
Emerging Technology - Smart Vents	Near-Term 2021-2025			X	X
Emerging Technology - Solar-Assisted Air Conditioning	Long-Term 2031-2035	X	X	X	X

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Residential Emerging Technology: HVAC Heating

The emerging technology HVAC heating measures makes up 15% of the 20-year residential portfolio achievable potential for emerging technology measures. The HVAC heating measures are a subset of the HVAC measures bundle, which makes up 46% of the 20-year residential portfolio achievable potential for emerging technology measures.

Bundle Measure Names and Residential Sector Applicability

Table C-9 shows the eight measures in the HVAC heating measures bundle, as well as the residential sectors in which the measures can be installed.

Table C-9. HVAC Heating Measure Names and Applicable Segments

Measure Name	Single Family	Single Family Low Income	Multifamily	Multifamily Low Income	Manufactured	Manufactured Low Income
Emerging Technology - Advanced Air-Source Heat Pump	X	X	X	X	X	X
Emerging Technology - Advanced Furnace Fan	X	X	X	X	X	X
Emerging Technology - Advanced Wall Heater	X	X	X	X	X	X
Emerging Technology - Electro Caloric Heat Pump	X	X	X	X	X	X
Emerging Technology - Heat Pump with Integrated Desuperheater	X	X	X	X	X	X
Emerging Technology - Horizontal Drainpipe Heat Exchanger	X	X	X	X	X	X
Emerging Technology - Radiant Panels	X	X	X	X	X	X
Emerging Technology - Well-Connected Geothermal Heat Pump	X	X				

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-10 shows several characteristics for each measure: the annual percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, measure life, and commercial availability start year. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-10. Percentage Energy Savings over the Baseline Technology

Measure Name	Energy Savings (%)	Energy Savings (kWh)	Demand Reduction (kW)	Incremental Cost Per Home	Incremental Cost (Per Unit)	Units Per Home	Measure Life
Emerging Technology - Advanced Air-Source Heat Pump	6% - 7%	358 - 680	0.07 - 0.1	$758 - $1,199	$381/heat pump ton	1.9 - 3.1	15
Emerging Technology - Advanced Furnace Fan	17% - 27%	188	0.02	$302	$302/ furnace fan	1	10
Emerging Technology - Advanced Wall Heater	30% - 31%	1,807 - 4,505	-	$78 - $139	$71.50/ 12,000 Btuh electric room heat	1.1 - 2.0	20
Emerging Technology - Electro Caloric Heat Pump	33%	1,791 - 3,657	0.8 - 1.6	$1,997 - $3,156	$1,003/heat pump ton	1.9 - 3.2	15
Emerging Technology - Heat Pump with Integrated Desuperheater	10% - 24%	170 - 318	0.02 - 0.04	1257.65	$1,258/ water heater	1	15
Emerging Technology - Horizontal Drainpipe Heat Exchanger	3% - 10%	50 - 170	0.008 - 0.03	$1,366	$1,366/ drainpipe heat exchanger	1	20
Emerging Technology - Radiant Panels (cool central)	30%	145 - 537	0.2 - 0.8	$28,180-50,018	$27/sq ft	1,271 - 1,352	20
Emerging Technology - Radiant Panels (heat pump, heat central)	30%	1,611 - 6,966	0.7 - 1.5	$28,180-50,019	$27/sq ft	1,271-1,352	20
Emerging Technology - Well-Connected Geothermal Heat Pump	26% - 48%	1,961 - 3,524	0.4 - 0.6	$12,654 - $17,337	$12,654 - $17,337/ home	1	15

Path to Commercialization

The commercialization dates for the residential emerging HVAC heating measures range from 2021 to 2026; however, they face barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Incremental cost

Table C-11 shows the path to commercialization for each measure.

Table C-11. Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Advanced Air-Source Heat Pump	Mid-Term 2026-2030	X		X	X
Emerging Technology - Advanced Furnace Fan	Short-Term 2021-2035			X	X
Emerging Technology - Advanced Wall Heater	Short-Term 2021-2035			X	X
Emerging Technology - Electro Caloric Heat Pump	Long-Term 2036-2040	X	X	X	X
Emerging Technology - Heat Pump with Integrated Desuperheater	Short-Term 2021-2035			X	X
Emerging Technology - Horizontal Drainpipe Heat Exchanger	Short-Term 2021-2035		X	X	X
Emerging Technology - Radiant Panels	Short-Term 2021-2035			X	X
Emerging Technology - Well-Connected Geothermal Heat Pump	Short-Term 2021-2035			X	X

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Residential Emerging Technology: Lighting

Emerging residential lighting measures make up 5% of the 20-year residential portfolio achievable potential.

Bundle Measure Names and Residential Sector Applicability

Table C-12 shows the seven measures in the emerging lighting bundle, as well as the residential sectors in which the measures can be installed.

Table C-12. Residential Emerging Lighting Measure Names and Applicable Segments

Measure Name	Single Family	Single Family Low Income	Multifamily	Multifamily Low Income	Manufactured	Manufactured Low Income
Emerging Technology - Advanced Daylighting	X	X	X	X	X	X
Emerging Technology - General Service Lamp - Advanced Lighting	X	X	X	X	X	X
Emerging Technology - General Service Lamp - Connected LED	X	X	X	X	X	X
Emerging Technology - Linear Lamp - Advanced Lighting	X	X	X	X	X	X
Emerging Technology - Linear Lamp - Connected TLED	X	X	X	X	X	X
Emerging Technology - Specialty Lamp - Advanced Lighting	X	X	X	X	X	X
Emerging Technology - Specialty Lamp - Connected LED	X	X	X	X	X	X

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-13 shows several characteristics for each measure: the annual percentage energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, measure life, and commercial availability start year. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-13. Percentage Energy Savings over the Baseline Technology

Measure Name	Energy Savings (%)	Energy Savings (kWh)	Demand Reduction (kW)	Incremental Cost Per Home	Incremental Cost (Per Unit)	Units Per Home	Measure Life
Emerging Technology - Advanced Daylighting	5%	0.80 - 1.8	0.000001	$6,784 - $12,041.60	$6.5/sq ft	1,044 - 1,852	15
Emerging Technology - General Service Lamp - Advanced Lighting	5%	9.0 - 90.0	0.00001 - 0.00007	$6,784 - $12,041.60	$6.5/sq ft	1,044 - 1,852	15
Emerging Technology - General Service Lamp - Connected LED	16% - 24%	4.3	0.005100	$8	$8.14/lamp	1	15
Emerging Technology - Linear Lamp - Advanced Lighting	10% - 16%	2.6 - 2.7	0.003200	$4	$3.88/lamp	1	15
Emerging Technology - Linear Lamp - Connected TLED	25% - 26%	6.7	0.008200	$218	$217.88/ lamp	1	18
Emerging Technology - Specialty Lamp - Advanced Lighting	15% - 16%	4.1 - 4.2	0.005000	$109	$108.88/ lamp	1	18
Emerging Technology - Specialty Lamp - Connected LED	8% - 13%	2.8	0.003300	$32	$32.19/ lamp	1	15
Emerging Technology - Advanced Daylighting	5% - 8%	1.7	0.002000	$15	$15.34/ lamp	1	15

Path to Commercialization

The commercialization dates for the emerging lighting residential measures range from 2021 to 2036; however, they face barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Incremental cost

Table C-14 shows the path to commercialization for each measure.

Table C-14. Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Advanced Daylighting	Mid-Term 2026-2030	X	X	X	X
Emerging Technology - General Service Lamp - Advanced Lighting	Long-Term 2036-2040	X		X	X
Emerging Technology - General Service Lamp - Connected LED	Short-Term 2021-2025		X	X	
Emerging Technology - Linear Lamp - Advanced Lighting	Long-Term 2036-2040	X		X	X
Emerging Technology - Linear Lamp - Connected TLED	Short-Term 2021-2025		X	X	
Emerging Technology - Specialty Lamp - Advanced Lighting	Long-Term 2036-2040	X		X	X
Emerging Technology - Specialty Lamp - Connected LED	Short-Term 2021-2025		X	X	

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Residential Emerging Technology: Online Services

The emerging technology online services measure makes up 32% of the 20-year residential portfolio achievable potential for emerging technology measures.

Bundle Measure Names and Residential Sector Applicability

Table C-185 shows the one measure in the online services bundle, as well as the residential sectors in which the measure can be installed.

Table C-15. Other Measure Names and Applicable Segments

Measure Name	Single Family	Single Family Low Income	Multifamily	Multifamily Low Income	Manufactured	Manufactured Low Income
Emerging Technology - Web Portal	X	X	X	X	X	X

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-16 shows several characteristics for the measure: the annual percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, measure life, and commercial availability start year. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-16. Percentage Energy Savings over the Baseline Technology

Measure Name	Energy Savings (%)	Energy Savings (kWh)	Demand Reduction (kW)	Incremental Cost Per Home	Incremental Cost (Per Unit)	Units Per Home	Measure Life
Emerging Technology - Web Portal	1.5% - 3.5%	131	0.0007 - 0.02	$2	$2/home	1	1

Path to Commercialization

The web portal measure will be commercially available in 2021; however, it faces barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer awareness of the offering
- Incremental cost (until enough customers enroll to make the offering cost-effective)

Table C-17 shows the path to commercialization for each web portal.

Table C-17. Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Web Portal	Short-Term 2021-2025		X	X	

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Residential Emerging Technology: Other Measures

Emerging technology other measures (other) make up 9% of the 20-year residential portfolio achievable potential for emerging technology measures.

Bundle Measure Names and Residential Sector Applicability

Table C-18 shows the four measures in the other bundle, as well as the residential sectors in which the measures can be installed.

Table C-18. Other Measure Names and Applicable Segments

Measure Name	Single Family	Single Family Low Income	Multifamily	Multifamily Low Income	Manufactured	Manufactured Low Income
Emerging Technology - Dryer - Ultrasonic Clothes Dryer	X	X	X	X	X	X
Emerging Technology - Integrated Design	X	X	X	X	X	X
Emerging Technology - Ozone Laundry System	X	X	X	X	X	X
Emerging Technology - Phase Change Material	X	X	X	X	X	X

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-19 shows several characteristics for each measure: the annual percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, measure life, and commercial availability start year. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-19. Percentage Energy Savings over the Baseline Technology

Measure Name	Energy Savings (%)	Energy Savings (kWh)	Demand Reduction (kW)	Incremental Cost Per Home	Incremental Cost (Per Unit)	Units Per Home	Measure Life
Emerging Technology - Dryer - Ultrasonic Clothes Dryer	9% - 11%	61.1	0.2	$148.91	$149.91/ dryer	1	12
Emerging Technology - Integrated Design (cool room, cool central)	50%	93 - 660	0.0001 - 0.0004	$26,094 - $$46,314	$25/sq ft	1,044 - 1,853	20
Emerging Technology - Integrated Design (heat room, heat pump, heat central)	50%	2,687 - 6,336	0 - 0.001	$26,094 - $$46,314	$25/sq ft	1,044 - 1,853	20
Emerging Technology - Integrated Design (lighting)	50%	9 - 16	0.0001 - 0.0002	$26,094 - $46,315	$25/sq ft	1,044 - 1,853	20
Emerging Technology - Integrated Design (ventilation and circulation)	50%	350	0.00002 - 0.00003	$26,094 - $46,315	$25/sq ft	1,044 - 1,853	20
Emerging Technology - Integrated Design (water heating)	50%	354 - 1,356	0.00003 - 0.0001	$26,094 - $46,315	$25/sq ft	1,044 - 1,853	20
Emerging Technology - Ozone Laundry System	5% - 35%	94.72 - 256.77	0.9	$109 - $297	$297/ system	0.37 - 1.0	5
Emerging Technology - Phase Change Material (cool room, cool central)	18% - 25%	36 - 595	0.06-0.6	$625 - $2,613	$625 - $2,613/ home	1	25
Emerging Technology - Phase Change Material (heat pump, heat room, heat central)	12% - 24%	768 - 5,347	0.0 - 1.1	$625 - $2,615	$625 - $2,613/ home	1	25

Path to Commercialization

The commercialization dates for the emerging lighting residential measures range from 2021 to 2031. They face barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Incremental cost

Table C-20 shows the path to commercialization for each measure.

Table C-20. Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Dryer - Ultrasonic Clothes Dryer	Mid-Term 2026-2030	X		X	X
Emerging Technology - Integrated Design	Long-Term 2031-2035	X	X	X	X
Emerging Technology - Ozone Laundry System	Short-Term 2021-2025			X	X
Emerging Technology - Phase Change Material	Short-Term 2021-2025	X	X	X	X

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Residential Emerging Technology: Shell Measures

Emerging technology shell measures make up 10% of the achievable potential for emerging technology measures.

Bundle Measure Names and Residential Sector Applicability

Table C-21 shows the 10 measures in the shell measures bundle, as well as the residential sectors in which the measures can be installed.

Table C-21. Shell Measure Names and Applicable Segments

Measure Name	Single Family	Single Family Low Income	Multifamily	Multifamily Low Income	Manufactured	Manufactured Low Income
Emerging Technology - Advanced Walls	X	X	X	X	X	X
Emerging Technology - Advanced Windows	X	X	X	X	X	X
Emerging Technology - Basement Wall Insulation - Nanoinsulation	X	X	X	X		
Emerging Technology - Belly Insulation - Nanoinsulation					X	X
Emerging Technology - Ceiling / Attic Insulation - Nanoinsulation	X	X	X	X	X	X
Emerging Technology - Crawlspace Insulation - Nanoinsulation	X	X	X	X	X	X
Emerging Technology - Floor Insulation - Nanoinsulation	X	X	X	X	X	X
Emerging Technology - Rim and Band Joist Insulation - Nanoinsulation	X	X				
Emerging Technology - Wall Insulation - Nanoinsulation	X	X	X	X	X	X
Emerging Technology - Window Cellular Shades	X	X	X	X	X	X

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-22 shows several characteristics for each measure: the annual percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, and measure life. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-22. Percentage Energy Savings over the Baseline Technology

Measure Name	Energy Savings (%)	Energy Savings (kWh)	Demand Reduction (kW)	Incremental Cost Per Home	Incremental Cost (Per Unit)	Units Per Home	Measure Life
Emerging Technology - Advanced Walls (cool central, cool room)	1% - 15%	7 - 27	0.07 - 0.11	$973 - $1,555	$973 - $1,555/ 1,000 sq ft wall area	0.94 - 1.51	25

Measure Name	Energy Savings (%)	Energy Savings (kWh)	Demand Reduction (kW)	Incremental Cost Per Home	Incremental Cost (Per Unit)	Units Per Home	Measure Life
Emerging Technology - Advanced Walls (heat room, heat pump, heat central)	2% - 13%	139 - 838	0.014 - 0.08	$973 - $1,556	$973 - $1,555/ 1,000 sq ft wall area	0.94 - 1.52	25
Emerging Technology - Advanced Windows	0% - 13%	1 - 889	0.0 - 0.1	$3,422 - $6,074	$3,422 - $6,074/per 100 sq ft window area	0.89 - 1.58	30
Emerging Technology - Basement Wall Insulation - Nanoinsulation	0% - 11%	0 - 673	0.0 - 0.0004	$1,233 - $1,421	$1,233 - $1,421/home	1	25
Emerging Technology - Belly Insulation - Nanoinsulation	2% - 36%	10 - 1,947	0.0 - 1.9	$243 - $264	$243 - $263.53/ home	1	25
Emerging Technology - Ceiling/Attic Insulation - Nanoinsulation (cool room, cool central)	1% - 29%	5 - 376	0.01 - 0.33	$2,155 - $10,454	$2,155 - $10,455/home	1	25
Emerging Technology - Ceiling/Attic Insulation - Nanoinsulation (heat room, heat pump heat central)	1% - 51%	73 - 3,974	0.0 - 0.3	$2,155 - $10,455	$2,155 - $10,455/home	1	25
Emerging Technology - Crawlspace Insulation - Nanoinsulation (cool central, cool room)	0.2% - 16%	0 - 120	0	$868 - $1,757	$868 - $1,758/ home	1	25
Emerging Technology - Crawlspace Insulation - Nanoinsulation (heat room, heat pump heat central)	3% - 67%	12- 1,141	(0.01) - (0.0001)	$868 - $1,758	$868 - $1,758/ home	1	25
Emerging Technology - Floor Insulation - Nanoinsulation	0% - 4%	0 - 418	-0.01	$868 - $1,669	$868 - $1,669/ home	1	25
Emerging Technology - Rim and Band Joist Insulation - Nanoinsulation	0.1% - 3%	2.3 - 76	0.0 - 0.04	$142 - $196	$142 - $197/ home	1	25
Emerging Technology - Wall Insulation - Nanoinsulation (cool room, cool central)	1.3% - 28%	14 - 50	0.01 - 0.2	$2,498 - $3,993	$2,498 - $3,993/home	1	25
Emerging Technology - Wall Insulation - Nanoinsulation (heat room, heat pump heat central)	3% - 25%	226 - 1,553	0 - 0.16	$2,498 - $3,994	$2,498 - $3,993/home	1	25
Emerging Technology - Window Cellular Shades (cool room, cool central)	0.06%	10.8 - 142.0	0.03 - 0.2	$1,412 - $2,506	$1,412 - $2,506/ window area sq ft	89.2 - 158.3	15

Measure Name	Energy Savings (%)	Energy Savings (kWh)	Demand Reduction (kW)	Incremental Cost Per Home	Incremental Cost (Per Unit)	Units Per Home	Measure Life
Emerging Technology - Window Cellular Shades (heat pump)	0.02%	107 - 464	0 - 0.04	$1,586 - $1,722	$1,412 - $2,506/ window area sq ft	89.2 - 158.4	15

Path to Commercialization

The commercialization dates for the emerging residential shell measures range from 2021 to 2026; however, they face barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Incremental cost

Table C-23 shows the path to commercialization for each measure.

Table C-23. Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Advanced Walls	Short-Term 2021-2025			X	X
Emerging Technology - Advanced Windows	Mid-Term 2026-2030	X		X	X
Emerging Technology - Basement Wall Insulation - Nanoinsulation	Mid-Term 2026-2030	X	X	X	X
Emerging Technology - Belly Insulation - Nanoinsulation	Mid-Term 2026-2030	X	X	X	X
Emerging Technology - Ceiling / Attic Insulation - Nanoinsulation	Mid-Term 2026-2030	X	X	X	X
Emerging Technology - Crawlspace Insulation - Nanoinsulation	Mid-Term 2026-2030	X	X	X	X
Emerging Technology - Floor Insulation - Nanoinsulation	Mid-Term 2026-2030	X	X	X	X
Emerging Technology - Rim and Band Joist Insulation - Nanoinsulation	Mid-Term 2026-2030	X	X	X	X
Emerging Technology - Wall Insulation - Nanoinsulation	Mid-Term 2026-2030	X	X	X	X
Emerging Technology - Window Cellular Shades	Short-Term 2021-2025			X	X

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Commercial Emerging Technology: Domestic Hot Water

Domestic hot water emerging technologies make up 6% of the 20-year commercial portfolio achievable potential.

Bundle Measure Names and Commercial Sector Applicability

Table C-24 shows the two measures within the domestic hot water bundle, as well as the commercial sectors in which the measures can be installed.

Table C-24. Domestic Hot Water Heater Measure Names and Applicable Segments

Measure Name	Education	Grocery	Health	Lodging	Office	Other	Restaurant	Retail	Warehouse
Emerging Technology - Advanced DHW	X	X	X	X	X	X	X	X	X
Emerging Technology - Multifamily Hot Water System Demand Recirculation Pumps and Controls						X			

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-25 shows several characteristics for each measure: the percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, and measure life. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-25. Percentage Energy Savings over the Baseline Technology

Measure Name	Unit	Energy Savings	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost	Measure Life
Emerging Technology - Advanced Domestic Hot Water - Cooling Direct Expansion	Per building sq ft	26% - 31%	0.10 - 0.93	0.0011 - 0.0013	$18.27	20 Years
Emerging Technology - Advanced Domestic Hot Water - Heat Pump	Per building sq ft	22% - 25%	0.51 - 2.18	0.00047 - 0.002	$18.27	20 Years
Emerging Technology - Advanced Domestic Hot Water - Space Heat	Per building sq ft	40%	1.84 - 5.88	0.00021 - 0.00067	$18.27	20 Years
Emerging Technology - Advanced Domestic Hot Water - Water Heat	Per building sq ft	10% - 22%	0.02 - 0.53	0.000002 - 0.000059	$18.27	20 Years
Emerging Technology - Multifamily Hot Water System Demand Recirculation Pumps and Controls - Water Heat	Per circulator	14%	357	0.0205	$4,662	15 Years

Path to Commercialization

Both measures included in the commercial domestic hot water category are expected to be commercially available by 2026; however, they face barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Lack of established design practices for combined HVAC and domestic hot water systems
- Lack of coordination between trade allies and design professionals across technology types

- Lack of contractor and distributor trust in and understanding of the technology
- Incremental cost

Table C-26 shows the path to commercialization for both commercial domestic hot water measures.

Table C-26. Development Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Advanced Domestic Hot Water	Mid-Term (2026-2030)	X	X	X	
Emerging Technology - Multifamily Hot Water System Demand Recirculation Pumps and Controls	Mid-Term (2026-2030)			X	

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Commercial Emerging Technology: HVAC

HVAC emerging technologies make up 33% of the 20-year commercial portfolio achievable potential.

Bundle Measure Names and Commercial Sector Applicability

Table C-27 shows the 11 measures within the HVAC bundle, as well as the commercial sectors in which the measures can be installed.

Table C-27. Emerging HVAC Names and Applicable Segments

Measure Name	Education	Grocery	Health	Lodging	Office	Other	Restaurant	Retail	Warehouse
Emerging Technology - Advanced Dedicated Outdoor Air System	X	X	X	X	X	X	X	X	X
Emerging Technology - Advanced Duct Sealing	X	X	X	X	X	X	X	X	X
Emerging Technology - Advanced Energy Management System	X	X	X	X	X	X	X	X	X
Emerging Technology - Advanced Envelope	X	X	X	X	X	X	X	X	X
Emerging Technology - Advanced HVAC Controls	X	X	X	X	X	X	X	X	X
Emerging Technology - Advanced HVAC Equipment	X	X	X	X	X	X	X	X	X
Emerging Technology - Advanced Windows	X	X	X	X	X	X	X	X	X
Emerging Technology - Eco-snap Air Conditioning and Do-it-Yourself Ductless Air Conditioning Units	X	X	X	X	X	X	X	X	X
Emerging Technology - Very High Efficiency Dedicated Outdoor Air System	X	X	X	X	X	X	X	X	X
Emerging Technology - Adsorbent Air Filtration	X	X	X	X	X	X	X	X	X
Emerging Technology - Biofeedback Thermostat	X	X	X	X	X	X	X	X	X

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-28 shows several characteristics for each measure: the percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, and measure life. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-28. Percentage Energy Savings over the Baseline Technology

Measure Name	Unit	Energy Savings	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost	Measure Life
Emerging Technology - Advanced Dedicated Outdoor Air System - Cooling Direct Expansion	Per building sq ft	63 - 65%	0.25 - 2.13	0 - 0.0032	$25.37[a]	15 Years
Emerging Technology - Advanced Dedicated Outdoor Air System - Heat Pump	Per building sq ft	52 - 61%	1.39 - 4.31	<0.00001	$25.37	15 Years
Emerging Technology - Advanced Dedicated Outdoor Air System - Space Heat	Per building sq ft	49 - 60%	2.77 - 7.27	0.00032 - 0.00083	$25.37	15 Years
Emerging Technology - Advanced Duct Sealing - Cooling Direct Expansion	Per building sq ft	1 - 4%	0.01 - 0.12	0 - 0.00016	$1.01[d]	10 Years
Emerging Technology - Advanced Duct Sealing - Heat Pump	Per building sq ft	2 - 12%	0.10 - 0.89	0 - 0.00092	$1.01	10 Years
Emerging Technology - Advanced Duct Sealing - Space Heat	Per building sq ft	2 - 14%	0.16 - 1.82	0 - 0.00021	$1.01	10 Years
Emerging Technology - Advanced Emergency Management System - Cooling Chillers	Per building sq ft	15%	0.10 - 0.30	0.000005 - 0.000028	$1.01	15 Years
Emerging Technology - Advanced EMS - Cooling DX	Per building sq ft	15%	0.05 - 0.51	0.00008 - 0.00077	$1.01	15 Years
Emerging Technology - Advanced EMS - Heat Pump	Per building sq ft	15%	0.36 - 1.29	0.00056 - 0.00129	$1.01	15 Years
Emerging Technology - Advanced EMS - Space Heat	Per building sq ft	15%	0.69 - 2.21	0.00008 - 0.00025	$1.01	15 Years
Emerging Technology - Advanced Envelope - Cooling	Per building sq ft	10%	0.02 - 0.30	0.000004 - 0.000458	$3.04	20 Years
Emerging Technology - Advanced Envelope - Heat Pump	Per building sq ft	10%	0.10 - 0.83	0 - 0.00036	$3.04	20 Years
Emerging Technology - Advanced Envelope - Heating	Per building sq ft	10%	0.23 - 1.47	0.000026 - 0.000168	$3.04	20 Years
Emerging Technology - Advanced HVAC Controls - Cooling Chillers	Per building sq ft	13%	0.05 - 0.26	<0.00001	$1.01	5 Years
Emerging Technology - Advanced HVAC Controls - Cooling Direct Expansion	Per building sq ft	13%	0.05 - 0.45	0.00008 - 0.00069	$1.01	5 Years
Emerging Technology - Advanced HVAC Controls - Heat Pump	Per building sq ft	13%	0.30 - 1.09	<0.00001	$1.01	5 Years
Emerging Technology - Advanced HVAC Controls - Space Heat	Per building sq ft	13%	0.60 - 1.91	0.000069 - 0.000218	$1.01	5 Years
Emerging Technology - Advanced HVAC Equipment - Cooling Chillers	Per building sq ft	24 - 29%	0.11 - 0.56	0.00001 - 0.00005	$3.04	15 Years
Emerging Technology - Advanced HVAC Equipment - Cooling Direct Expansion	Per building sq ft	19 - 24%	0.08 - 0.70	0.000095 - 0.000859	$3.04	15 Years
Emerging Technology - Advanced HVAC Equipment - Heat Pump	Per building sq ft	17 - 21%	0.38 - 1.64	0.00035 - 0.00150	$3.04	15 Years
Emerging Technology - Advanced Windows	Per building sq ft	12 - 16%	0.04 - 0.44	<0.00001	$9.74[m]	25 Years
Emerging Technology - Eco-snap Air Conditioner and Do-it-Yourself Ductless Air Conditioner Units - Room Cool	Per room AC (10,000 btuh)	13%	23 - 125	0.000002 - 0.000019	$901.2[p]	15 Years

Measure Name	Unit	Energy Savings	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost	Measure Life
Emerging Technology - Very High Efficiency Dedicated Outdoor Air System - Cooling Direct Expansion	Per building sq ft	39 - 40%	0.16 - 1.31	0.00024 - 0.00199	$15.22[s]	15 Years
Emerging Technology - Very High Efficiency Dedicated Outdoor Air System - Heat Pump	Per building sq ft	32 - 37%	0.85 - 2.65	0.00088 - 0.00274	$15.22	15 Years
Emerging Technology - Very High Efficiency Dedicated Outdoor Air System - Space Heat	Per building sq ft	30 - 37%	1.70 - 4.48	0.00019 - 0.00051	$15.22	15 Years
Emerging Technology - Adsorbent Air Filtration - Cooling Direct Expansion	Per building	15%	648 - 7,581	0.98 - 11.50	$329 - $3,847	15 Years
Emerging Technology - Adsorbent Air Filtration - Heat Pump	Per building	15%	2,696 - 134,151	2.79 - 20.79	$1,368 - $10,210	15 Years
Emerging Technology - Adsorbent Air Filtration - Space Heat	Per building	15%	3,965 - 247,476	14.87 - 139.19	$2,012 - $18,835	15 Years
Emerging Technology - Biofeedback Thermostat - Cooling Direct Expansion	Per thermostat	5%	177 - 1,150	0.27 - 1.74	$162.37	10 Years
Emerging Technology - Biofeedback Thermostat - Heat Pump	Per thermostat	5%	573 - 3,123	0.000004 - 0.000021	$162.37	10 Years
Emerging Technology - Biofeedback Thermostat - Space Heat	Per thermostat	5%	866 - 5,790	0.00	$162.37	10 Years

Path to Commercialization

All measures are expected to be commercially available by 2036. However, they face barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Lack of established design practices for complex HVAC systems
- Lack of coordination between trade allies and design professionals across technology types
- Lack of contractor and distributor trust in and understanding of the technology
- Lack of guidance on code compliance of alternative ventilation solutions
- Incremental cost

Table C-29 shows the path to commercialization for each commercial HVAC measure.

Table C-29. Development Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Advanced Dedicated Outdoor Air System	Long-Term (2031-2040)	X		X	
Emerging Technology - Advanced Duct Sealing	Mid-Term (2026-2040)			X	
Emerging Technology - Advanced Energy Management System	Mid-Term (2026-2040)	X		X	
Emerging Technology - Advanced Envelope	Mid-Term (2026-2040)	X		X	
Emerging Technology - Advanced HVAC Controls	Mid-Term (2026-2040)	X		X	
Emerging Technology - Advanced HVAC Equipment	Near-Term (2021-2040)			X	
Emerging Technology - Advanced Windows	Near-Term (2021-2040)			X	
Emerging Technology - Eco-snap Air Conditioning and Do-it-Yourself Ductless Air Conditioning Units	Near-Term (2021-2040)		X	X	
Emerging Technology - Very High Efficiency Dedicated Outdoor Air System	Near-Term (2021-2031)			X	
Emerging Technology - Adsorbent Air Filtration	Mid-Term (2026-2040)	X	X	X	X
Emerging Technology - Biofeedback Thermostat	Long-Term (2036-2040)	X	X	X	

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Commercial Emerging Technology: IT Systems

Domestic IT emerging technologies make up 3% of the 20-year commercial portfolio achievable potential.

Bundle Measure Names and Commercial Sector Applicability

Table C-30 shows the eight measures within the commercial emerging IT bundle, as well as the commercial sectors in which the measures can be installed.

Table C-30. Commercial Emerging IT System Measure Names and Applicable Segments

Measure Name	Education	Grocery	Health	Lodging	Office	Other	Restaurant	Retail	Warehouse
Emerging Technology - Future Server - Quantum Computing Servers/Data Centers	X	X	X	X	X	X	X	X	X
Emerging Technology - IT Systems - Decommissioning of Unused Servers	X				X	X			
Emerging Technology - IT Systems - Energy Efficient Data Storage Management	X				X	X			
Emerging Technology - IT Systems - Hot or Cold Aisle Configuration	X				X	X			
Emerging Technology - IT Systems - Hot or Cold Aisle Configuration with Containment	X				X	X			
Emerging Technology - IT Systems - Install Misters, Foggers, or Ultrasonic Humidifiers	X				X	X			
Emerging Technology - IT Systems - Server Virtualization/ Consolidation	X				X	X			
Emerging Technology - IT Systems - Uninterruptible Power Supply Upgrade	X				X	X			

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-31 shows several characteristics for each measure: the percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, and measure life. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-31. Percentage Energy Savings over the Baseline Technology

Measure Name	Unit	Energy Savings	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost	Measure Life
Emerging Technology - Future Server - Quantum Computing Servers/Data Centers	Per building	20%	39 - 454	0.007-0.769	$18.27	4 Years
Emerging Technology - IT Systems - Decommissioning of Unused Servers	Per MWh DC load	0.2 - 0.9%	67.1	0	$2.25	5 Years
Emerging Technology - IT Systems - Energy Efficient Data Storage Management	Per MWh DC Load	0.2 - 0.8%	55.8	0	$4.37	5 Years
Emerging Technology - IT Systems - Hot or Cold Aisle Configuration	Per MWh DC load	<0.1%	1.3	0	$0.24	10 Years
Emerging Technology - IT Systems - Hot or Cold Aisle Configuration with Containment	Per MWh DC load	<0.1%	2.6	0	$0.59	10 Years
Emerging Technology - IT Systems - Install Misters, Foggers, or Ultrasonic Humidifiers	Per MWh DC load	<0.1%	2.6	0	$1.04	10 Years
Emerging Technology - IT Systems - Server Virtualization/ Consolidation	Per MWh DC load	1.0% - 4.2%	301.1	0	$26.97	5 Years
Emerging Technology - IT Systems - Uninterruptible Power Supply Upgrade	Per MWh DC load	0.1% - 0.6%	44.3	0	$19.10	15 Years

Path to Commercialization

All the measures in the commercial emerging IT systems category, with the exception of quantum computing, are expected to be commercially available by 2021; however, they face barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Lack of contractor and distributor trust in and understanding of the technology
- Lack of established distribution channels to serve affected customers
- Incremental cost

Table C-32 shows the path to commercialization for each commercial emerging IT systems measure.

Table C-32. Development Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Future Server - Quantum Computing Servers/Data Centers	Long-Term (2031-2035)	X			
Emerging Technology - IT Systems - Decommissioning of Unused Servers	Near-Term (2021-2025)		X	X	

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - IT Systems - Energy Efficient Data Storage Management	Near-Term (2021-2025)			X	
Emerging Technology - IT Systems - Hot or Cold Aisle Configuration	Near-Term (2021-2025)			X	
Emerging Technology - IT Systems - Hot or Cold Aisle Configuration with Containment	Near-Term (2021-2025)			X	
Emerging Technology - IT Systems - Install Misters, Foggers, or Ultrasonic Humidifiers	Near-Term (2021-2025)			X	
Emerging Technology - IT Systems - Server Virtualization/ Consolidation	Near-Term (2021-2025)			X	
Emerging Technology - IT Systems - Uninterruptible Power Supply Upgrade	Near-Term (2021-2025)			X	

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Commercial Emerging Technology: Lighting

Emerging lighting technologies make up 9% of the 20-year commercial portfolio achievable potential.

Bundle Measure Names and Residential Sector Applicability

Table C-33 shows the two measures within the commercial emerging lighting bundle, as well as the commercial sectors in which the measures can be installed.

Table C-33. Commercial Emerging Lighting Measure Names and Applicable Segments

Measure Name	Education	Grocery	Health	Lodging	Office	Other	Restaurant	Retail	Warehouse
Emerging Technology - Advanced Daylighting Controls	X	X	X	X	X	X	X	X	X
Emerging Technology - Future Lighting - Perovskite LEDs	X	X	X	X	X	X	X	X	X

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-34 shows several measure characteristics for each measure: the percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, and measure life. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-34. Percentage Energy Savings over the Baseline Technology

Measure Name	Unit	Energy Savings	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost	Measure Life
Emerging Technology - Advanced Daylighting Controls	Per building sq ft	2% - 6%	0.15 - 1.05	0 - 0.0004	$3.04	30 Years
Emerging Technology - Future Lighting - Perovskite LEDs	Per building sq ft	14%	1.0	0.00018	$0.41	15 Years

Path to Commercialization

Both measures are expected to be commercially available by 2036; however, they face barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer awareness of the technology and understanding of the required integration of advanced lighting controls with other building systems
- Incremental cost and coordination required to maximize the benefits of advanced lighting controls

Table C-35 shows the path to commercialization for both commercial lighting measures.

Table C-35. Development Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Advanced Daylighting Controls	Mid-Term (2026-2030)		X	X	
Emerging Technology - Future Lighting - Perovskite LEDs	Long-Term (2036-2040)	X		X	

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Commercial Emerging Technology: Other Technologies

Commercial emerging other technologies make up 13% of the 20-year commercial portfolio achievable potential.

Bundle Measure Names and Commercial Sector Applicability

Table C-36 shows the seven measures within the other emerging technology bundle, as well as the commercial sectors in which the measures can be installed.

Table C-36. Commercial Emerging Other Technology Measure Names and Applicable Segments

Measure Name	Education	Grocery	Health	Lodging	Office	Other	Restaurant	Retail	Warehouse
Emerging Technology - Advanced Food Service	X	X	X	X	X	X	X	X	X
Emerging Technology - Advanced Laundry	X	X	X	X	X	X	X	X	X
Emerging Technology - Advanced Motors	X	X	X	X	X	X	X	X	X
Emerging Technology - CO2 Laundry - Front Loading	X	X	X	X	X	X	X	X	X
Emerging Technology - CO2 Laundry - Top Loading	X	X	X	X	X	X	X	X	X
Emerging Technology - Commercial Behavioral	X	X	X	X	X	X	X	X	X
Emerging Technology - Spring-Loaded Garage Door Hinges	X	X	X	X	X	X	X	X	X

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-37 shows several characteristics for each measure: the percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, and measure life. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-37. Percentage Energy Savings over the Baseline Technology

Measure Name	Unit	Energy Savings	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost	Measure Life
Emerging Technology - Advanced Food Service	Per cooking appliance	0.1 - 0.6%	525[a]	0.0969	$7,104 [a]	12 Years
Emerging Technology - Advanced Laundry	Per dryer	29 - 33%	229.88	0.006	$882	12 Years
Emerging Technology - Advanced Motors	Per HP	11.8%	1,204.65	0.109	$304	15 Years
Emerging Technology - CO2 Laundry - Front Loading	Per commercial washer	0 - 19%	15,278	0.391	$142,072	10 Years
Emerging Technology - CO2 Laundry - Top Loading	Per commercial washer	0 - 16%	13,015	0.333	$142,072	10 Years

Measure Name	Unit	Energy Savings	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost	Measure Life
Emerging Technology - Commercial Behavioral (chillers, direct expansion, PTAC, room cool) [h]	Per commercial account	0.25%	7.48 - 126	0.002 - 0.027	$10.15	1 Year
Emerging Technology - Commercial Behavioral (room eat, space heat)	Per commercial account	0.25%	45.59 - 619	0.010 - 0.133	$10.15	1 Year
Emerging Technology - Commercial Behavioral (heat pump, PTHP)	Per commercial account	0.25%	29.51 - 336	0.006 - 0.072	$10.15	1 Year
Emerging Technology - Commercial Behavioral (exterior lighting, interior lighting)	Per commercial account	0.25%	0.09 - 218	0 - 0.047	$10.15	1 Year
Emerging Technology - Commercial Behavioral (other end uses)	Per commercial account	0.25%	0 - 880	0 - 0.189	$10.15	1 Year
Emerging Technology - Spring-Loaded Garage Door Hinges (heat pump, room heat, space heat)	Per garage door	1%	316 - 10,127	0 - 4	$200.70	20 Years

Path to Commercialization

All seven measures in the commercial emerging other technologies category are expected to be commercially available by 2031; however, they face barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Lack of contractor and distributor trust in and understanding of the technology
- Lack of established distribution channels to serve affected customers
- Lack of regulatory acceptance of behavioral savings
- Delivery cost considerations for behavioral savings
- Incremental cost

Table C-38 shows the path to commercialization for each commercial other measure.

Table C-38. Development Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Advanced Food Service	Near-Term (2021-2025)			X	
Emerging Technology - Advanced Laundry	Mid-Term (2026-2030)			X	
Emerging Technology - Advanced Motors	Mid-Term (2026-2030)			X	
Emerging Technology - CO2 Laundry - Front Loading	Near-Term (2021-2025)	X	X	X	
Emerging Technology - CO2 Laundry - Top Loading	Near-Term (2021-2025)	X	X	X	
Emerging Technology - Commercial Behavioral	Long-Term (2031-2035)		X		X
Emerging Technology - Spring-Loaded Garage Door Hinges	Near-Term (2021-2025)			X	

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Commercial Emerging Technology: Refrigeration

Commercial emerging refrigeration technologies make up 15% of the 20-year commercial portfolio achievable potential.

Bundle Measure Names and Commercial Sector Applicability

Table C-39 shows the two measures within the commercial emerging refrigeration bundle, as well as the commercial sectors in which the measures can be installed.

Table C-39. Commercial Emerging Refrigeration Measure Names and Applicable Segments

Measure Name	Education	Grocery	Health	Lodging	Office	Other	Restaurant	Retail	Warehouse
Emerging Technology - Advanced Refrigeration/CO2 Systems	X	X	X	X	X	X	X	X	X
Emerging Technology - Aerofoils for Open Display Cases	X	X	X	X		X	X	X	

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-40 shows several characteristics for each measure: the percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, and measure life. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-40. Percentage Energy Savings over the Baseline Technology

Measure Name	Unit	Energy Savings	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost	Measure Life
Emerging Technology - Advanced Refrigeration/CO2 Systems	Per building	12.5% [a]	310.9 - 4,4004	0.035 - 5.012	$13,263 - 108,660	20 Years
Emerging Technology - Aerofoils for Open Display Cases	Per refrigerated case	0.3 - 20.3%	4,588	0.3764	$311.54	10 Years

Path to Commercialization

Both measures included in the commercial refrigeration category are expected to be commercially available by 2021 or 2026; however, they face barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Lack of established design practices for combined HVAC and domestic hot water systems
- Lack of contractor and distributor trust in and understanding of the technology
- Lack of established distribution channels
- Incremental cost

Table C-41 shows the path to commercialization for each commercial refrigeration measure.

Table C-41. Development Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Advanced Refrigeration/CO2 Systems	Mid-Term (2026-2030)		X	X	
Emerging Technology - Aerofoils for Open Display Cases	Near-Term (2021-2025)			X	

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Industrial Emerging Technology: Agricultural

Industrial emerging agricultural technologies make up 5% of the 20-year industrial portfolio achievable potential.

Bundle Measure Names and Industrial Sector Applicability

Table C-42 shows the 13 measures within the emerging agricultural bundle, as well as the industrial sectors in which the measures can be installed.

Table C-42. Industrial Emerging Agricultural Measure Names and Applicable Segments

Measure Name	Apparel	Beverage and Tobacco	Chemical	Computer and Electronics	Electrical Equipment	Fabricated Metal Products	Food Manufacturing	Furniture Manufacturing	Industrial Machinery	Leather	Misc.	Nonmetallic Mineral	Paper Manufacturing	Petroleum Coal Products	Plastics Rubber Products	Primary Metal Manufacturing	Printing Related Support	Textile Mills	Textile Product Mills	Transportation Equipment Mfg.	Wood Product Manufacturing	Wastewater	Water	Mining	Agriculture
Emerging Technology - Future Dairy - Lighting Efficiency Improvement																									X
Emerging Technology - Future Dairy - Other Efficiency Improvement																									X
Emerging Technology - Future Dairy - Process Refrigeration and Cooling Efficiency Improvement																									X
Emerging Technology - Future Dairy - Pumps Efficiency Improvement																									X
Emerging Technology - Future Dairy - Ventilation Efficiency Improvement																									X
Emerging Technology - Future Dairy - Water Heat Efficiency Improvement																									X
Emerging Technology - Future Irrigation - Pumps Efficiency Improvement																									X

Measure Name	Apparel	Beverage and Tobacco	Chemical	Computer and Electronics	Electrical Equipment	Fabricated Metal Products	Food Manufacturing	Furniture Manufacturing	Industrial Machinery	Leather	Misc.	Nonmetallic Mineral	Paper Manufacturing	Petroleum Coal Products	Plastics Rubber Products	Primary Metal Manufacturing	Printing Related Support	Textile Mills	Textile Product Mills	Transportation Equipment Mfg.	Wood Product Manufacturing	Wastewater	Water	Mining	Agriculture
Emerging Technology - Future Miscellaneous Ag - Lighting Efficiency Improvement																									X
Emerging Technology - Future Miscellaneous Ag - Other Efficiency Improvement																									X
Emerging Technology - Future Miscellaneous Ag - Process Refrigeration and Cooling Efficiency Improvement																									X
Emerging Technology - Future Miscellaneous Ag - Pumps Efficiency Improvement																									X
Emerging Technology - Future Miscellaneous Ag - Ventilation Efficiency Improvement																									X
Emerging Technology - Future Miscellaneous Ag - Water Heat Efficiency Improvement																									X

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-43 shows several characteristics for each measure: the percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, and measure life. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-43. Percentage Energy Savings over the Baseline Technology

Measure Name	Unit	Energy Savings	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost	Measure Life
Emerging Technology - Future Dairy - Lighting Efficiency Improvement	Per site	20%	8,182,943	0	$3,272,177	10 Years
Emerging Technology - Future Dairy - Other Efficiency Improvement	Per site	20%	9,463,964	0	$3,785,586	10 Years
Emerging Technology - Future Dairy - Process Refrigeration and Cooling Efficiency Improvement	Per site	20%	1,506,902	0	$602,761	10 Years
Emerging Technology - Future Dairy - Pumps Efficiency Improvement	Per site	20%	37,086,150	0	$14,834,460	10 Years
Emerging Technology - Future Dairy - Ventilation Efficiency Improvement	Per site	20%	28,271,340	0	$11,308,536	10 Years
Emerging Technology - Future Dairy - Water Heat Efficiency Improvement	Per site	20%	2,486,543	0	$994,617	10 Years
Emerging Technology - Future Irrigation - Pumps Efficiency Improvement	Per site	20%	37,086,150	0	$14,834,460	10 Years
Emerging Technology - Future Miscellaneous Ag - Lighting Efficiency Improvement	Per site	20%	8,182,943	0	$3,273,177	10 Years
Emerging Technology - Future Miscellaneous Ag - Other Efficiency Improvement	Per site	20%	9,463,964	0	$3,785,586	10 Years
Emerging Technology - Future Miscellaneous Ag - Process Refrigeration and Cooling Efficiency Improvement	Per site	20%	1,506,902	0	$602,761	10 Years
Emerging Technology - Future Miscellaneous Ag - Pumps Efficiency Improvement	Per site	20%	37,086,150	0	$14,834,460	10 Years
Emerging Technology - Future Miscellaneous Ag - Ventilation Efficiency Improvement	Per site	20%	28,271,340	0	$11,308,536	10 Years
Emerging Technology - Future Miscellaneous Ag - Water Heat Efficiency Improvement	Per site	20%	2,486,543	0	$4994,617	10 Years

Path to Commercialization

All 13 measures included in the industrial agricultural measure technologies category are expected to be commercially available by 2031; however, they face barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Lack of established distribution channels to serve affected customers
- Incremental cost

Table C-44 shows the path to commercialization for each industrial agricultural measure.

Table C-44. Development Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Future Dairy - Lighting Efficiency Improvement	Long-Term (2031-2035)	X			
Emerging Technology - Future Dairy - Other Efficiency Improvement	Long-Term (2031-2035)	X			
Emerging Technology - Future Dairy - Process Refrigeration and Cooling Efficiency Improvement	Long-Term (2031-2035)	X			
Emerging Technology - Future Dairy - Pumps Efficiency Improvement	Long-Term (2031-2035)	X			
Emerging Technology - Future Dairy - Ventilation Efficiency Improvement	Long-Term (2031-2035)	X			
Emerging Technology - Future Dairy - Water Heat Efficiency Improvement	Long-Term (2031-2035)	X			
Emerging Technology - Future Irrigation - Pumps Efficiency Improvement	Long-Term (2031-2035)	X			
Emerging Technology - Future Miscellaneous Ag - Lighting Efficiency Improvement	Long-Term (2031-2035)	X			
Emerging Technology - Future Miscellaneous Ag - Other Efficiency Improvement	Long-Term (2031-2035)	X			
Emerging Technology - Future Miscellaneous Ag - Process Refrigeration and Cooling Efficiency Improvement	Long-Term (2031-2035)	X			
Emerging Technology - Future Miscellaneous Ag - Pumps Efficiency Improvement	Long-Term (2031-2035)	X			
Emerging Technology - Future Miscellaneous Ag - Ventilation Efficiency Improvement	Long-Term (2031-2035)	X			
Emerging Technology - Future Miscellaneous Ag - Water Heat Efficiency Improvement	Long-Term (2031-2035)	X			

Bibliography

PSE's PY2016/17 Commercial Rebate and New Construction Programs, Council (7th Plan) assumptions, Evan Mills (DOE), Manifest Mind report and other secondary sources. This data was also informed by communications with Brad Queen (CubeResourses) and Aaron Block (Allumia), as well as by one Colorado site visit and one survey response, plus one additional site visit and online survey conducted in Colorado. The team updated the customer account forecast for 2020 (no new customers), updated values to 2020 dollars with adjusted LED costs using 2021 Council data of LED cost forecast, and updated to the account level for PSE accomplishments.

Industrial Emerging Technology: Fans

Industrial emerging fan technologies make up 2% of the 20-year industrial portfolio achievable potential.

Bundle Measure Names and Industrial Sector Applicability

Table C-475 shows the one measure within the emerging fans bundle, as well as the industrial sectors in which the measure can be installed.

Table C-45. Industrial Emerging Technology Fan Measure Names and Applicable Segments

Measure Name	Apparel	Beverage and Tobacco	Chemical	Computer and Electronics	Electrical Equipment	Fabricated Metal Products	Food Manufacturing	Furniture Manufacturing	Industrial Machinery	Leather	Misc.	Nonmetallic Mineral	Paper Manufacturing	Petroleum Coal Products	Plastics Rubber Products	Primary Metal Manufacturing	Printing Related Support	Textile Mills	Textile Product Mills	Transportation Equipment Mfg.	Wood Product Manufacturing	Wastewater	Water	Mining	Agriculture
Emerging Technology - Advanced Motor - Fans	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-46 shows several characteristics for the measure: the percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, and measure life. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-46. Percentage Energy Savings over the Baseline Technology

Measure Name	Unit	Energy Savings	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost [a]	Measure Life
Emerging Technology - Advanced Motor - Fans	Per site	5%	0 - 5,166,509	0 - 746.939	$0 - 1,676710	20 Years

Path to Commercialization

The one measure in the industrial emerging fans category is expected to be commercially available by 2026; however, it faces barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Lack of contractor and distributor trust in and understanding of the technology
- Incremental cost

Table C-47 shows the path to commercialization for the industrial emerging fan measure.

Table C-47. Development Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Advanced Motor - Fans	Mid-Term (2026-2030)	X			

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[a] For this value, the team assumed future advancement through either existing technology (just reconfigured) or emerging technologies improvements on process end uses. The team added emerging technology measures for transformational potential. Based on DNV GL conversations, process improvements will continually evolve and are unlikely to decline. These emerging technology bundles include both existing and new technologies that will advance process improvements. DNV GL indicated that process improvements combined will account for 50% of the Consumers Energy program savings.

Industrial Emerging Technology: Indoor Agricultural

Industrial indoor agricultural emerging technologies, that address multiple end-uses, make up 4% of the 20-year industrial portfolio achievable potential.

Bundle Measure Names and Industrial Sector Applicability

Table C-48 shows the 18 measures within the emerging indoor agricultural bundle, as well as the industrial sectors in which the measures can be installed.

Table C-48. Industrial Emerging Indoor Agricultural Measure Names and Applicable Segments

Measure Name	Apparel	Beverage and Tobacco	Chemical	Computer and Electronics	Electrical Equipment	Fabricated Metal Products	Food Manufacturing	Furniture Manufacturing	Industrial Machinery	Leather	Misc.	Nonmetallic Mineral	Paper Manufacturing	Petroleum Coal Products	Plastics Rubber Products	Primary Metal Manufacturing	Printing Related Support	Textile Mills	Textile Product Mills	Transportation Equipment Mfg.	Wood Product Manufacturing	Wastewater	Water	Mining	Agriculture
Emerging Technology - Future Indoor Agriculture - Production Facility Grower A - Dehumidification - Indoor Ag Efficiency Improvement																									X
Emerging Technology - Future Indoor Agriculture - Production Facility Grower A - HVAC - Indoor Ag Efficiency Improvement																									X
Emerging Technology - Future Indoor Agriculture - Production Facility Grower A - Lighting - Indoor Ag Efficiency Improvement																									X
Emerging Technology - Future Indoor Agriculture - Production Facility Grower B - Dehumidification - Indoor Ag Efficiency Improvement																									X

Measure Name	Apparel	Beverage and Tobacco	Chemical	Computer and Electronics	Electrical Equipment	Fabricated Metal Products	Food Manufacturing	Furniture Manufacturing	Industrial Machinery	Leather	Misc.	Nonmetallic Mineral	Paper Manufacturing	Petroleum Coal Products	Plastics Rubber Products	Primary Metal Manufacturing	Printing Related Support	Textile Mills	Textile Product Mills	Transportation Equipment Mfg.	Wood Product Manufacturing	Wastewater	Water	Mining	Agriculture
Emerging Technology - Future Indoor Agriculture - Production Facility Grower B - HVAC - Indoor Ag Efficiency Improvement																									X
Emerging Technology - Future Indoor Agriculture - Production Facility Grower B - Lighting - Indoor Ag Efficiency Improvement																									X
Emerging Technology - Future Indoor Agriculture - Production Facility Grower C - Dehumidification - Indoor Ag Efficiency Improvement																									X
Emerging Technology - Future Indoor Agriculture - Production Facility Grower C - HVAC - Indoor Ag Efficiency Improvement																									X
Emerging Technology - Future Indoor Agriculture - Production Facility Grower C - Lighting - Indoor Ag Efficiency Improvement																									X
Emerging Technology - Indoor Agriculture - Production Facility Grower A - Dehumidification System																									X
Emerging Technology - Indoor Agriculture - Production Facility Grower A - LED Lighting																									X
Emerging Technology - Indoor Agriculture - Production Facility Grower A - VRF Heat Pump																									X

Measure Name	Apparel	Beverage and Tobacco	Chemical	Computer and Electronics	Electrical Equipment	Fabricated Metal Products	Food Manufacturing	Furniture Manufacturing	Industrial Machinery	Leather	Misc.	Nonmetallic Mineral	Paper Manufacturing	Petroleum Coal Products	Plastics Rubber Products	Primary Metal Manufacturing	Printing Related Support	Textile Mills	Textile Product Mills	Transportation Equipment Mfg.	Wood Product Manufacturing	Wastewater	Water	Mining	Agriculture
Emerging Technology - Indoor Agriculture - Production Facility Grower B - Dehumidification System																									X
Emerging Technology - Indoor Agriculture - Production Facility Grower B - LED Lighting																									X
Emerging Technology - Indoor Agriculture - Production Facility Grower B - VRF Heat Pump																									X
Emerging Technology - Indoor Agriculture - Production Facility Grower C - Dehumidification System																									X
Emerging Technology - Indoor Agriculture - Production Facility Grower C - LED Lighting																									X
Emerging Technology - Indoor Agriculture - Production Facility Grower C - VRF Heat Pump																									X

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-49 shows several characteristics for each measure: the percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, and measure life. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-49. Percentage Energy Savings over the Baseline Technology

Measure Name	Unit	Energy Savings	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost	Measure Life
Emerging Technology - Future Indoor Agriculture - Production Facility Grower A - Dehumidification - Indoor Ag Efficiency Improvement	Per site	2%	377,486	0	$150,994	10 Years
Emerging Technology - Future Indoor Agriculture - Production Facility Grower A - HVAC - Indoor Ag Efficiency Improvement	Per site	2%	629,143	0	$251,657	10 Years
Emerging Technology - Future Indoor Agriculture - Production Facility Grower A - Lighting - Indoor Ag Efficiency Improvement	Per site	2%	1,384,115	0	$553,646	10 Years
Emerging Technology - Future Indoor Agriculture - Production Facility Grower B - Dehumidification - Indoor Ag Efficiency Improvement	Per site	1%	107,853	0	$43,141	10 Years
Emerging Technology - Future Indoor Agriculture - Production Facility Grower B - HVAC - Indoor Ag Efficiency Improvement	Per site	1%	179,755	0	$71,902	10 Years
Emerging Technology - Future Indoor Agriculture - Production Facility Grower B - Lighting - Indoor Ag Efficiency Improvement	Per site	1%	395,461	0	$158,185	10 Years
Emerging Technology - Future Indoor Agriculture - Production Facility Grower C - Dehumidification - Indoor Ag Efficiency Improvement	Per site	17%	2,660,377	0	$1,064,151	10 Years
Emerging Technology - Future Indoor Agriculture - Production Facility Grower C - HVAC - Indoor Ag Efficiency Improvement	Per site	17%	4,433,961	0	$1,773,584	10 Years
Emerging Technology - Future Indoor Agriculture - Production Facility Grower C - Lighting - Indoor Ag Efficiency Improvement	Per site	17%	9,754,715	0	$3,901,886	10 Years
Emerging Technology - Indoor Agriculture - Production Facility Grower A - Dehumidification System	Per site	2%	251,699	0	$39,620	10 Years
Emerging Technology - Indoor Agriculture - Production Facility Grower A - LED Lighting	Per site	5%	3,075,811	486.886	$1,256,642	4 Years

Measure Name	Unit	Energy Savings	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost	Measure Life
Emerging Technology - Indoor Agriculture - Production Facility Grower A - VRF Heat Pump	Per site	3%	913,736	0	$357,271	20 Years
Emerging Technology - Indoor Agriculture - Production Facility Grower B - Dehumidification System	Per site	1%	94,829	0	$15,544	10 Years
Emerging Technology - Indoor Agriculture - Production Facility Grower B - LED Lighting	Per site	2%	878,803	139.110	$359,041	4 Years
Emerging Technology - Indoor Agriculture - Production Facility Grower B - VRF Heat Pump	Per site	1%	261,067	0	$102,077	20 Years
Emerging Technology - Indoor Agriculture - Production Facility Grower C - Dehumidification System	Per site	30%	4,678,270	0	$285,569	10 Years
Emerging Technology - Indoor Agriculture - Production Facility Grower C - LED Lighting	Per site	38%	21,677,144	3,431.390	$8,856,337	4 Years
Emerging Technology - Indoor Agriculture - Production Facility Grower C - VRF Heat Pump	Per site	20%	5,246,151	0	$2,517,910	20 Years

Path to Commercialization

All 18 measures included in the industrial indoor agriculture category are expected to be commercially available by 2031; however, they face barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Lack of established distribution channels to serve affected customers
- Lack of customer trust in and understanding of the technology
- Incremental cost

Table C-50 shows the path to commercialization for each industrial indoor agriculture measure.

Table C-50. Development Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Future Indoor Agriculture - Production Facility Grower A - Dehumidification - Indoor Ag Efficiency Improvement	Long-Term (2031-2035)	X		X	
Emerging Technology - Future Indoor Agriculture - Production Facility Grower A - HVAC - Indoor Ag Efficiency Improvement	Long-Term (2031-2035)	X		X	
Emerging Technology - Future Indoor Agriculture - Production Facility Grower A - Lighting - Indoor Ag Efficiency Improvement	Long-Term (2031-2035)	X		X	
Emerging Technology - Future Indoor Agriculture - Production Facility Grower B - Dehumidification - Indoor Ag Efficiency Improvement	Long-Term (2031-2035)	X		X	
Emerging Technology - Future Indoor Agriculture - Production Facility Grower B - HVAC - Indoor Ag Efficiency Improvement	Long-Term (2031-2035)	X		X	
Emerging Technology - Future Indoor Agriculture - Production Facility Grower B - Lighting - Indoor Ag Efficiency Improvement	Long-Term (2031-2035)	X		X	
Emerging Technology - Future Indoor Agriculture - Production Facility Grower C - Dehumidification - Indoor Ag Efficiency Improvement	Long-Term (2031-2035)	X		X	
Emerging Technology - Future Indoor Agriculture - Production Facility Grower C - HVAC - Indoor Ag Efficiency Improvement	Long-Term (2031-2035)	X		X	
Emerging Technology - Future Indoor Agriculture - Production Facility Grower C - Lighting - Indoor Ag Efficiency Improvement	Long-Term (2031-2035)	X		X	
Emerging Technology - Indoor Agriculture - Production Facility Grower A - Dehumidification System	Near-Term (2021-2025)			X	
Emerging Technology - Indoor Agriculture - Production Facility Grower A - LED Lighting	Near-Term (2021-2025)			X	
Emerging Technology - Indoor Agriculture - Production Facility Grower A - VRF Heat Pump	Near-Term (2021-2025)			X	
Emerging Technology - Indoor Agriculture - Production Facility Grower B - Dehumidification System	Near-Term (2021-2025)			X	
Emerging Technology - Indoor Agriculture - Production Facility Grower B - LED Lighting	Near-Term (2021-2025)			X	

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Indoor Agriculture - Production Facility Grower B - VRF Heat Pump	Near-Term (2021-2025)			X	
Emerging Technology - Indoor Agriculture - Production Facility Grower C - Dehumidification System	Near-Term (2021-2025)			X	
Emerging Technology - Indoor Agriculture - Production Facility Grower C - LED Lighting	Near-Term (2021-2025)			X	
Emerging Technology - Indoor Agriculture - Production Facility Grower C - VRF Heat Pump	Near-Term (2021-2025)			X	

Bibliography

PSE's PY2016/17 Commercial Rebate and New Construction Programs, Council (7th Plan) assumptions, Evan Mills (DOE), Manifest Mind report and other secondary sources. This data was also informed by communications with Brad Queen (CubeResourses) and Aaron Block (Allumia), as well as by one Colorado site visit and one survey response, plus one additional site visit and online survey conducted in Colorado. The team updated the customer account forecast for 2020 (no new customers), updated values to 2020 dollars with adjusted LED costs using 2021 Council data of LED cost forecast, and updated to the account level for PSE accomplishments.

Industrial Emerging Technology: Lighting

Industrial emerging lighting technologies make up 8% of the 20-year industrial portfolio achievable potential.

Bundle Measure Names and Industrial Sector Applicability

Table C-51 shows the one measure within the industrial emerging lighting bundle, as well as the industrial sectors in which the measure can be installed.

Table C-51. Industrial Emerging Lighting Measure Names and Applicable Segments

Measure Name	Apparel	Beverage and Tobacco	Chemical	Computer and Electronics	Electrical Equipment	Fabricated Metal Products	Food Manufacturing	Furniture Manufacturing	Industrial Machinery	Leather	Misc.	Nonmetallic Mineral	Paper Manufacturing	Petroleum Coal Products	Plastics Rubber Products	Primary Metal Manufacturing	Printing Related Support	Textile Mills	Textile Product Mills	Transportation Equipment Mfg.	Wood Product Manufacturing	Wastewater	Water	Mining	Agriculture
Emerging Technology - Advanced Lighting Controls	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-52 shows several characteristics for the measure: the percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, and measure life. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-52. Percentage Energy Savings over the Baseline Technology

Measure Name	Unit	Energy Savings	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost	Measure Life
Emerging Technology - Advanced Lighting Controls	Per site	42%	0 - 80,790,515	0 - 11,680.143	$0 - 181,771,987	8 Years

Path to Commercialization

The one measure in the industrial emerging lighting category is expected to be commercially available by 2021; however, it faces barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Lack of contractor and distributor trust in and understanding of the technology
- Incremental cost

Table C-53 shows the path to commercialization for the industrial emerging lighting measure.

Table C-53. Development Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Advanced Lighting Controls	Near-Term (2021-2025)			X	

Bibliography

Michigan Public Service Commission (supplied by Morgan Marketing Partners). Accessed 2020 version. “Michigan Energy Measures Database.” https://michigan.gov/mpsc/0,9535,7-395-93309_94801_94808_94811---,00.html

Industrial Emerging Technology: Motors

Industrial motors emerging technologies make up 6% of the 20-year industrial portfolio achievable potential.

Bundle Measure Names and Industrial Sector Applicability

Table C-54 shows the one measure within the industrial motors bundle, as well as the industrial sectors in which the measure can be installed.

Table C-54. Industrial Motors Measure Names and Applicable Segments

Measure Name	Apparel	Beverage and Tobacco	Chemical	Computer and Electronics	Electrical Equipment	Fabricated Metal Products	Food Manufacturing	Furniture Manufacturing	Industrial Machinery	Leather	Misc.	Nonmetallic Mineral	Paper Manufacturing	Petroleum Coal Products	Plastics Rubber Products	Primary Metal Manufacturing	Printing Related Support	Textile Mills	Textile Product Mills	Transportation Equipment Mfg.	Wood Product Manufacturing	Wastewater	Water	Mining	Agriculture
Emerging Technology - Advanced Motor - Motors Other	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-55 shows several characteristics for the measure: the percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, and measure life. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-55. Percentage Energy Savings over the Baseline Technology

Measure Name	Unit	Energy Savings	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost	Measure Life
Emerging Technology - Advanced Motor - Motors Other	Per site	5% [a]	0 – 11,684,177	0 - 1,689.289	$0 - 3,791,917 [b]	20 Years

[a] The Cadmus team assumed future advancement through either existing technology (just reconfigured) or emerging technology improvements on process end uses. The team added existing technology measures for transformational potential. Based on DNV GL conversations, process improvements will continually evolve and are unlikely to decline. These existing technology bundles include both existing and new technologies that will advance process improvements. DNV GL indicated that process improvements combined will account for 50% of the Consumers Energy program savings.
[b] The team assumed incremental cost would be twice the average current costs.

Path to Commercialization

The one measure in the industrial emerging motors category is expected to be commercially available by 2026. However, it faces barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Incremental cost
- Lack of established distribution channels to serve affected customers

Table C-56 shows the path to commercialization for the industrial motor measure.

Table C-56. Development Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Advanced Motor - Motors Other	Mid-Term (2026-2030)	X		X	

Bibliography

Minnesota Department of Commerce. January 1, 2020. “C/I Motors.” *Minnesota Technical Reference Manual, Version 3.0.* https://mn.gov/commerce/industries/energy/utilities/cip/technical-reference-manual/

Industrial Emerging Technology: Process

Industrial emerging process technologies make up 20% of the 20-year industrial portfolio achievable potential.

Bundle Measure Names and Industrial Sector Applicability

Table C-57 shows the five measures within the industrial emerging process bundle, as well as the industrial sectors in which the measures can be installed.

Table C-57. Industrial Emerging Process Measure Names and Applicable Segments

Measure Name	Apparel	Beverage and Tobacco	Chemical	Computer and Electronics	Electrical Equipment	Fabricated Metal Products	Food Manufacturing	Furniture Manufacturing	Industrial Machinery	Leather	Misc.	Nonmetallic Mineral	Paper Manufacturing	Petroleum Coal Products	Plastics Rubber Products	Primary Metal Manufacturing	Printing Related Support	Textile Mills	Textile Product Mills	Transportation Equipment Mfg.	Wood Product Manufacturing	Wastewater	Water	Mining	Agriculture
Emerging Technology - Process Improvement - Air Compressor	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
Emerging Technology - Process Improvement - Electro Chemical	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
Emerging Technology - Process Improvement - Heat	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
Emerging Technology - Process Improvement - Other	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	
Emerging Technology - Process Improvement - Refrigeration and Cooling	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-58 shows several characteristics for each measure: the percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, and measure life. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-58. Percentage Energy Savings over the Baseline Technology

Measure Name	Unit	Energy Savings [a]	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost [b]	Measure Life [c]
Emerging Technology - Process Improvement - Air Compressor	Per site	5%	0 – 6,832,217	0 - 987.756	$0 – 3,460,278	15 Years
Emerging Technology - Process Improvement - Electro Chemical	Per site	10%	0 – 23,349,499	0 – 3,375.712	$0 – 2,434,273	10 Years
Emerging Technology - Process Improvement - Heat	Per site	5%	0 – 18,770,930	0 – 2,713.773	$0 – 1,717,727	15 Years
Emerging Technology - Process Improvement - Other	Per site	5% - 15%	0 – 7,739,592	0 – 1,118.938	$0 – 1,691,864	10 Years
Emerging Technology - Process Improvement - Refrigeration and Cooling	Per site	13%	0 – 49,699,005	0 – 7,185.144	$0 – 13,422,194	10 Years

[a] For these savings, the Cadmus team assumed future advancement through either existing technology (just reconfigured) or emerging technology improvements on process end uses. The team added emerging technology measures for transformational potential. Based on DNV GL conversations, process improvements will continually evolve and are unlikely to decline. These emerging technology bundles include both existing and new technologies that will advance process improvements. DNV GL indicated that process improvements combined will account for 50% of the Consumers Energy program savings.
[b] For the incremental costs, the team assumed maximum costs for existing technology.
[c] To determine measure life, the Cadmus team assumed similar EULs to existing technology.

Path to Commercialization

All five measures in the industrial emerging process category are expected to be commercially available by 2021; however, they face barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Lack of contractor and distributor trust in and understanding of the technology
- Incremental cost

Table C-59 shows the path to commercialization for each industrial process measure.

Table C-59. Development Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Process Improvement - Air Compressor	Near-Term (2021-2025)			X	
Emerging Technology - Process Improvement - Electro Chemical	Near-Term (2021-2025)			X	
Emerging Technology - Process Improvement - Heat	Near-Term (2021-2025)			X	
Emerging Technology - Process Improvement - Other	Near-Term (2021-2025)			X	
Emerging Technology - Process Improvement - Refrigeration and Cooling	Near-Term (2021-2025)			X	

Bibliography

N/A

Industrial Emerging Technology: Pumps

Industrial emerging pump technologies make up 4% of the 20-year industrial portfolio achievable potential.

Bundle Measure Names and Industrial Sector Applicability

Table C-60 shows the one measure within the emerging pumps bundle, as well as the industrial sectors in which the measure can be installed.

Table C-60. Industrial Emerging Pumps Measure Names and Applicable Segments

Measure Name	Apparel	Beverage and Tobacco	Chemical	Computer and Electronics	Electrical Equipment	Fabricated Metal Products	Food Manufacturing	Furniture Manufacturing	Industrial Machinery	Leather	Misc.	Nonmetallic Mineral	Paper Manufacturing	Petroleum Coal Products	Plastics Rubber Products	Primary Metal Manufacturing	Printing Related Support	Textile Mills	Textile Product Mills	Transportation Equipment Mfg.	Wood Product Manufacturing	Wastewater	Water	Mining	Agriculture
Emerging Technology - Advanced Motor - Pumps	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	X	

Measure Characteristics Energy Savings, Demand Reduction, and Incremental Cost

Table C-61 shows several characteristics for each measure: the percentage of energy savings over the baseline technology, annual energy savings and demand reduction, incremental cost, and measure life. The team assumed the same measure cost and incremental cost over the 20-year planning horizon.

Table C-61. Percentage Energy Savings over the Baseline Technology

Measure Name	Unit	Energy Savings	Annual Energy Savings (kWh)	Annual Demand Reduction (kW)	Incremental Cost	Measure Life
Emerging Technology - Advanced Motor - Pumps	Per site	5%	0 - 8,193,352	0-1,184.539	$0-2,659,025	20 Years

Path to Commercialization

The one measure in the industrial emerging pumps category is expected to be commercially available by 2026; however, it faces barriers to adoption that are common to many new energy-efficient technologies:

- Lack of customer and contractor awareness of the technology
- Lack of contractor and distributor trust in and understanding of the technology
- Incremental cost

Table C-62 shows the path to commercialization for the industrial pumps measure.

Table C-62. Development Path to Commercialization

Measure Name	Development Timeline	Development Path			
		Technology Development and Demonstration	Delivery Strategy Optimization	Customer and Trade Ally Outreach	Regulatory Review and Acceptance
Emerging Technology - Advanced Motor - Pumps	Mid-Term (2026-2030)	X	X	X	

Bibliography

Minnesota Department of Commerce. January 1, 2020. "C/I Motors." *Minnesota Technical Reference Manual, Version 3.0.* https://mn.gov/commerce/industries/energy/utilities/cip/technical-reference-manual/

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

EXHIBITS

OF

EMILY A. MCGRAW

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected DR Program Size by Year
2021 - 2040

Case No: U-20190
Exhibit No: A-82 (EAM-1)
Page: 1 of 1
Witness: EAMcGraw
Date: June 2021

Total Base Outlook & Incremental DR MW

Line No.	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
1	AC Peak Cycling (DLA)	45	53	57	58	60	62	65	67	70	72	72	72	72	72	72	72	72	72	72	72
2	Smart Thermostat (STP)	22	50	60	64	68	72	76	80	84	88	88	88	88	88	88	88	88	88	88	88
3	Dynamic Peak Pricing (DPP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
4	Summer Peak Rate*	49	75	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	Commercial DR Program	221	235	285	287	290	295	300	305	310	315	315	315	315	315	315	315	315	315	315	315
6	Small Business DPP			6	11	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
7	Rate GI / GI2 / LTIRR	137	137	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151
8	Rate EIP	48	48	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
9	**Total Demand Response (MW)**	531	607	618	630	641	652	664	675	687	698	698	698	698	698	698	698	698	698	698	698

Incremental DR MW

Line No.	Description	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
10	AC Peak Cycling (DLA)	0	0	4	5	7	9	12	14	17	19	19	19	19	19	19	19	19	19	19	19
11	Smart Thermostat (STP)	0	0	10	14	18	22	26	30	34	38	38	38	38	38	38	38	38	38	38	38
12	Dynamic Peak Pricing (DPP)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Summer Peak Rate*	0	0	-75	-75	-75	-75	-75	-75	-75	-75	-75	-75	-75	-75	-75	-75	-75	-75	-75	-75
14	Commercial DR Program	0	0	50	52	55	60	65	70	75	80	80	80	80	80	80	80	80	80	80	80
15	Small Business DPP	0	0	6	11	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
16	Rate GI / GI2 / LTIRR	0	0	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
17	Rate EIP	0	0	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
18	**Total Demand Response (MW)**	0	0	11	23	34	45	57	68	80	91	91	91	91	91	91	91	91	91	91	91

* Impacts of Summer Peak Rate included in the load forecast 2023 and beyond.
* Total Summer Peak Rate MW exceed the MW included to reach 2021 & 2022 Base Outlook targets.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
Projected DR Program Cost by Year
2021 - 2040
(000)

Case No: U-21090
Exhibit No: A-83 (EAM-2)

Witness: EAMcGraw
Date: June 2021

Line No.	Description	2019 (1)	2020 (1)	2021 (2)	2022 (3)	2023	2024	2025	2026	2027	2028	2029
	Base Outlook Capital Investment (4)	$13,048	$8,360	$8,868	$9,317	$9,317	$9,317	$9,317	$9,317	$9,317	$9,317	$9,317
	Incremental Capital Investment	-	-	-	-	89	181	277	376	480	589	699
	Total Capital Investment	$13,048	$8,360	$8,868	$9,317	$9,406	$9,498	$9,594	$9,693	$9,797	$9,906	$10,016
	Base Outlook O&M (4)	$16,312	$23,776	$39,272	$42,777	$42,777	$42,777	$42,777	$42,777	$42,777	$42,777	$42,777
	Incremental O&M	-	-	-	-	665	1,360	2,075	2,822	3,598	4,416	5,240
	Total O&M (5)	$16,312	$23,776	$39,272	$42,777	$43,442	$44,137	$44,852	$45,599	$46,375	$47,193	$48,017
	Performance Incentive (6)	$2,447	$4,755	$7,854	$8,555	$8,688	$8,827	$8,970	$9,120	$9,275	$9,439	$9,603
	Total Investment	$31,807	$36,891	$55,994	$60,649	$61,536	$62,463	$63,416	$64,412	$65,447	$66,537	$67,637

Line No.	Description	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Base Outlook Capital Investment (4)	$9,317	$9,317	$9,317	$9,317	$9,317	$9,317	$9,317	$9,317	$9,317	$9,317	$9,317
	Incremental Capital Investment	827	844	863	878	896	914	934	951	970	989	1,011
	Total Capital Investment	$10,144	$10,161	$10,180	$10,195	$10,213	$10,231	$10,251	$10,268	$10,287	$10,306	$10,328
	Base Outlook O&M (4)	$42,777	$42,777	$42,777	$42,777	$42,777	$42,777	$42,777	$42,777	$42,777	$42,777	$42,777
	Incremental O&M	6,206	6,330	6,475	6,586	6,718	6,852	7,008	7,129	7,271	7,417	7,586
	Total O&M (5)	$48,983	$49,107	$49,252	$49,363	$49,495	$49,629	$49,785	$49,906	$50,048	$50,194	$50,363
	Performance Incentive (6)	$9,797	$9,821	$9,850	$9,873	$9,899	$9,926	$9,957	$9,981	$10,010	$10,039	$10,073
	Total Investment	$68,924	$69,090	$69,282	$69,431	$69,606	$69,785	$69,994	$70,155	$70,345	$70,539	$70,764

(1) 2019 & 2020 based on actuals
(2) 2021 based on U-20679 approved rates
(3) 2022 based on U-20963 projections
(4) Base Capital Expenditures and O&M equal to U-20963 projections 2022-2040
(5) Includes customer credits for device cycling programs and Peak Time Rewards
(6) Incentive based on 20% for 2020 - 2040

CONSUMERS ENERGY

2020 Demand Response Annual Report

Case No. U-21080

June 1, 2021

Consumers Energy
Count on Us®

2020 Demand Response Annual Report

This *2020 Demand Response Annual Report* summarizes Consumers Energy Company's ("Consumers Energy" or the "Company") 2020 electric demand response achievements and describes the Company's portfolio of Demand Response programs, which are designed to reduce load on peak days and offer savings opportunities to customers. This report serves to inform Consumers Energy's stakeholders, encourage transparency and collaboration, and provide an overview of residential and business demand response activities for the 2020 calendar year. This includes all customer enrollment activities throughout 2020 for the Midcontinent Independent System Operator, Inc. ("MISO") planning year that begins June 1, and for the demand response event season (from June 1 to September 30).

Consumers Energy submits this *2020 Demand Response Annual Report* to the Michigan Public Service Commission ("MPSC" or "Commission") as part of its annual Demand Response Reconciliation filing.

In compliance with the October 29, 2020 Order in MPSC Case No. U-20628, an updated Exhibit B from MPSC Case No. U-17936 is provided as Attachment A to this report and customer communication protocols are incorporated in the demand response portfolio and program sections.

History of Demand Response Regulatory Framework

Public Act 342 of 2016 encouraged the development and implementation of demand-side resources, such as demand response, to address current and future electric generation capacity needs in Michigan. On May 11, 2017, in Case No. U-18369, the Commission directed its staff to convene a stakeholder work group to explore and recommend a regulatory framework for evaluating the efficiency of demand response programs and cost recovery of utility investments in these programs. In its September 15, 2017 Order in Case No. U-18369, the Commission approved its staff's recommended three-phase approach of approval and cost recovery occurring in Integrated Resource Plans ("IRP") and rate cases and an annual reconciliation for demand response programs.

Table of Contents

Tables

Acronyms and Abbreviations

Acronym	Definition
Commission	Michigan Public Service Commission
Company	Consumer Energy Company
CPP	Critical Peak Pricing
DPP program	Dynamic Peak Pricing program
DR	Demand Response
EM&V	Evaluation, Measurement, and Verification
IRP	*Integrated Resource Plan*
MISO	Midcontinent Independent System Operator, Inc.
MPSC	Michigan Public Service Commission
O&M	Operations and Maintenance
PTR	Peak Time Rewards
STP	Smart Thermostat Program

Executive Summary

The full deployment of the Company's business and residential demand response ("DR") programs in 2017 marked a milestone in its journey to provide reliable, safe, affordable, and sustainable clean energy offerings to customers. The Company integrated DR into its capacity portfolio to meet the aggressive DR program goals in its approved IRP, MPSC Case No. U-20165.

In 2020, the Company continued to draw from previous years' learnings to expand and improve upon its DR programs. While the COVID-19 pandemic impacted DR, the DR programs delivered on the Company's triple bottom line of people, planet, and prosperity, making significant advancements in building a transformative, cost-effective DR capacity resource.

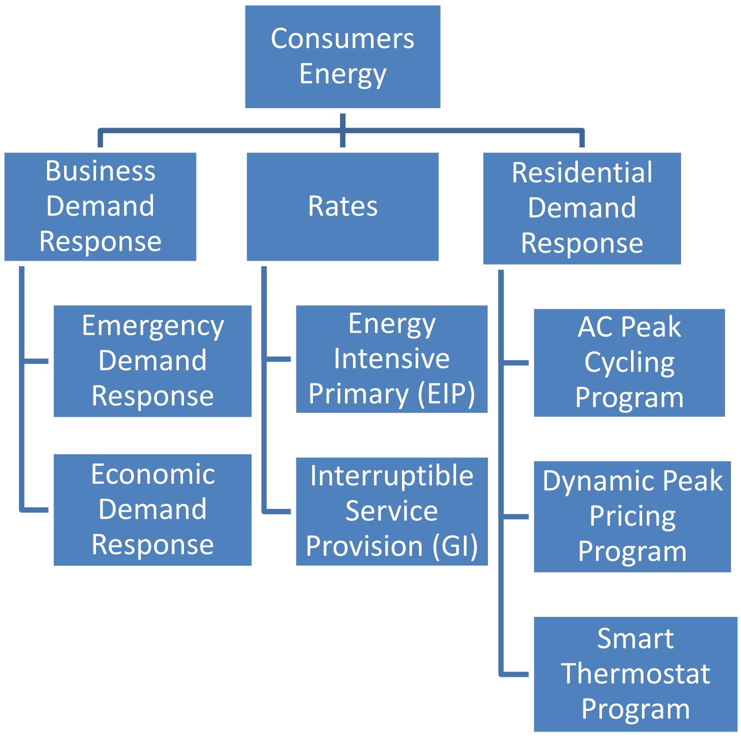
Consumers Energy's DR programs help customers save money and reduce the Company's need to purchase, produce, and deliver additional energy at peak times, when prices are high. Through its DR portfolio, Consumers Energy also offered its customers an opportunity to build energy awareness, save money, and understand energy price signals. Consumers Energy takes pride in its environmental leadership and commitment to managing customer bill impacts responsibly. The Company's 2020 DR portfolio achievements also exemplify its commitment to customers and communities by providing a wide variety of choices to meet energy needs throughout Michigan.

In 2020, Consumers Energy's DR program faced significant challenges due to the COVID-19 pandemic, including engaging customers who were facing pandemic-related economic uncertainty while also spending more time at home, program safety challenges, and pauses to all program activation requiring in-person activity during the stay-at-home orders. Despite these challenges, the Company exceeded its 2020 DR enrollment goals. Other milestone 2020 DR program achievements include:

- A 30% increase in DR program enrollment from 2019 levels. By December 31, 2020, 145,849 business and residential customers were enrolled in Consumers Energy's DR programs;
- Successful transition of the Smart Thermostat pilot to a full DR program, exceeding customer enrollment targets;
- Continued high customer satisfaction ratings;
- Utilization of DR to reduce peak demand through seven AC Peak Cycling program events, six Dynamic Peak Pricing events, and seven Smart Thermostat Program events; and
- Development of additional pilot proposals for 2021 to ensure that the Company is prepared to deliver the aggressive DR goals proposed in its IRP for 2021 and beyond.

2020 Demand Response Portfolio

This chapter outlines investments, savings achievements, successes, and lessons learned for the 2020 business and residential DR programs.



*There were no enrollments in the Business Economic DR program in 2020

Demand Response Program Investments

The Company invested $32.1 million in its business and residential demand response programs in 2020 (Table 1). The Company also offered business customers two interruptible rates, Rate GI and Rate EIP. These combined investments achieved 473.9 MW in demand reduction.

Table 1. Demand Response Portfolio Investments

Demand Response Program	Capital	O&M Expenditure	Customer Payments	Total
Business	$ 376,049	$ 2,278,211	$4,099,840	**$6,754,100**
Residential	$3,824,200	$ 9,315,646	$2,738,227	**$15,878,073**
Administrative/Pilots/IT	$4,159,417	$ 5,344,288	$ -	**$ 9,503,706**
Total	**$8,359,666**	**$16,938,145**	**$6,838,067**	**$32,135,878**

Demand Response Program Savings Achievements

The December 31, 2020 demand reduction of 473.9 MW (Table 2) is a significant accomplishment that exceeds the 451 MW projection from the Company's approved IRP. The 2020 DR portfolio savings achievement clearly demonstrates the Company's commitment to building a cost-effective DR portfolio to be called upon to meet Michigan's electric needs.

Table 2. Demand Response Program Savings

Demand Response Program	Program Saving (MW)		
	December 31, 2019	June 1, 2020	December 31, 2020
Business	111.4	153.6	153.6
Residential	65.3	73.2	94.3
Rate GI	157.3	157.3	157.3
Rate EIP	68.7	68.7	68.7
Total	**431.8**	**452.8**	**473.9**

Notes: AC Peak Cycling program demand reduction per-customer planning values changed from 0.70 kW in 2019 to .63 kW in 2020. Dynamic Peak Pricing ("DPP") program demand reduction per-customer planning values changed from 0.48 kW in 2019 to .5 kW for Critical Peak Pricing and .32 kW for Peak Time Rewards in 2020. The Smart Thermostat Program ("STP") was commercialized from our Pilot in 2019. Program demand reduction per-customer planning values were calculated and registered at 1.2 kW per household and utilized for the 2020 STP year.

Demand Response Program Successes

- By December 31, 2020, 145,849 business and residential customers were enrolled in Consumers Energy's DR programs, an increase of 29.7% from 2019 levels.
- The Company operationalized its STP in 2020, exceeding customer enrollment targets and successfully calling seven DR events. The program added Google Nest and Emerson thermostats to the program offering, making the program available to more customers.
- Customer satisfaction with residential DR programs remained high. The AC Peak Cycling program achieved ratings of 9.3, 8.7, and 9.2 for the call center, website, and installation experience, respectively (based on a 10-point scale, where 1 meant *not at all satisfied* and 10 meant *very satisfied*). The DPP program achieved ratings of 9.2 and 8.3 for the call center and website experience, respectively. The STP achieved overall customer satisfaction scores of 8.4 before event season and 8.8 after event season. The STP post season findings also recorded a Net Promoter Score of +60 and a CXi of +82.
- In 2020, Consumers Energy called seven AC Peak Cycling program events, six DPP events, and seven STP events on non-holiday weekdays between June 1

and September 30 on the summer's hottest afternoons when electric demand for cooling was highest, thus maximizing the demand reduction potential.

- The Company dispatched one geotargeted AC Peak Cycling event as part of the Company's Non Wires Solutions pilot.
- The Company dispatched an STP critical test event on August 10 to test the program's response and performance during emergency conditions. The critical test event simulated the conditions of a MISO emergency event and as such the pre-cooling and customer notification times were reduced.

- The Company completed evaluation and measurement efforts including residential DR program evaluations.
- The Company's industry benchmarking and evaluation work led to developing additional pilot proposals for 2021. These pilots will help prepare the Company to deliver the aggressive DR goals proposed in its IRP for 2021 and beyond.

Business Demand Response Emergency and Economic Programs

Through the business DR emergency program, Consumers Energy provides grid reliability in the event that peak energy demand exceeds the available supply. During the 2020 DR season, the Company enrolled 153.6 MW, representing 262 customer facilities in its business DR program. The Company also offers a business DR economic option for customers enrolled in the emergency program; however, no customers subscribed to the economic option in 2020.

Consumers Energy communicated with enrolled customers prior to the beginning of the DR season on June 1 with marketing materials, updates, and reminders of participation in the program. Additionally, at the end of the DR season, Consumers Energy communicated with participants thanking them for their role in supporting our Clean Energy Plan and IRP process.

As no MISO Emergency Events were called in 2020, there were no communications to customers on curtailment requirements. If MISO had called a DR event, per the Company's established communication protocol, enrolled customers would have been provided at least one, possibly two, notices of probable interruption by MISO at least 30 minutes prior to required interruption. Customers are notified by telephone to the contact numbers provided by the customer with the customer confirming receipt through the automated response process. Failure to acknowledge receipt does not relieve the customer of the obligation for interruption. The customer is also informed, when possible, of the estimated duration of the interruption. At the end of the event season, customers receive communication that the DR season has ended and that they will receive bill credits based on contracted capacity payment.

In 2020, business DR customers received $4,099,840 in incentives for their willingness and ability to support grid reliability by participating in the Business DR Emergency program (Table 3).

Table 3. Business Demand Response Expenditures and Enrollments

Year	Capital Expenditure	O&M Expenditure	Customer Incentive Payments	Cumulative Enrollments (December 31)
2017	$1,419,366	$1,686,055	$ -	50.1 MW
2018	$ 517,313	$1,159,364	$ -	73.1 MW
2019	$1,317,026	$2,295,854	$2,808,394	111.4 MW
2020	$ 376,049	$2,278,210	$4,099,840	153.6 MW

* Historical actuals updated to exclude administrative, IT, and pilot costs

Residential Demand Response

This chapter outlines details of the 2020 events and expenditures for each of Consumers Energy's three residential DR program offerings.

In 2020, the Company communicated with its residential customers in the STP and DPP programs through pre-event communications (email, text, or voicemail) notifying customers of the upcoming event and post-event notifications outlining their performance during the event. Additionally, at the end of the DR season, Consumers Energy communicated with STP participants thanking them for their role in supporting our Clean Energy Plan and IRP process.

AC Peak Cycling

AC Peak Cycling is a residential direct load management program, through which the Company places a two-way communicating load control switch on the outside of a customer's central air conditioning condenser. Participants receive a gift card for enrolling in the program and earn an $8.00 per month bill credit during the peak event season lasting June through September. During Energy Savings Day events, the Company activates the switch to cycle the central air conditioner based on a 50% cycle strategy to reduce customer electric use for short periods of time. The Company may call up to 10 Energy Savings Day events between 7 a.m. and 8 p.m. during the event season.

In 2020, the Company called 6 Energy Savings Day events (Table 4), achieving maximum peak hour savings of 0.63 kW per customer on July 9, 2020. The Company also called one geotargeted AC Peak Cycling test event related to the non wires alternative pilot, which is highlighted in the Exhibit A-4 (SQM-4) Non-Wires Alternative Candidate Analysis.

Table 4. AC Peak Cycling Energy Savings Day Events (2020)

Date	Time	Responsive Switches	Average Temperature [a]	Per-Switch kW Reduction [b]	
				Average	Maximum
July 1	3 p.m. to 7 p.m.	74,445	85°F	0.25	0.27 (6 p.m. to 7 p.m.)
July 2	3 p.m. to 7 p.m.	74,114	87°F	0.45	0.46 (3 p.m. to 4 p.m.)
July 8	3 p.m. to 7 p.m.	73,837	86°F	0.57	0.61 (4 p.m. to 5 p.m.)
July 9	2 p.m. to 6 p.m.	73,850	87°F	0.57	0.63 (2 p.m. to 3 p.m.)
August 26	2 p.m. to 6 p.m.	73,374	83°F	0.36	0.40 (4 p.m. to 5 p.m.)
August 27	2 p.m. to 6 p.m.	73,816	83°F	0.44	0.49 (2 p.m. to 3 p.m.)

[a] The Cadmus team calculated this temperature estimate as the weighted average of National Oceanic and Atmospheric Administration weather data for Consumers Energy service territory, using the closest weather stations for each participant zip code.

[b] These estimates reflect the average value among responsive switches.

In 2020, the Company installed 11,462 switches; however, higher-than-anticipated program attrition of 7,791 resulted in 3,671 net switches for the year. This attrition was primarily due to a high move-out rate and customers de-enrolling from the program. The Company has engaged in strategies to help mitigate move-out program impacts, including gaining approval to notify and auto-enroll customers who move into properties where a switch is already installed.

The Company monitored customer satisfaction with field services, the call center, and the website, with customers' rating their overall satisfaction with each as 9.3, 8.7, and 9.2, respectively, based on a 10-point scale (where 1 meant *not at all satisfied* and 10 meant *very satisfied*).

Table 5 outlines expenditures and enrollments for the AC Peak Cycling program.

Table 5. AC Peak Cycling Expenditures and Enrollments

Year	Capital Expenditure	O&M Expenditure	Customer Incentive Payments	Cumulative Enrollments (Dec 31)
2015	$ 269,976	$ 194,683	$ 36,962	-
2016	$1,200,429	$ 477,431	$ 74,625	1.96 MW
2017	$5,987,902	$2,256,160	$ 577,216	33.85 MW
2018	$6,157,580	$2,672,294	$1,326,857	30.62 MW
2019	$7,291,856	$3,258,957	$2,191,891	51.54 MW
2020	$3,824,200	$2,144,911	$2,442,898	48.70 MW

* Historical actuals updated to exclude administrative, IT, and pilot costs

Dynamic Peak Pricing

Through the DPP program, Consumers Energy offers Critical Peak Pricing ("CPP") and Peak Time Rewards ("PTR") options to residential electric customers with advanced metering infrastructure meters. The Company designed this program to reduce energy loads during summer peak hours and to encourage energy savings by shifting load from high-cost periods to low-cost periods.

Customers can select between the two DPP program options. CPP customers pay a penalty of $0.95 per kWh for energy used and PTR customers earn an incentive of $0.95 per kWh for energy saved. The Company measures the penalty or reward provided for peak hours against a baseline use. The Company may call CPP and PTR events up to 14 times between 2 p.m. and 6 p.m. during summer months.

In 2020, the Company used a per-customer demand reduction factor of 0.50 kW for CPP and 0.32 kW for PTR and achieved program enrollment of 15.1 MW for the DR season.

The Company monitored customer satisfaction with the website, the call center enrollment experience, and their likelihood to recommend the program with customers' rating their overall satisfaction with each as 8.3, 9.2, and 8.0, respectively, based on a 10-point scale (where 1 meant *not at all satisfied* and 10 meant *very satisfied*). The satisfaction with the call center increased significantly to 9.2 in 2020, up from 8.6 in 2019.

Table 6 outlines expenditures and enrollments for the DPP Program, while Table 7 outlines details of the six events called during the 2020 season.

Table 6. Dynamic Peak Pricing Expenditures and Enrollments

Year	Capital Expenditure	O&M Expenditure	Customer Incentive Payments	Cumulative Enrollments (Dec 31)
2015	$ -	$ -	$ -	-
2016	$ -	$ 206,353	$ 124	0.02 MW
2017	$ -	$2,015,148	$ 40,282	11.0 MW
2018	$ -	$ 635,503	$213,496	13.8 MW
2019	$ -	$ 650,943	$ 72,993	13.8 MW
2020	$ -	$ 923,561	$295,329	15.1 MW

* Historical actuals updated to exclude administrative, IT, and pilot costs

Table 7. Dynamic Peak Pricing Energy Savings Day Events (2020)

Date	Participants in Sample		Average Demand Impacts (kW)		Peak Demand Impacts (kW)	
	CPP	PTR	CPP	PTR	CPP	PTR
July 1	7,744	28,591	-0.15	-0.16	-0.19	-0.19
July 2	7,744	28,591	-0.10	-0.13	-0.15	-0.15
July 8	7,744	28,591	-0.24	-0.23	-0.26	-0.26
July 9	7,744	28,591	-0.13	-0.16	-0.21	-0.19
August 26	7,744	28,591	-0.13	-0.09	-0.16	-0.12
August 27	7,744	28,591	-0.10	-0.06	-0.12	-0.07

Smart Thermostat Program

Consumers Energy enrolled 25,436 customers in the 2020 STP and included three thermostat brands (Ecobee, Emerson, and Google Nest).

In response to the COVID-19 pandemic and more customers working from home, the Company quickly responded with an STP energy waste reduction and DR coordinated program to help customers meet energy savings goals and the Company meet STP enrollment targets. This innovative effort prioritized customer, employee, and trade ally safety through an offering that did not require a professional installer in the customer's home. Through this coordinated campaign, the Company offered nearly free Google Nest E smart thermostats to customers who also enrolled in the STP at the time of purchase, resulting in 10,500 new customers participating in the STP.

Prior to an STP Energy Savings Day event, the thermostat was set to pre-cool the home to reduce or eliminate the air conditioning runtime during the Energy Savings Day event, typically between 2 p.m. and 7 p.m. Events could occur from June 1 through September 31, between 7 a.m. and 8 p.m. In 2020, the Company called six STP Energy Savings Day events and one STP Critical Test Event (

Table 8), achieving maximum peak hour savings of 0.98 kW per customer on July 8, 2020. Note that the Company utilized demand reduction performance on the Consumers Energy System peak day (July 9) to calculate forward looking kW/customer planning values.

Table 8. Smart Thermostat Pilot Energy Savings Day Events (2020)

Date	Time	Event Participants[a]	Average Temperature[b]	Average Per Participant Demand Reduction (kW)	Average Peak Hourly Per Participant Demand Reduction (kW) and Hour
July 1	3 p.m. to 7 p.m.	12,838	87°F	0.90	1.10 (3 p.m. to 4 p.m.)
July 2	3 p.m. to 7 p.m.	12,931	90°F	0.82	1.12 (3 p.m. to 4 p.m.)
July 8[c]	3 p.m. to 7 p.m.	13,297	87°F	0.98	1.30 (3 p.m. to 4 p.m.)
July 9[d]	3 p.m. to 7 p.m.	13,378	86°F	0.88	1.31 (3 p.m. to 4 p.m.)
August 10[e]	3 p.m. to 7 p.m.	16,608	86°F	0.78	1.16 (3 p.m. to 4 p.m.)
August 26	2 p.m. to 6 p.m.	16,983	86°F	0.75	0.84 (3 p.m. to 4 p.m.)
August 27	2 p.m. to 6 p.m.	17,036	86°F	0.86	0.97 (3 p.m. to 4 p.m.)
Average	-	**14,724**	**87°F**	**0.85**	**1.11**

[a] Customers whose thermostats were controlled during the event.

[b] Weighted average of temperature conditions recorded by National Oceanic and Atmospheric Administration (NOAA) weather stations nearest to each participant.

[c] July 8 was the best performing event in terms of average per participant demand reduction.

[d] July 9 was the Consumers Energy 2020 summer peak demand day.

[e] August 10 was a critical test event.

The Company monitored customer satisfaction using a pre- and post-event season customer survey provided by Consumers Energy's Customer Experience Team. The overall customer satisfaction rating was 8.8 on a 10-point scale (where 1 meant *not at all satisfied* and 10 meant *very satisfied*) and the pilot observed a customer experience index score of 82.

Table 9 outlines expenditures and enrollments for the Smart Thermostat program.

Table 9. Smart Thermostat Pilot Expenditures and Enrollments

Year	Capital Expenditure	O&M Expenditure	Cumulative Enrollments (December 31)
2019	$ -	$1,806,311	1.4 MW
2020	$ -	$6,247,174	30.5 MW

* Historical actuals updated to exclude administrative, IT, and pilot costs

Evaluation, Measurement, and Verification

An evaluation, measurement, and verification ("EM&V") plan is necessary to ensure that Consumers Energy's DR programs are delivering reliable demand reduction and to improve overall program design and operation. The Company developed its EM&V Plan to evaluate and measure savings for electric DR products during and after each performance year in order to confirm that savings and technical assumptions are accurate. The robustness of any EM&V plan must be balanced against the cost of performing EM&V, keeping in mind the objectives of ensuring accurate savings calculations, while keeping expenditures prudent and maintaining program cost-effectiveness.

Description of Overall Evaluation Process

The Company commissioned the Cadmus team to conduct its evaluation and measurement activities. The Cadmus team's 2020 EM&V approach included the impact evaluation activities described in more detail below.

Impact Evaluation

The Cadmus team used regression analysis to determine peak demand reduction, event day and non-event day impacts, and energy use impacts.

AC Peak Cycling

To estimate the impact of program events, the Cadmus team compared program participants' energy savings and demand reduction to those of a randomized control group of nonparticipants using a regression analysis designed to identify peak demand reduction and overall energy use.

Dynamic Peak Pricing

To estimate participants' enrollment and event impacts, the Cadmus team relied on an industry standard methodology to identify program impacts by comparing the energy use between program participants and a matched control group of nonparticipants. The team used panel regression analysis to identify peak demand reduction (during event and non-event days), in addition to overall changes in energy use.

Smart Thermostat

The Cadmus team conducted two distinct impact analysis activities to evaluate the STP: 1) a regression analysis to measure demand reduction and energy savings, and 2) analysis of thermostat telemetry data to identify factors that influenced event performance.

To analyze demand impacts during events, the Cadmus team used a regression model to compare the difference in average consumption between program participants randomly assigned to the treatment group and the randomly selected control group (customers who were enrolled in the program but who did not receive the pre-cooling treatment during a particular program event). The regression included independent variables for temperature conditions (cooling degree hours) and hour-of-sample fixed effects. To control for differences in average demand between customers in the treatment and control groups, the regression included customer average demand during the same hour on non-holiday, non-event weekdays during the program season.

To identify factors that influenced event performance, Cadmus assessed environmental conditions, participant behaviors and characteristics, and event operations during each event to isolate the factors that contributed to differences in event performance between the 2019 and 2020 program seasons. The research concluded that temperature, humidity, and pre-cooling time impact demand reduction performance.

Pilots

The Company initiated two new residential DR pilot programs in 2020.

The Generator pilot is aimed at recruiting residential customers with whole home generators. During a DR event, the generator will become the source of electricity for the customer's home. In 2020, the pilot focused on designing the solution. In 2021, the Company is focusing on enrolling customers and dispatching DR events to measure demand reduction.

The Multi-use Switch pilot enrolled over 500 customers in 2020 with the majority of switches installed on hot water heaters. In 2021, the Company will dispatch DR events to these switches to measure demand reduction.

Looking to the future, the Company has included a Low-Income DR pilot and a Smart Home Pilot in the most recent electric rate case to support the development of the residential DR portfolio.

Future Plans

Looking ahead, the Company will continue to offer cost-effective options to help customers meet their energy and sustainability goals. For both the residential and business programs, the Company plans to leverage data analytics, including propensity models and load shapes, to optimize customer acquisition.

The business DR program will continue to investigate expanding options for customers to participate in DR such as the addition of products within the MISO market. Additionally, the business DR program launched a small business DR pilot to focus on the needs of small to medium businesses and evaluate opportunities to increase DR participation from this customer segment.

The Residential portfolio will launch several enhancements to the customer enrollment experience, making it easier for customers to enroll in DR programs and eliminate waste in back-end processes. Those enhancements include a customized DR offer as part of the online move-in move-out experience and an automated enrollment flow on the Consumers Energy website that allows customers to 'browse' all residential DR programs at once, select the one that best fits their needs, and move forward with enrollment without entering an account number. Additionally, the team will launch a customer communication plan for the summer peak rate, which will incorporate residential DR programs as a tool to control energy consumption and save money on the new summer peak rate.

The DPP program, which serves as the entry-level, no-regrets step into DR, is exploring new ways to expand eligibility criteria, including further utilization of Interactive Voice Response to allow customers that do not have email or text message access to enroll in the program and receive pre-and post-event notifications through automated voice messages to a landline or cell phone. It is believed that this could help increase enrollment numbers and allow for more equitable solutions for certain demographics including senior citizens and low-income customers.

Finally, the Company will continue to scale the STP to its maximum potential within our service territory, with an aggressive enrollment glide path. As the market penetration of smart thermostats grows, this is a thoughtful step toward delivering efficient and reliable demand response resources. In future years, we will work to continuously improve the program's performance by working to reduce opt-outs and improve notification methods. The Company plans to add further thermostat manufacturers as well as improve customer experience in the coming years.

Demand Response Potential Study

2021–2040

June 2021

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This report is a deliverable submitted to Consumers Energy as part of a multiyear, independent evaluation contract to conduct impact, process, and market assessment studies of residential energy waste reduction and demand response programs administered by Consumers Energy. This specific study was funded by Consumers Energy's Demand Response Team. The independent evaluation team includes the following firms:

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Acronyms and Abbreviations

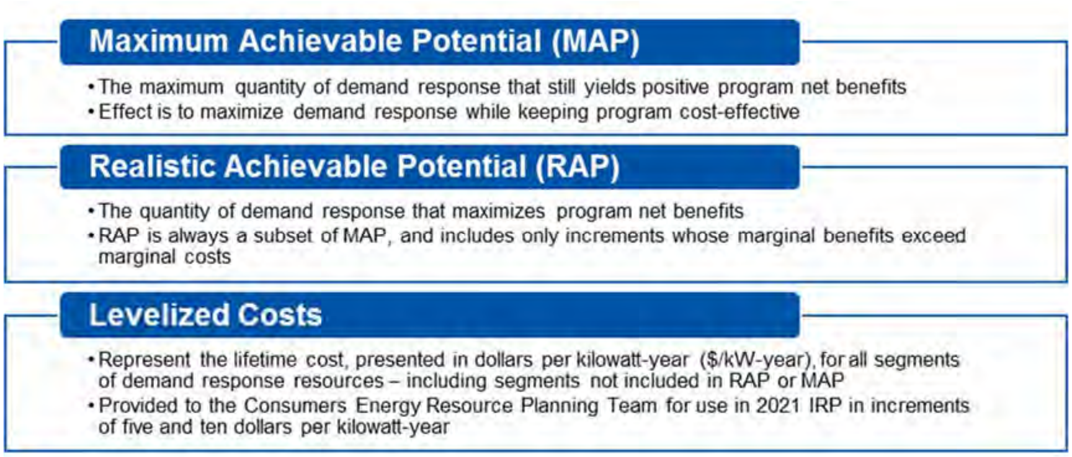
Acronym	Definition
ACPC	Air Conditioning Peak Cycling
AEG	Applied Energy Group
AMI	Advanced metering infrastructure
BYOD	Bring Your Own Device
CONE	Cost of new entry
CPP	Critical Peak Pricing
DPP	Dynamic Peak Pricing
EAM	Earnings adjustment mechanism
EIP rate	Energy Intensive Primary rate
GI rate	General Interruptible rate
IRP	Integrated resource plan
kW	Kilowatt
kWh	Kilowatt-hour
MAP	Maximum achievable potential
MISO	Midcontinent Independent System Operator
MW	Megawatt
MWh	Megawatt-hour
PJM	PJM Interconnection LLC
PTR	Peak Time Rewards
RAP	Realistic achievable potential
TOU	Time of use
UCT	Utility cost test

Executive Summary

Consumers Energy contracted with an independent evaluation firm, Cadmus, to conduct electric energy waste reduction and demand response market potential studies. Cadmus and subcontractor Demand Side Analytics (collectively known as the Cadmus team) completed the two studies in parallel, incorporating a high degree of coordination with Consumers Energy program staff and system planners. This report presents the results of the demand response potential study; the results of the energy waste reduction potential study are presented in a separate companion report. The Cadmus team completed an initial draft of the demand response potential study in July 2020 and updated the analysis in early 2021 to reflect the latest available program enrollment and cost information.

The Cadmus team designed this demand response potential study to provide a foundation for continuing utility-administered electric demand response programs in the Consumers Energy service area and for determining the remaining opportunities for cost-effective peak load reduction in the residential and business sectors. This study presents the ***maximum achievable potential (MAP)*** and the ***realistic achievable potential (RAP)*** for each demand response program, as well as ***levelized costs*** comprised of different demand response program segments for the Consumers Energy Resource Planning team to use for in the 2021 Integrated Resource Plan (IRP). Figure 1 describes these three concepts in more detail.

Figure 1. Results Presented in Report



Research Objectives

This report addresses two research objectives:

1) Develop estimates of demand response potential that can be translated into meaningful, actionable recommendations for Consumers Energy's demand response programs.
2) Provide disaggregated estimates of demand response potential and associated costs to the Consumers Energy Integrated Resource Planning Team for use in its 2021 Integrated Resource Plan (IRP)

Research Approach

To address the research objectives, the Cadmus team conducted several distinct research activities for the 2020-2021 Consumers Energy demand response potential study:

- Assessed the potential for load reduction from eight programs in the residential and business sectors. This involved analyzing original data from Consumers Energy including the peak load forecast, hourly electricity use data, customer characteristics data, demand response marketing campaign data, and program evaluation data, as well as data from external sources.
- Developed detailed cost, marketing, and operational assumptions for each program based on Consumers Energy's historical experience and internal planning for demand response programs.
- Compared the cost of achieving load reduction in each program to the benefits of such load reduction in the form of avoided generation capacity costs and avoided energy costs.
- Reported the resulting MAP and RAP in this potential study and provided corresponding levelized costs by program and cost tranche for use in the 2021 IRP.

Summary of Results

In total, the Cadmus team studied eight distinct programs that included direct load control, behavioral response via dynamic peak pricing (DPP) rates or riders, and load curtailment agreements. Our objective was to perform a detailed analysis of the opportunities for expansion of current program offerings and to develop estimates of demand response potential for program designs currently under consideration by Consumers Energy. The programs modeled were not intended to be an all-encompassing list of demand response technologies.

Consumers Energy and the broader Midcontinent Independent System Operator (MISO) balancing authority are summer-peaking systems and are expected to remain summer-peaking over the study horizon, so the team focused this study on summer demand response capability. Table 1 outlines the programs we analyzed in this study, along with the MAP and RAP by 2040. All potential is measured at the system level, accounting for line losses of 3.7%.

Table 1. Maximum Achievable and Realistic Achievable Potential by Program

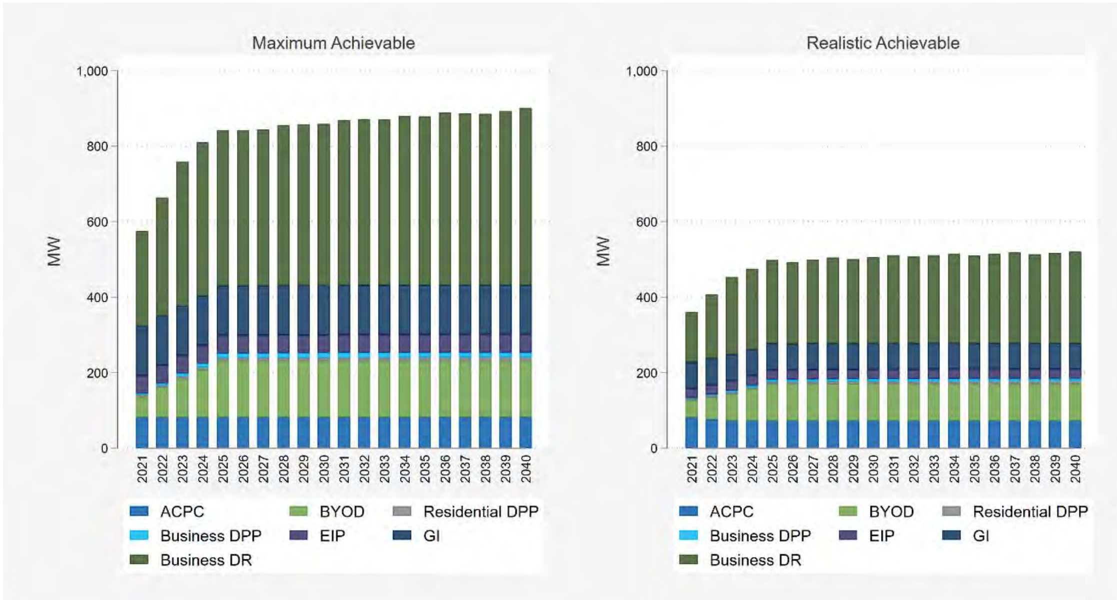
Program	Program Status	Acronym	Program Type	MAP (MW)	RAP (MW)
Residential Sector					
Air Conditioning Peak Cycling	Existing Program	ACPC	Air conditioning (load curtailment)	82	73
Bring Your Own Device	Pilot Completed in 2019[b]	BYOD	Air conditioning (smart thermostat)	149	97
Dynamic Peak Pricing	Existing Program	Residential DPP	Rate Provision	9	9
Water Heater Direct Load Control	Pilot Underway in 2020	Water Heaters	Load curtailment	0	0
Business Sector					
Small Business Dynamic Peak Pricing	Program Does Not Yet Exist	Business DPP	Rate Provision	13	6
Energy Intensive Primary Rate	Existing Program	EIP rate	Load curtailment	48	25
General Interruptible Rate	Existing Program	GI rate	Load curtailment	131	68
Commercial and Industrial Demand Response	Existing Program	Business DR	Load curtailment	469	243
Total [a]				**901**	**521**

[a] Total row may not equal the sum of program values due to rounding

[b] The BYOD Pilot transitioned to full program status as the Smart Thermostat Program in 2020.

Figure 2 shows the MAP and RAP by program over the 20-year study horizon (2021 through 2040). The Water Heater Direct Load Control program did not pass cost-effectiveness screening, so the estimated potential is zero and the program was omitted from the figures. We assume that most potential can be procured in a relatively short amount of time and grow the current levels of demand response to MAP and RAP within three to four years. Programmatically, Consumers Energy might elect for a more gradual trajectory of program expansion. Once the ramp up period is complete around 2025, the potential is essentially flat. The MAP and RAP estimates represent 11% and 6.5% of Consumers Energy's forecasted 2040 peak demand, respectively. The business sector accounted for the majority (73%) of MAP, with the residential sector accounting for the remainder.

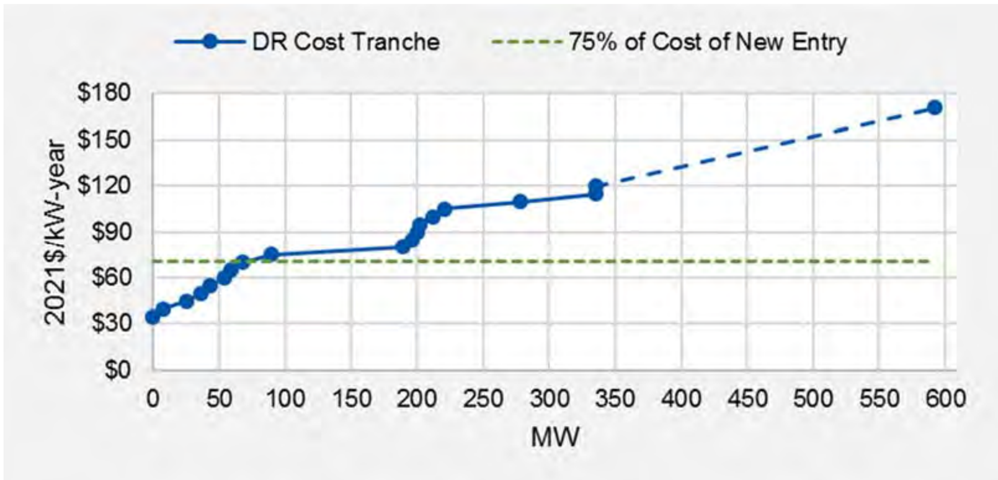
Figure 2. Demand Response Potential by Scenario, Program, and Year



Our estimates of MAP and RAP consider the economics of demand response compared to a static forecast of the avoided cost of generation capacity. The Cadmus team also provided the Consumers Energy Resource Planning Team with demand response potential (in megawatts) and the associated levelized costs (in 2021 dollars per kW-year) for different segments of each program, for a total demand response quantity of 1,090 MW. Figure 3 shows the resulting supply curve for 592 MW of new demand response resources, which consist of expansions to existing programs and additions of entirely new programs. 498 MW of existing demand response resources as of February 2021 are not shown.[1] Costs are broken into tranches of five dollars per kW-year. The dotted green line is at 75% of the MISO Local Resource Zone 7 cost of new entry (CONE), the avoided capacity cost against which Consumers Energy currently evaluates its demand response portfolio, and the capacity cost the Cadmus team used to estimate MAP and RAP. All demand response segments above $120 per kilowatt-year are shown as having a cost of $170 per kW-year, the capacity-weighted average cost of these segments. In Figure 3, this final tranche of resources above $120 per kW-year is connected to the granular supply curve with a dotted blue line.

[1] Our estimate of existing resources may not match Consumers Energy estimates of existing demand response potential due to differences in assumed demand reductions and changes in enrollment levels.

Figure 3. Levelized Cost Tranches for New Demand Response Resources



Report Organization

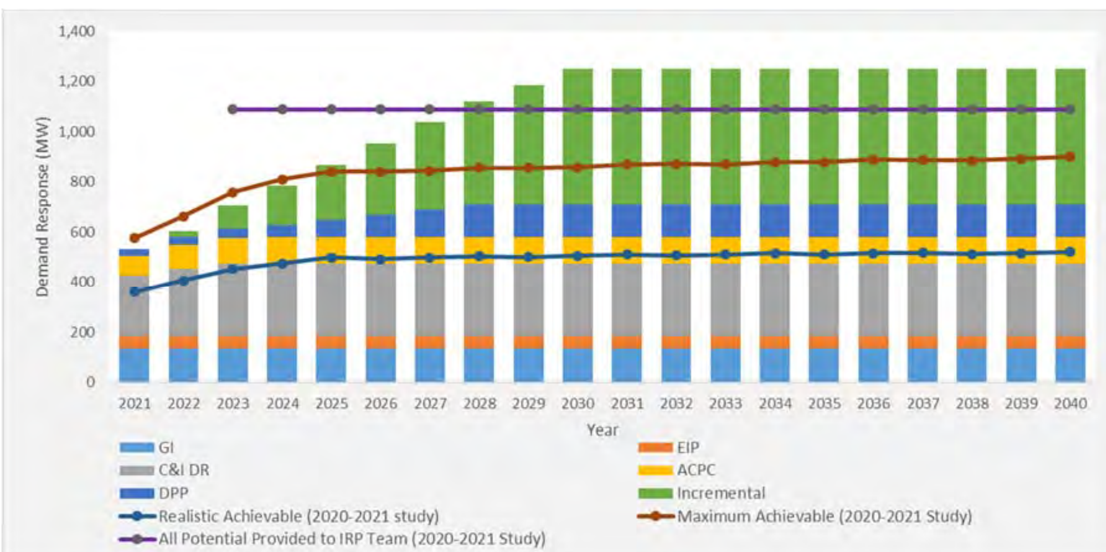
We organized this report as follows:

- Comparison of this study's results to the demand response projections in Consumers Energy 2018 Integrated Resource Plan
- Context for quantifying demand response market potential
  - Consumers Energy peak load characterization
  - Economic modeling framework
- Detailed findings from the residential sector
  - Air conditioning programs
  - Water Heater Direct Load Control program
  - Dynamic Peak Pricing program
- Detailed findings from the business sector
  - Load curtailment programs
  - Small business dynamic peak pricing program
- Appendices
  - Appendix A. Smart thermostat market share and penetration
  - Appendix B. Retention rates
  - Appendix C. Incorporating external studies into propensity scores
  - Appendix D. ACPC Detailed Inputs and Summary Outputs
  - Appendix E. BYOD Detailed Inputs and Summary Outputs

Comparison to Consumers Energy's 2018 Integrated Resource Plan

The demand response potential values adopted in the Consumers Energy 2018 IRP[2] proposed course of action were based on a statewide demand response potential study prepared by Applied Energy Group (AEG).[3] The AEG study did not directly estimate demand response potential for Consumers Energy service territory, so Consumers Energy's Resource Planning Team assigned a subset of the Lower Peninsula totals to its service territory using share of peak demand or number of electric customers. Figure 4 shows the projected demand response contribution by program from the 2018 IRP as stacked bars. The RAP and MAP estimates from this study are overlaid as blue and red lines, respectively. The purple line represents the full 1,090 MW of demand response potential presented to Consumers Energy's Resource Planning Team without economic screening. Beginning in 2023, Consumers Energy's Resource Planning Team will allow segments of demand response potential to compete with supply resources. The optimal mix of demand response and other resources will be determined based on levelized cost, operational characteristics, and other modeling constraints. Because of the dynamic nature of the system optimization software, it is possible that different Integrated Resource Plan scenarios will select different volumes of demand response.

Figure 4. Comparison of this Study's Findings with 2018 Integrated Resource Plan



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2 State of Michigan. June 15, 2018. "In the Matter of the Application of Consumers Energy Company for Approval of an Integrated Resource Plan under MCL 460.6t and for Other Relief." https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000231ujAAA

3 Applied Energy Group. September 29, 2017. "State of Michigan Demand Response Potential Study: Technical Assessment." Prepared for the Michigan Public Service Commission. https://michigan.gov/documents/mpsc/State_of_Michigan_-_Demand_Response_Potential_Report_-_Final_29sep2017__602435_7.pdf

During the first four years of the study horizon (2021 through 2025), our estimates of the demand response MAP are larger than the projections included in Consumers Energy's 2018 IRP. In 2026, our estimates of demand response potential plateau while the 2018 IRP projections continue to increase linearly through the end of the decade. In the second decade of the study horizon, our estimates of RAP are approximately 42%—and our estimates of MAP are approximately 72%—of the 2018 IRP projections. For this study, the Cadmus team incorporated several changes compared to the 2018 IRP and the 2017 AEG potential study:

- The 2018 IRP includes incremental potential beginning in 2022, which aligned the proposed course of action with the outputs of the 2017 AEG study, without allocating the megawatts to a specific Consumers Energy demand response program offering. In contrast, the Cadmus team only estimated potential from known and defined offerings. Especially in the second half of the study horizon, it is possible and even likely that new demand response technologies or program types will emerge and become economically viable that are not yet known and therefore not included in our estimates of demand response potential.
- We removed approximately 270 MW from the study peak load forecast to account for the expected impacts of residential default time-of-use (TOU) pricing and conservation voltage reduction. These two offerings represented 26% of the High Case demand response potential in the 2017 AEG study. The transition to default residential TOU pricing also negatively affected potential from the residential DPP program, which is much lower in our study than in the 2018 IRP. Additional detail on these and other adjustments to the peak load forecast is presented in the *Consumers Energy Peak Loads* section of this report.
- We used an avoided cost of generation capacity assumption of 75% of CONE to align with current Michigan energy waste reduction benefit-cost screening assumptions, while the 2017 AEG study used an avoided cost assumption of 100% of CONE. The Cadmus team also added 20% to all non-capital expenses to reflect the earnings adjustment mechanism (EAM). Both these differences resulted in lower potential in this study, all else equal.
- The 2017 AEG study largely used a top-down methodology. Where Michigan-specific numbers were used, they were largely taken from DTE Energy's experience with demand response programs. In contrast, for this study the Cadmus team used a number of bottom-up components with Consumers Energy–specific inputs, which was possible for several reasons:
  - There has been a significant proliferation of advanced metering infrastructure (AMI) since the 2017 AEG study was completed. The team anchored our approach in hourly AMI data collected for tens of thousands of homes and businesses.
  - Consumers Energy's demand response portfolio has grown exponentially since the 2017 AEG study and 2018 IRP were developed. This allowed the Cadmus team to replace secondary assumptions with primary data. Consumers Energy has also performed robust evaluation, measurement, and verification of its demand response offerings during the pilot phase, and the Cadmus team used those results to more precisely estimate demand reduction from program expansion.

    - Consumers Energy kept detailed records of marketing and customer acquisition activities for demand response programs. This allowed the Cadmus team to model the propensity of customers to adopt demand response and to align demand reduction with the cost of acquiring that reduction.

- Like the 2017 AEG study, we included multiple perspectives of demand response potential. This study provides estimates of MAP and RAP. The key outputs of the 2017 AEG study were "Realistic Achievable Potential – Integrated Low Case" and "Realistic Achievable Potential – Integrated High Case." The proposed course of action in Consumers Energy's 2018 IRP was based on the Integrated High Case. A key difference between this study and the 2017 AEG study is that the Cadmus team included variable program administration costs. The 2017 AEG study assumed the same program administration cost for the Low and High cases, while for this study the team assumed that it costs more to administer a large program than a small program.

Consumers Energy Peak Loads

To provide context for demand response market potential within broader IRP activities and to frame the magnitude relative to total system load, this chapter describes and characterizes the Consumers Energy peak load forecast the Cadmus team used for the study. One of the central goals of the IRP is to identify adequate resources to meet long-run projections of peak loads for the Consumers Energy service territory plus a reserve margin. Demand response is one of the resource types the Consumers Energy Resource Planning Team considers to satisfy the capacity requirements of the system. Other resource types include thermal generation, renewable generation, and energy waste reduction.

Consumers Energy Peak Load Forecast

Consumers Energy provided the Cadmus team with a base unadjusted peak load forecast for use in this market potential study, as well as the peak load impacts of items including retail open access customers, existing energy waste reduction, conservation voltage reduction, and transition to default TOU rates. The Cadmus team developed a "study" peak load forecast by subtracting the items listed above from the base unadjusted peak load forecast. The total magnitude of the adjustments by year are shown as green bars in Figure 5, and Table 2 provides a breakdown for select years. To develop an assumption about each sector's contribution to peak load, we examined the peak load contributions of the residential and business sectors on peak days in 2018 and 2019. After adding back the evaluated impacts from residential demand response events called on those 2018 and 2019 peak days, the residential sector accounted for 47% and the business sector accounted for 53% of the total peak load. Applying these values to the study peak load forecast resulted in the final disaggregated peak load forecast shown in Figure 5. The compound annual growth rate from 2021 through 2040 is 0.4%.

Figure 5. Disaggregated Peak Load Forecast, 2021 through 2040

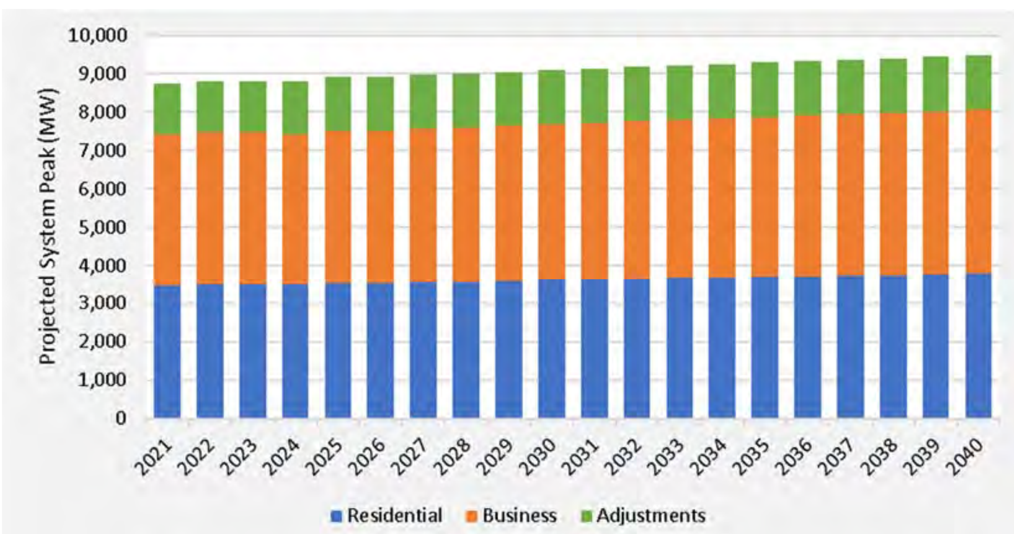


Table 2: Peak Load Forecast Adjustments in Select Years (MW)

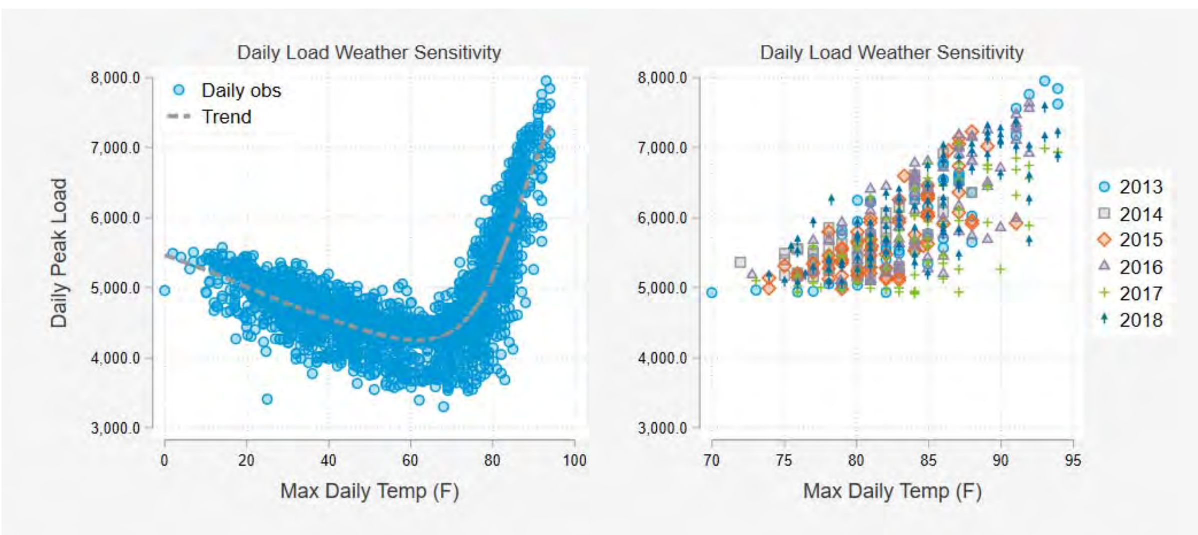
Adjustment Type	2022	2026	2030	2040
Installed Energy Waste Reduction	625	625	625	625
Retail Open Access Load	536	536	502	535
Default Residential Time-of-Use Pricing	119	152	152	152
Conservation Voltage Reduction	48	96	120	120

Characterization of Peak Loads

The primary use case for demand response resources considered in this study is to shave peak loads on high-demand days. Because the season, timing, and duration of peak loads can impact the ability of demand response resources to deliver peak load reduction, it is important to characterize the peak demand according to the following dimensions:

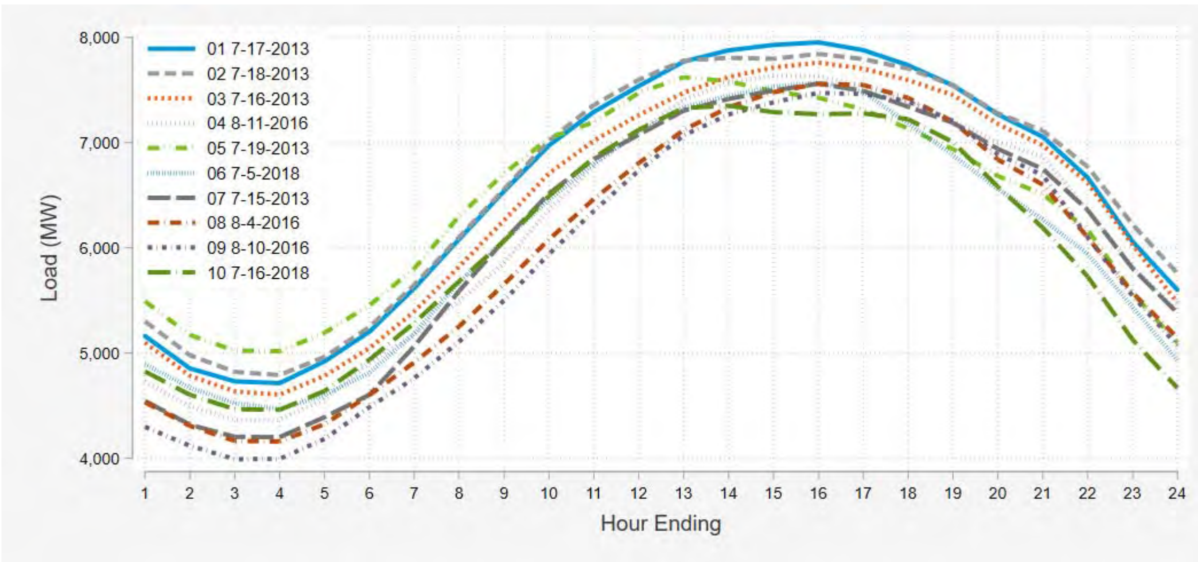
- ***Season of peak and weather sensitivity.*** Figure 6 shows the daily peak load versus daily maximum temperature for the top 100 highest load days within each year from 2013 to 2018. The Consumers Energy system has historically been summer-peaking, with summer loads that are roughly 2,000 MW higher than winter loads. We expect loads to continue to peak during the summer over the study horizon, so all potential presented in this study represents summer potential. The figure also shows that weather conditions are a major driver of the actual peak load within a given year. For instance, the peak load in 2013 was 7,953 MW but in 2014 peak load was only 6,915 MW, mostly due to changes in peak-day temperatures.

Figure 6. Daily Peak Load versus Daily Maximum Temperature



- ***Timing and duration of peak.*** The Consumers Energy system has historically peaked between 2 p.m. and 6 p.m., with peaks being relatively long (broad) in duration. For instance, for the highest load day, July 17, 2013, the total load was within 500 MW of the peak load for eight consecutive hours. Figure 7 shows the top 10 highest peak load days from 2013 to 2018. A relatively broad peak requires longer dispatch of demand response resources to fully shave peaks and avoid peak notching.

Figure 7. Load Profile for Ten Highest-Load Days, 2013 through 2018



Peak Load Weather Conditions

With weather being a key driver of peak loads as well as affecting certain demand response resources (such as air conditioning), it is important to define the weather conditions over which demand response potential is estimated and reported. The Cadmus team understands that the Consumers Energy peak load forecast represents expected peak loads under typical peak-day weather conditions (i.e., weather conditions that occur every other year). To be consistent with that approach, the Cadmus team reported the capacity of demand response resources under typical peak-day weather conditions (those that occur every other year), as determined from the last 10 years of weather at the Lansing Capital City Airport (the primary weather station used by Consumers Energy for weather analysis).

Figure 8 shows the maximum and mean daily temperatures on the highest-temperature days at the Lansing Capital City Airport from 2010 to 2019. Based on this weather history, we selected the peak day weather conditions for 2018—with a maximum daily temperature of 93 degrees Fahrenheit (°F) and a mean daily temperature of 82.7°F—to represent typical peak-day weather conditions.

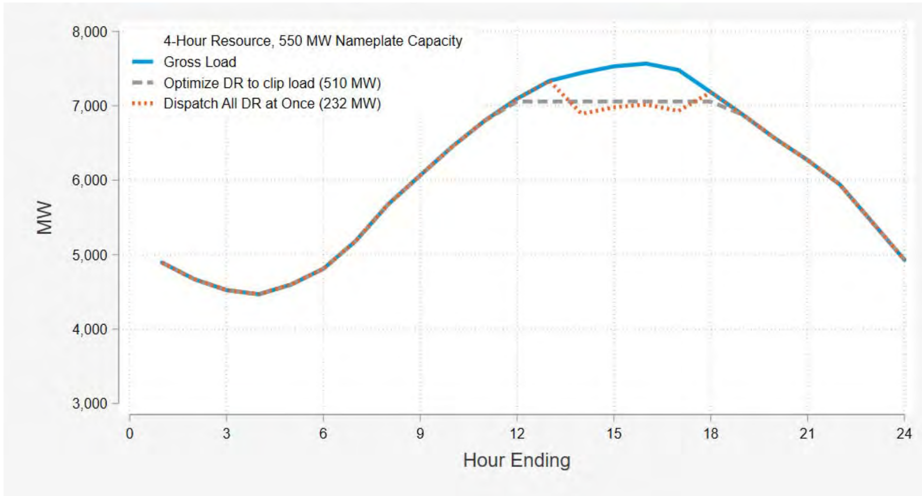
Figure 8. Lansing Capital City Airport Maximum and Mean Daily Temperature, 2010 through 2019

Effective Capacity

If peak loads are sufficiently high and long in duration, then the nameplate capacity of a demand response resource does not necessarily equal the load reduction that resource can actually deliver because demand response resources have a limited dispatch duration. Because the primary benefit of demand response is peak load reduction, it is necessary to develop an assumption about a demand response resource's ***effective capacity***; that is, the ratio of actual peak demand reduction for planning compared to the nameplate capacity of the demand response resource. In this section, we explain the concept of effective capacity in more detail and provide justification for the study's assumed effective capacity of 95% for residential demand response program and 100% for business sector demand response programs.

Figure 9 illustrates an instance where the nameplate capacity of a demand response resource does not equal the load reduction that resource can actually deliver. It shows two strategies for dispatching a four-hour 550 MW nameplate capacity demand response resource on a recent peak day (July 5, 2018). The dotted orange line shows the effect of dispatching of all demand response resources for the four highest-load hours. Under this strategy, the new peak demand is set the hour before the event and is only 232 MW lower than the original peak, and the effective capacity is only 42%. The dashed gray line represents a strategy that shaves peaks to a constant level by staggering dispatch of the resource. The new peak load is 510 MW lower than the old peak, for an effective capacity of 93%.

Figure 9. Illustration of Effective Capacity



To this point, we have looked only at the Consumers Energy ***gross*** loads. In practice, however, demand resonse resources will be dispatched against ***net*** loads, defined as the gross load minus output from variable renewable energy (such as solar generation).[4] Figure 10 illustrates the impact of a sufficiently large amount of solar (2,200 MW) on loads during a typical peak day compared to the case where there is no solar generation, using the average July solar shape for Michigan based on a solar production profile provided by the Consumers Energy Resource Planning Team. The figure shows that daytime solar generation tends to shift the system peak to later in the afternoon and to shorten the length of the peak, which in turn increases the effective capacity of demand response resources that are limited in duration. In this example, the demand response resource achieves 550 MW of load reduction (100% effective capacity), compared to 510 MW without solar (93% effective capacity). For reference, the 2018 IRP (Exhibit No. A-38) proposed course of action consisted of 2,200 MW of solar capacity by 2026 and 4,400 MW of solar by 2030, assuming a 50% capacity credit for solar.

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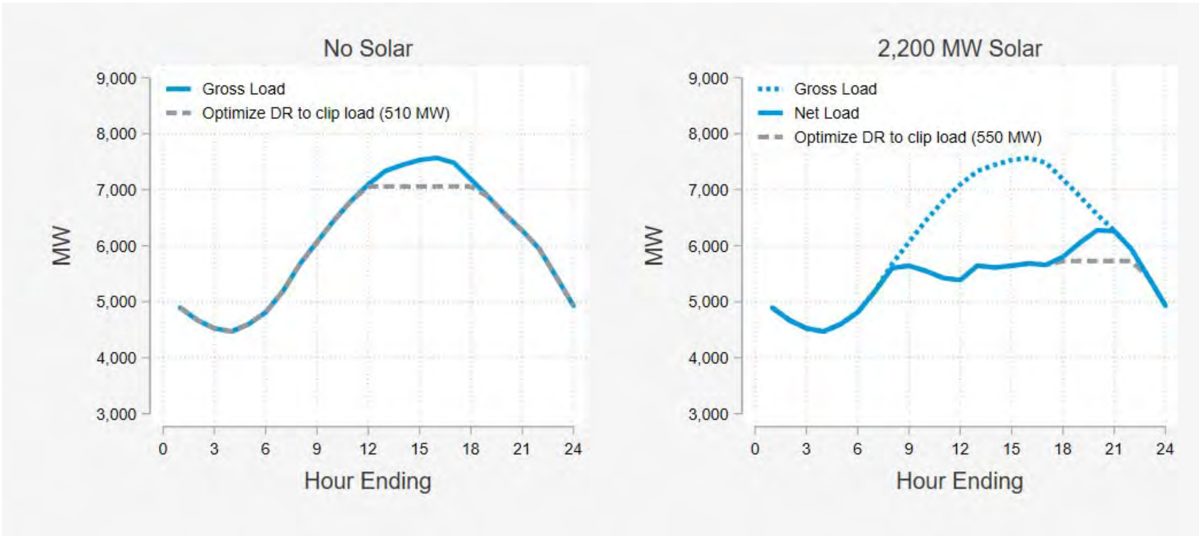
[4] Solar generation is relatively predictable, especially under summer peak conditions when cloud cover is typically low. By contrast, wind generation can vary substantially from day to day.

Figure 10. Impact of Solar on Demand Response Effective Capacity (Illustrative Example)



To inform the effective capacity assumption used in this analysis, the Cadmus team calculated the effective capacity for various quantities of solar and demand response capacity, assuming a four-hour duration. We varied the ***solar capacity*** from 500 MW to 5,000 MW using increments of 500 MW, using the Consumers Energy hourly load forecast for 2024 (which has a similar shape to the historical load shape) and the average July solar daily profile for Michigan, based on a solar profile provided by the Consumers Energy Resource Planning Team. We then varied the ***demand response capacity*** from 100 MW to 1,200 MW using increments of 100 MW.

Table 3 shows the effective capacity for each combination of solar and demand response capacity, with two key takeaways:

- ***Under expected near-term system conditions, the effective capacity is less than 100%.*** The 2018 IRP proposed course of action in 2022 includes approximately 500 MW of solar capacity and 600 MW of demand response capacity, shown in the blue cells of Table 3. The effective capacity ranges from 76% to 86%, and does not reach 100% because peak loads are sufficiently long in duration to require staggered dispatch of demand response resources over at least four hours in order to avoid setting new peaks before or after events.
- ***Under medium- and longer-term system conditions, the effective capacity approaches 100%.*** The 2018 IRP proposed course of action in 2025 and 2030 includes approximately 1,500 MW and 4,500 MW of solar capacity and could include from 600 MW to 1,100 MW of demand response resources in 2025 and 2030, respectively (shown in the green and yellow cells of Table 3). Under these conditions, which involve high levels of solar penetration, net loads are concentrated over only a few hours, and a four-hour duration demand response resource can shave peaks for the entire peak duration.

Table 3. Effective Capacity by Solar Capacity and Demand Response Quantity for a Four-Hour Resource

Demand Response Capacity (MW)	Solar Capacity (MW)												
	500	1,000	1,500	2,000	2,500	3,000	3,500	4,000	4,500	5,000	5,500	6,000	6,500
100	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
200	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
300	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
400	95%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
500	**86%**	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
600	**80%**	93%	**100%**	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
700	**76%**	87%	**99%**	100%	100%	100%	100%	100%	**100%**	100%	100%	100%	100%
800	71%	81%	**95%**	99%	100%	100%	100%	100%	**100%**	100%	100%	100%	100%
900	69%	78%	90%	96%	100%	100%	100%	100%	**100%**	100%	100%	100%	100%
1,000	66%	74%	87%	92%	100%	100%	100%	100%	**100%**	100%	100%	100%	100%
1,100	65%	71%	84%	90%	97%	100%	100%	100%	**100%**	100%	100%	100%	100%
1,200	63%	68%	81%	88%	93%	98%	100%	100%	100%	100%	100%	100%	100%

Note: The blue, green, and yellow boxes correspond to approximate solar conditions in 2022, 2025, and 2030 from the 2018 IRP proposed course of action, respectively.

In summary, our analysis shows that effective capacities are likely to be lower in the near term but reach 100% after sufficiently large quantities of solar capacity have come online. To reflect this trend, the Cadmus team assumed an effective capacity of 95% for all residential programs and for the business DPP program and of 100% for the three business load curtailment programs. The team differentiated between the two types of demand response because residential and business DPP programs are typically four-hour resources, while business load curtailment programs have more flexibility around dispatch criteria.

Economic Modeling Framework

This section describes the cost-effectiveness test the Cadmus team used in this study and the conceptual background behind the two types of potential (MAP and RAP) presented in this report.

Utility Cost Test

Demand response programs can be evaluated using various cost-effectiveness tests. The Cadmus team used the utility cost test (UCT), also known as the program administrator cost test, to evaluate Consumers Energy's demand response options. For each program, we calculated the UCT by comparing the net present value of that program's costs to the net present value of that program's benefits. A UCT ratio less than 1.0 indicates that the program costs exceed the program benefits, while a UCT value of 1.0 indicates that the program costs and benefits are identical and a UCT ratio greater than 1.0 indicates that the program benefits exceed the costs (and the program is therefore cost-effective). Table 4 summarizes the costs and benefits components for the UCT. The UCT does not include benefits to society at large such as avoided emissions. Table 5 summarizes other key assumptions, including the discount rate, inflation rate, and analysis period.

Table 4. Summary of Costs and Benefit Components

Type	Component
Costs [a]	Program equipment costs
	Program labor costs
	Program marketing costs
	Other program operations and maintenance costs
Benefits	Avoided capacity costs of generation (75% of CONE)
	Avoided energy costs

[a] All non-equipment costs incorporate an adder of 20% to reflect the EAM.

Table 5. Utility Cost Test Key Parameters

Parameter	Value	Source
Discount Rate	7.4%	Consumers Energy
Inflation	2%	
Analysis Time Period	20 years	
EAM	20%, applied to non-capital (non-equipment) costs	
Line Losses	3.7%	
Cost of New Entry	$94/kW-year, escalated with inflation	MISO
Effective Capacity	95% for all residential programs and for business DPP program; 100% for three business load curtailment programs	Cadmus team

Five key factors affect the cost-effectiveness of demand response programs:

1. ***The amount of load reduction (in kW) offered by each participant:*** Load reductions must be sufficiently high to produce program net benefits. All else equal, higher load reductions result in higher potential.
2. ***The avoided capacity and energy costs:*** Avoided generation capacity costs comprise the majority of demand response benefits in this analysis, and were valued at $70.50/kW-year,

equal to 75% of the MISO Local Resource Zone 7 CONE. Benefits also come in the form of avoided energy costs, which are the difference between summer on-peak and off-peak energy prices, assuming that demand response events are largely energy neutral and that customers simply shift use from on-peak periods to off-peak periods.

3. ***The amount of capacity enrolled in each program by year:*** Program enrollment affects the level of aggregate benefits for each program and whether the program is cost-effective when including overhead costs. The amount of capacity reflects line losses and the assumed effective capacity (as opposed to nameplate capacity).
4. ***The fixed and variable costs of each program:*** Variable costs, including the costs of equipment and installation, marketing, and labor, must be less than per-customer benefits for the program to be cost-effective at the margin. Fixed costs are not affected by program size, but factor into cost-effectiveness. See the following section for a more detailed description of costs.
5. ***Key financial assumptions:*** Assumptions such as the discount rate and analysis period affect program potential.

Categorization of Costs

Table 6 summarizes the possible cost categories for each program. Costs are categorized as either fixed or volumetric – based on whether they scale directly with program enrollments – and are incurred on either a one-time or a recurring basis. For instance, annual incentives are volumetric recurring costs because they are paid to each participant each year, while equipment and installation costs are volumetric one-time costs because they are incurred only once. Marketing costs are described in more detail within each section, as are "other" costs, which are specific to each program. All cost assumptions were developed based on Consumers Energy's historical program expenditures or forecast of program expenditures, with the Cadmus team including an adder of 20% to all non-equipment costs to reflect the additional cost of the EAM.

Table 6. Cost Categorization

Component	Cost Type	Cost Frequency
Equipment	Volumetric	One time
Installation Labor	Volumetric	One time
Other One-Time Costs	Volumetric	One time
Support Labor	Fixed	Recurring
	Volumetric	
Sign-Up Incentive	Volumetric	One time
Annual Incentive	Volumetric	Recurring
Other Direct Costs	Volumetric	Recurring

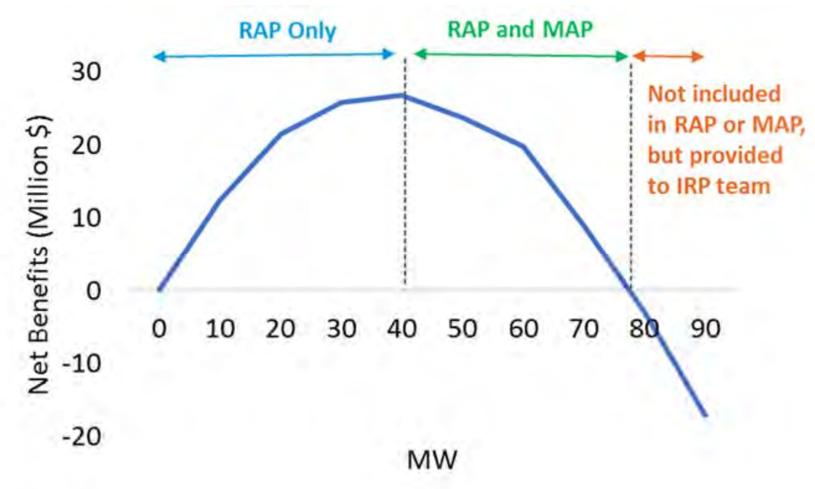
Maximum Achievable Potential and Realistic Achievable Potential

This report presents two estimates of potential—***MAP*** and ***RAP***—that correspond to different perspectives of program costs and benefits (as summarized in Figure 1):

- For each program, the ***maximum achievable potential*** is the quantity of demand response that makes the program exactly cost-effective (where benefits are equal to costs and the UCT is 1.0). The MAP is the maximum quantity of demand response that a program can procure cost-effectively under the UCT.
- For each program, the ***realistic achievable potential*** includes only demand response capacity increments where marginal benefits exceed marginal cost (that is, the quantity of demand response that maximizes the UCT). The RAP, a subset of MAP, is the quantity of demand response that maximizes the net benefits of the program.

Figure 11 further illustrates the relationship between MAP and RAP, using a hypothetical demand response program. The horizontal axis represents the quantity of demand response, while the vertical axis represents the cumulative net benefits associated with that quantity of demand response. The MAP, 80 MW, corresponds to the point where the net benefits curve intercepts the x-axis and is associated with a UCT of 1.0. The RAP, 40 MW, corresponds to the peak of the curve and is associated with a UCT ratio of 1.6. All MAP and RAP values presented in this report are consistent with this representation.

Figure 11. Illustration of Maximum Achievable Potential and Realistic Achievable Potential



Levelized Costs

The Cadmus team also calculated the levelized costs for **all** demand response program segments for the Consumers Energy Resource Planning Team to use in the 2021 IRP (not just resources included in RAP or MAP). Whereas RAP and MAP present estimates of potential based on a defined avoided cost, 75% of CONE, the use of levelized costs allows for all demand response resources to be compared to other supply-side resources for selection in the 2021 IRP in a dynamic modeling setting that may result in a different quantity of demand response resources selected than presented in MAP or RAP. Figure 12 shows the supply curve of demand response by levelized cost, in increments of $5/kW-year, for all new demand response resources, which consists of both expansions to existing programs and entirely new programs (498 MW of existing demand response resources are not shown). The avoided cost used in this study, 75% of CONE, is shown in green for reference. All demand response segments above $120 per kilowatt-year are shown as having a cost of $170 per kW-year, the capacity-weighted average cost of these segments. This final tranche of resources above $120 per kW-year is connected to the granular supply curve with a dotted blue line in Figure 12.

Figure 12. Levelized Cost Tranches for New Demand Response Resources

Detailed Findings: Residential Sector

Table 7 shows the breakdown of 2040 potential for all residential programs. The 20-year MAP across the four residential programs totaled 241 MW and the RAP totaled 178 MW, equal to 6.4% and 4.7% of the residential peak load forecast in 2040. The BYOD program had the largest MAP (62% of the residential total), followed by the ACPC (34% of total) and the residential DPP (4% of total) programs. The Water Heaters program did not pass the cost-effectiveness test, yielding a MAP of 0 MW. The distribution of potential among programs is similar for RAP. Table 8 shows the MAP and RAP by residential program for select years within the study horizon.

Table 7. Residential Maximum and Realistic Achievable Potential by Program (Cumulative to 2040)

Program	MAP MW	MAP Percentage of 2040 Residential Peak Load	RAP MW	RAP Percentage of 2040 Residential Peak Load
ACPC	82	2.2%	73	1.9%
BYOD	149	4.0%	97	2.6%
Residential DPP	9	0.2%	9	0.2%
Water Heaters	0	0.0%	0	0.0%
Total [a]	**241**	**6.4%**	**178**	**4.7%**

[a] Total row may not equal the sum of program values due to rounding

Table 8. Residential Maximum and Realistic Achievable Potential by Program (Cumulative by Year)

Program	Maximum Achievable Potential (MW)				Realistic Achievable Potential (MW)			
	2022	2026	2030	2040	2022	2026	2030	2040
ACPC	82	82	82	82	77	73	73	73
BYOD	79	149	149	149	58	97	97	97
Residential DPP	6	8	8	9	5	7	8	9
Water Heaters	0	0	0	0	0	0	0	0
Total [a]	**167**	**239**	**240**	**241**	**140**	**176**	**177**	**178**

[a] Total row may not equal the sum of program values due to rounding

The following sections present the methodology and results for the four residential programs. The Cadmus team evaluated ACPC and BYOD using the same methodology, and these are presented together, followed by the Water Heaters and residential DPP programs.

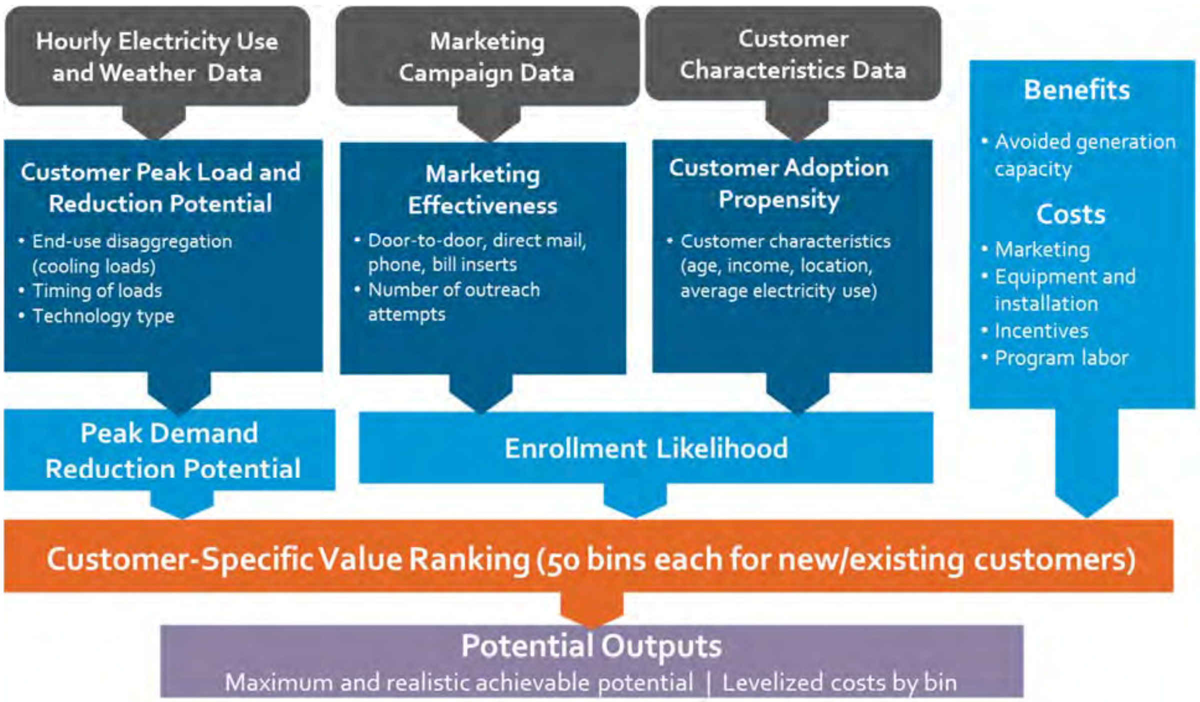
Residential Air Conditioning Programs (ACPC and BYOD)

The ACPC and BYOD programs achieve peak demand reduction by controlling residential customers' air conditioning use on event days. As of February 2021, approximately 77,000 customers were enrolled in the ACPC program and roughly 25,000 customers were enrolled in the BYOD pilot's successor – the Smart Thermostat program. The two programs rely on different technologies: load control switches in the case of ACPC and smart thermostats in the case of BYOD. For this study, we divided program eligibility based on whether customers have a smart thermostat or not. In future years, the thermostat program makes up the majority of the enrollments as smart thermostat become more ubiquitous and load control switches are not necessary for load control (*Appendix A. Smart Thermostat Market Share and Penetration* provides more detail).

Methodology

Figure 13 summarizes the key data sources and analysis steps the Cadmus team used to calculate the MAP and RAP for ACPC and BYOD. We calculated the costs and benefits of enrollment for 50 representative segments of new program participants and 50 representative segments of existing program participants (for a total of 100 segments), based on customers' summer energy use and weather sensitivity. To develop the MAP and RAP, we screened each segment for cost-effectiveness based on its expected peak load reduction, projected participation rates, and the cost of customer acquisition and retention. The MAP and RAP consist of different customer segments according to the results of the cost-effectiveness analysis.

Figure 13. Residential Air Conditioning Methodology Summary



Data Sources

Table 9 provides more detail on each data source the team used for the ACPC and BYOD programs. These include hourly electricity use and weather data, marketing campaign data, and customer characteristics data (as depicted at the top of Figure 13 above, in dark gray).

Table 9. Residential Air Conditioning Program Data Sources

Data Source	Source	Notes
Hourly Electricity Use Data	Consumers Energy	Data from May through September 2019 were provided for a random sample of 10,000 customers from the population of demand response participants and 10,000 customers from the population of nonparticipants [a]
Weather Data	National Oceanic and Atmospheric Administration	Obtained for Lansing Capital City Airport (Consumers Energy uses temperatures from this location for demand response dispatch strategies)
Marketing Campaign Data	Consumers Energy	Provided for 19 marketing campaigns for demand response programs undertaken in summer 2019
Customer Characteristics Data	Consumers Energy	Provided for all residential customers

[a] Of the 10,000 demand response participants for which we had hourly data, approximately 7,000 were ACPC participants (the remainder had participated in residential DPP or an EV Tariff). We confirmed that the customers in each sample did not systematically differ from the full customer population by comparing the distribution of key customer characteristics in each sample to the full population.

Customer Segmentation

The magnitude of air conditioner load and reduction potential varies with weather conditions, hour of the day, and the degree of control. The devices can be instructed to pre-cool the home, to set back the air conditioner run time, or to curtail energy use completely. However, there is a wide variation in air conditioner use across customers due to variation in occupancy patterns, home size, and customer preferences. Some customer segments have more air conditioner peak load to curtail, and are thus more cost-effective to enroll. The Cadmus team made the critical decision to divide the population of existing and new customers (or participants and nonparticipants) into 50 segments each to assess the load reduction potential and cost-effectiveness for each. We used these customer segments to identify which customers are included in the MAP and the RAP.

Because only certain types of customers are cost-effective to enroll in air conditioning programs, the team developed segments that could be readily applied by the Consumers Energy Demand Response Team. In particular, we used metrics that can be calculated from a customer's monthly billing data. The first axis of segmentation was daily average electricity use, and the second was based on customer weather sensitivity, which the Cadmus team measured as the correlation between monthly electricity use and monthly cooling degree days using a base of 60°F. We segmented customers into 10 use categories and five weather sensitivity categories, based on the distribution of use and weather sensitivity within the nonparticipant population. Doing so for participants and nonparticipants yielded a total of 100 segments.[5]

To estimate the expected reduction for each segment, we first used the hourly electricity use data for 20,000 customers to estimate the cooling loads as a function of weather. The approach allowed the

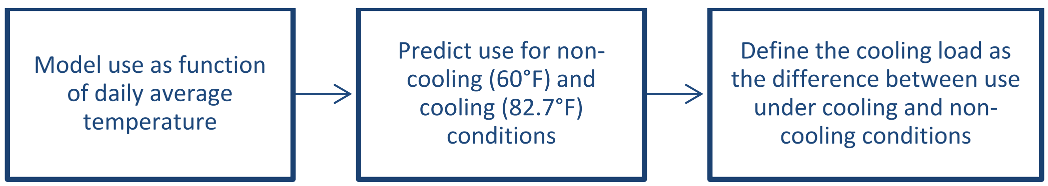
[5] Because we conducted the segmentation based on the nonparticipant population, the nonparticipants were evenly distributed among the 10 use categories and five weather sensitivity categories, while the participants were not necessarily evenly distributed across the categories.

Cadmus team to produce hourly cooling load profiles under different temperature conditions. We generated cooling load estimates for each of the 20,000 customers, then aggregated the results into customer segments used to analyze potential and cost-effectiveness.

Hourly Cooling Loads

Figure 14 shows the basic steps the Cadmus team used to calculate cooling loads for each of the 20,000 customers for which we had detailed hourly electricity use data. The size of customer cooling loads may be the most important factor in the potential for demand reduction from air conditioning demand response programs. The higher the cooling load, the greater the potential for load reduction.

Figure 14. Cooling Load Calculation Process



As the first step in calculating hourly cooling loads, the team modeled customer use as a function of daily average temperature by analyzing the historical variation in use for each customer *i* at hour *t*:

$$kW_{i,t} = \beta_0 + \beta_1 * spline55_{i,t} + \beta_2 * spline60_{i,t} + \beta_3 * spline65_{i,t} + \beta_4 * spline70_{i,t} + \beta_5 * DayOfWeek_{i,t}$$

The variables from spline55 to spline70 represent spline functions of the daily average temperature in increments of 5°F (0°F to 55°F, 55°F to 60°F, 60°F to 65°F, 65°F to 70°F, and above 70°F), which allows for different temperature responses within each temperature range rather than using a single coefficient for temperature. The day of week indicator variable captures additional differences in individual customer behavior attributable to day-specific use patterns. Finally, the team excluded days when demand response events were called from the regression equations for demand response participants.

As the second step in calculating hourly cooling loads, the Cadmus team predicted each customer's use under two average daily temperatures at the Lansing Capital City Airport: under 60°F non-cooling conditions and under a range of weather conditions, including 82.7°F (corresponding to average peak weather conditions).[6]

Predicted use for the first temperature condition (60°F) represents each customer's use when cooling equipment is off or operating at a very low level. We refer to this level of use as the base non-cooling load. Predicted use under the second temperature condition (82.7°F) represents each customer's expected use when cooling equipment is used. Therefore, each customer's cooling load is simply the difference between their total use under cooling conditions and their base non-cooling load. For example, if a customer's base non-cooling load is 2 kW and their predicted use is 3 kW at 82.7°F, then their cooling load is 1 kW at 82.7°F. For each hour, the cooling load is the portion of load that increases

[6] We selected the day of week as Wednesday. In general, the day of week coefficients were not statistically significant.

with temperature, while the base non-cooling load is always the same, regardless of underlying temperature conditions.[7]

Figure 15 shows the distribution of cooling load from 2 p.m. to 6 p.m. for the sample of ACPC participants and nonparticipants, under typical peak-day weather conditions. ACPC participants had larger average cooling loads than nonparticipants, which is expected because some nonparticipants lack central air conditioning and the program has historically targeted higher usage customers.

Figure 15. Distribution of Cooling Loads (2 p.m. to 6 p.m.) for ACPC Participants versus Nonparticipants

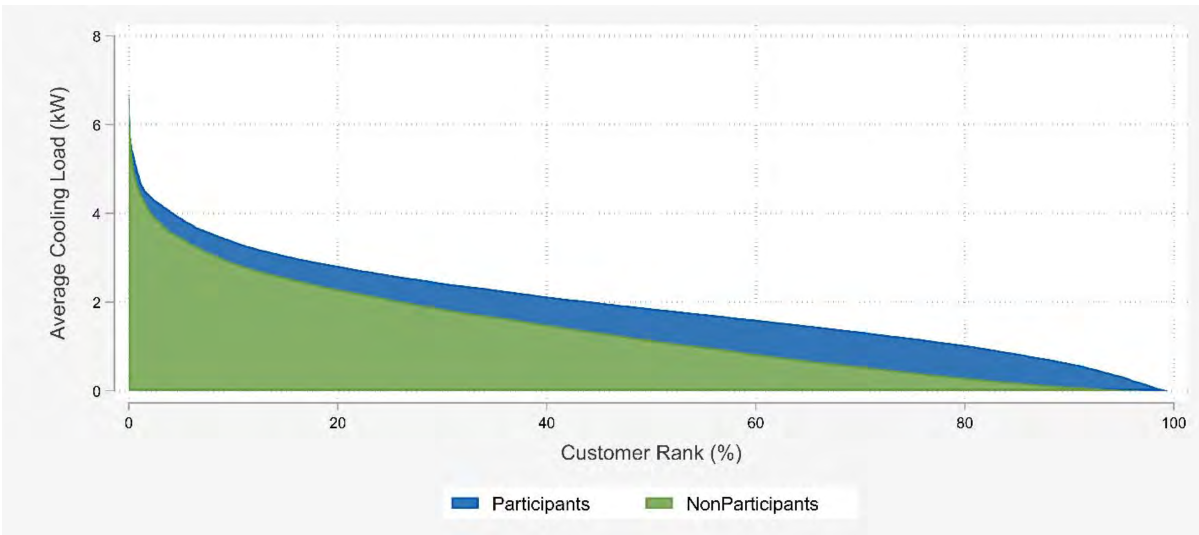


Figure 16 shows the average nonparticipant cooling load from 2 p.m. to 6 p.m. among the 10 use categories and five weather sensitivity categories. The 10 lines correspond to the 10 use categories and the five spaced markers on each line correspond to the five weather sensitivity categories. As expected, the cooling loads calculated from the hourly electricity use data are positively correlated with the daily average use and weather sensitivity derived from monthly billing data, with the highest cooling loads belonging to customers who have both high use and high weather sensitivity.

[7] As noted previously, Consumers Energy is transitioning to TOU rates for residential customers in 2021. For ACPC and BYOD, we assumed that cooling loads do not change in response to TOU rates, as cooling loads represent only a portion of total electricity usage. For the residential DPP program, described in the next section, we assumed that customers' total electricity consumption is reduced by 3.3% during on-peak times in response to TOU rates.

Figure 16. Average Cooling Load by Use and Weather Sensitivity Segments for Nonparticipants

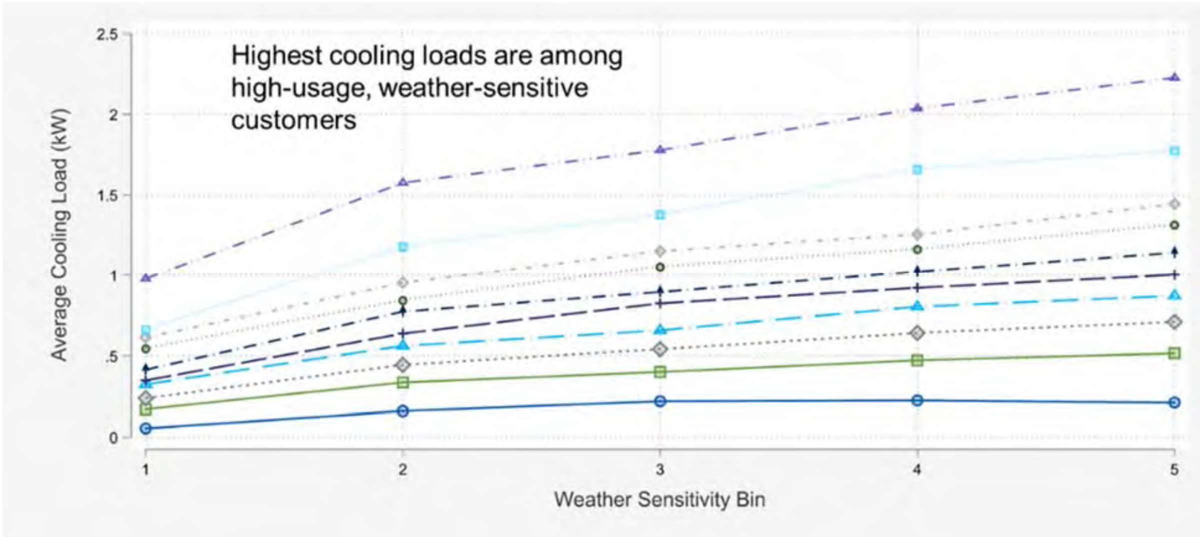
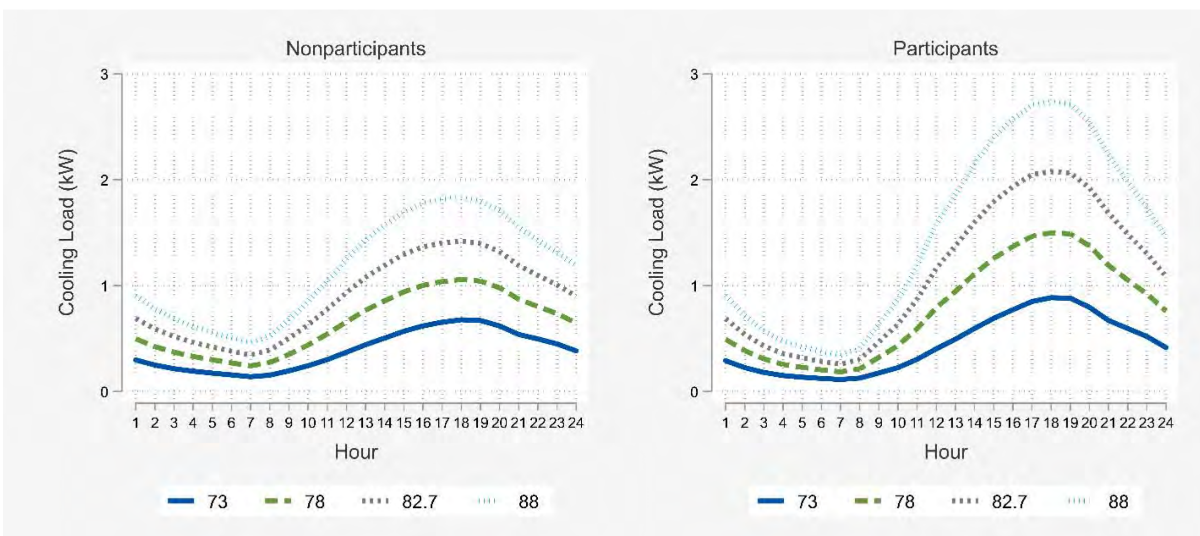


Figure 17 shows the mean nonparticipant cooling load as a function of daily average temperature for nonparticipants and ACPC participants. Cooling loads vary substantially with average daily temperatures, so the peak load reduction for residential air conditioning programs will vary based on weather conditions at the event time.

Figure 17. Hourly Cooling Loads by Temperature Condition, ACPC Participants versus Nonparticipants



Demand Reduction Percentage

To reduce peak demand, load control devices limit the run-time of the air conditioner compressor or a thermostat modifies the temperature settings. In both instances, the utility implements algorithms to achieve a higher or lower percentage of demand reduction but must balance the decision against incentive levels and customer comfort.

To date, Consumers Energy has used a 50% adaptive cycling algorithm for the ACPC program, which achieves air conditioner load reduction of 40% to 50%. To maximize potential, we recommend modifying the algorithm to allow for 75% cycling, only during emergency conditions, thus delivering larger reduction when the energy is needed most. Duke Energy Ohio and Duke Energy Indiana currently use higher cycling algorithms for emergency conditions. Customers enroll in either a moderate load control option (50% cycling) or a high load control option (66% cycling). However, when emergency conditions require, the affected utility dispatches both options using a 75% cycling algorithm.

Figure 18, drawn from a randomized control trial of over 48,000 air conditioners by Duke Energy Ohio, shows a comparison of the reduction under normal operations to reduction using the algorithm reserved for emergency conditions. Duke Energy Ohio measured the impacts using whole-building and end-use air conditioner data (with a smaller sample). Air conditioners reduced demand by 65% using the algorithm reserved for emergency conditions. We therefore assume 65% reductions in cooling load for the ACPC program.

Figure 18. Emergency Operations (75% Cycling) versus Moderate Operations (50% Cycling)

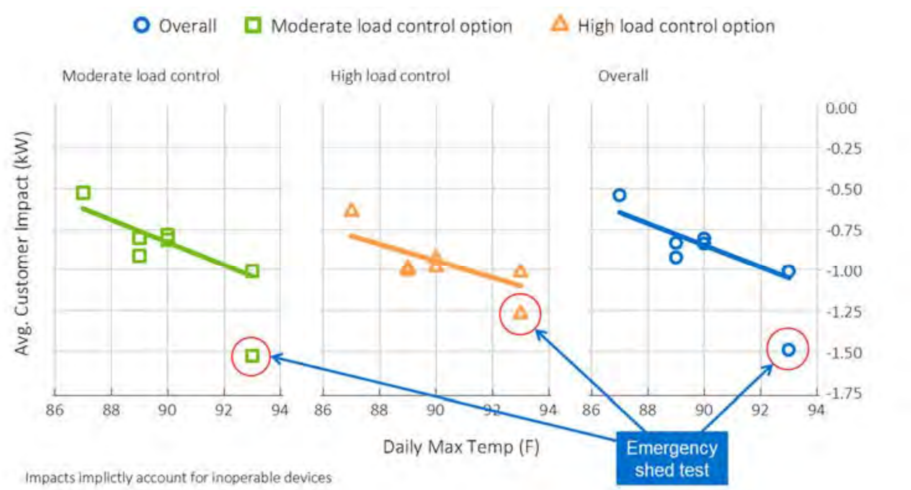


Image source: Duke Energy Ohio. 2016. "Power Manager Evaluation."

For thermostats, the attainable demand reduction depends on the customer's use of pre-cooling and how they adjust temperature settings during the event. On the peak day for the 2019 BYOD pilot participants, shown in Figure 19, the thermostats reduced air conditioner demand by 87.8% by relying on pre-cooling in advance of the shed event. The Cadmus team assumed an 80% reduction to the cooling load for each segment.

Figure 19. Bring Your Own Device Program Demand Reduction on 2019 Peak Day

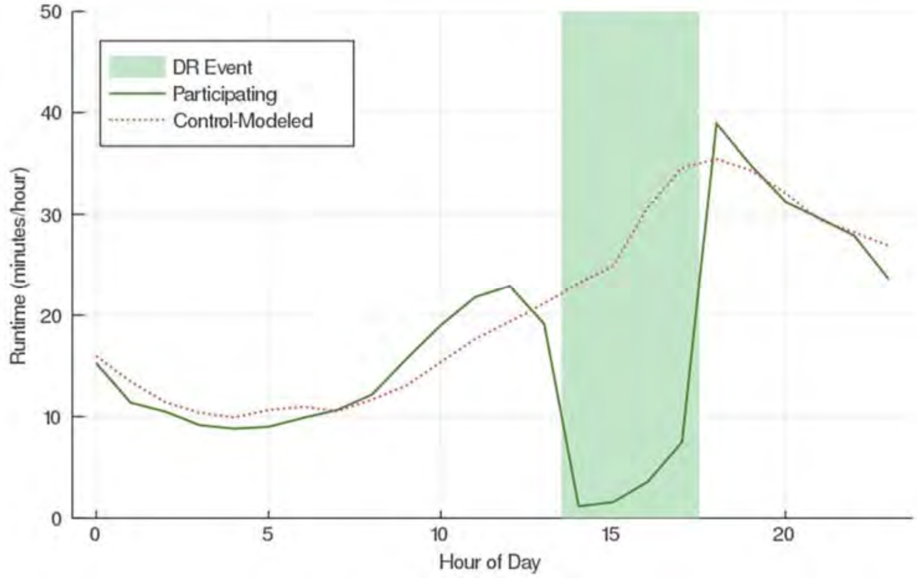


Image source: Consumers Energy. Summer 2019. "Orchestrated Energy Impact Analysis."

Enrollment Likelihood

Enrollment rates are a central element of estimating achievable demand response potential. The magnitude of demand response resources that can be acquired is fundamentally the result of customer preferences, program or offer characteristics (including incentive levels), marketing tactics, and how extensively programs are marketed.

In recent years, Consumers Energy has tracked marketing efforts for the ACPC and residential DPP programs, and provided the Cadmus team with data on the 2019 marketing effort, which included over 600,000 customers and 19 recruitment campaigns. This data showed which program was marketed to each customer (ACPC or residential DPP), the mode of communication (direct mail, phone, or email), how many times each customer was recruited, and the outcome. This data provided an empirical basis for the Cadmus team to identify which customer segments were more likely to enroll and how marketing techniques and intensity affected enrollment rates.

The 2019 historical marketing data had some limitations, however:

- It did not fully reflect the enrollment levels that could be attained with multiple years of attempts.
- There was limited variability in customer incentives.
- Not all recruitment modes were tested for each program (all of the recruitment for the DPP programs was conducted via email).
- The 600,000 customers were not targeted at random.
- Some of the planned marketing was designed to increase customer awareness of demand response (such as bill inserts and social media), but we lacked the empirical tests to quantify their effect. As a result, we used the Consumers Energy data to calibrate the adoption

propensity scores but also incorporated information from studies in California and New York to reflect the impact of specific marketing tactics. Our method for incorporating external studies is discussed in *Appendix C. Incorporating External Studies into Propensity Scores*.

Enrollment rates are influenced by sign-up incentives and the total number and mode of recruitments attempts. Table 10 shows the assumptions about the level of recruitment attempts, which reflect the cumulative efforts over five years. For the mode and volume of marketing tactics, the Cadmus team incorporated input from the Consumers Energy Demand Response Team.

Table 10. Residential Air Conditioning Marketing Assumptions

Marketing Mode	Cost per Attempt	EAM Multiplier	ACPC Attempts	BYOD Attempts
Door-to-door (door knock)	$10.00	120%	0	0
Phone (three attempts)	$1.25	120%	0	0
Direct mail	$1.00	120%	6	6
Email	$0.01	120%	20	20
Bill inserts	$0.05	120%	20	20
Social media	$0.02	120%	20	20

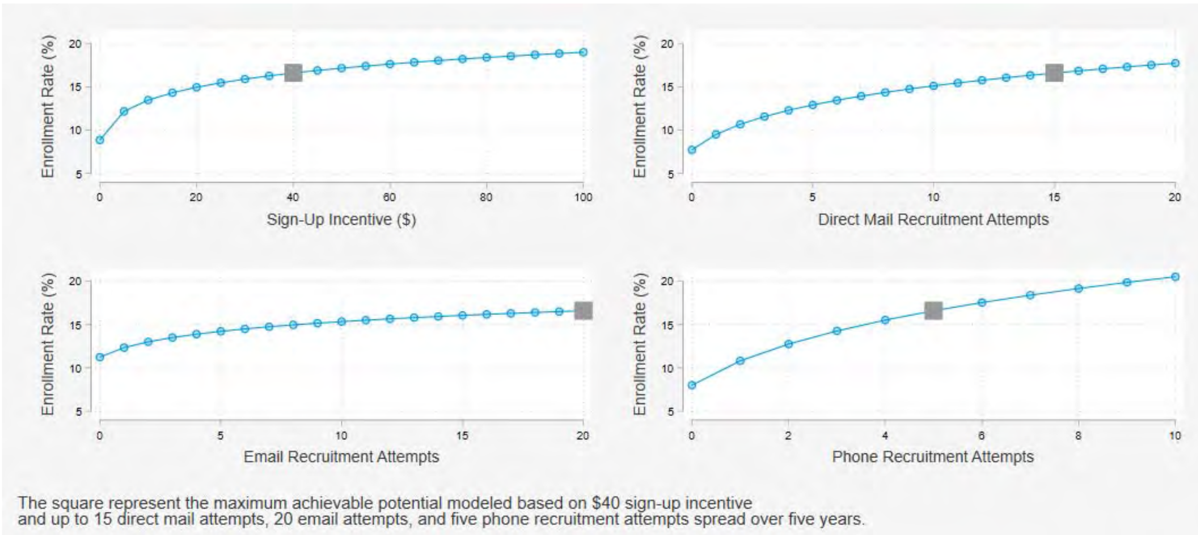
Both sign-up incentives and mode of recruitment attempts have diminishing returns. The enrollment yield is higher in the first enrollment attempt using a certain mode than in subsequent attempts but, in aggregate, multiple recruitment attempts produce higher enrollments. Table 11 shows the coefficients for specific marketing tactics.[8] Because the adoption propensity score model is non-linear, it is easier to show how recruitment tactics influence enrollment visually, as in Figure 20. Each panel in the figure shows the impact of different marketing levels on program enrollment likelihood over five years, holding all other aspects constant. The large square represents the assumed marketing tactics for this study and the line show how changing one tactic at a time influences the expected enrollment rate. In each case, the use of the tactic had positive but diminishing returns.

Table 11. Marketing Propensity Probit Coefficients

Marketing Mode	Probit Coefficient
Door-to-door outreach	0.362
Natural log of phone recruitment	0.242
Natural log of direct mail recruitment	0.163
Natural log of sign up incentive	0.102
Natural log of email recruitment	0.080

8 Probit models are based on a cumulative normal distribution (an S-curve). The coefficient represents the change in normalized standard deviations due to a one-unit change in the variable. The effect magnitude depends on a segment's starting point. If a customer is strongly pre-disposed against enrollment, the marketing efforts do not increase enrollment likelihood much, but if a customer is more pre-disposed to enrollment, an additional recruitment attempt or higher incentive can increase enrollment likelihood and result in enrollment.

Figure 20. Enrollment Rate Sensitivity to Changes in Marketing Tactics



Eligible Customer Populations

Enrollment rates are combined with an eligible customer population to determine the total possible participant population for each program. For this study, we assumed that only customers with smart thermostats enroll in BYOD and only customers without smart thermostats enroll in ACPC. We divided eligible customers into the ACPC and BYOD programs based on the projected natural penetration levels in 2030. This assumption was driven by the fact that Consumers Energy is undertaking a concerted effort to increase the market share of smart thermostats, which will accelerate adoption above naturally occurring adoption. *Appendix A. Smart Thermostat Market Share and Penetration* details the Cadmus team's full assumptions regarding the natural adoption of smart thermostats and eligible customer population split over time.

Figure 21 shows the final potential enrollments and eligible customers for all 50 ACPC and BYOD nonparticipant segments, with each segment's enrollment probability corresponding to the expected share of population participating in that segment. Across the 50 segments, the expected enrollment rate after five years of marketing is 15.9% of the population. Since only 60.4% of Consumer Energy's residential customers have central air conditioners, attaining the potential involves enrolling 24.8% (15.9%/60.4%) of air conditioner units in its territory. The split between ACPC and BYOD simply reflects the reality that Consumers has already installed a substantial amount of switches. The variation in results reflects the propensity of different customer segments to enroll in an air conditioner load control program based on the marketing to date, with projected enrollment rates that reflect marketing over five years. Finally, note that these values represent the enrollment rates for all 50 ACPC and BYOD nonparticipant segments, but not all segments are cost-effective and, thus, not all segments are included in the estimates of RAP and MAP.

Figure 21. Enrollment Probabilities by Segment

Usage Decile	Weather Correlation Decile	Population	ACPC Potential Participants	BYOD Potential Participants	Total Participants	Participation Rate
01 Bottom 10%	01 Bottom 20%	76,202	1,148	4,680	5,828	7.6%
	02 20-40%	38,564	454	1,939	2,393	6.2%
	03 40-60%	19,899	308	1,247	1,555	7.8%
	04 60-80%	11,723	173	703	876	7.5%
	05 Top 20%	6,479	102	413	515	8.0%
02 10-20%	01 Bottom 20%	49,207	1,291	4,594	5,884	12.0%
	02 20-40%	37,638	845	3,128	3,973	10.6%
	03 40-60%	32,239	1,080	3,220	4,299	13.3%
	04 60-80%	20,207	745	2,034	2,779	13.8%
	05 Top 20%	13,420	724	1,490	2,213	16.5%
03 20-30%	01 Bottom 20%	41,803	1,744	5,488	7,232	17.3%
	02 20-40%	33,165	1,182	3,883	5,065	15.3%
	03 40-60%	29,000	1,706	3,732	5,438	18.8%
	04 60-80%	28,228	1,577	3,713	5,290	18.7%
	05 Top 20%	20,516	1,641	2,986	4,627	22.6%
04 30-40%	01 Bottom 20%	27,766	1,318	4,001	5,320	19.2%
	02 20-40%	34,707	1,367	4,370	5,737	16.5%
	03 40-60%	31,314	1,879	4,345	6,224	19.9%
	04 60-80%	32,548	2,084	4,561	6,645	20.4%
	05 Top 20%	26,377	2,214	4,023	6,237	23.6%
05 40-50%	01 Bottom 20%	26,686	973	3,177	4,150	15.6%
	02 20-40%	31,005	1,479	3,675	5,155	16.6%
	03 40-60%	31,931	2,322	4,002	6,324	19.8%
	04 60-80%	31,468	2,916	4,078	6,993	22.2%
	05 Top 20%	31,776	2,873	4,412	7,284	22.9%
06 50-60%	01 Bottom 20%	21,596	736	2,446	3,182	14.7%
	02 20-40%	26,532	1,447	2,574	4,021	15.2%
	03 40-60%	33,165	2,527	3,897	6,424	19.4%
	04 60-80%	34,861	2,754	3,910	6,664	19.1%
	05 Top 20%	36,558	3,240	4,571	7,811	21.4%
07 60-70%	01 Bottom 20%	18,202	497	1,710	2,207	12.1%
	02 20-40%	30,234	1,307	2,591	3,897	12.9%
	03 40-60%	33,782	2,397	3,419	5,816	17.2%
	04 60-80%	35,478	2,365	3,326	5,691	16.0%
	05 Top 20%	35,170	3,088	3,640	6,728	19.1%
08 70-80%	01 Bottom 20%	17,122	540	1,486	2,026	11.8%
	02 20-40%	24,989	1,209	2,029	3,239	13.0%
	03 40-60%	32,085	2,171	2,926	5,097	15.9%
	04 60-80%	34,399	2,581	3,126	5,707	16.6%
	05 Top 20%	43,962	2,646	4,594	7,240	16.5%
09 80-90%	01 Bottom 20%	13,574	582	1,818	2,400	17.7%
	02 20-40%	26,069	1,469	2,794	4,263	16.4%
	03 40-60%	31,776	1,922	3,852	5,774	18.2%
	04 60-80%	35,324	2,505	4,257	6,763	19.1%
	05 Top 20%	46,122	3,045	6,032	9,078	19.7%
10 Top 10%	01 Bottom 20%	13,574	318	1,164	1,481	10.9%
	02 20-40%	22,367	1,091	1,562	2,652	11.9%
	03 40-60%	30,388	1,836	2,569	4,405	14.5%
	04 60-80%	41,186	1,976	3,311	5,287	12.8%
	05 Top 20%	45,042	2,527	3,883	6,410	14.2%

Other Program Assumptions

Program assumptions for ACPC and BYOD for non-cost program elements and equipment and labor costs are shown in Table 12 and Table 13. There are several notes on particular program assumptions:

- ***Weather conditions:*** The weather conditions chosen for program planning (82.7°F average daily temperature) corresponds to typical peak-day weather conditions. Per-participant reductions would be larger under more extreme weather conditions.
- ***Marketing efforts:*** The team modeled program potential under a five-year marketing scenario. Since Consumers Energy has not marketed programs for more than five years, this required us to extrapolate the marketing impacts observed to date to match more aggressive marketing efforts than have occurred in the past. Lower marketing efforts will result in fewer enrollments.
- ***Cooling load reduction:*** As discussed in previous sections, we assumed that cooling loads are reduced by 65% for ACPC participants and by 80% for BYOD participants. For ACPC, the assumed load reduction would require the Consumers Energy Demand Response Team to modify the dispatch strategy currently in use.
- ***The hour when demand is measured:*** We assumed that demand response potential targets the hour from 6 p.m. to 7 p.m. In 2018 and 2019, Consumers Energy called the majority of events from 2 p.m. to 6 p.m. The Cadmus team assumed a later peak hour because of the planned procurement of solar capacity, which will shift Consumers Energy's net loads to later in the day, but notes that cooling loads are lower earlier in the day.
- ***Existing versus new participants:*** As of January 2020, roughly 72,000 participants were enrolled in ACPC and 2,000 participants were enrolled in BYOD. We assumed that existing participant levels will be maintained and only counted the costs of ongoing maintenance (including the replacement of customer attrition). For new enrollees, the team included all the costs of recruitment, installation, and ongoing maintenance.

Table 12. Residential Air Conditioning Non-Cost Assumptions

Parameter	ACPC	BYOD
Expected Equipment Useful Life	20	15
Retention Rate	94%	94%
Percentage Reduction in Cooling Load	65%	80%
Event Duration	4 hours	4 hours
Effective Capacity	95%	95%
Peak Hour Definition	6 p.m. to 7 p.m.	6 p.m. to 7 p.m.
Peak Hour Weather Conditions	82.7°F mean, 93°F max	82.7°F mean, 93°F max

- ***Cost assumptions.*** Cost assumptions, including the EAM multiplier assumption, are shown in Table 13. Equipment and installation costs are based on Consumers Energy's historic equipment and installation costs. The "other" volumetric one-time costs of $65 for ACPC reflect the costs of labor to support installations, including setting up visits, coordinating them, and responding to customer questions. The "other" volumetric one-time costs of $35 for BYOD reflect API fees for commissioning the device. Support labor has both a fixed overhead component and a variable component to account for additional labor to support additional installations. The sign-up incentive and annual incentives were based on current program budgets and experience. Finally, we include a $35 recurring volumetric "other" cost for BYOD to cover annual vendor fees for thermostat control.

Table 13. Residential Air Conditioning Cost Assumptions

Component	Cost Type	Cost Frequency	Value	EAM Multiplier	Value	EAM Multiplier
			ACPC		BYOD	
Equipment	Volumetric	One time	$83	100%	$15	100%
Installation Labor	Volumetric	One time	$81	100%	-	100%
Other One-Time Costs	Volumetric	One time	$65	100%	$34	120%
Support Labor	Fixed	Recurring	$100,000	120%	$866,000	120%
	Volumetric	Recurring	$7.50	120%	$1	120%
Sign-Up Incentive	Volumetric	One time	$25	100%	$75	100%
Annual Incentive	Volumetric	Recurring	$24	120%	$25	120%
Other Direct Costs	Volumetric	Recurring	-	120%	$35	120%

Cost-Effectiveness Results

The key objective of cost-effectiveness modeling was to calculate the total costs and benefits and the corresponding UCT ratio for each of the 100 customer segments in the ACPC and BYOD programs. The major factors for determining cost-effectiveness were each customer segment's peak load reduction, enrollment likelihood, and cost of acquisition and retention.

Table 14 shows the MAP and RAP for ACPC and BYOD for select years of the analysis period. There are several factors for Consumers Energy to consider when viewing these potential values:

- ***The BYOD program shows higher MAP and RAP than the ACPC program.*** This is due to higher assumed load reduction per participant and lower customer acquisition costs, and represents a change from the 2018 IRP, which did not include smart thermostat programs but reflected an ACPC potential of 103 MW by 2023.
- ***For these ACPC potential results, the Cadmus team assumed a more aggressive cycling pattern than is currently practiced.*** We assumed that air conditioning units will be more aggressively cycled—only under emergency conditions—to provide larger load reduction, a strategy that has been adopted by other utilities in the case of system emergencies, and which can increase ACPC cost-effectiveness and potential.

- ***The BYOD program will take longer to ramp to full capacity than the ACPC program.*** The ACPC program has 77,000 customers enrolled as of February 2021, compared to 25,000 enrollments for BYOD. The MAP implies enrollments of roughly 81,000 participants for ACPC and 101,000 participants for BYOD.
- ***Results are contingent on assumed weather conditions and time of day.*** As stated above, demand reduction and hence overall potential will increase if the peak day temperature is higher than typical peak-day weather conditions. On the other hand, if peak loads do not shift to slightly later in the day (6 p.m. to 7 p.m.) as assumed here, the amount of peak load reduction from air conditioning programs will be lower.

Table 14. Residential Air Conditioning Maximum and Realistic Achievable Potential by Year

Program	Maximum Achievable Potential (MW)					Realistic Achievable Potential (MW)				
	2022	2026	2030	2040	UCT	2022	2026	2030	2040	UCT
ACPC	82	82	82	82	**1.3**	77	73	73	73	**1.7**
BYOD	79	149	149	149	**1.0**	58	97	97	97	**1.2**

Table 15 shows the modeling outputs the Cadmus team provided to Consumers Energy's Resource Planning Team by levelized cost for both programs, in groups of $10 per kW-year. Each group is comprised the existing and new customer segments. These outputs are not constrained by the 75% of CONE assumption for the avoided cost of generation capacity used in the MAP and RAP estimates. This presents the IRP model with all load curtailment potential, absent economic screening so that the model can optimize the quantity of resources selected based on economics and other characteristics.

Table 15. Residential Air Conditioning Levelized Costs by Program

	ACPC		BYOD	
Levelized Cost ($/kW-year)	Marginal Incremental MW	Cumulative Incremental MW	Marginal Incremental MW	Cumulative Incremental MW
$30	14.7	14.7	0	0
$40	23.1	37.8	13.9	13.9
$50	19.6	57.4	36.7	50.6
$60	8.3	65.7	22.7	73.3
$70	6.2	71.8	20.3	93.5
$80	1.3	73.2	19.9	113.4
$90	3.4	76.6	13.3	126.7
$100	1.3	77.9	12.9	139.6
$110	1.0	78.9	3.2	142.9
$120	0.1	79.0	3.7	146.6
Greater than $120	3.3	82.3	29.2	175.8

Water Heater Direct Load Control Program

Water heater direct load controls use switch technologies to control the electric water heater loads of participating customers. As of 2019, Consumers Energy did not offer a full-scale water heater direct load control demand response program, but proposed in Case U-20563[9] to conduct a pilot in 2020 called Customized Load Control Switch that targets residential water heaters as well as pool pumps and hot tub controls.

Methodology

To calculate the potential for the residential Water Heaters program, the team assumed that all homes have the same load reduction and cost of acquisition. As with other programs, we applied the EAM to all costs except the costs of equipment (capital). The full set of program and cost assumptions are displayed in Table 16 and Table 17.

Table 16. Water Heater Direct Load Control Program Assumptions

Component	Value	Source/Notes
Demand Reduction per Participant	0.3 kW at meter	Based on review of other summer afternoon water heater direct load control impacts
Participation Rate	15% (56,800 total participants)	The participation rate helps to determine the program size but has almost no impact on cost-effectiveness
Expected Useful Life of Equipment	20 years	Determined in conjunction with Consumers Energy
Effective Capacity	100%	Cadmus team assumption
Retention Rate	100%	

Table 17. Water Heater Cost Assumptions

Component	Cost Type	Cost Frequency	Value	EAM Multiplier	Source
Equipment	Volumetric	One time	$120	100%	California and South Carolina programs
Installation Labor	Volumetric	One time	$100	120%	
Other One-Time Costs	Volumetric	One time	$25	120%	Consumers Energy
Support Labor	Fixed	Recurring	$40,000	120%	
	Volumetric	Recurring	$5	120%	
Sign-Up Incentive	Volumetric	One time	-	-	
Annual Incentive	Volumetric	Recurring	$25	120%	
Other Direct Costs	Volumetric	Recurring	-	-	

One of the most important assumptions is the per-participant demand reduction. Because no data were available that directly applied to the Consumers Energy territory, the Cadmus team reviewed verified summer demand response load impacts from water heaters in other jurisdictions, summarized in Figure 22 and taken from a prior Cadmus evaluation of water heater demand impacts.[10] Demand

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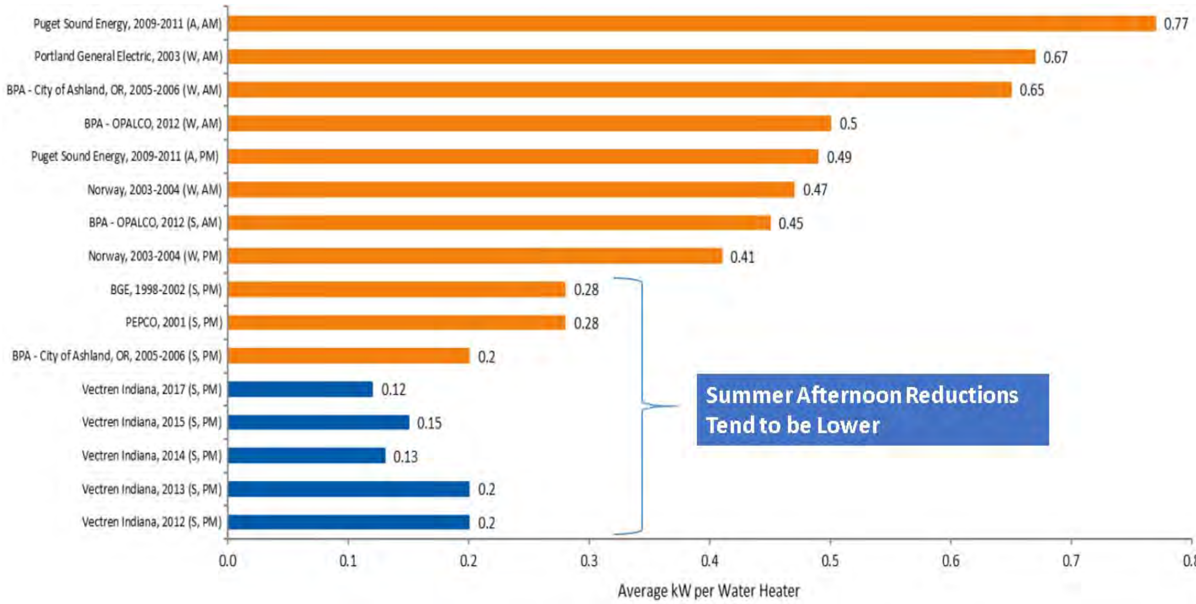
9 Consumers Energy. May 31, 2019. "Application and Testimony and Exhibits of Consumers Energy Company Witnesses Patrick C. Ennis, Laura M. Collins, Rachel L. Dziewiatkowski, David B. Hays, Derek D. Kirchner, Svitlana Lykhytska, Emily A. McGraw, and Richard A. Morgan in Case U-20563." https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000004n8OaAAI

10 Cadmus. January 26, 2017. *Summer Cycler Program 2017 Impact Evaluation Report.* p. 35. Prepared for Vectren Energy Delivery of Indiana. https://vectren.com/assets/downloads/planning/irp/IRP-2017-summer-cycle-evaluation.pdf

reductions for summer afternoon events are lower than for winter and morning events, because water heaters use less energy on summer afternoons. Based on this review, the team assumed a summer demand reduction of 0.3 kW per participant, the upper range from industry benchmarking.

Figure 22. Verified Demand Reduction Jurisdictional Review for Water Heaters



Cost-Effectiveness Results

Under the program assumptions described above, the Water Heaters program had a UCT ratio of 0.42 (and was not cost-effective). As a result, the MAP and RAP is zero. The Cadmus team did present 18 MW of water heater direct load control potential to the Consumers Energy Integrated Resource Planning Team at a levelized cost of $197/kW-year. The program would be cost-effective (with a UCT of 1.0 or greater) if the average demand reduction were 0.71 kW, which corresponds to a resource of 42 MW at the system level (including line losses). We recommend that Consumers Energy use the results from the Customized Load Control Switch pilot evaluation, when completed, as values for future program planning. No water heater programs were included in the 2018 IRP proposed course of action.

Dynamic Peak Pricing Program

Consumers Energy currently offers two residential dynamic peak pricing (DPP) program rates to customers: Critical Peak Pricing (CPP) and Peak Time Rewards (PTR).[11] Both rates help customers to manage their electric costs by reducing load during peak pricing event hours. PTR customers face the same volumetric rate schedule as standard residential accounts, while CPP participants receive a discounted rate during off-peak hours. Consumers Energy can deem up to 14 peak pricing events per year, where customers either earn (for PTR) or are charged (for CPP) $0.95 per kilowatt-hour relative to

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[11] CPP is also referred to as Residential with Dynamic Pricing (RDP). https://peakpowersavers.com/cpp
PTR is also referred to as Residential with Dynamic Peak Rebate (RDPR). https://peakpowersavers.com/time

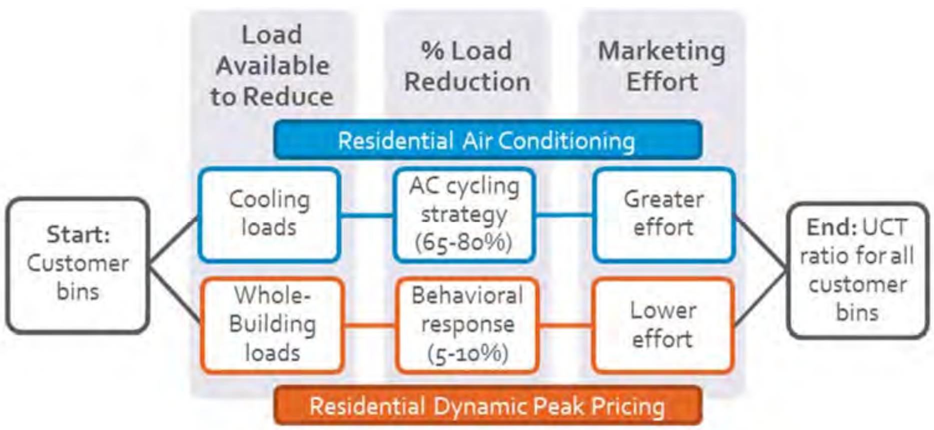
a baseline. As of January 2020, approximately 8,000 customers were enrolled in CPP and 21,000 customers were enrolled in PTR.

When considering the potential attributable to the residential DPP program, it is important to consider that Consumers Energy is planning to implement default summer TOU rates for residential customers starting in 2021, in which on-peak prices will be roughly 1.5 times higher than off-peak prices.[12] The new TOU rate will incent all customers to shift energy use away from peak periods on a daily basis. The introduction of default TOU rates for all customers will eliminate the residential DPP load reduction attributable to the TOU rate structure in previous years (a reduction that should be counted within the impact of default TOU rates), leaving only the event-day impacts.

Methodology

The methods the Cadmus team used to produce the MAP and RAP for residential DPP were similar to the methods we used for the residential air conditioning programs. The most important methodological difference is the approach used to calculate the assumed load reduction for program participants. Other key differences are the assumed marketing efforts, retention rates, and incentive and equipment costs, as summarized in Figure 23.

Figure 23. Residential Air Conditioning and Dynamic Peak Pricing Methodology Comparison



Data Sources

The Cadmus team relied on the same data sources as for the residential air conditioning programs, plus one additional data source, the *2019 Peak Time of Use Pricing Plans Program Annual Evaluation Report*, produced by Cadmus for Consumers Energy, which the Cadmus team used to calculate the percentage of load reduction for the PTR and CPP rates.

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12 The transition to a default TOU was originally scheduled for summer 2020, but is now scheduled to be delayed to summer 2021 as a result of the coronavirus pandemic.

Load Reduction Percentages

As discussed above, Consumers Energy historically provided economic incentives through the residential DPP program to reduce energy use on all summer days (via TOU rates), and provided an additional incentive on event days via increased costs of electricity use during event windows. Moving forward, PTR participants will face the default residential pricing structure with a provision to earn credits on pricing event days. Table 18 provides the verified load reduction on all summer days and on event days from the *2019 Peak Time of Use Pricing Plans Program Annual Evaluation Report*. Load reduction is provided in terms of demand (kilowatts) and on a percentage basis, relative to a 2.4 kW reference load. The *Annual Evaluation Report* found that customers on CPP reduced electricity use by 2.9% on all summer days as a result of the TOU rate and an additional 9.4% on event days, while PTR customers reduced use by 4.6% on all summer days and an additional 5.7% on event days.

Table 18. Residential Dynamic Peak Pricing Load Reduction Assumptions

Parameter	CPP	PTR	Source/Notes
Reference Load	2.40	2.40	Cadmus. *2019 Peak Time of Use Pricing Plans Program Annual Evaluation Report.*
Non-Event Weekday Impact (kW)	-0.07	-0.11	
Non-Event Weekday Impact (%)	-2.9%	-4.6%	Used the price response on non-event days to estimate TOU
Event Weekday Impact (kW)	-0.22	-0.13	Cadmus. *2019 Peak Time of Use Pricing Plans Program Annual Evaluation Report.*
Event Weekday Impact (%)	-9.4%	-5.7%	Used the price response on event days on top of everyday impact to estimate load reduction

To develop estimates of future load reduction attributable to the residential DPP program—accounting for the transition to default TOU rates—the Cadmus team started with total whole-building loads for each customer segment, calculated from the hourly AMI electricity use data as described in the *Residential Air Conditioning Programs (ACPC and BYOD)* section. To capture the effect of default TOU, we reduced whole-build loads by 3.3% for the hours over which TOU was active (1 p.m. to 8 p.m.). The Cadmus team determined the peak-period impact of 3.3% using elasticities developed from the CPP and PTR verified load reduction for all summer non-event weekdays (the average load reduction was 2.9% for CPP and 4.6% for PTR). Next, to estimate the impact of peak-period pricing provisions, we applied an additional load reduction of 9.4% for CPP and 5.7% for PTR, consistent with the values in the *Annual Evaluation Report*. The team assumed the peak period impact to be the mean impact from 5 p.m. 7 p.m., which accounts for shifting peak loads to later in the afternoon due to greater solar capacity.

Marketing Efforts

Table 19 shows the assumed marketing effort for the residential DPP program. The Cadmus team used the same marketing coefficients presented in the *Residential Air Conditioning Programs (ACPC and BYOD)* section. We assumed that marketing is conducted only via email, as modeling indicates that the marginal cost of more expensive marketing modes is greater than the marginal benefit and decrease the overall program cost-effectiveness (this is also consistent with the Consumers Energy Demand Response Team's current marketing strategy). With a lower marketing effort assumed, the mean propensity to enroll was 3.0%.

Table 19. Dynamic Peak Pricing Program Marketing Costs and Attempts by Mode

Marketing Mode	Cost per Attempt	EAM Multiplier	Attempts
Email	$0.01	120%	6
Door-to-door	$10.00	120%	0
Phone (three attempts)	$1.25	120%	0
Direct mail	$1.00	120%	0
Bill inserts	$0.05	120%	0
Social media	$0.02	120%	0

Other Program Assumptions

There are several notes about particular assumptions for the residential DPP program (summarized in Table 20 and Table 21):

- ***Volumetric costs:*** Compared to other residential programs, DPP rates have lower total volumetric upfront costs because no equipment is required for program participation. However, the $25 sign-up incentive is difficult to overcome for customer segments with low peak loads.
- ***CPP/PTR split:*** The Cadmus team combined CPP and PTR into a single residential DPP program for reporting purposes. We assumed that one-third of customers would enroll in CPP and two-thirds would enroll in PTR, based on the historical enrollment ratio between the two programs.
- ***Retention rate:*** The assumed 85% retention rate, based on the historical retention rate, is lower than for other residential programs and reduces the amount of program potential. *Appendix B. Retention Rates* includes additional details regarding the residential DPP program retention rate.

Table 20. Dynamic Peak Pricing Program Assumptions

Component	Cost Type	Cost Frequency	Value	EAM Multiplier
Equipment	Volumetric	One time	-	-
Installation Labor	Volumetric	One time	-	-
Other One-Time Costs	Volumetric	One time	-	-
Support Labor	Fixed	Recurring	$100,000	120%
	Volumetric	Recurring	$5	120%
Sign-Up Incentive	Volumetric	One time	$25	120%
Annual Incentive	Volumetric	Recurring	-	-
Other Direct Costs	Volumetric	Recurring	-	-

Table 21. Dynamic Peak Pricing Program Other Assumptions

Component	Value	Notes
CPP / PTR Enrollment Split	33% / 67%	Based on historical CPP/PTR enrollment split
Effective Capacity	95%	Consistent with residential effective capacity assumption
Retention Rate	85%	Calculated from historical enrollment data

Cost-Effectiveness Results

The key objective of cost-effectiveness modeling was to calculate the total costs and benefits and the corresponding UCT ratio for each customer segment in DPP. Key factors for cost-effectiveness include each segment's peak load reduction, probability of enrollment, and cost of customer acquisition and retention. Table 22 shows the MAP and RAP for DPP for select years of the analysis period.

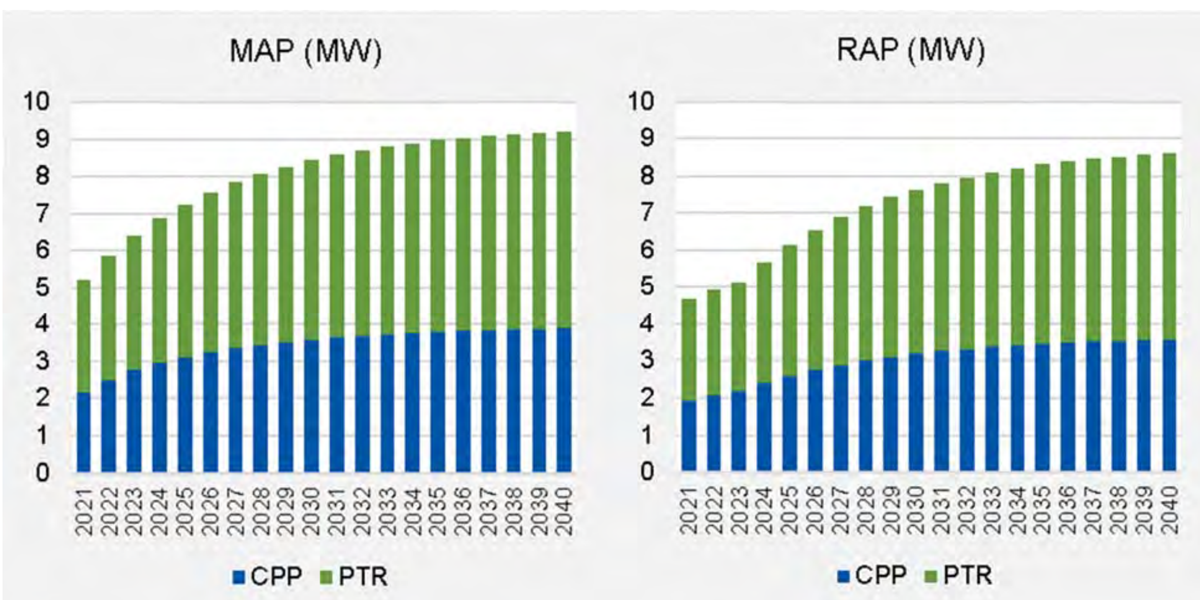
Table 22. Residential Dynamic Peak Pricing Potential by Year and Modeling Perspective

Program	Maximum Achievable Potential (MW)					Realistic Achievable Potential (MW)				
	2022	2026	2030	2040	UCT	2022	2026	2030	2040	UCT
Residential DPP	6	8	8	9	**1.0**	5	7	8	9	**1.1**

Figure 24 shows the program potential over time. Combined, the CPP and PTR rates have a MAP of 9.2 MW and a RAP of 8.6 MW in 2040. There are several reasons for the relatively low estimates of program potential:

- ***With the introduction of default TOU rates, rate plan impacts are not counted as peak load reduction.*** The rate plan impacts that are currently attributable to CPP and PTR disappear with the default TOU rates, leaving only event-day impacts. Including rate plan impacts would increase the total impact by approximately 50%, with a larger effect on potential.
- ***With low demand reduction and high customer attrition, only the highest use customers are cost-effective.*** It is difficult to overcome the $25 sign-up incentive in particular, given the low per-customer impacts and low retention rate**.**
- ***The current marketing efforts are limited to digital strategies.*** This limits the enrollment, yet more effective (but more expensive) marketing efforts are not supported.

Figure 24. Residential Dynamic Peak Pricing Potential by Year and Potential Type



Our analysis shows significantly lower potential than the potential approved in the 2018 IRP. The 2018 IRP peak demand reduction was 24 MW in 2020, ramping up to 131 MW in 2028. The MAP presented here, 9.2 MW, is only 7% of the potential listed in the 2018 IRP. In addition to the general notes listed in the *Comparison to Consumers Energy's 2018 Integrated Resource Plan* section (such as different CONE assumptions), one key reason for the difference in estimated demand reduction is that the rollout of default TOU is treated as a forecast adjustment in this study. Accounting for the transition to residential default TOU pricing in the peak demand forecast reduces the load reduction potential of residential DPP offerings. A second key reason for the difference is that the assumed load reductions in the AEG study—19% in the low case and 28.6% in the high case—are more than twice as high as those the Cadmus team determined in this potential study (9.4% for CPP and 5.7% for PTR) based on our evaluation of the residential DPP program.

The Cadmus team presented the residential DPP program to Consumers Energy Integrated Resource Planning Team in two blocks, consistent with the MAP and RAP scenarios in the previous tables. The first block was simply the RAP and associated costs, while the second block was the incremental megawatt impacts from MAP to RAP and the marginal cost of the expanded program footprint.

Detailed Findings: Business Sector

The Cadmus team estimated business sector MAP and RAP of approximately 660 MW and 343 MW by 2040, respectively. Table 23 shows the estimated megawatts of demand response potential by program type along with the share of Consumers Energy's 2040 business sector peak load forecast it represents.

Table 23. Maximum and Realistic Achievable Potential by Business Sector Program (Cumulative to 2040)

Program	MAP MW	MAP Percentage of 2040 Business Peak Load	RAP MW	RAP Percentage of 2040 Business Peak Load
Business DPP	13	0.3%	6	0.1%
Business DR	469	11.0%	243	5.7%
EIP rate[13]	48	1.1%	25	0.6%
GI rate[14]	131	3.1%	68	1.6%
Total [a]	**660**	**15.4%**	**343**	**8.0%**

[a] Total row may not equal the sum of program values due to rounding

Table 24 shows the MAP and RAP, by business program, for select years within the study horizon.

Table 24. Maximum and Realistic Achievable Potential by Business Sector Program (Cumulative by Year)

Program	Maximum Achievable Potential (MW)				Realistic Achievable Potential (MW)			
	2022	2026	2030	2040	2022	2026	2030	2040
Business DPP	5	12	12	13	3	6	6	6
Business DR	313	412	428	469	169	217	228	243
EIP rate	48	48	48	48	26	25	26	25
GI rate	131	131	131	131	71	69	70	68
Total [a]	**497**	**602**	**619**	**660**	**268**	**317**	**329**	**343**

[a] Total row may not equal the sum of program values due to rounding

[13] The Energy Intensive Primary (EIP) Rate is available to any Full Service electric metal melting customer taking service at the Company's Primary Voltage levels, where the electric load on this rate is utilized for industrial metal melting processes such as electric arc or induction furnaces or to any Full Service electric industrial customer who qualified as energy intensive. See sheet D-74 at https://www.consumersenergy.com/-/media/CE/Documents/rates/electric-rate-book.ashx?la=en&hash=3A1AD0D43993427E419F0FA34720246E7879A6CC

[14] The General Interruptible (GI) Rate is available to any customer account willing to contract for at least 500 kW of On-Peak Billing Demand as interruptible. See sheet D-64 at https://www.consumersenergy.com/-/media/CE/Documents/rates/electric-rate-book.ashx?la=en&hash=3A1AD0D43993427E419F0FA34720246E7879A6CC

Business Load Curtailment Programs (EIP Rate, GI Rate, and Business Demand Response)

Load curtailment is a class of demand response programs where customers agree to reduce load upon request in exchange for a financial incentive, which can be tariff-based or a supplemental payment contract:

- ***Tariff-Based:*** Participants are assigned to a tariff with more favorable billing determinants in exchange for agreeing to have a portion of their load interrupted or operations curtailed in response to direction from the utility or grid operator. Because the financial mechanism is embedded in rates, the EAM does not apply to these offerings.
- ***Payment Contract:*** Participants enter a separate contract with the utility or grid operator to curtail load upon request. Generally, the program administrator will specify the dispatch parameters and participants will commit to reducing a certain amount of load upon dispatch for one or more years.

Consumers Energy's current offerings include both types of financial incentives. Table 25 provides a high-level overview, with system-level megawatt totals (that have been adjusted for line losses). The megawatt totals shown in Table 25 are based on enrollment levels in early 2021.

Table 25. Summary of Existing Business Sector Demand Response Offerings

Program	Assumed Capacity (MW)	Agreement Type	Financial Details
Business DR	200	Payment Contract	Consumers Energy provides a $25 to $28/kW-year performance contract and a $0.05/kWh incentive for event performance.
EIP rate	48	Tariff	Consumers Energy provides reduced kWh charges on a four-tiered rate that includes a critical price on event days.
GI rate	131	Tariff	Consumers Energy provides a demand charge credit of $7/kW during June through September, and $6/kW-month October through May.
Total [a]	**379**	-	-

[a] Total row may not equal the sum of program values due to rounding

Methodology

The load curtailment potential for business customers is a function of several important factors. For our top-down model, the Cadmus team uses summer peak load forecasts as a foundation, with other relevant inputs that include financial variables (retail rates, avoided capacity costs, and avoided energy costs), customer sensitivity to changes in electricity price (demand response price elasticity), and components of the program design (frequency and duration of events and amount of notification time and incentive payments).

Regarding program design, the Cadmus team made several simplifying assumptions rather than producing an array of scenario-based estimates. Table 26 describes these assumptions, as well as the sources for other key inputs into the demand response potential estimates, followed by a discussion of the price elasticity of demand response supply and how it can be used to estimate load curtailment potential.

Table 26. Summary of Input Assumptions and Sources

Input Variable	Sources, Notes, and Assumptions
Retail Electricity Cost ($/MWh)	The Cadmus team calculated the all-in retail rates for the business sector using U.S. Energy Information Administration data.[a] An all-in rate expresses all billing determinants per-kWh by dividing revenue by energy sales. After escalating 2018 retail rates for inflation, the team assumed 2021 rates of $0.085 per kWh for the primary class and $0.137 per kWh for the secondary class.
Avoided Cost of Generation Capacity ($/kW-year)	Consumers Energy provided the Cadmus team with avoided costs of generation capacity across the study horizon based on 75% of CONE for MISO Local Resource Zone 7, escalated with inflation.
Avoided Energy Costs ($/MWh)	Avoided energy costs represent the difference between the summer on-peak and summer off-peak periods. This differential was approximately $12 per MWh in 2021 and escalates by 2% annually over the study horizon to account for inflation.
Program Design (number and duration of events, notification level)	The team assumed an average of 10 event hours per summer across the study horizon. We also produced potential estimates assuming 20 hours and 40 hours of dispatch. Larger commitments lead to lower potential estimates. For our load curtailment potential estimates, we assumed a *day-of* notification design, with a three- to six-hour notice, for consistency with recent MISO rulemaking. Potential would be higher under a *day-ahead* notification design, which provides participants with more opportunity to shift energy-intensive tasks to off-peak periods.
Participant Incentive	For load curtailment programs, the Cadmus team modeled the incentive as an annual reservation payment provided to the participant. In exchange, the participant agrees to curtail load when events are dispatched. For RAP, we set the optimal incentive level using maximized net benefits, performing a simulation where the critical input was the incentive level and the critical output was the net benefit of the demand response program. The team leveraged several of the inputs discussed herein for this simulation and repeated it for each of the 20 years in the study horizon to establish different incentive levels by year. Table 29 shows the incentive levels by year and modeling perspective.
Price Elasticity of Demand Coefficients	The team derived the price elasticity of demand coefficients from auction clearing results from the PJM Interconnection LLC (PJM) Reliability Pricing Model and from business load curtailment evaluation results from Pennsylvania, California, and New Mexico. More information is included in the *Price Elasticity* section.
Program Management Budget (Non-Incentive Costs)	The team assumed three program management budget components: (1) We assumed that ***fixed program management costs*** start at $300,000 in 2021 and escalate annually. (2) We set the ***marketing and customer acquisition costs*** during the expansion period at $200,000 in 2021 and escalated annually until 2025 (after which there is no fixed cost for marketing and customer acquisition). (3) We set the ***variable program administration costs***, the largest component that scales according to program size, using a 30% adder to the total incentive cost. We considered the assumed program management costs discussed above as operation and maintenance and further scaled the budget to reflect the earning adjustment mechanism.
Line Losses	The team used a top-down model for the load curtailment opportunity using system loads, so the resulting estimates of demand response potential are inclusive of line losses.
Ramp Rate	To account for the Business Demand Response Program needing a few years to fully mature, the Cadmus team assumed a three-year ramp up to full program potential. In the first year (2021), we applied a 75% ramp rate factor to program potential. In the second and third ramp years, we used ramp rate factors of 85% and 95%, respectively.

[a] U.S. Energy Information Administration. Re-released March 16, 2020. “Annual Electric Power Industry Report, Form EIA-861 Detailed Data Files.” https://eia.gov/electricity/data/eia861/. At the time of this research, the most recent year available was 2018. Costs were escalated annually, so the rates are in 2021 dollars.

The Cadmus team produced estimates of both MAP and RAP, which are defined in the context of business load curtailment as follows:

- ***Maximum achievable potential*** is the load curtailment potential for a program where customer incentives are as high as possible while still producing a cost-effective program (that is, the largest incentive value such that the UCT ratio does not fall below 1.0).
- ***Realistic achievable potential*** is the load curtailment potential for a program where customer incentives are designed to maximize the present value of the net program benefits.

The Cadmus team used Consumers Energy's peak load forecast, which is discussed in the *Consumers Energy Peak Loads* section of this report. After accounting for existing energy efficiency, conservation voltage reduction, the upcoming residential TOU deployment, and the retail open access load, the starting point in the 2021 forecast was 7,409 MW: this peak is attributable to both residential and business sector customers.

To disaggregate the peak load forecast to the sector level, the Cadmus team used interval data to estimate peak load shares for residential and business customers. After applying these shares to the overall peak load forecast, the starting point for the business sector peak load forecast was 3,932 MW.

After splitting the residential and business sector peak load forecast, the Cadmus team further disaggregated the business load into two sectors based on principle business activity using North American Industry Classification System codes provided by Consumers Energy:

- ***Commercial*** business types include retail, education, office, warehouse, health, grocery, restaurant, and lodging.
- ***Industrial*** business types include manufacturing operations and energy-intensive infrastructure operations such as wastewater treatment.

The second business segmentation dimension was customer class. Consumers Energy organizes business rate codes based on service type:

- ***Primary*** customers take service at 2,400 volts or greater and are responsible for maintaining their own transforming equipment.
- ***Secondary*** customers take service at secondary voltage.

Figure 25 illustrates a key distinction between primary and secondary customers. While relatively few in number, primary customers are very large energy users with an average peak load contribution of nearly 500 kW. Conversely, Consumers Energy has over 200,000 secondary customers, but their average peak load contribution is much smaller, at approximately 8.2 kW. Table 27 shows the number of active bundled electric accounts by business sector and class as of January 2020, along with the Cadmus team's estimated contribution to the peak load forecast.

Figure 25. Customer Size and Count by Class

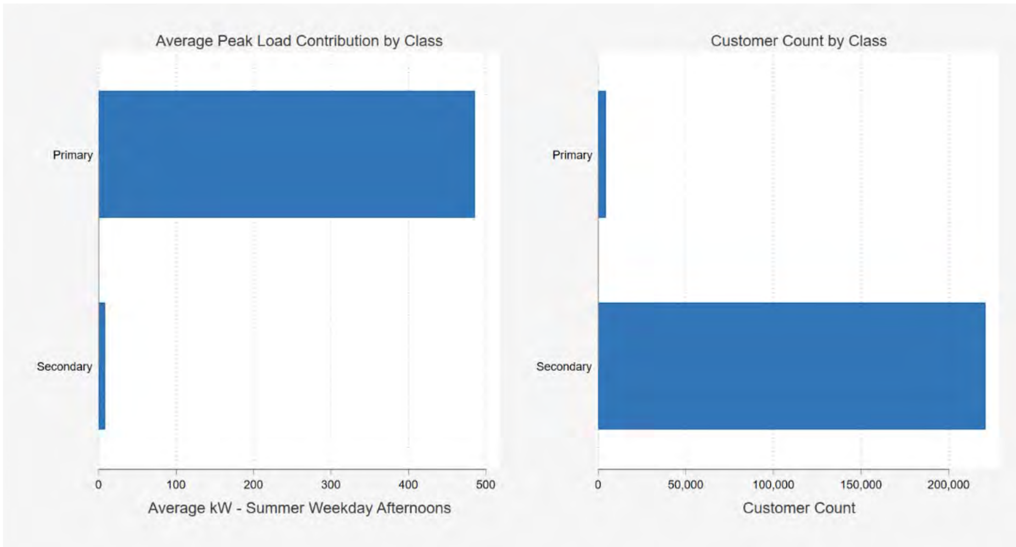


Table 27. Number of Accounts and Peak Load Contribution by Sector and Class

Parameter	Industrial Primary	Industrial Secondary	Commercial Primary	Commercial Secondary
Number of Accounts	1,213	19,882	3,082	201,071
Share of Peak Load	30.4%	7.6%	23.8%	38.2%
2021 Peak Load Contribution (MW)	1,196	300	935	1,501
Average Customer Size (peak kW)	986	15.1	303	7.5

Price Elasticity

The price elasticity of demand is the ratio between the percentage change in the quantity of electricity demanded and the percentage change in the price (including an incentive) of demand response:

$$Elasticity = \frac{Percentage\ Change\ in\ Quantity}{Percentage\ Change\ in\ Price}$$

Where:

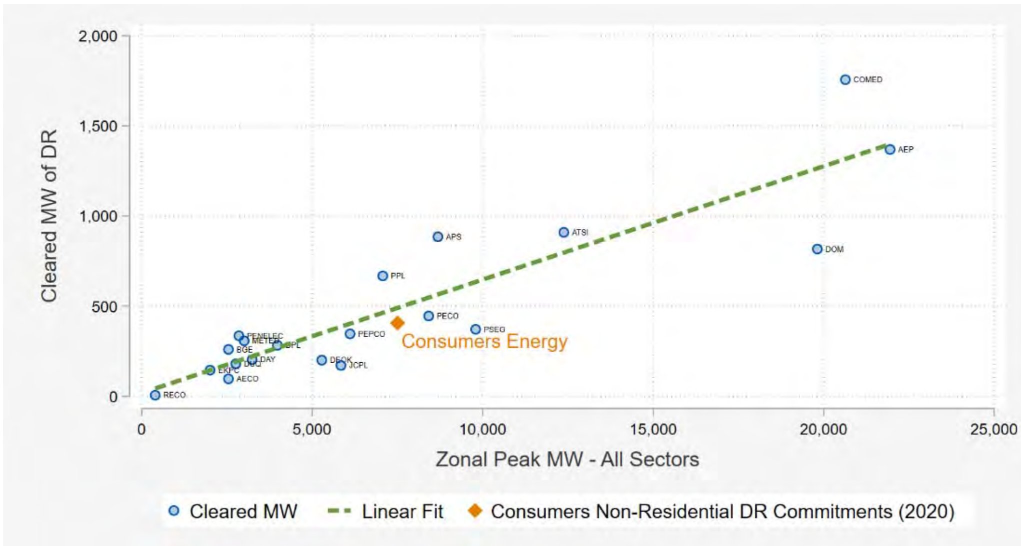
$$Percentage\ Change\ in\ Quantity = \frac{(Summer\ Peak - \ Demand\ Response\ Potential) - Summer\ Peak}{Summer\ Peak} * 100\%$$

$$Percentage\ Change\ in\ Price = \frac{(Retail\ Rate + Incentive\ Payment) - Retail\ Rate}{Retail\ Rate} * 100\%$$

The Cadmus team derived the price elasticity of demand coefficients used in this study from multiple sources. To anchor the expected price response of the business customer base as a whole, we compiled the outcomes of recent Base Residual Auctions conducted by PJM. The PJM market is a useful benchmark because the capacity performance[15] definition largely excludes residential demand response from the market. It is also more competitive than MISO, with a more horizontal demand curve.

Figure 26 shows the average demand response commitments for the PJM region by zone against the summer peak load. The team added Consumers Energy's current business demand response commitments and peak load to the figure for reference.

Figure 26. Three-Year Average PJM Zonal Demand Response Commitments versus Peak Load



Following each auction, PJM provides a detailed report[16] that includes the level of demand response offered and cleared by zone, along with the zonal clearing price. The Cadmus team compiled the offered and cleared demand response megawatts by delivery year, along with several factors for each zone:

- Summer peak load forecasts and an estimate of the percentage of peak load attributable to business customers.
- Average retail rates for commercial customers and for industrial customers according to EIA Form-861. For states with competitive supply, this includes both energy and delivery to create a bundled all-in cost per kWh.
- Estimates of expected dispatch frequency. This represents the number of hours a participant anticipates being curtailed. We assumed 15 hours per year to balance the historically infrequent dispatch with the extremely broad definition of availability.

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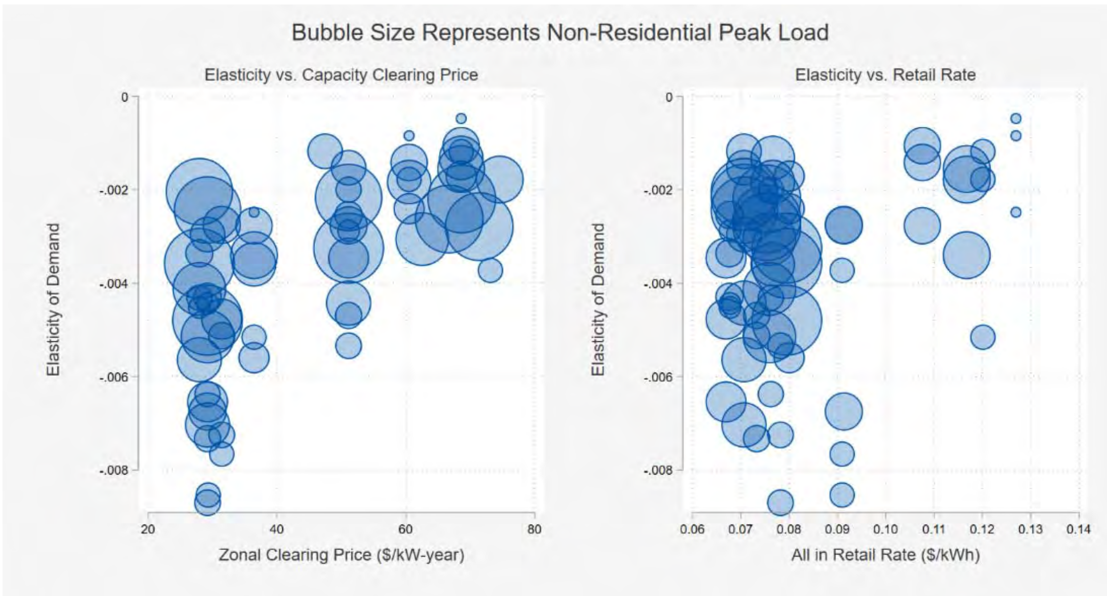
15 The transition to capacity performance is discussed in detail in *PJM Manual 18*: PJM Interconnection LLC. December 5, 2019. https://pjm.com/~/media/documents/manuals/m18.ashx

16 The most recent Base Residual Auction report can be found online: PJM Interconnection LLC. n.d. "2021/2022RPM Base Residual Auction Results." PJM #5154776. https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx

Figure 27 shows the results. The weighted average price elasticity is approximately -0.003. However, there is variability across the zones. Zones with a significant amount of manufacturing tend to have lower retail rates and larger (more negative) price elasticity estimates.

Figure 27. Analysis of Three-Year Average PJM Auction Results



To estimate the variation in price elasticity by class and sector, the Cadmus team leveraged evaluation results from multiple jurisdictions. We calculated the percentage change in quantity based on evaluated baselines and impacts for participants and the share of the utility peak load participants represent. We calculated the percentage change in price based on the program-specific incentive level, number of event hours, and retail rate, then assigned participants to a class and sector and summarized the class- and sector-level results.

Demand response programs can provide participants with day-ahead or day-of notification of curtailment events. In some cases, the secondary program data represented day-ahead elasticity values, rather than the day-of elasticity values of interest for this study. To produce day-of elasticities, the Cadmus team leveraged elasticity research conducted in California.[17] Using the California elasticity data, we estimated the ratio between day-ahead and day-of elasticities, then used this ratio to convert evaluation results from day-ahead programs to day-of elasticity values, shown in Table 28. We converted these to positive values to return the amount of demand response supplied, which is functionally a load reduction.

[17] For a summary of the application of the California price elasticity research, see: Statewide Evaluation Team. February 25, 2015. *Demand Response Potential Pennsylvania.* Final Report. Prepared for Pennsylvania Public Utility Commission. http://puc.pa.gov/pcdocs/1345077.docx

Table 28. Price Elasticity Values

Sector and Class	Day-Of Elasticity
Industrial Primary	0.005
Industrial Secondary	0.004
Commercial Primary	0.002
Commercial Secondary	0.001

Sample Calculation

Rearranging the terms from the *Price Elasticity e*quation yields a sample calculation:

$$Percentage\ Change\ in\ Quantity = Elasticity * \ Percentage\ Change\ in\ Price$$

Note that the price elasticity and the sample calculation both have percentage change in quantity equation. These two equations can be combined:

$$Elasticity * \ Percentage\ Change\ in\ Price = \frac{(Summer\ Peak - \ Demand\ Response\ Potential) - Summer\ Peak}{Summer\ Peak} * 100\%$$

The terms in the above equation can then be rearranged to solve for demand response potential:

$$Demand\ Response\ Potential = \frac{Elasticity * \ Percentage\ Change\ in\ Price * Summer\ Peak}{100\%}$$

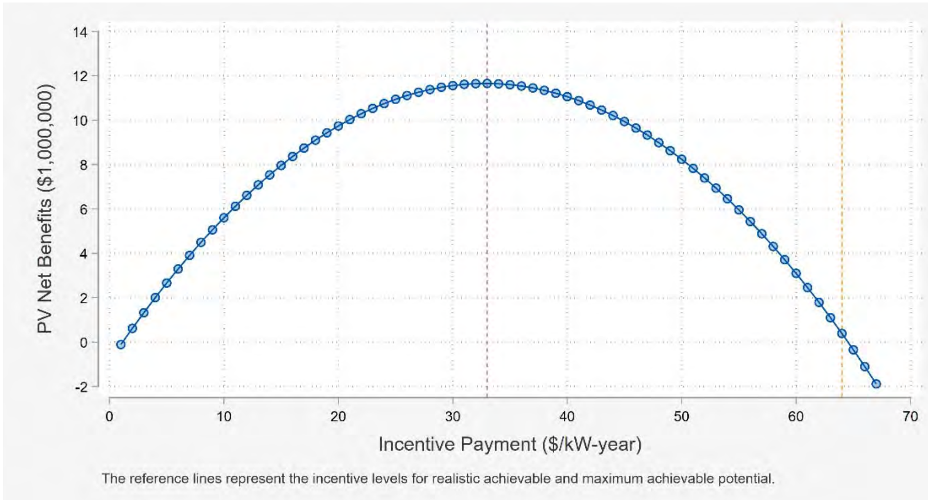
Using the industrial primary day-ahead elasticity from Table 28 (0.005), a summer peak of 1,200 MW, a retail rate of \$0.085 per kilowatt-hour, and an incentive reservation payment of \$30 per kW-year spread across 10 event hours, demand response potential would be 212 MW:

$$Demand\ Response\ Potential = \ -0.005 * \left(\frac{\left(0.085 + \frac{30}{10}\right) - 0.085}{0.085}\right) * 1{,}200 = 212\ MW$$

Cost and Benefit Streams

The primary costs of a business load curtailment program are the customer incentive costs and program management costs incurred by Consumers Energy. As noted above, the Cadmus team approached incentives from two perspectives. We calculated estimates of MAP using the highest incentive possible without net benefits dropping below \$0, and calculated estimates of RAP using an incentive level that maximizes the net benefits of the program: Figure 28 summarizes the simulation exercise. In this example, the greatest incentive level that maintains positive net benefits is \$64/kW-year – this is the value that would be used to estimate MAP. The highest level of net benefits is approximately \$12 million, at which point the incentive payment is \$33/kW-year. This incentive level would then be used to estimate RAP.

Figure 28. Relationship between Net Benefits and Incentive Level



The simulation results are shown in Table 29. The team conducted a simulation for the business sector as a whole and applied the aggregate simulation results to each subgroup.

Table 29. Incentive Payments by Year

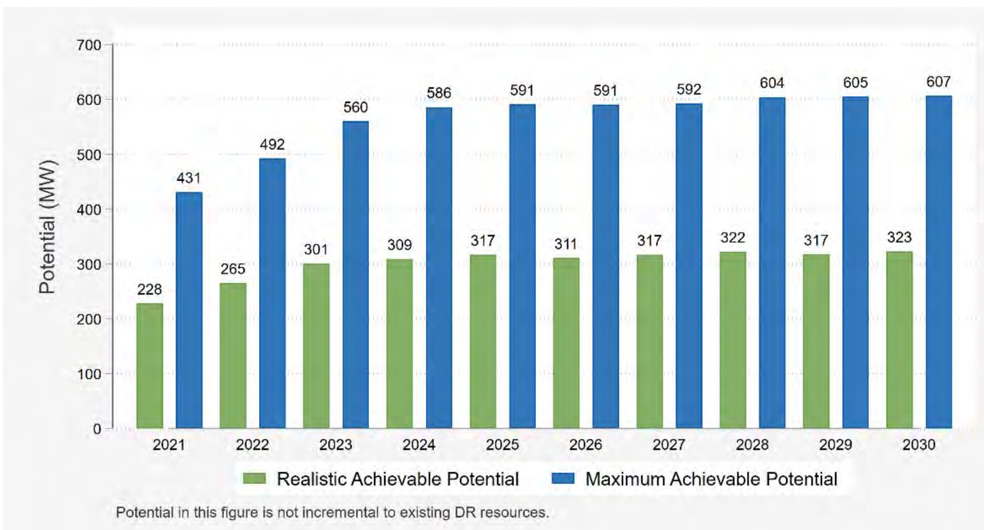
Year	MAP Incentive ($/kW-year)	RAP Incentive ($/kW-year)
2021	$51	$27
2022	$52	$28
2023	$54	$29
2024	$55	$29
2025	$56	$30
2026	$57	$30
2027	$58	$31
2028	$60	$32
2029	$61	$32
2030	$62	$33
2031	$64	$34
2032	$65	$34
2033	$66	$35
2034	$68	$36
2035	$69	$36
2036	$71	$37
2037	$72	$38
2038	$73	$38
2039	$75	$39
2040	$77	$40

There are two benefit streams in the cost-effectiveness calculations: avoided energy benefits and avoided capacity benefits. Regarding ***avoided energy benefits***, the Cadmus team assumed that the load curtailment programs will be energy neutral (that is, that the energy avoided during the demand response event hours will be used during off-peak hours). Thus, the avoided energy benefit is simply the product of demand response potential and the differential between on-peak and off-peak energy prices (which the Cadmus team assumed to be $12 per megawatt-hour in 2021, escalated annually to account for inflation). We calculated the ***avoided capacity benefits*** in a similar manner: as the product of demand response potential and the sum of avoided generation, transmission, and distribution capacity costs.

Results

For 2021 through 2030, Figure 29 shows estimates of MAP and RAP under a day-of notification program design for all bundled business load. The estimates of potential are essentially flat for the remainder of the study horizon. The results are inclusive of existing business demand response resources; that is, this potential is not incremental to the EIP rate, GI rate, and C&I Demand Response programs. The trajectory in years 2021 through 2023 can be attributed to the ramp rate discussed in Table 26.

Figure 29. Business Sector Demand Response Potential by Year, 2021 through 2030



In Figure 30 and Figure 31, MAP and RAP are broken out by sector and class, showing that the majority of the business sector demand response potential falls in the industrial primary subgroup. The differences in potential estimates among the four business subgroups are driven by three factors: the peak load forecast for each business subgroup, retail rates, and the price elasticity assumption. Directionally, larger peak loads and lower retail rates produce greater estimates of demand response potential.

Figure 30. Business Sector Maximum Achievable Demand Response Potential by Segment, 2021 through 2030

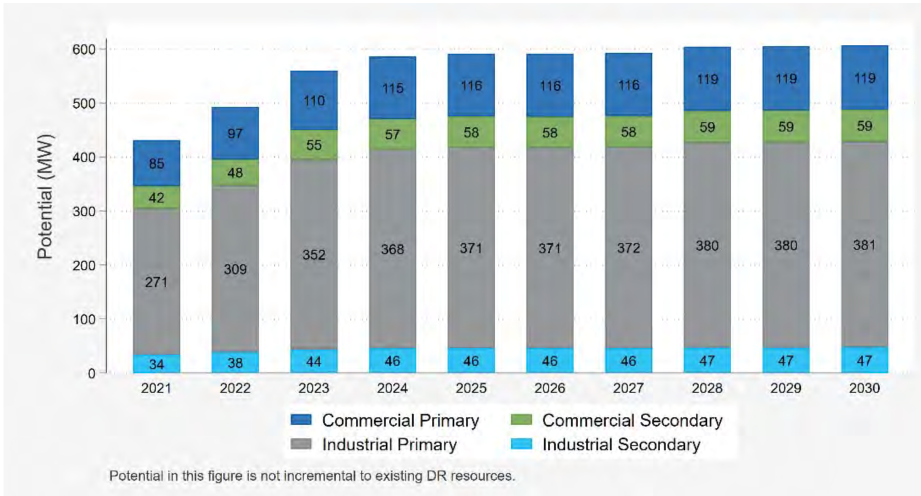
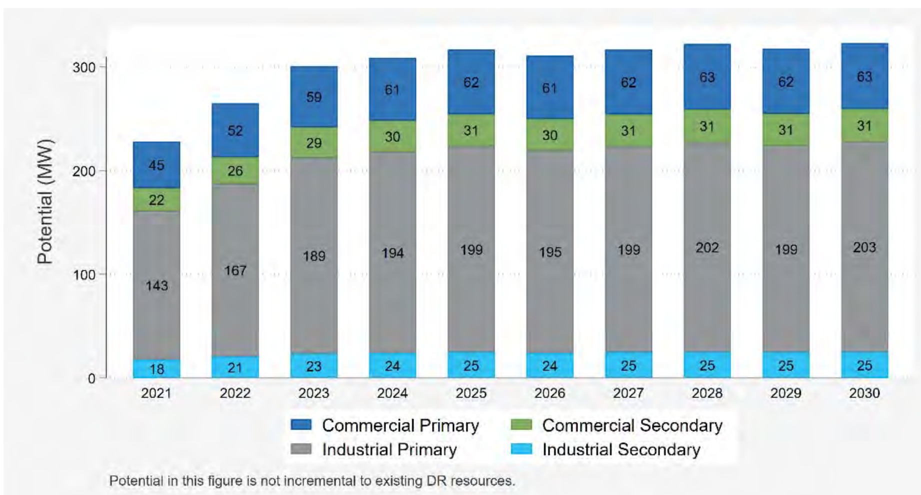


Figure 31. Business Sector Realistic Achievable Demand Response Potential by Segment, 2021 through 2030



For a subset of years, Table 30 shows total business sector potential and potential by subgroup. As noted above, most of the potential falls in the industrial primary subgroup.

Table 30. Demand Response Potential by Segment and Year

Year	Maximum Achievable Potential (MW)					Realistic Achievable Potential (MW)				
	IP	IS	CP	CS	Total [a]	IP	IS	CP	CS	Total [a]
2022	309	38	97	48	**492**	167	21	52	26	**265**
2026	371	46	116	58	**591**	195	24	61	30	**311**
2030	381	47	119	59	**607**	203	25	63	31	**323**
2040	407	50	127	63	**648**	211	26	66	33	**336**

[a] Total columns may not equal the sum of segment values due to rounding
Notes: IP = Industrial Primary; IS = Industrial Secondary; CP = Commercial Primary; CS = Commercial Secondary

Recall that for this analysis, the Cadmus team assumed an average of 10 hours of demand response dispatch per summer. If more demand response hours are dispatched, estimates of potential decrease. For select years, Table 31 shows potential estimates if we assume 20 hours or 40 hours of dispatch (without adjusting incentive levels or any other factors). The results for 10 hours of dispatch are shown for comparison, as 10 hours was the Cadmus team's assumption (used elsewhere in this report).

Table 31. Business Sector Demand Response Potential by Average Number of Dispatch Hours per Summer

Year	Business Sector MAP (MW)			Business Sector RAP (MW)		
	10 Hours	20 Hours	40 Hours	10 Hours	20 Hours	40 Hours
2022	492	246	123	265	133	66
2026	591	295	148	311	155	78
2030	607	303	152	323	161	81
2040	648	324	162	336	168	84

Cost-Effectiveness

Table 32 shows total expenditures across the 20-year study horizon, along with present value costs and benefits associated with capturing the demand response potential outlined above. These values are shown for the full business sector rather than the four individual subgroups. The "Scenario Spend ($)" row represents total spending without discounting, while the "Present Value Benefit (2021$)" and "Present Value Cost (2021$)" rows are discounted. The "Present Value of Net Benefits (2021$)" row is simply the difference between present value benefits and costs. The table also shows UCT ratios. Recall that, by design, we estimated MAP such that the UCT ratio does not drop below 1.0.

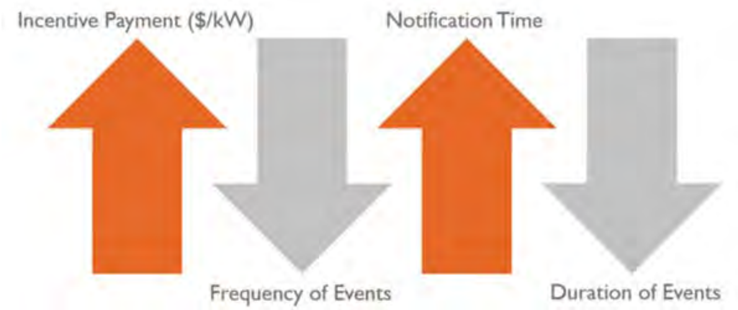
Table 32. Cost-Effectiveness Results

Component	MAP ($1,000)	RAP ($1,000)
Scenario Spend ($)	$1,000,095	$284,219
Present Value Benefit (2021$)	$534,839	$283,011
Present Value Cost (2021$)	$510,516	$146,361
Present Value of Net Benefits (2021$)	$24,322	$136,650
UCT Ratio	1.05	1.93

Comparison to Current Demand Response Commitments

For Consumers Energy's three existing business sector load curtailment programs—EIP rate, GI rate, and Business DR —current demand response commitments at the system level are 379 MW. The estimates of load curtailment potential presented here include those current commitments, which should not be added to the demand response potential estimates. Figure 32 shows the four key drivers of load curtailment potential along with their directional effect. These four drivers are useful when interpreting and comparing this study's results to existing business sector demand response commitments.

Figure 32. Key Drivers of Business Sector Demand Response Potential



Our RAP estimates are lower than the sum of current commitments because the modeled RAP incentive levels are more modest than the current GI and EIP rates. The financial mechanisms of these two tariff-based programs resemble the MAP perspective. The RAP results should be interpreted with caution because the GI and EIP options are incorporated in rates, and it seems unlikely that Consumers Energy would modify the tariffs to offer less aggressive price signals.

For the primary load curtailment results presented in this report and provided to Consumers Energy, the Cadmus team assumed 10 hours of dispatch annually. Although limited, 10 hours per summer represents an increase from historical operations. Consumers Energy has not dispatched its Business Demand Response program resources in the last decade. Because demand response and renewables account for a larger share of the planned supply mix, it is inevitable that the dispatch frequency will increase compared to historical levels. However, we assume that load curtailment programs will remain one of the last resources in the loading order.

Table 31 above presented estimates of load curtailment potential assuming increased dispatch frequency. These estimates are significantly lower than current commitments. The key takeaway from this sensitivity analysis is that if Consumers Energy starts to dispatch business participants frequently, the existing participants are likely to leave the program or reduce their commitments.

Integrated Resource Plan Inputs

The incentive level is an independent variable in the business load curtailment potential model. Assuming a fixed number of dispatch hours and a price elasticity of demand response supply, increasing the incentive level increases the estimated quantity of demand response potential. With this modeling approach, it is straightforward to estimate an incremental load curtailment resources supply curve for modeling alongside traditional supply resources in the IRP model.

Table 33 shows the modeling outputs the Cadmus team provided to Consumers Energy's Resource Planning Team. Each row represents an incentive increase of $5 per kW-year relative to the previous row and generates approximately 53 MW of additional demand response potential. The "Marginal" columns show the megawatts and levelized cost associated with each additional $5 per kW-year block above existing commitments. The "Cumulative" columns show the total incremental megawatts of demand response potential and the cumulative levelized cost. These outputs are not constrained by the 75% of CONE assumption for the avoided cost of generation capacity used in the MAP and RAP estimates. This presents the IRP model with all load curtailment potential, absent economic screening so that the model can optimize the quantity of resources selected based on economics and other characteristics.

Table 33. Incremental Load Curtailment Resources

Incentive Level ($/kW-year)	Marginal Incremental MW	Cumulative Incremental MW	Marginal Levelized Cost ($/kW-year)	Cumulative Levelized Cost ($/kW-year)
$45	96	96	$77.14	$77.14
$50	53	149	$106.29	$87.51
$55	53	202	$113.35	$94.29
$60	52	254	$136.15	$102.86
$65	53	307	$152.50	$111.43
$70	53	360	$169.64	$120.00
$75	53	413	$186.78	$128.57

Small Business Dynamic Peak Pricing Program

Consumers Energy does not currently offer a small business DPP program. The Cadmus team developed this program archetype based on discussions with Consumers Energy and a review of similar offerings in other jurisdictions. Small business customers are traditionally challenging to reach with demand-side management programming, since small business owners juggle many responsibilities and energy costs do not typically represent a large component of the operating cost or margins. The Cadmus team assumed several program attributes for modeling purposes:

- The program is available to business customers who opt-in and receive bundled secondary service. As was shown in Table 27, this includes over 200,000 bundled electric customer accounts and represents approximately 1,800 MW of Consumers Energy's peak load.
- Participants face a significantly reduced volumetric rate, except on a small number of event days when the retail rate increases to approximately $1 per kilowatt-hour during a critical peak window.
- Consumers Energy provides opt-in customers with a free Wi-Fi connected thermostat to help shift their HVAC loads out of critical peak periods (but does not directly manipulate the setpoint).
- Marketing of the rate is targeted to accounts and business types that exhibit weather sensitivity and are thus likely able to modify loads to take advantage of the rate.

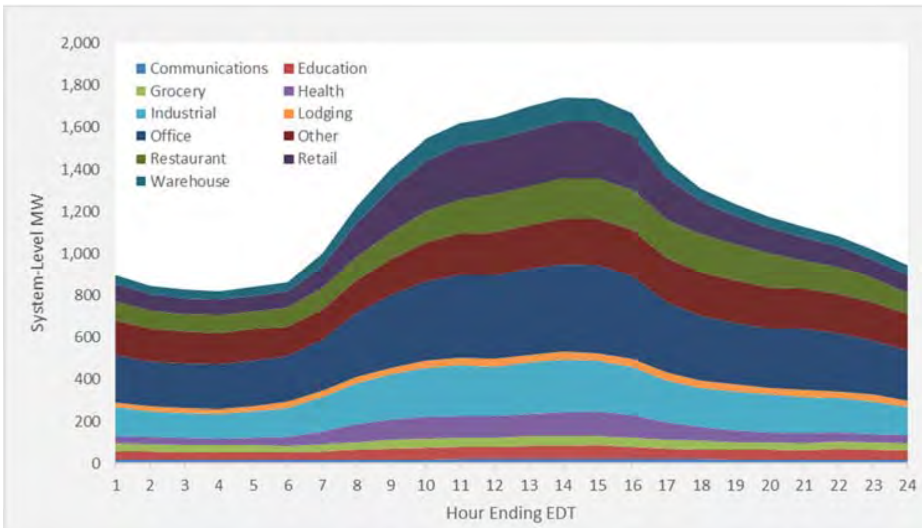
Methodology

To produce the MAP and RAP estimates for a small business DPP program, the Cadmus team included components used for the residential DPP, ACPC, and business load curtailment programs.

Data Sources

As the basis for our small business DPP program analysis, the team used two summers of hourly AMI data for a random sample of 5,000 general service secondary accounts, which we mapped to business types as part of our broader market potential business segmentation effort. Then we calculated frequency weights for expanding the AMI sample to the population and examined the loads on summer weekdays when the daily high temperature in Lansing was 88 degrees (F) or above. Figure 33 shows the distribution of eligible loads by business type and hour.

Figure 33. Peak Summer Weekday Loads by Business Type and Hour



We defined the likely event hours as 2 p.m. to 7 p.m. There is a notable reduction in loads for several business types and in total at the conclusion of typical business hours around 5 p.m. This definition allows for including a blend of business and after-business hours. While the expected transition of Consumers Energy's system peak to later in the evening increases demand response potential in the residential sector, it will have the opposite effect for potential in the small business sector.

Load Reduction Percentages

To estimate the demand response potential for each business type, the Cadmus team first calculated the weather sensitivity of each business type using the AMI sample and hourly weather data from the Lansing Capital City Airport. We found that the health, retail, office, and restaurant business types were the most weather sensitive, while education, communications, industrial, and warehouse were the least weather sensitive. The low weather sensitivity for the education business type is likely a function of the hottest summer days coinciding with school summer breaks.

Next, we combined business type–specific weather sensitivities with the short-run price elasticity coefficient from the residential CPP program so that the more weather-sensitive business types were assigned higher price elasticity and the less weather-sensitive business types were assigned lower price elasticity coefficients. Across business types, this approach returned a weighted average load reduction per participant of 0.86 kW, or an 11.4% reduction in premise load, which is slightly larger than the 9.4% assumption used for the residential CPP program.

Several differences should be considered when comparing the residential and business DPP programs:

- The team assumed a CPP rate structure for the business DPP that is more aggressive than what we assumed for the residential DPP, as the critical price applies to all energy used during the event rather than just to energy above a baseline. For context, our assumed critical rate is a nearly 700% increase compared to a standard volumetric rate. A rate with a higher peak to off-peak price ratio would produce higher estimates of demand response potential, while a rate with a lower peak to off-peak price ratio would produce lower estimates of demand response potential.
- Consumers Energy provides participants with a free connected thermostat for enrolling. While this is a significant upfront cost, without the enabling technology it is challenging to obtain peak demand reduction from small business customers. For reference, when San Diego Gas & Electric instituted default CPP to its approximately 115,000 small business customers and offered free thermostats, the demand response contribution from the 3,000 customers who received a thermostat was almost as large as the aggregate demand reduction from the 112,000 who were assigned the rate but did not elect to receive a thermostat.[18]
- One program design option would be to directly control the connected thermostats provided to participating business. This strategy would result larger kilowatt impacts, but would add several cost elements used for the BYOD program (such as manufacturer application programming interface and DR management system fees) and increase overall program costs.

Marketing Efforts

Consumers Energy does not currently offer a small business DPP program. Because of the absence of primary data on marketing campaigns and customer response to enrollment offers, the Cadmus team made assumptions based on secondary data, industry experience, and professional judgement. Table 34 shows the marketing efforts we assumed for the MAP and RAP scenarios. The expected per-participant load impact for small business DPP is much larger than for residential DPP, which allows for the use of more expensive marketing modes.

[18] Demand Side Analytics, LLC. April 1, 2018. "SDG&E Small Commercial Time Varying Pricing and Commercial Thermostat Evaluation for Program Year 2017." Final Report. CALMAC ID: SDG0311. https://demandsideanalytics.com/wp-content/uploads/2019/04/11-SDGE-Small-Commercial-DR-Evaluations-Final-Report.pdf

Table 34. Small Business Dynamic Peak Pricing Program Marketing Costs and Attempts by Mode

Marketing Mode	Cost per Attempt	EAM Multiplier	MAP Attempts	RAP Attempts
Email	$0.01	120%	3	6
Social media	$0.02	120%	3	6
Bill inserts	$0.05	120%	2	4
Phone (three attempts)	$1.25	120%	1	2
Door-to-door	$10.00	120%	0	1
Direct mail	$1.00	120%	0	1

We assumed a mean propensity to enroll of 8% for the MAP scenario and 4% for the RAP scenario. Although the more aggressive marketing tactics assumed for the MAP scenario led to a higher success rate, the costs are significantly higher. Table 35 shows the estimated marketing cost per enrollment by scenario along with the Cadmus team's other assumptions about program cost. We treated the connected thermostat as a capital expense and considered all other costs as operation and maintenance, and adjusted them up from the values shown to account for the EAM. We do not assume any cost sharing with energy waste reduction programs. We assumed that the rate itself is revenue neutral, and did not include cost elements for reduced or increased collections.

Table 35. Small Business Dynamic Peak Pricing Program Cost Assumptions

Cost Element	Cost Type	Cost Frequency	MAP	RAP
Marketing Cost per Successful Recruit	Volumetric	One time	$173.50	$36.00
Program Management, Measurement and Verification, Call Center, IT	Fixed	Recurring	$100,000	$100,000
Program Management, Measurement and Verification, Call Center, IT	Variable	Recurring	$5	$5
Free Wi-Fi Connected Smart Thermostat	Variable	One time	$150	$150

The Cadmus team made two additional modeling assumptions for a small business DPP program:

- We assumed an ***annual retention rate*** of 95%, which is higher than for residential DPP and more consistent with historical retention rates in Consumers Energy's residential air conditioning and business load curtailment programs.
- We assumed an ***effective capacity*** of 95%. Consumers Energy will need to cap critical events to four or five hours at most. As discussed in the *Effective Capacity* section, the available duration of demand response resources impacts their effectiveness as a supply resource.

Results

Table 36 shows the estimated short-term and long-term demand response potential for a small business DPP program by economic modeling perspective.

Table 36. Small Business Dynamic Peak Pricing Potential for Selected Years

Year	Maximum Achievable Potential	Realistic Achievable Potential
2022	5.1	2.6
2026	12.0	6.0
2030	12.2	6.1
2040	12.6	6.3

The key difference between the two scenarios is the enrollment rate. The increased marketing expenditures for MAP result in higher enrollment rates and potential, but lower the program cost-effectiveness. Table 37 shows the economic results by scenario.

Table 37. Small Business Dynamic Peak Pricing Cost-Effectiveness

Parameter	MAP ($1,000)	RAP ($1,000)
Scenario Spend ($)	$15,890	$6,860
Present Value Cost (2021$)	$9,592	$3,975
Present Value Benefits (2021$)	$9,775	$4,796
UCT Ratio	1.02	1.21
Levelized Cost (2021$/kW-year)	$87	$71

The Cadmus team presented a small business DPP program to Consumers Energy Integrated Resource Planning Team in two blocks, consistent with the MAP and RAP scenarios in the previous tables. The first block was simply the RAP and associated costs, while the second block was the incremental megawatt impacts from MAP to RAP and the marginal cost of the expanded program footprint.

Appendix A. Smart Thermostat Market Share and Penetration

A growing number of vendors nationwide market Internet-connected smart thermostats directly to residential customers. These devices are typically sold as home energy management tools that target energy savings for homeowners through occupancy detection, auxiliary heat lockout, and economizer capabilities. The saturation of smart thermostats is important because it determines the split of eligible customers for ACPC and BYOD programs (we assume in this study that only customers with smart thermostats are eligible for BYOD and only customers without smart thermostats are eligible for ACPC).

To develop an assumption of smart thermostat penetration for this study, we started with a market penetration model that forecasts the share of customers with smart thermostats based on the naturally occurring turnover in the thermostat market. The natural penetration of smart thermostats is driven by two factors: the market share of connected thermostats and the number of thermostat replacements each year. For the former, we project that connected thermostats will grow in market share from 25% of new thermostat sales to a limit of 70% of overall new sales. For the latter, we assume that in each year one in 15 homes in the Consumers Energy service territory with central air conditioning will replace their thermostat. Of the population of 1.62 million households, 64% have a central air conditioning unit and, on average, there are 1.05 units per household, providing the opportunity for 72,284 new thermostat sales per year. These details are shown in Table 38. Table 39 shows the resulting expected natural adoption of smart thermostats.

Rebates and upstream incentives for connected thermostats can drive down customer costs and influence how fast smart thermostats saturate households. Consumers Energy is undertaking a concerted effort to transform the market, increase the market share of smart thermostats, and drive higher penetration. As a result, for this study we based the split of eligible customers for the ACPC and BYOD programs on the projected natural penetration levels in 2030. The ACPC projection largely reflects the reality that Consumers has already installed a substantial number of load control switches and not all sites need a new thermostat. In practice, over time, the mix will tilt more heavily toward smart thermostats. Consumers also has the ability to influence the mix of load control devices and can influence the mix between switches and thermostats, if it chooses to do so.

Table 38. Smart Thermostat Market Assumptions

	Smart Thermostat Saturation Inputs	Value	Notes
A	Residential customers	1,616,000	Population
B	Percentage with central air conditioning	64%	Consumers Energy 2018 Appliance Saturation Survey
C	Air conditioning units per household	1.05	Consumers Energy 2018 Appliance Saturation Survey
D	Current market share	25%	Percentage of new thermostats that are smart thermostats
E	Current market penetration	8%	Percentage of households with air conditioning
F	Purchasing new t-stats (per year)	6.67%	One in 15 households per year
G	Market share cap	70.00%	Assumed (100% is not reasonable)
H	Year maximum market share reached	2025	Assumed

Table 39. Expected Natural Adoption of Smart Thermostats

Year	Thermostat Turnover	New Smart Thermostats			Total Smart Thermostats	
		Market Share	Incremental	Cumulative	Percentage of Air Conditioning Units	Percentage of Population
2020	72,284	25.0%	18,071	100,681	9.8%	5.9%
2021	72,284	44.6%	32,231	132,912	12.9%	7.8%
2022	72,284	60.0%	43,363	176,275	17.1%	10.4%
2023	72,284	67.4%	48,714	224,988	21.8%	13.3%
2024	72,284	69.6%	50,284	275,273	26.7%	16.2%
2025	72,284	70.0%	50,566	325,838	31.6%	19.2%
2026	72,284	70.0%	50,596	376,435	36.5%	22.2%
2027	72,284	70.0%	50,598	427,033	41.4%	25.2%
2028	72,284	70.0%	50,599	477,632	46.3%	28.1%
2029	72,284	70.0%	50,599	528,230	51.2%	31.1%
2030	72,284	70.0%	50,599	578,829	56.1%	34.1%
2031	72,284	70.0%	50,599	629,428	61.0%	37.1%
2032	72,284	70.0%	50,599	680,026	65.9%	40.1%
2033	72,284	70.0%	50,599	722,837	70.0%	42.6%
2034	72,284	70.0%	50,599	722,837	70.0%	42.6%
2035	72,284	70.0%	50,599	722,837	70.0%	42.6%
2036	72,284	70.0%	50,599	722,837	70.0%	42.6%
2037	72,284	70.0%	50,599	722,837	70.0%	42.6%
2038	72,284	70.0%	50,599	722,837	70.0%	42.6%
2039	72,284	70.0%	50,599	722,837	70.0%	42.6%
2040	72,284	70.0%	50,599	722,837	70.0%	42.6%

Appendix B. Retention Rates

A program's retention rate is the year-to-year percentage of customers that remain a participant in the program. Retention rates are important for cost-effectiveness because they dictate the costs of replacing customers lost to attrition. Lower attrition rates result in lower costs because fewer new customer acquisitions are required to maintain program capacities.

To develop retention rates for each program (shown in Table 40), the Cadmus team examined historical enrollment and un-enrollment data and analyzed the year-to-year proportion of customers who remained on each rate. Figure 34 and Figure 35 show the assumed retention rates for the ACPC and residential DPP programs, respectively.

Table 40. Retention Rate Assumptions by Program

Program	Value	Notes
ACPC	94%	Based on analysis of ACPC enrollments and un-enrollments from 2017 to 2019
BYOD	94%	Assumed to be same as ACPC
Residential DPP	85%	Based on analysis of CPP and PTR enrollments and un-enrollments from 2017 to 2019
Water Heaters	100%	Cadmus team assumption (program is not cost-effective under this assumption)
EIP and GI rates	100%	Participation is either tariff-based or a short-term (one to three year) contract
Business DPP	95%	Modeling assumption

Figure 34. Air Conditioning Peak Cycling Program Retention Rate Visualization

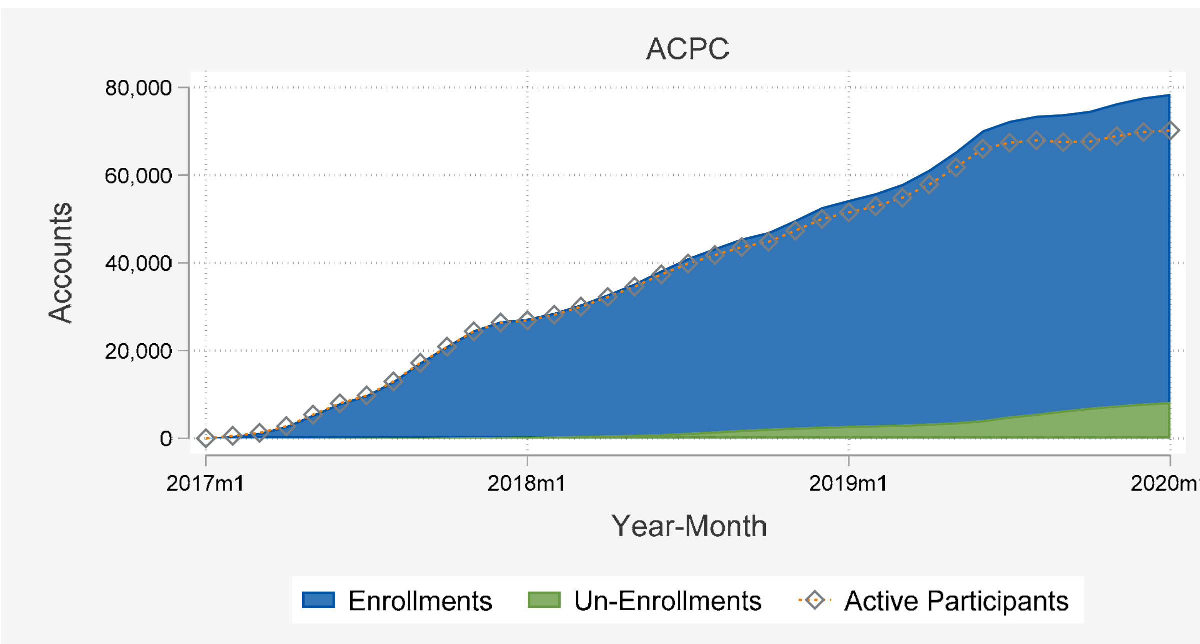
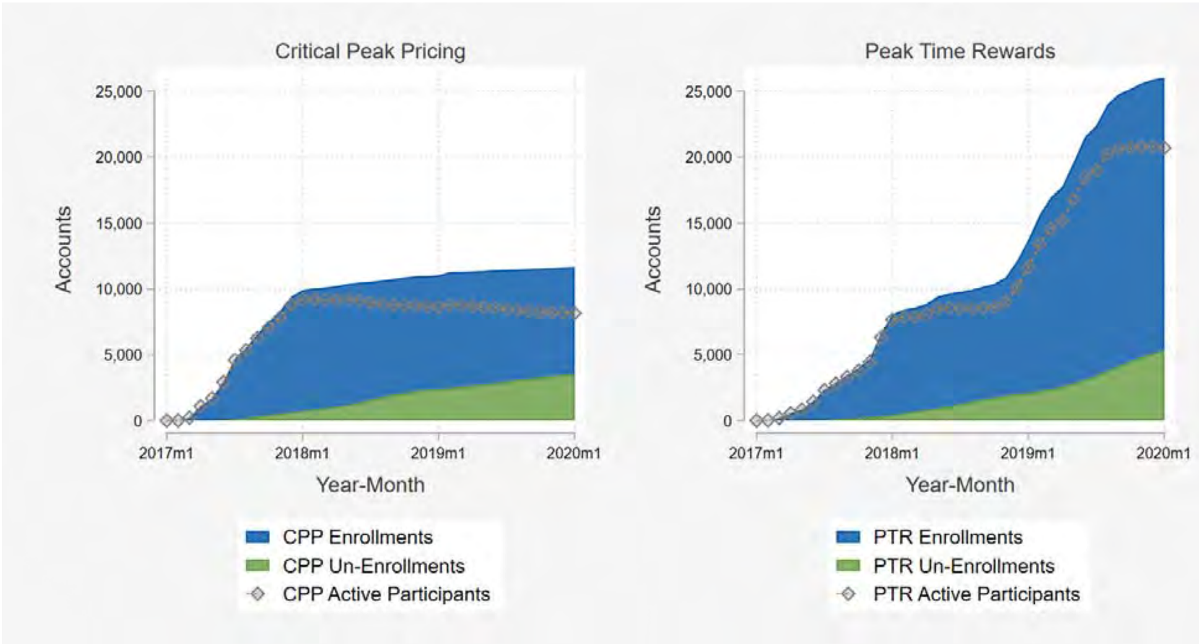


Figure 35. Residential Dynamic Peak Pricing Program Retention Rate Visualization



Appendix C. Incorporating External Studies into Propensity Scores

As noted in the main report, the 2019 historical marketing data had several limitations. It did not fully reflect the enrollment levels that could be attained with multiple years of attempts. There was also limited variability in customer incentives (because there had been previous tests). Finally, not all recruitment modes were tested for each program (as all of the recruitment for the DPP programs was conducted via email). As a result, the Cadmus team used the Consumers Energy data to calibrate the adoption propensity scores, and also incorporated information from studies in California and New York to reflect the impact of specific marketing tactics.

To understand how to incorporate the results from external studies, it is first necessary to understand how to interpret the coefficients. The team estimated propensity scores using probit models, which are simply cumulative normal distributions (S-curves) bounded between zero and one. The coefficients of a probit model represent the change in normalized standard deviations due to a one-unit change in the variable. For this study, the Cadmus team incorporated the probit coefficient reported in the 2017 *California Demand Response Potential Study*.[19]

In Figure 36, a movement in the x-axis (the normalized standard deviations) is associated with a change in probability; the magnitude of that change depends on the starting point. In other words, if a customer is strongly pre-disposed against enrollment, the marketing efforts do not move them much. However, for a customer who is more pre-disposed, an additional recruitment attempt or higher incentive can have a larger impact. Just as is possible to estimate the change in probability from probit model coefficients, it is possible to estimate the coefficient based on the change in probability.

Figure 36. Example Relationship between Propensity Score Model Coefficient and Probabilities

[19] Lawrence Berkeley National Laboratory. March 1, 2017. *2025 California Demand Response Potential Study: Charting California's Demand Response Future*. Phase 2 Appendices A – J. https://cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442452699

Appendix D. ACPC Detailed Inputs and Summary Outputs

General Inputs

Component	Value
Discount Rate	7.40%
Inflation	2.00%
Analysis Start	2020
Analysis Period	20
Line Losses	3.70%
Daily Avg. Temp (Lansing)	82.7
System Peak hour	19
Generation CONE (2020) $/kW-yr	$94.00
Capacity Value % of CONE	75%

Summary Outputs

Metric	Maximize Net Benefits	Maximize MW
Participants	58,466	80,919
MW Nameplate	72.9	82.3
Benefits (NPV)	$67,113,477	$75,741,174
Costs (NPV)	$40,396,408	$57,815,181
Net Benefits	$26,717,069	$17,925,993
Benefit Cost Ratio	1.66	1.31
Levelized Cost incl. Fixed Costs (2021$/kW	$43	$55
Impact per Customer	1.25	1.02
Customer Acquisition Cost (not including ad	$52	$65

Program Costs

Component	Cost Type	Cost Frequenc	Value	EAM Multiplier
Equipment	Volumetric	One time	$82.89	100%
Installation Labor	Volumetric	One-time	$81.45	100%
Other One-Time Costs	Volumetric	One-time	$65.00	100%
Support Labor	Fixed	Recurring	$100,000	120%
Support Labor	Volumetric	Recurring	$7.50	120%
Sign-up incentive	Volumetric	One-time	$25.00	100%
Annual incentive	Volumetric	Recurring	$24.00	100%
Other direct costs	Volumetric	Recurring	$0.00	120%

Other Program Inputs

Component	Value
Equipment Expected Useful Life	20
Annual retention rate	94%
Type of load	Cooling
% Reduction in AC load	65%
Max annual dispatch hours	40
Max event duration	4
Flexible availability	YES

Enrollment/Marketing Inputs

Recruitment Mode	Cost per attempt	Total	EAM Multiplier
Door-to-door	$10.00	0	120%
Phone (3 attempts)	$1.25	0	
DM	$1.00	6	
Email	$0.01	20	
Bill inserts	$0.05	20	
Social media	$0.02	20	

Smart Thermostat Saturation Inputs (Impacts eligible population)

Driver	Input	Notes or source
Residential customers	1,616,000	Population
% with Central AC	64%	Consumers Energy Appliance Saturation Survey
AC units per household	1.05	Consumers Energy Appliance Saturation Survey
Current Market Share	25%	% of new thermostats
Current Market Penetration	8%	% of Households with AC
Purchasing new t-stats (per year)	6.67%	1 in 15 households per year
Market share cap	70.00%	Assumed - 100% is not reasonable
Year max market share reached	2025	Assumed
% Connected and with app	80%	Assumes all recruitment is done by utilities after installation
Percent enrolling in DR	50%	Eco+ experiment, ETO Seasonal Savings, Tendril OE Pilot

Appendix E. BYOD Detailed Inputs and Summary Outputs

General Inputs

Component	Value
Discount Rate	7.40%
Inflation	2.00%
Analysis Start	2020
Analysis Period	20
Line Losses	3.70%
Daily Avg. Temp (Lansing)	82.7
System Peak hour	19
Generation CONE (2020) $/kW-yr	$94.00
Capacity Value % of CONE	75%

Summary Outputs

Metric	Maximize Net Benefits	Maximize MW
Participants	52,559	101,463
MW Nameplate	96.8	149.5
Benefits (NPV)	$89,068,119	$137,592,855
Costs (NPV)	$77,168,395	$137,336,030
Net Benefits	$11,899,723	$256,825
Benefit Cost Ratio	1.15	1.00
Levelized Cost incl. Fixed Costs (2021$/kW	$62	$72
Impact per Customer	1.84	1.47
Customer Acquisition Cost (not including ad	$82	$76

Program Costs

Component	Cost Type	Cost Frequenc	Value	EAM Multiplier
Equipment	Volumetric	One time	$15.00	100%
Installation Labor	Volumetric	One-time	$0.00	100%
Other One-Time Costs	Volumetric	One-time	$34.30	120%
Support Labor	Fixed	Recurring	$866,004	120%
Support Labor	Volumetric	Recurring	$1.00	120%
Sign-up incentive	Volumetric	One-time	$75.00	100%
Annual incentive	Volumetric	Recurring	$25.00	100%
Other direct costs	Volumetric	Recurring	$35.23	120%

Other Program Inputs

Component	Value
Equipment Expected Useful Life	15
Annual retention rate	94%
Type of load	Cooling
% Reduction in AC load	80%
Max annual dispatch hours	40
Max event duration	4
Flexible availability	YES

Enrollment/Marketing Inputs

Recruitment Mode	Cost per attempt	Total	EAM Multiplier
Door-to-door	$10.00	0	120%
Phone (3 attempts)	$1.25	1	
DM	$1.00	12	
Email	$0.01	25	
Bill inserts	$0.05	25	
Social media	$0.02	25	

Smart Thermostat Saturation Inputs (Impacts eligible population)

Driver	Input	Notes or source
Residential customers	1,616,000	Population
% with Central AC	64%	Consumers Energy Appliance Saturation Survey
AC units per household	1.05	Consumers Energy Appliance Saturation Survey
Current Market Share	30%	% of new thermostats
Current Market Penetration	8%	% of Households with AC
Purchasing new t-stats (per year)	6.67%	1 in 15 households per year
Market share cap	70.00%	Assumed - 100% is not reasonable
Year max market share reached	2025	Assumed
% Connected and with app	70%	Assumes all recruitment is done by utilities after installation
Percent enrolling in DR	50%	Eco+ experiment, ETO Seasonal Savings, Tendril OE Pilot

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

EXHIBITS

OF

MATTHEW S. HENRY

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
CVR Benefits Forecast

Case No.: U-21090
Exhibit No.: A-86 (MSH-1)
Page: 1 of 1
Witness: MSHenry
Date: June 2021

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line No.	Year	# of CVR Circuits Enabled (New)	# of CVR Circuits Enabled (Cumulative)	CVR MW Reduction (New)	CVR MW Reduction (Cumulative)	CVR MWh Reduction (New)	CVR MWh Reduction (Cumulative)	VVO MWh Reduction (New)	VVO MWh Reduction (Cumulative)	Total MWh Reduction (New)	Total MWh Reduction (Cumulative)
1	2021	85	160	10.47	19.63	24,237	45,483	848	1,592	25,085	47,075
2	2022	85	245	10.54	30.17	24,446	69,929	856	2,448	25,302	72,377
3	2023	85	330	10.62	40.78	24,615	94,544	862	3,309	25,477	97,853
4	2024	85	415	10.68	51.46	24,834	119,379	869	4,178	25,703	123,557
5	2025	85	500	10.70	62.16	24,723	144,102	865	5,044	25,588	149,145
6	2026	85	585	10.73	72.89	24,869	168,971	870	5,914	25,739	174,885
7	2027	85	670	10.78	83.66	25,005	193,976	875	6,789	25,881	200,765
8	2028	85	755	10.85	94.51	25,184	219,160	881	7,671	26,065	226,830
9	2029	85	840	10.89	105.40	25,291	244,450	885	8,556	26,176	253,006
10	2030	60	900	7.72	113.12	17,948	262,399	628	9,184	18,576	271,582
11	2031	0	900	0.00	113.12	00	262,399	00	9,184	00	271,582
12	2032	0	900	0.00	113.12	00	262,399	00	9,184	00	271,582
13	2033	0	900	0.00	113.12	00	262,399	00	9,184	00	271,582
14	2034	0	900	0.00	113.12	00	262,399	00	9,184	00	271,582
15	2035	0	900	0.00	113.12	00	262,399	00	9,184	00	271,582
16	2036	0	900	0.00	113.12	00	262,399	00	9,184	00	271,582
17	2037	0	900	0.00	113.12	00	262,399	00	9,184	00	271,582
18	2038	0	900	0.00	113.12	00	262,399	00	9,184	00	271,582
19	2039	0	900	0.00	113.12	00	262,399	00	9,184	00	271,582
20	2040	0	900	0.00	113.12	00	262,399	00	9,184	00	271,582

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
CVR Capital Investments Forecast

Case No.: U-21090
Exhibit No.: A-87 (MSH-2)

Witness: MSHenry
Date: June 2021

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	Year	# of CVR Circuits Enabled (New)	# of CVR Circuits Enabled (Cumulative)	Capital Labor	Capital Circuit Conditioning	Total Capital	Incentive
1	2021	85	160	$ 340,930	$ 3,730,000	$ 4,070,930	$ -
2	2022	85	245	$ 421,389	$ 3,730,000	$ 4,151,389	$ 758,504
3	2023	85	330	$ 434,031	$ 3,530,000	$ 3,964,031	$ 1,061,162
4	2024	85	415	$ 447,052	$ 3,430,000	$ 3,877,052	$ 1,432,946
5	2025	85	500	$ 460,464	$ 3,330,000	$ 3,790,464	$ 1,801,410
6	2026	85	585	$ 474,278	$ 3,230,000	$ 3,704,278	$ 2,213,428
7	2027	85	670	$ 488,506	$ 3,230,000	$ 3,718,506	$ 2,634,754
8	2028	85	755	$ 503,161	$ 3,230,000	$ 3,733,161	$ 3,079,789
9	2029	85	840	$ 518,256	$ 3,230,000	$ 3,748,256	$ 3,596,972
10	2030	60	900	$ 533,804	$ 2,280,000	$ 2,813,804	$ 3,987,691
11	2031	0	900	$ -	$ -	$ -	$ 4,073,920
12	2032	0	900	$ -	$ -	$ -	$ 4,243,929
13	2033	0	900	$ -	$ -	$ -	$ 4,418,330
14	2034	0	900	$ -	$ -	$ -	$ 4,594,310
15	2035	0	900	$ -	$ -	$ -	$ 4,777,619
16	2036	0	900	$ -	$ -	$ -	$ 4,963,980
17	2037	0	900	$ -	$ -	$ -	$ 5,153,024
18	2038	0	900	$ -	$ -	$ -	$ 5,345,627
19	2039	0	900	$ -	$ -	$ -	$ 5,545,430
20	2040	0	900	$ -	$ -	$ -	$ 5,747,949

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
CVR O&M Costs Forecast

Case No.: U-21090
Exhibit No.: A-88 (MSH-3)
Page: 1 of 1
Witness: MSHenry
Date: June 2021

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	Year	# of CVR Circuits Enabled (New)	# of CVR Circuits Enabled (Cumulative)	O&M Labor	O&M Circuit Conditioning	Total O&M
1	2021	85	160	$ 174,070	$ 102,240	$ 276,310
2	2022	85	245	$ 215,151	$ 156,555	$ 371,706
3	2023	85	330	$ 221,605	$ 210,870	$ 432,475
4	2024	85	415	$ 228,253	$ 265,185	$ 493,438
5	2025	85	500	$ 235,101	$ 319,500	$ 554,601
6	2026	85	585	$ 242,154	$ 373,815	$ 615,969
7	2027	85	670	$ 249,418	$ 428,130	$ 677,548
8	2028	85	755	$ 256,901	$ 482,445	$ 739,346
9	2029	85	840	$ 264,608	$ 536,760	$ 801,368
10	2030	60	900	$ 272,546	$ 575,100	$ 847,646
11	2031	0	900	$ 830,540	$ 575,100	$ 1,405,640
12	2032	0	900	$ 855,457	$ 575,100	$ 1,430,557
13	2033	0	900	$ 881,120	$ 575,100	$ 1,456,220
14	2034	0	900	$ 907,554	$ 575,100	$ 1,482,654
15	2035	0	900	$ 934,780	$ 575,100	$ 1,509,880
16	2036	0	900	$ 962,824	$ 575,100	$ 1,537,924
17	2037	0	900	$ 991,709	$ 575,100	$ 1,566,809
18	2038	0	900	$ 1,021,460	$ 575,100	$ 1,596,560
19	2039	0	900	$ 1,052,104	$ 575,100	$ 1,627,204
20	2040	0	900	$ 1,083,667	$ 575,100	$ 1,658,767

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
CVR Cost Approval Request

Case No.: U-21090
Exhibit No.: A-89 (MSH-4)
Page: 1 of 1
Witness: MSHenry
Date: June 2021

	(a)	(b)	(c)	(d)	(e)
Line No.	Year	MW Reduction	MWh Reduction	Capital Costs	O&M Costs
1	2023	40.78	97,853	$ 3,964,031	$ 432,475
2	2024	51.46	123,557	$ 3,877,052	$ 493,438
3*	2025 (6 months)	56.81	136,351	$ 1,895,232	$ 277,300

* Line No. 3 is from January 1, 2025 - June 30, 2025

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
CVR Benefits

Case No.: U-21090
Exhibit No.: A-90 (MSH-5)
Page: 1 of 1
Witness: MSHenry
Date: June 2021

Date Range: 8/7/2019 12/31/2020

Line No.	CVR Circuit #	Feeder ID	Headquarter	Substation	Circuit	CVR Enable Date	CVR On - Hours	CVR Off - Average Voltage	CVR On - Average Voltage	Voltage Reduction	CVR Off - Average Load (kW)	CVR On - Average Load (kW)	Load Reduction	CVRf	Energy Savings (MWh)	Forecast Energy Savings (MWh)	Demand Reduction (kW)	Forecast Demand Reduction (kW)	Percentage of AMI Reads in Range	CVR Off - Average AMI Voltage	CVR On - Average AMI Voltage	CVR AMI Voltage Reduction	Customers	CVR AMI Voltage Reads
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)
1	1	010007	Grand Rapids	Wealthy Street	Godfrey	8/7/2019	3,662	124.9	121.8	2.51%	1,683	1,650	1.97%	0.79	126	301	69	134	99.8%	122.9	119.8	2.52%	866	6,341,718
2	2	118401	Owosso	Newburg	Bancroft	8/14/2019	5,278	125.0	122.4	2.09%	983	965	1.92%	0.92	104	172	75	129	100.0%	124.5	122.0	1.99%	724	7,642,544
3	3	043502	Hastings	Lake Odessa	Industrial	8/21/2019	5,482	122.9	120.1	2.31%	905	889	1.67%	0.72	86	137	80	89	100.0%	121.5	118.6	2.33%	700	7,674,100
4	4	017301	Lansing	Meridian	Towar Gardens	10/9/2019	4,676	122.4	119.3	2.53%	965	944	2.20%	0.87	103	193	104	125	100.0%	121.6	118.7	2.41%	964	9,014,846
5	5	133502	Lansing	Tallman	Clark Road	10/16/2019	5,020	125.0	121.7	2.62%	357	350	2.00%	0.76	37	65	38	46	100.0%	124.3	121.1	2.58%	266	2,670,773
6	6	041303	Muskegon	Terrace	Spring	10/23/2019	4,699	123.9	121.1	2.26%	991	974	1.68%	0.74	81	151	82	81	99.9%	122.8	120.1	2.24%	1,037	9,746,245
7	7	056802	Grand Rapids	Ramona	Blodgett	10/30/2019	4,822	124.9	122.0	2.26%	2,179	2,155	1.12%	0.49	122	221	90	110	99.9%	123.3	120.5	2.23%	704	6,789,024
8	8	010106	Fremont	Fremont	Reeman	11/6/2019	4,426	124.9	122.0	2.33%	3,215	3,162	1.64%	0.70	242	479	124	277	99.9%	123.2	120.4	2.34%	1,796	15,898,192
9	9	034401	North Kent	Hull Street	Lime Lake	11/13/2019	4,644	124.9	121.9	2.40%	1,641	1,607	2.05%	0.86	162	306	158	206	100.0%	123.9	121.0	2.39%	1,206	11,200,725
10	10	021802	Jackson	Wildwood	Macklin	11/20/2019	4,188	122.2	119.3	2.35%	1,079	1,050	2.72%	1.16	127	266	84	113	99.4%	120.8	118.0	2.28%	1,111	9,306,292
11	11	050403	Jackson	Oliver	King Street	1/8/2020	3,848	126.1	122.8	2.62%	2,512	2,473	1.54%	0.59	155	352	133	164	100.0%	124.4	121.3	2.47%	850	6,540,750
12	12	101902	Kalamazoo	Midway	Naomi	1/8/2020	3,800	122.3	120.1	1.78%	1,156	1,144	1.06%	0.59	48	111	30	44	99.2%	120.1	118.0	1.75%	795	6,042,398
13	13	023508	Grand Rapids	Beals Road	Godwin Heights	1/15/2020	4,108	124.7	122.4	1.90%	1,153	1,135	1.56%	0.82	77	164	41	193	99.7%	122.9	120.8	1.74%	541	4,444,856
14	14	090802	Jackson	Oak Street	West Ganson	1/15/2020	3,935	125.0	122.0	2.35%	1,867	1,839	1.54%	0.66	118	262	62	118	99.6%	122.2	119.3	2.38%	1,311	10,318,226
15	15	029901	Muskegon	Norton	Pontaluna Road	1/22/2020	2,598	124.8	122.1	2.19%	1,249	1,220	2.33%	1.06	78	264	64	243	100.0%	123.4	120.7	2.18%	1,247	6,480,036
16	16	007303	Big Rapids	Milton	Federal Screw	1/22/2020	3,689	124.0	120.9	2.54%	3,553	3,475	2.20%	0.86	298	709	280	348	99.9%	122.7	119.7	2.50%	735	5,422,830
17	17	034201	Muskegon	Hickory	Gateway	1/29/2020	5,293	124.0	120.9	2.47%	3,539	3,533	0.17%	0.07	33	55	12	26	100.0%	122.8	119.8	2.44%	498	5,271,579
18	18	157802	Greenville	Tremaine	Keefer Road	1/29/2020	3,819	125.1	121.5	2.83%	407	401	1.58%	0.56	26	59	29	31	100.0%	123.9	120.4	2.82%	247	1,886,710
19	19	063404	Kalamazoo	Kilgore	Timberlane	2/5/2020	3,813	123.5	120.6	2.33%	1,902	1,863	2.04%	0.88	154	353	85	149	99.7%	121.8	119.0	2.32%	879	6,702,815
20	20	072702	Grand Rapids	Burlingame	Michael	2/5/2020	3,691	124.9	122.3	2.10%	1,680	1,651	1.71%	0.82	110	261	145	201	99.7%	123.5	120.9	2.10%	1,059	7,816,479
21	21	031803	Muskegon	East Muskegon	Quarterline Road	2/12/2020	3,449	125.0	122.0	2.42%	1,470	1,439	2.05%	0.84	107	273	73	173	100.0%	123.9	120.9	2.41%	1,187	8,187,333
22	22	069902	Grand Rapids	Walker	Rosalie	2/12/2020	3,441	124.9	122.6	1.89%	3,446	3,393	1.55%	0.82	190	484	153	419	99.6%	123.2	120.9	1.90%	3,098	21,321,985
23	23	128803	Lansing	Bennett	Dobie Road	2/19/2020	3,550	125.1	121.8	2.66%	1,498	1,468	2.03%	0.76	112	276	130	176	100.0%	123.6	120.4	2.63%	879	6,240,461
24	24	110802	Hamilton	Williams	Cresent	2/19/2020	3,533	122.8	120.0	2.25%	867	852	1.81%	0.81	58	143	67	81	100.0%	121.1	118.4	2.25%	652	4,606,380
25	25	029203	Jackson	Manchester	Duncan	5/14/2020	2,417	123.0	119.9	2.56%	1,719	1,660	3.44%	1.34	148	537	147	198	99.6%	121.1	118.3	2.37%	1,175	5,679,363
26	26	148501	Grand Rapids	Crahen	Greenbrier	5/14/2020	2,432	124.9	121.7	2.56%	1,636	1,614	1.39%	0.54	58	207	102	133	99.6%	123.2	120.1	2.55%	407	1,979,445
27	27	102701	Muskegon	Savidge	Boom Road	3/4/2020	3,218	123.8	121.8	1.63%	2,487	2,457	1.20%	0.74	100	272	71	162	99.2%	121.5	119.5	1.66%	1,281	8,244,516
28	28	014301	Muskegon	Spring Lake	Spring Lake	3/4/2020	3,218	124.9	122.3	2.02%	2,689	2,646	1.60%	0.79	143	390	114	288	99.3%	123.1	120.6	2.07%	2,144	13,797,712
29	29	154901	GR East	Birchwood	Laraway Lake	3/11/2020	3,266	124.8	121.8	2.35%	1,520	1,497	1.58%	0.67	81	218	128	148	100.0%	123.5	120.6	2.35%	619	4,042,689
30	30	130301	Lansing	West Road	Wood Road	3/11/2020	3,190	123.7	120.6	2.48%	2,060	2,017	2.09%	0.84	142	390	99	130	99.8%	120.9	117.9	2.45%	2,146	13,689,334
31	31	073101	Muskegon	Mona Lake	Airport	3/18/2020	3,001	124.4	121.8	2.08%	2,880	2,831	1.70%	0.82	152	444	129	285	99.6%	122.5	119.9	2.10%	2,758	16,552,137
32	32	036902	Kalamazoo	Cooley	North Street	3/18/2020	2,512	124.0	121.3	2.16%	1,680	1,653	1.61%	0.75	71	246	55	100	99.4%	121.6	119.0	2.14%	1,525	7,662,363
33	33	029902	Muskegon	Norton	Hile Road	5/13/2020	2,517	124.8	122.4	1.94%	2,540	2,476	2.54%	1.31	169	586	196	475	99.6%	122.6	120.2	1.97%	2,183	10,989,222
34	34	028802	Jackson	Michigan Center	Ballard	5/13/2020	2,517	123.2	120.9	1.85%	2,507	2,465	1.67%	0.90	109	381	107	201	99.1%	121.2	118.9	1.83%	2,007	10,103,238
35	35	048301	Hastings	Aubil Lake	Towers	5/20/2020	2,273	123.5	121.1	1.97%	4,987	4,911	1.54%	0.78	181	696	179	329	99.4%	121.4	118.9	2.02%	2,690	12,227,395
36	36	090701	Muskegon	Club	Adventure	5/20/2020	2,359	124.9	122.0	2.28%	456	449	1.42%	0.63	16	59	25	34	99.8%	123.0	120.1	2.32%	285	1,344,488
37	37	118403	Owosso	Newburg	Shiatown	5/20/2020	2,360	125.0	121.6	2.71%	742	729	1.72%	0.63	31	116	53	72	100.0%	124.6	121.2	2.70%	531	2,506,055
38	38	128802	Lansing	Bennett	Jolly Road	5/27/2020	1,694	125.0	122.0	2.39%	1,995	1,975	1.02%	0.43	36	185	46	103	99.3%	123.1	120.3	2.33%	1,184	4,010,208
39	39	063802	Kalamazoo	Neeley	Doster	5/27/2020	2,334	123.0	120.7	1.85%	643	632	1.74%	0.94	27	101	29	45	97.4%	120.4	118.1	1.88%	540	2,520,720
40	40	021801	Jackson	Wildwood	Yardman	5/27/2020	2,342	123.6	120.7	2.38%	2,999	2,969	0.98%	0.41	71	266	63	107	99.4%	121.6	118.7	2.43%	1,868	8,747,844
41	41	133501	Lansing	Tallman	Wacousta	6/3/2020	2,246	125.0	122.0	2.38%	1,410	1,365	3.19%	1.34	105	408	146	336	99.9%	123.6	120.6	2.39%	1,481	6,651,171
42	42	154301	Greenville	Harvard Lake	Harvard Lake	6/3/2020	2,222	124.9	122.0	2.35%	2,411	2,366	1.86%	0.79	103	408	112	241	99.8%	123.0	120.1	2.36%	1,952	8,672,736
43	43	060701	Muskegon	Getty	Marquette	6/3/2020	1,155	124.4	121.6	2.24%	3,622	3,530	2.53%	1.13	110	832	176	435	99.9%	122.8	120.0	2.22%	3,503	8,088,427
44	44	065502	Traverse City	O-at-ka	East Bay	8/12/2020	1,353	124.9	122.2	2.23%	725	704	2.87%	1.29	29	189	43	170	100.0%	124.4	121.6	2.21%	465	1,258,523
45	45	001903	Jackson	Roberts Street	Bender	6/10/2020	2,082	122.5	119.5	2.41%	1,518	1,482	2.39%	0.99	78	330	72	84	98.2%	120.3	117.5	2.37%	519	2,161,376
46	46	063403	Kalamazoo	Kilgore	Mount Everest	6/10/2020	2,097	123.0	120.1	2.35%	1,776	1,735	2.33%	0.99	90	376	95	151	99.4%	121.3	118.5	2.34%	1,336	5,602,516
47	47	149502	Kalamazoo	Eleventh Street	Starr Road	6/17/2020	2,253	125.0	121.1	3.07%	323	315	2.52%	0.82	19	74	31	39	100.0%	123.5	119.8	3.00%	215	968,790
48	48	150002	West Branch	Withey Lake	Henderson	6/17/2020	2,090	124.9	121.7	2.55%	198	194	1.60%	0.63	7	29	11	18	99.9%	123.1	120.0	2.55%	213	890,127
49	49	081502	Lansing	Harper Road	Eifert	6/24/2020	1,613	125.0	121.6	2.69%	158	152	3.57%	1.33	9	51	22	249	100.0%	124.1	120.7	2.68%	94	303,150
50	50	070305	Lansing	Ingham	Greenwood Park	7/2/2020	1,763	123.5	120.5	2.40%	1,772	1,719	2.97%	1.24	96	477	102	176	99.7%	121.9	119.0	2.37%	1,414	4,985,057
51	51	027901	Grand Rapids	Hager Park	Wellington	10/28/2020	1,596	n/a	121.9	n/a	n/a	1,320	n/a	n/a	42	233	41	87	99.6%	n/a	120.7	n/a	882	1,407,672
52	52	048801	Benzonia	Arcadia	Starke	10/28/2020	1,559	n/a	122.0	n/a	n/a	920	n/a	n/a	29	162	28	60	99.9%	n/a	120.6	n/a	848	1,321,608
53	53	014302	Muskegon	Spring Lake	Country Club	10/28/2020	1,574	n/a	121.9	n/a	n/a	1,432	n/a	n/a	45	253	44	93	100.0%	n/a	120.8	n/a	1,525	2,399,588
54	54	032503	Grand Rapids	Boston Square	Hall	11/4/2020	1,423	n/a	123.3	n/a	n/a	2,174	n/a	n/a	62	383	64	136	99.8%	n/a	121.4	n/a	2,110	3,002,003
55	55	035002	Muskegon	Fruitpoty	Judson Road	11/4/2020	1,422	n/a	122.3	n/a	n/a	1,814	n/a	n/a	52	320	55	116	100.0%	n/a	120.8	n/a	1,628	2,315,016
56	56	054801	Grand Rapids	Leonard	Ionia	12/21/2020	63	n/a	121.9	n/a	n/a	2,936	n/a	n/a	4	518	70	147	100.0%	n/a	120.3	n/a	3,094	194,922
57	57	070601	Grand Rapids	Bowen	Aircraft	11/4/2020	1,430	n/a	121.4	n/a	n/a	1,316	n/a	n/a	38	232	36	76	99.4%	n/a	119.1	n/a	1,045	1,493,828
58	58	065701	Boyne City	East Jordan	Williams Street	11/11/2020	1,262	n/a	121.9	n/a	n/a	2,396	n/a	n/a	61	422	67	142	100.0%	n/a	120.2	n/a	453	571,460
59	59	002602	Lansing	St Johns	Waterworks	11/11/2020	1,262	n/a	121.9	n/a	n/a	1,142	n/a	n/a	29	201	31	66	100.0%	n/a	120.9	n/a	806	1,016,769
60	60	085902	Grand Rapids	Ivanrest	Harlo	11/11/2020	1,262	n/a	122.2	n/a	n/a	2,770	n/a	n/a	70	488	87	182	99.4%	n/a	121.2	n/a	636	802,314
61	61	035001	Muskegon	Fruitport	Fruitport	11/11/2020	1,262	n/a	121.0	n/a	n/a	1,484	n/a	n/a	38	262	41	87	99.9%	n/a	119.1	n/a	946	1,193,379
62	62	061902	Muskegon	Broadway	Black Creek	11/24/2020	950	n/a	121.8	n/a	n/a	1,979	n/a	n/a	38	349	53	111	100.0%	n/a	120.4	n/a	1,079	1,024,511
63	63	067403	Jackson	Dexter Trail	Murray	11/24/2020	950	n/a	122.2	n/a	n/a	623	n/a	n/a	12	110	18	37	99.8%	n/a	120.1	n/a	393	373,154
64	64	098203	Grand Rapids	Leffingwell	Rapidstan	11/24/2020	950	n/a	121.8	n/a	n/a	422	n/a	n/a	8	74	13	27	100.0%	n/a	121.3	n/a	471	447,215
65	65	049903	Grand Rapids	Standale	Village	11/24/2020	950	n/a	122.0	n/a	n/a	1,151	n/a	n/a	22	203	32	68	99.9%	n/a	120.4	n/a	895	849,803
66	66	145101	Tawas	Noble	Duby	12/2/2020	735	n/a	121.0	n/a	n/a	404	n/a	n/a	6	71	11	23	100.0%	n/a	121.3	n/a	545	400,575
67	67	017601	Muskegon	Western Avenue	Barclay	12/2/2020	735	n/a	121.5	n/a	n/a	1,106	n/a	n/a	16	195	29	60	100.0%	n/a	120.7	n/a	1,537	1,129,695
68	68	103502	Grand Rapids	Knapp	Dunnigan	12/2/2020	758	n/a	119.3	n/a	n/a	1,659	n/a	n/a	25	292	46	97	99.9%	n/a	119.0	n/a	881	667,358
69	69	026401	Lansing	North Lansing	Valley Farms	12/2/2020	735	n/a	120.0	n/a	n/a	2,345	n/a	n/a	35	413	61	129	99.6%	n/a	118.1	n/a	2,122	1,559,670
70	70	112604	East Kent	Cascade	River	12/2/2020	735	n/a	122.0	n/a	n/a	1,169	n/a	n/a	17	206	31	65	99.9%	n/a	121.6	n/a	658	483,630
71	71	104202	North Kent	Rogue River	Rogue River	12/16/2020	234	n/a	122.2	n/a	n/a	1,411	n/a	n/a	7	249	37	78	100.0%	n/a	120.8	n/a	1,080	252,180
72	72	133504	Lansing	Tallman	Eagle	12/16/2020	422	n/a	122.1	n/a	n/a	1,243	n/a	n/a	11	219	33	69	100.0%	n/a	120.0	n/a	714	300,951
73	73	025203	Benzonia	Onekama	Chief	12/16/2020	407	n/a	122.1	n/a	n/a	951	n/a	n/a	8	168	24	50	99.1%	n/a	120.9	n/a	608	247,152
74	74	077402	Grand Rapids	Dewey	Seating	12/16/2020	407	n/a	122.0	n/a	n/a	4,022	n/a	n/a	33	709	101	213	99.9%	n/a	120.0	n/a	4,112	1,671,528
75	75	154302	Greenville	Harvard Lake	Courtland	12/16/2020	71	n/a	121.9	n/a	n/a	1,082	n/a	n/a	2	191	29	61	100.0%	n/a	120.2	n/a	786	55,413
76	**Total**						**183,125**			**2.32%**			**1.90%**	**0.82**	**5,643**	**21,247**	**5,646**	**10,667**	**99.7%**			**2.30%**	**87,741**	**376,427,281**

MICHIGAN PUBLIC SERVICE COMMISSION

Consumers Energy Company

CVR Costs

Case No.: U-21090
Exhibit No.: A-91 (MSH-6)
Page: 1 of 1
Witness: MSHenry
Date: June 2021

	(a)	(b)	(c)	(d)
Line No.	**Cost Category**	**2019**	**2020**	**Total**
1	Capital Circuit Conditioning	$ 81,744	$ 899,909	$ 981,653
2	Voltage Device Upgrades	$ -	$ 93,099	$ 93,099
3	DSCADA Deployment	$ -	$ 826,390	$ 826,390
4	Other Capital Costs	$ -	$ 117,195	$ 117,195
5	O&M Circuit Conditioning	$ 2,578	$ -	$ 2,578
6	Total Capital Spend	$ 81,744	$ 1,936,594	$ 2,018,337
7	Total O&M Spend	$ 2,578	$ -	$ 2,578

Consumers Energy

Conservation Voltage Reduction Measurement and Verification Independent Assessment

May 2021

ESTA International, LLC
21525 Ridgetop Circle, Suite 200
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USA

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EXECUTIVE SUMMARY

Conservation Voltage Reduction (CVR) is the practice of reducing service delivery voltage to the lower portion of the acceptable industry range as specified in ANSI Standard C84.1 to reduce energy consumption for waste energy reduction purposes and/or reduce peak electrical demand. Consumers Energy of Jackson, Michigan has conducted a CVR Demonstration Project that included implementing CVR on fifty of its electric distribution feeders that are located throughout the Consumers Energy service territory and has been operating in CVR reduced-voltage mode on alternating days since 2019.

To determine the waste energy and peak demand reduction that can be attributed to voltage reduction, Consumers Energy has conducted a Measurement and Verification (M&V) analysis of the electrical measurement data collected for each of the fifty feeders during the period of CVR alternating-day (aka, "day-on/day-off") operation. This analysis separates the electrical impacts of voltage reduction from other factors that affect the energy consumption and peak electrical demand, such as naturally varying custom behavior and ambient weather conditions, as well as variations in energy consumption for different hours of the day, days of the week, seasons, and other temporal variations.

In January 2021, Consumers Energy hired ESTA International, Ltd. (ESTA), an independent consulting firm specializing in electric utility automation and energy analysis to review and critique the Consumers Energy CVR project and associated M&V analysis performed by Consumers Energy. This report summarizes the results of this assessment.

M&V ASSESSMENT FACTORS

ESTA's assessment of the Consumers Energy CVR M&V approach included the following items:

- Process for Selecting Feeders. Consumers Energy will use the results of the CVR demonstration project to determine whether CVR implementation on additional feeders is justified. Therefore, the 50 feeders selected for the CVR demonstration should have characteristics (customer mix, regional distribution, etc.) that are representative of other Consumers Energy feeders on which CVR may be implemented in the future. Consumers Energy used a two-step process for selecting feeders for the CVR demonstration:

  - During Step 1, Consumers Energy identified 1,700 feeders that are viable candidates for implementing CVR based on factors such as availability of remote-controlled devices and telecommunication facilities. These feeders are labeled the "CVR Proposed" set.

  - During Step 2, Consumers Energy selected 50 feeders from the CVR Proposed set on which to implement CVR for demonstration purposes. In selecting these 50 feeders, preference was given to feeders with characteristics that best match the CVR proposed set. Preference was given to feeders that have a similar mix of residential, commercial and industrial customers.

  The feeder selection process used by Consumers Energy is far more detailed and superior to the selection process used by other utility companies. In ESTA's opinion, the selected CVR feeders are representative of the CVR Proposed set of feeders and, therefore, it is acceptable to assume that similar results will be obtained as CVR is added by Consumers Energy to additional feeders.

- CVR System. The CVR system deployed by Consumers Energy is like most CVR systems that have been deployed in the past 5 to 10 years by other electric utilities. This system applies fixed "rules" that have been predetermined by Engineering to real-time measurements obtained by the Consumers Energy SCADA system to determine what control actions (if any) are needed for switched capacitor banks and voltage regulators. The CVR system automatically switched between CVR-On mode (reduced voltage) to CVR Off mode (normal voltage) on alternating days. In ESTA's opinion, the rules-based approach is a cost-effective approach that is well suited to the project's "proof of concept" objectives. One shortcoming of this approach is that the system must be disabled for a given feeder if that feeder is reconfigured. This is not a major problem because such reconfiguration is infrequent. However, ESTA recommends a "model-driven" approach to CVR that automatically adapts when feeders are reconfigured. This approach can be implemented on the new Consumers Energy ADMS.

- <u>Controlled Devices:</u> The Consumers Energy CVR system controls switched capacitor banks and voltage regulators as needed to accomplish the CVR objectives. This is consistent with industry practice. Consumers Energy has a significant advantage over many other utility companies because voltage regulation is done on an individual-feeder basis. This enables Consumers Energy to reduce voltage on some feeders even if other feeders fed by the same substation are "voltage limited". In the future, control of other devices such as Distributed Energy Resources (DERs) with "smart inverters", may be required by Consumers Energy. The previously mentioned model-drive solution will be able to handle the addition of such devices.

- <u>Data Collected During the Demonstrations:</u> ESTA reviewed the list of electrical measurements collected during the CVR demonstrations to determine if the measurements taken are sufficient for effective operation of the CVR algorithms and determining the CVR factors. ESTA concludes that the collected data is consistent with the data collected by other utilities and is sufficient for computing the CVR factors for the CVR demonstration feeders. Some "data scrubbing" was performed by Consumers Energy to eliminate data anomalies. However, ESTA notes that the amount of data scrubbing needed by Consumers Energy for its data was much less than the data scrubbing needed by other utilities, indicating that the Consumers Energy data quality, in general, is very good.

- <u>Method of Computing CVR factors for Waste Energy Reduction and Peak Demand Reduction</u>. ESTA reviewed the method used by Consumers Energy to compute the CVR factors. Consumers used a method called "Matching Pairs" to compute a CVR factor, which is an important metric for CVR effectiveness. The Matching Pairs method compares weekday load and voltage measurements with reduced voltage (CVR On days) to weekday measurements when normal voltage normal voltage was applied (CVR Off days). Separate calculations were performed for each season because average ambient temperature can have a significant impact on CVR factor. having similar ambient temperature. The resulting CVR factor for Waste Energy Reduction was 0.82, meaning that when voltage is reduced by 1%, load is reduced by 0.82%. The result is consistent with results obtained by other utility companies, which generally fall in the range of 0.7 to 0.8.

  The most common method used in the industry to calculate CVR factors is multiple regression analysis to determine the impact of ambient temperature, voltage, and other factors on load. To confirm the results obtained by Consumers Energy, ESTA performed an independent calculation of CVR factor using regression analysis on the data supplied by Consumers Energy. The result of this analysis was a CVR factor of 0.77 +/- 3.7%. In ESTA's opinion, the results of this independent calculation confirms the accuracy of the Consumers Energy matching pairs method.

  ESTA also used the regression method to determine a CVR factor for Peak Reduction. The Peak Reduction CVR factor is typically significantly different than the Waster Energy Reduction CVR factor because the equipment complement and consumer appliances are different during peak load conditions than the on-line equipment complement during off peak periods. The results of this analysis is a Peak CVR factor of 1.51 with a model error of +/- 3.89%. ESTA is only aware of one utility (undisclosed) that has published a Peak

Demand CVR factor. The published CVR factor was 1.45, which is comparable the results obtained by ESTA.

Later this year, Consumers Energy is planning to use a load forecasting software tool called "MetrixND" (supplied by ITRON) for computing CVR factors. This software tool uses regression analysis to estimate what the load "would have been" with normal voltage for a given day of week an average ambient temperature. ESTA strongly recommends using this type of analysis for determining CVR factors.

CONCLUSIONS

For reasons given above, ESTA concludes that the CVR system software and hardware are well-suited and adequate for conducting the CVR demonstration and that the results obtained for the 50-feeder demonstration can be applied to other Consumers Energy feeders. While the "Matching Pairs" method used by Consumers Energy for computing CVR factor is somewhat unique, the results obtained using this approach match the independent calculations performed by ESTA reasonably well.

Going forward, ESTA encourages Consumers Energy to implement the MetrixND method, not only for estimating peak demand reduction but also for distribution load forecasting in general. ESTA also recommends that Consumers Energy implement a model-driven, ADMS-based approach to CVR because this approach has operational advantages described in this report.

TABLE OF CONTENTS

FIGURES

TABLES

Purpose of this Document:

This document summarizes the processes and procedures to be used by the project team members.

Ver. No.	Description	Prepared By	Reviewed By
0	**Initial Document for Comments**	**Bob Uluski**	**Spandan Gandhi**
1	**Additional sections added**	**Bob Uluski**	**Spandan Gandhi**
2	**Final Draft Version of Report**	**Bob Uluski**	**Spandan Gandhi**
3	**Final Report**	**Bob Uluski**	**Spandan Gandhi**

1 INTRODUCTION

Conservation Voltage Reduction (CVR) is the practice of reducing service delivery voltage to the lower portion of the acceptable industry range as specified in ANSI Standard C84.1 to reduce energy consumption for waste energy reduction purposes and/or reduce peak electrical demand. Consumers Energy of Jackson, Michigan has conducted a CVR Demonstration Project that included implementing CVR on fifty of its electric distribution feeders that are located throughout the Consumers Energy service territory and has been operating in CVR reduced-voltage mode on alternating days since 2019.

To determine the waste energy and peak demand reduction that can be attributed to voltage reduction, Consumers Energy has conducted a Measurement and Verification (M&V) analysis of the electrical measurement data collected for each of the fifty feeders during the period of CVR alternating-day (aka, “day-on/day-off”) operation. This analysis separates the electrical impacts of voltage reduction from other factors that affect the energy consumption and peak electrical demand, such as naturally varying custom behavior and ambient weather conditions, as well as variations in energy consumption for different hours of the day, days of the week, seasons, and other temporal variations.

The results of the CVR M&V analysis conducted by Consumers Energy indicate that the CVR factor, an important metric for measuring the load-to-voltage sensitivity, ranges from 0.07 to 1.34 for the 50 feeders that Consumers Energy has analyzed. This means that reducing the voltage applied to these electric distribution feeders by 1% will reduce electrical demand on these feeders by between 0.07% and 1.34% without any adverse electrical impacts or load shedding by Consumers Energy customers. The average CVR factor for the 50 CVR circuits is 0.82, which is consistent with CVR factors reported by other electric distribution utilities that have implemented CVR.

Consumers Energy is seeking an independent assessment of its CVR efforts to verify the results to date and assist Consumers Energy in determining whether implementing CVR on additional feeders would be beneficial to Consumers Energy and its customers. In January 2021, Consumers Energy hired ESTA International, Ltd. (ESTA), an independent consulting firm specializing in electric utility automation and energy analysis to review and critique the Consumers Energy CVR project and associated M&V analysis performed by Consumers Energy. This report summarizes the results of this assessment.

2 SCOPE OF THE INDEPENDENT CVR ASSESSMENT

The objective of the consulting assignment is to review and critique the methods used by Consumers Energy to conduct the Day-On/Day-Off CVR demonstration and to assess the method used to analyze the resulting data to determine the CVR factor, which is an important performance metric for CVR. ESTA's assessment included the following items:

- Process for Selecting Feeders. ESTA reviewed and critiqued the method Consumers Energy used to select the feeders on which the CVR demonstration was performed. Ideally, the selected feeders are representative of Consumers Energy feeders where it is practical and economical to implement CVR. That is, the selected feeders should have characteristics that are like the characteristics of the larger set of feeders on which CVR could be implemented. Such characteristics included (but were not limited to) feeder length and configuration, customer mix (residential, commercial, industrial), and location (North, South, East, West).

- CVR Software Algorithms. ESTA reviewed the algorithms and principles of operation of the CVR application software (furnished by the Consumers Energy Distribution Management System (DMS) supplier OSI International (OSII)) to gain a thorough understanding of the approaches used for 24-hour-a-day energy conservation and peak demand reduction.

- Controlled Devices: ESTA reviewed the list of devices that are controlled by the CVR application software, such as feeder voltage regulators and switched feeder capacitor banks. The feeders in question do not include significant penetrations of Distributed Energy Resources (DERs) such as rooftop solar photovoltaic generators which can affect the distribution feeder voltage and reduce the "net" load measured on the feeder. Hence, the DER impact on the results of this study are not significant.

- Data Collected During the Demonstrations: ESTA reviewed the list of electrical measurements collected during the CVR demonstrations to determine if the measurements taken are sufficient for effective operation of the CVR algorithms and determining the CVR factors. ESTA also reviewed the methods used for "data scrubbing" that is needed to eliminate data anomalies, such as bad and missing data, that may produce incorrect results.

- Method of Computing CVR factors for Waste Energy Reduction and Peak Demand Reduction. ESTA reviewed the method used by Consumers Energy to compute the CVR factors. The objective of this activity was to determine if the analytical methods are accurate and consistent with establish industry practices. ESTA compared the Consumers Energy methodology with the analytical approaches described in IEEE Standard 1885: "Guide for Assessing, Measuring and Verifying Volt-Var Control Optimization on Distribution Systems" to ensure consistency with this standard.

ESTA compared the Consumers Energy approach for each of the items listed above against the approach used by other electric distribution utilities that have similar characteristics to Consumers Energy and have already implemented CVR to determine if the Consumers Energy approach is consistent with best industry practices.

In addition to the assessment of Consumers Energy CVR M&V strategy described above, the project also includes developing a mechanism for predicting what CVR factor would be achieved by implementing CVR on additional feeders. This mechanism is described later in a separate report.

3 QUALIFICATIONS OF ESTA FOR PERFORMING THIS ASSESSMENT

ESTA is uniquely qualified for performing this assessment of Consumers Energy CVR projects and results for reasons stated below:

- ESTA has recently completed a detailed M&V assessment of CVR for Consolidated Edison of New York and has also conducted similar assessments for other utility companies that are similar in size and electrical characteristics to Consumers Energy.

- ESTA's team lead, Mr. Robert Uluski, has served as Chair of the IEEE's Power and Energy Society Task Force on Volt-VAR control and optimization and played a lead role in developing IEEE Standard 1885: "Guide for Assessing, Measuring and Verifying Volt-Var Control Optimization on Distribution Systems". This standard identifies ways in which electric distribution utilities can evaluate the CVR benefits. This standard was recently approved and published by IEEE. Mr. Uluski has also managed EPRI's "Smart Distribution" research program that included extensive work in laboratory testing to identify load-voltage sensitivity of major electrical appliances and equipment and in load-voltage modelling.

- ESTA's energy analyst, Mr. Spandan Gandhi, has considerable experience in advanced techniques for CVR M&V, including use of neural nets and multiple-regression analysis for modelling and analyzing the impacts of voltage reduction, as well as data scrubbing to identify data anomalies that can distort the M&V results.

- ESTA is a fully independent consulting firm that has no relationships with any system vendor and no vested interest in any commercial product. As a result, our findings, conclusions, and recommendations are completely unbiased by any such relationships.

4 LIST OF ACRONYMS

Following is a list of acronyms and key terms used in this report.

Table 4-1 List of Acronyms

Acronym/ term	Description
AMI	**Advanced Metering Infrastructure -** Facilities for periodically measuring and reporting customer electrical consumption at intervals of an hour or less for billing purposes, and for determining customer consumption patterns. AMI outputs in the form of "last gasp" messages have become a commonly-used mechanism for detecting power outages at individual customer sites. AMI may also be used for detecting low or high voltage conditions and the customer meter and reporting such conditions to the system operator and other persons responsible for outage management.
ANSI	**American National Standards Institute** - a private, non-profit organization that administers and coordinates the U.S. voluntary standards such as C48.1 ("Electric Power Systems Voltage Ratings")
CVR	**Conservation Voltage Reduction** - the process of intentionally reducing the voltage on a distribution circuit to the lower portion of the acceptable voltage range permitted by ANSI standard C84.1.
Day-On/Day-Off	A process of activating a system (such as CVR) on alternating days, and comparing measurements recorded during the "system on" day versus the "system off" day. of comparing
DER	**Distributed Energy Resource -** small scale generators, energy storage units, and controllable loads that are connected to the electric distribution system in close proximity to the load centers. DERs are most commonly used today to supply real and reactive power and curtail load when needed, the objective being to lower dependence on large scale centralized generators and high voltage transmission line as the sole source of supply. In addition, some DERs, such as solar and wind power are renewable energy sources that can help lower greenhouse gas emissions.
DMS	**Distribution Management System** - a computer and communication system the enables electric distribution system operators to monitor and control the distribution system assets and overall electric distribution system performance from the distribution control center.
DR	**Demand Reduction -** a set of processes used to curtail electrical consumption during system emergencies.
DSCADA	**Distribution Supervisory Control and Data Acquisition -** a computer and communication system that enables distribution system operators to monitor and control electric system power apparatus from a control center. The SCADA system is a fully integrated element of the Consumers Energy DMS.
EPRI	**Electric Power Research Institute -** an American independent, nonprofit organization that conducts research and development related to the generation, delivery, and use of electricity to help address challenges in electricity, including reliability, efficiency, affordability, health, safety, and the environment.
ESTA	**ESTA International, Ltd** - an independent consulting firm specializing in the planning, implementation, and the post-implementation analysis of benefits associated with electric utility automation systems. Consumers Energy hired ESTA to perform an independent assessment of its CVR system.

IEEE	**Institute of Electrical and Electronic Engineers -** a large worldwide professional association for electronic engineering and electrical engineering. IEEE is one of several recognized standards-making bodies for electric power systems.
kVAR	**Kilo-volt-ampere-reactive -** A measure of reactive power
LTC	**Load Tap Changer -** A device that automatically regulates the voltage supplied by a substation transformer to the electric distribution feeders. Note that Consumers Energy uses voltage regulators on individual feeders and does not use LTCs.
M&V	**Measurement and Verification** - the process of using measurements to determine actual savings created within an individual facility by an energy management, energy conservation or energy efficiency project or program. M&V is commonly used for estimating the benefits that cannot be measured directly, such as CVR benefits.
OSII	**Open Systems International, Inc, -** the system vendor that supplied the Consumers Energy ADMS that is used to implement CVR.
VVO	**Volt-VAR Optimization -** A software application running on the DMS for improving the efficiency and voltage quality on the electric distribution system. CVR is a subfunction of VVO.

5 ESTA ASSESSMENT OF CONSUMERS ENERGY CVR PROGRAM AND M&V APPROACH

ESTA's assessment of each of the items related to Consumers Energy CVR program is contained in the following sections. The following items are included:

1. Feeder Selection
2. CVR Software Algorithms
3. Controlled Devices
4. Data Collection
5. Method of Computing CVR factor

For each of the items listed above, ESTA has provided the following information:

a) General requirements pertaining to each item.
b) ESTA's understanding of the Consumers Energy approach for each item.
c) Comparison of Consumers Energy approach to best industry practices.
d) ESTA's Findings, conclusions, and overall assessment of Consumers Energy approach to each item.

5.1 FEEDERS SELECTED FOR CVR IMPLEMENTATION

The purpose of this section is to determine if the CVR benefit results for subset of feeders selected for this CVR demonstration project are representative of the CVR benefits that could be gained by implementing CVR on additional feeders.

a) General Requirements and Industry Practice for Feeder Selection

- Feeders should not be "voltage limited". If the service delivery voltage on a given feeder is near the low limit specified in ANSI standard C84.1 at one or more feeder locations during some loading conditions, it may not be possible to reduce voltage when needed. Feeder infrastructure improvements (reconductoring, etc.) may be needed to "flatten" the voltage profile on voltage-limited feeders and provide a suitable operating margin for voltage reduction.

- The customer mix (percentages of residential, commercial, and industrial customers) served by the feeder should be representative of the typical customer mix on other Consumers Energy feeders. Consumers Energy should not select a feeder that has a unique customer mix because results for that feeder may not be indicative of results that may be obtained on other Consumers Energy feeders.

- Voltage and VAR control devices on the feeder should be equipped with remote control capabilities that are needed for the Consumers Energy CVR system (see Section 5.2 for a description of the Consumers Energy CVR system).

- Feeders should have a suitable mechanism for determining the lowest voltage on the feeder. This will provide feedback to the CVR software to ensure voltage is not reduced below the low voltage limit specified in the ANSI standard.

- The feeders selected for CVR demonstration should be widely dispersed throughout the Consumers Energy service territory because the results for feeders in different geographic regions may be different. For example, the results for feeders in the Northern portion of the state may differ from feeders in the Southern portion of the state due to different energy consumption for heating and cooling in these two regions.

b) ESTA's Understanding of the Consumers Energy Approach to Feeder Selection

Consumers Energy used a two-step process for selecting feeders on which to implement CVR during the CVR demonstration project, as described below:

1. During step one of this process, Consumers Energy created a "CVR Potential" circuit pool consisting of approximately 1,700 distribution feeders that are viable "candidates" for CVR implementation. Feeders with the following characteristics were selected for the CVR Potential circuit pool:

    i. Feeder has substation DSCADA telemetry to enable remote monitoring and control capabilities. The Consumers Energy CVR system requires near-real-time DSCADA measurement data, such as reactive power flow, to determine if feeder capacitor bank switching is required. In addition, the CVR Potential circuits must have upgraded line voltage regulators that can be monitored and controlled by DSCADA and the CVR system

    ii. Circuit is not a Dedicated-Customer circuit. Most dedicated customer circuits have unique loading characteristics so the results would not be representative of other Consumers Energy circuits.

    iii. The circuit is not supplied by a delta (3-wire) substation. There are relatively few delta circuits at Consumers Energy, so the CVR results for this type of feeder would not be representative. In addition, the CVR control logic would be more complicated than wye-grounded (4-wire) circuits.

    iv. At least 50% of the customers on the feeder are residential customers. Circuits that primarily serve Commercial and Industrial customers (i.e., % of C/I customers greater than 66%) were excluded from the CVR potential circuits. Feeders with a proportionately higher number of residential customers is common at Consumers Energy, so circuits that serve a high percentage of residential customers are more representative of Consumers Energy distribution feeders.

2. During step 2 of the selection process, Consumers Energy selected 50 of the CVR Potential feeders with characteristics that are most representative of the total set of CVR Potential distribution feeders. Factors considered in selecting the 50 CVR feeders from the CVR Potential list of feeders included customer type breakdown, Archetype, circuit length, customer count, and the percentage of residential customer. ESTA's assessment of each of these feeder selection criteria is provided below:

a) **Customer Type Breakdown:** Customer type breakdown (or the percentages of residential, commercial, and industrial customers on a given feeder) is the primary factor used by Consumers Energy in selecting the CVR feeders from the CVR Potential list. The CVR factor is primarily impacted by the types of customers served by the feeder and the complement of electrical equipment and appliances used by these customers. Therefore, selecting feeders with customer type breakdown that matches the CVR Potential Set is critical for identifying representative feeders for CVR deployment. ESTA computed the customer type breakdown of feeders that were selected for CVR and the CVR Potential group. As seen in below, the differences in percentage mix of customers in the selected set and the CVR Potential set are very small. Therefore, ESTA concludes that the selected CVR circuits are representative of the Consumers Energy CVR potential feeders.

Table 5-1 Comparison by Customer Type Breakdown

	Customer Type Breakdown		
Customer Type	CVR Potential	CVR Selected	Difference
% Commercial	13.3%	11.5%	1.8%
% Industrial	0.2%	0.1%	0.1%
% Residential	84.8%	86.9%	-2.1%

b) **Archetype:** ESTA compared the Archetype breakdown for the selected CVR circuits with the Archetype breakdown for the CVR Potential group, as shown below. The breakdown of feeders by Archetype in the selected CVR set of feeders differs from the CVP Potential set by between 0% and 9%. The most significant difference is that a higher percentage of urban circuits (Archetypes 3 and 4) was selected over rural circuits (Archetypes 5, 6, and 7). In ESTA's opinion, the choice of urban feeders over rural feeders is justified, because urban feeders usually provide higher overall CVR benefits than rural circuits due to shorter length (less voltage drop) and heavier loading (more kWh reduction per unit voltage reduction). ESTA also believes, based on industry experience, that the percentages of rural feeders in the CVR Potential set are too high and that it is unlikely the Consumers Energy would actually add CVR to such a high number of rural circuits due to the lower payback opportunity.

Table 5-2 Comparison by Archetype

Archetype	Archetype Description	CVR Potential	CVR Selected	Difference
0	Circuit has not been assigned an Archetype Value yet	1%	0%	1%
1	Most Large C&I customers, short circuits that are primarily underground, best reliability	2%	25	0%
2	Circuits with greatest mix of customers and high proportion of small C&I, moderate reliability	11%	16%	-5%
3	Urban residential customers, short lines with high customer density, strong reliability, high NPS	14%	18%	-4%
4	Urban customers, longer circuits with high customer density that are more susceptible to outages	27%	36%	-9%
5	Rural circuits primarily in central/south, better reliability than rural circuit peers	20%	12%	8%

6	Rural circuits, low customers per line mile, high frequency of outages and long outage durations	15%	12%	3%
7	Rural customers primarily in the north, longest circuits, worst reliability across the system	10%	4%	6%
8	Radial, unshielded, higher risk HVD groups	0%	0%	0%
9	Core, looped HVD system	0%	0%	0%

c) **Circuit Length:** In general, circuit length does not have a significant impact on the CVR factor. However, since longer feeders will experience a greater voltage drop over the length of the feeder, feeder length impacts the percent voltage reduction that is possible, and therefore, impacts the CVR benefit (lower energy savings and smaller peak shaving possible). Table 5-3 shows the length breakdown of feeders in the selected CVR set of feeders and the CVR Potential circuits. As can be seen in the table, the selected CVR feeder set has a significantly higher percentage of shorter feeders than the CVR Potential set. In ESTA's opinion, this difference is not a matter of concern when computing CVR factor, because, as stated above, feeder length by itself does not impact CVR factor.

Table 5-3 Comparison by Feeder Length

Feeder length (Miles)	CVR Potential	CVR Selected	Difference
0-10	18.6%	40.0%	-21.4%
10-25	31.3%	24.0%	7.3%
25-40	19.2%	24.0%	-4.8%
40-55	14.1%	4.0%	10.1%
56+	16.8%	8.0%	8.8%

d) **Residential Percentage:** ESTA compared the residential percentages in the selected CVR circuits with the residential percentages in the CVR Potential circuit pool. As can be seen in this table, the percentage of residential customers matches reasonably well between the selected CVR circuits and the CVR Potential circuits except for circuits where the percentage of residential customers is less than 80%. Since the Consumer Energy focus is on feeders that have a high percentage of residential customers, this difference should not be a significant problem. Hence, ESTA concludes that here is a good match in residential customer percentages between to the two sets of circuits.

Table 5-4 Comparison by Residential Percentage

% Residential	CVR Potential	CVR Selected	Difference
0-80%	19.4%	8.0%	10.6%
80-85%	19.5%	24.0%	-4.5%
85-90%	30.9%	36.0%	-5.1%
90-100%	30.2%	32.0%	-1.8%

e) **Customer Count:** As can be seen in Table 5-5, the breakdown of total customer count for the selected feeders matches very well with the breakdown of customer count for the CVR Potential circuits.

Table 5-5 Comparison by Customer Count

Customer Count	CVR Potential	CVR Selected	Difference
0-500	17.7%	18.0%	-0.3%
501-1000	34.2%	32.0%	2.2%
1001-1500	26.6%	24.0%	2.6%
>1500	21.5%	26.0%	-4.5%

f) **Other comparisons**

- **Region:** Feeder location can have a significant impact on CVR factor, especially for circuits that are in the Northern versus Southern portions of the State of Michigan. The latitude and longitude of the selected CVR circuits is consistent with the Potential CVR circuit pool. The feeders in both the circuit pool and the selected set are primarily located in the southern and central part of the State, with a few outliers in the North. Both sets appear to be split equally between substations in the Eastern and Western parts of the State. Note that the North and south difference is more significant when computing a CVR factor, because energy consumption patterns and associated CVR factors may be different for northern (colder) regions and southern (warmer) regions of the state.

c) **Comparison of Consumers Energy approach to best industry practices**

Several other factors may be considered when selecting circuits for CVR:

a. **Worst performing feeders:** Some utilities have elected to implement CVR (and the broader application Volt-VAR Optimization) on circuits that have historically experienced low power factor. The VVO application can improve power factor and thus reduce losses on these worst performing feeders in addition to accomplishing peak shaving and energy conservation using CVR.

b. **Heavily Loaded Circuits:** Heavily loaded circuits are often selected (provided they are not voltage limited) because the energy savings and peak shaving benefits for a given amount of voltage reduction are greater for a given circuit than a lightly loaded feeder having the same CVR factor.

c. **Groups of Feeders from Same Substation:** Groups of feeders fed off the same substation bus are usually selected for CVR at the same time. This is because voltage reduction actions are performed by a substation load tap changer (LTC) transformer which impacts all feeders that are connected to the low side bus of the transformer. This does not apply to Consumers Energy, which uses individual feeder voltage regulators.

d) **Findings, conclusions, and overall assessment of Consumers Energy approach**

In ESTA's opinion, the process used by Consumers Energy for selecting feeders for its CVR demonstration far exceeds the feeder selection process used by other utilities that have demonstrated and/or implemented CVR. Most utilities have selected feeders based on a limited set of factors such as the availability of DSCADA and remotely controllable volt-VAR devices (feeder capacitor banks and voltage regulators).

Based on the analysis described above, ESTA concludes that the feeders that have been selected by Consumers Energy for CVR are representative of the broader set of CVR Potential feeders. This conclusion is based primarily on the customer type breakdown which matches well between the two groups of feeders. While there are some differences in other selection criteria between the selected CVR circuits and the CVR Potential group of feeders, these factors in general should not have a major impact on the overall CVR factors.

In the case of Archetype differences between the two sets of feeders, ESTA concludes this is due to having too many rural feeders in the CVR Potential set. If the percentages of rural feeders in the CVR Potential set are reduced, the two sets would have comparable breakdowns by Archetype.

As a result, it is reasonable to conclude that the CVR factors computed for the selected feeders are representative of the results that will be obtained if CVR is applied to other circuits in the CVR Potential circuit pool.

5.2 CVR SOFTWARE ALGORITHMS

In this section, ESTA compared the Consumers Energy CVR system with CVR systems that are that have been implemented by other utilities in North America.

a) General Requirements

a. The CVR system should be able to lower the voltage on selected distribution feeders by a Consumers Energy-specified amount to achieve a reduction in waste energy and/or peak electrical demand.

b. A suitable mechanism should be provided to ensure that the service delivery voltage at all customer meters on the feeder does not go below the limits specified in applicable ANSI standards when CVR is activated. CVR must be transparent to the consumers and must not adversely impact the operation of customer-owned equipment.

c. The CVR system shall be able to operate in either of the following Consumers Energy-selectable modes:

   i. <u>Energy Waste Reduction mode:</u> In this mode, voltage shall be reduced by the specified amount whenever possible, up to 24 hours per day. The objective of this mode is to reduce energy (MWh) consumption without customer load shedding for overall efficiency improvement.

ii. Peak Demand Reduction mode: In Peak Demand Reduction mode, the voltage is lowered for a few hours during which peak demand occurs, with normal voltage applied during other hours. For example, if peak load occurs at 5:00 PM, voltage may be reduced between 4:00PM and 6:00PM, with normal voltage being applied during other hours. The objective of this mode of operation is to reduce the maximum load in megawatts on the feeder. The Peak Demand Reduction algorithms shall ensure that restoration of normal voltage following the CVR peak shaving event does not create a new peak; this can happen when diversity of thermostat-controlled devices is diminished during the voltage reduction period.

d. The CVR algorithms shall ensure that voltage and VAR control devices are properly time coordinated so that "hunting" and contradicting control actions are avoided. For example, control actions by voltage regulators to lower the feeder voltage should not be immediately followed by switched capacitor banks operating to raise the voltage.

e. The CVR algorithms shall not initiate improper or invalid voltage control and VAR control commands when the feeder is reconfigured. Feeder reconfiguration can change the position of capacitor banks and midline voltage regulators relative to the power source which, in turn, can result in improper coordination between devices. Furthermore, CVR shall not attempt to control any switched capacitor bank, voltage regulator, or other VVC device that is tagged out of service.

f. The control strategy for volt-VAR devices shall respect device operating restrictions, such as capacitor bank closing within the capacitor bank discharge time and prevention of "local" regulator over-voltages ("first house" protection).

g. The system shall include mechanisms for monitoring the operation of individual capacitor banks, voltage regulators, controllers, and communication facilities and shall be able to detect failures in any of these components that would prevent the device from operating as needed upon command. Failed components should be excluded from the CVR control strategy.

b) ESTA's understanding of the Consumers Energy approach

a. The Consumers Energy CVR approach is best described as a "rules-based" approach. That is, the CVR logic compares SCADA measurements against predetermined setpoints and then initiates control actions based on "if-then-else" rules. For example, if the reactive power flow to the feeder exceeds a specified setpoint, then switch a capacitor bank on the feeder to the "ON" position; otherwise do nothing. Figure 5-1 depicts a SCADA rules-based solution such as that used by Consumers Energy. Simply stated, when reactive power flow measured at the substation end of the feeder exceeds a pre-determined threshold, the CVR system sends commands to one or more capacitor bank switches, which, in turn, reduces the reactive power flow from the substation.

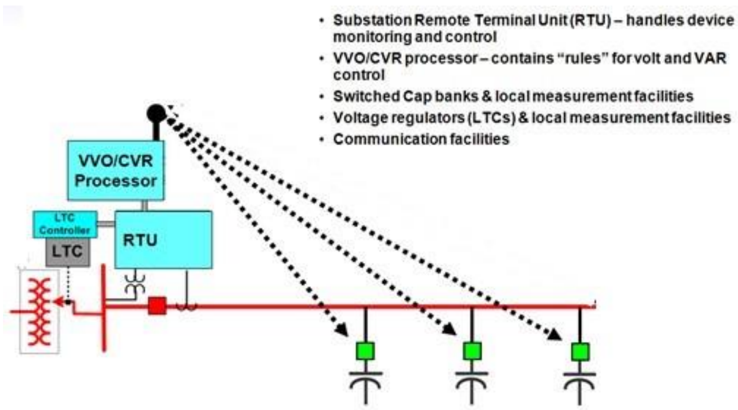

Figure 5-1 SCADA Rules Based CVR System

b. The CVR system setpoints and operating strategies that have been incorporated in the CVR logic have been determined in advance for each feeder by the Consumers Energy Distribution Engineering group using power flow analysis. These setpoints and control strategies have considered "worst case" (e.g., heavy load) conditions to ensure that the recommended CVR control actions will not produce unacceptable, adverse electrical conditions (low or high voltage, equipment overloads, etc.).

c. CVR is currently configured (for demonstration and M&V purposes) to run on alternate days (also known as Day-On/Day-Off strategy). Each day at approximately midnight, the CVR system automatically switches to the opposite operating mode (reduced voltage mode to normal voltage mode or normal voltage mode to reduced voltage mode).

d. To provide proper time coordination of voltage regulators and capacitor banks and avoid "hunting", Consumers Energy has incorporated the following rules in its CVR system:

- **i.** Capacitor banks are controlled first, followed by voltage regulators.
- **ii.** Device coordination is accomplished using different pre-determined time delays on each device.
- **iii.** Capacitor banks that are closest to the load center (i.e., furthest from the source) are switched on first. This allows upstream capacitor banks to see the change in reactive power flow caused by downstream capacitor banks switching before operating to prevent overcompensation.
- **iv.** Voltage regulator control actions (raise or lower tap position) are first executed on substation voltage regulators, followed by the control of midline voltage regulators.

e. Capacitor bank switching is initiated by the CVR software whenever the reactive power flow measured at the substation end of the feeder exceeds a predetermined amount (typically set at +/-

400 kVAR). The CVR system selects the capacitor bank that is closest to the load center (furthest from the substation) whose size in kVAR does not exceed the measured amount. After this capacitor bank is switched, the logic is repeated until no additional capacitor bank switching is possible.

f. If the measured VAR flow at the substation end of the feeder becomes negative (reactive power flow back into the substation (i.e., leading power factor)), the CVR software will switch off capacitor banks using similar logic to that described above (i.e., largest capacitor banks that are closest to the load center switched off first).

g. After a predetermined delay to allow capacitor bank switching to complete, voltage regulator operation is permitted using the predetermined Energy Waste Reduction settings. If midline voltage regulators are present, the time delay for these voltage regulators will be larger than the time delay for the substation voltage regulator for proper time coordination of substation and midline devices.

h. Peak Demand reduction is activated manually by the Distribution Operator during periods when peak shaving is required, such as during Merchant Operations demand reduction (DR) events. The logic used by Peak Demand Reduction CVR logic for controlling capacitor banks and voltage regulators is the same as Energy Waste Reduction. However, the logic is triggered at the start of the event (an hour or two before the system peak) and returned to normal an hour or two following the system peak.

i. If the feeder is reconfigured for any reason, the CVR logic is disabled to avoid switching capacitor banks that are no longer connected to its normal feeder and to avoid improper time coordination due to having a different location of a device relative to its source. It is not practical to incorporate additional rules to handle all the possible switching combinations using simple Boolean logic, and maintenance of such complex logic would be labor intensive. When the CVR system is disabled, the distribution voltage and reactive power control strategy reverts to local autonomous control performed by the individual device controllers.

j. Customer voltages reported by the Consumers Energy Advanced Metering Infrastructure (AMI) are checked the following day to determine if any low or high voltage deviations occurred during the previous day's voltage reduction actions. If frequent voltage deviations are observed for a given customer meter or location, the voltage regulator and capacitor banks settings for the associated feeder are adjusted as needed to avoid reoccurrence of these deviations. If necessary, feeder infrastructure improvements (e.g., reconductoring) may be implemented to eliminate significant voltage deviations that cannot be mitigated by setting changes alone.

c) Comparison of Consumers Energy approach to best industry practices

a. Most of the existing CVR solutions that today's electric utilities have implemented are SCADA "rule-based" systems that use logic like the Consumers Energy CVR system. That is, control decisions are based on "if-then-else" (Boolean) logic performed on measurements received from the utility's distribution SCADA system.

b. Some utilities use proprietary CVR solutions offered by vendors such as Utilidata, Dominion Voltage, Eaton IVVC, and other system vendors. These proprietary solutions are often considerably more expensive per substation then SCADA rules-based solutions due to the sophisticated algorithms and additional hardware needed to identify and implement required control actions. Incremental benefits offered by these systems include the potential for fewer voltage regulator tap position changes and nearly-real-time voltage feedback from strategic feeder locations for rapid detection and correction of voltage deviations. Note that the solution type does not impact the CVR factor, which is determined primarily by the electrical equipment and appliances used on a feeder. Like the Consumers Energy system, these proprietary solutions are often switched off when feeder reconfiguration occurs.

c. A growing trend is the deployment of “model-driven” Volt-VAR Optimization (VVO) solutions that are incorporated in the electric utility’s Advanced Distribution Management System (ADMS). These ADMS solutions perform power flow analysis on an as-switched (as operated) electrical model to determine the “optimal” set of voltage and reactive power control actions to achieve one or more selected operating objectives. Selectable operating objectives may include reduce losses, conserve energy, peak shaving, voltage profile improvement, reactive power support to the bulk power grid, minimize use of high maintenance equipment, or a weighted combination of the above. Besides providing selectable business objectives, model driven solutions can provide the following additional benefits:

   i. The power flow solution automatically provides supplies continuous feedback about the voltage at all points on the feeder so that low or high voltage conditions are rapidly detected and corrected.

   ii. Model-driven solutions adapt automatically when feeder reconfiguration occurs so that CVR does not have to be shut down. While the results for a reconfigured feeder may not represent “optimal” results, they do provide the best possible CVR solution with no voltage deviations given the current as-switched condition of the feeder.

   iii. Model driven solutions are better able to accommodate the impacts of distributed energy resources (DERs) and, where possible, leverage the opportunities offered by DERs, such as using “smart” inverters to supply reactive power. Currently, the DER penetration level is not high enough to warrant consideration of these devices in the CVR system. However, if penetration level rises in the future, a model-driven strategy may be the most effective approach.

The benefits listed above come at a high price (including implementation costs and O&M costs). However, since Consumers Energy is currently implementing an ADMS that will have the necessary model and application software, a cost-effective model-driven solution may be possible Consumers Energy in the future.

d) Findings, conclusions, and overall assessment of Consumers Energy approach

a. The Consumers Energy SCADA rules-based approach is a very effective solution that has achieved significant Waste Energy Reduction benefits and Peak Demand reductions benefits for Consumers Energy customers and Consumers Energy itself at a reasonable cost.

b. The rules-based approach is well-suited for “proof of concept” as well as achieving actual operational benefits.

c. As discussed above, there are two significant limitations of the rules-based approach used by Consumers Energy: inability to handle feeder reconfiguration and lack of immediate voltage feedback when low voltage conditions occur at some customer meters.

    i. In the future, feeder reconfiguration may occur more frequently than before as Consumers Energy introduces new ADMS applications, such as Fault Location, Isolation, and Service Restoration (FLISR). ESTA assumes that when a feeder is reconfigured for any reason, Consumers Energy will endeavor to restore the feeder to its normal configuration as soon as possible. Therefore, the period that CVR will be disabled is minimized. However, in the long run, Consumers Energy should consider implementing CVR on its new ADMS to avoid a complete shutdown of the CVR application when feeder reconfiguration occurs.

    ii. Due to the lack of near-real-time voltage feedback, a small number of customers may at times experience voltage at the low end of the standard voltage range. Such rare voltage deviations are detected manually by reviewing AMI data the day after a voltage reduction event. Upon detecting the problem, Consumers Energy may alter the CVR settings and, if necessary, plan for infrastructure improvements for more serious and severe problems. This method of low voltage detection is acceptable if the voltage deviation is infrequent, relatively small (less than 2-3% below the minimum voltage) and is promptly corrected. However, failure to deal with severe low voltage conditions on a timely basis can result in customer voltage complaints and, in the worst case, damage to customer-owned equipment.

    This problem can be addressed by adding bellwether voltage meters at feeder extremities and other strategic locations and incorporating measurements from these meters in the CVR logic. This is shown in Figure 5-2 below. If possible, near-real-time low voltage alarms from AMI meters can also be incorporated in the logic. The ADMS model-driven solution provides another possible remedy because the ADMS Powerflow computes the voltage at all feeder locations on a continuous basis and will automatically block control actions that would produce voltage deviations.

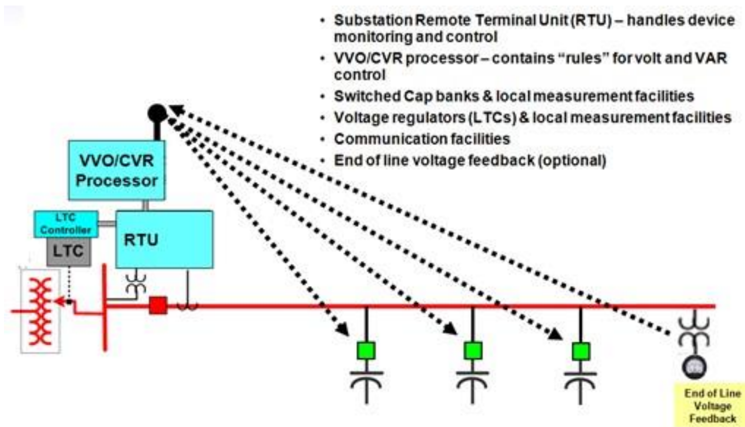

Figure 5-2 Rules-Based CVR with Voltage Feedback

Note that having continuous feedback on feeder voltage level will enable Consumers Energy to operate with a smaller voltage margin to the low voltage threshold, thus enabling Consumers Energy to obtain greater Waste Reduction and Peak Demand reduction benefits.

5.3 CONTROLLED DEVICES

This section contains an assessment of the devices controlled by the Consumers Energy CVR system.

a) General Requirements

The CVR solution should be able to manage the operation of all controllable devices that affect the reactive power flow and voltage profile on the feeder. Controlled devices should include (as a minimum):

i. Voltage regulators located at the head end of the feeder and at mid-line locations (Consumers Energy has few midline regulators on its distribution system and none of these devices on the CVR demonstration feeders)

ii. All switched capacitor banks located out on the feeders.

In the future, the CVR system may need to control additional devices:

iii. “"Edge of network” devices (if any) such as smart inverters and distributed VAR sources located on the secondary side of distribution service transformers.

iv. Distributed energy resources (energy storage, distributed generators with smart inverters, etc.) that are capable of supplying or absorbing real and reactive power on demand.

b) ESTA’s understanding of the Consumers Energy approach

a. Consumers Energy CVR system manages the operation of distribution voltage regulators and switched capacitor banks that are installed on the electric distribution system.

b. There are no "Edge of Network" or controllable DERs that are connected to the electric distribution system.

c. Consumers Energy uses separate voltage regulators on all individual feeders. This provides a significant advantage over most other utilities that have multiple feeders connected to a common voltage-controlled substation bus. Consumers Energy can implement different control actions as needed on all feeders out of a single substation without being concerned that a CVR control action will benefit one feeder and adversely impact another feeder that is connected to the same substation. For example, if one substation feeder is voltage limited, it would not be possible to lower the voltage on the remaining feeders connected to the same bus. However, with individual feeder voltage controls, it is possible to lower voltage on feeders that are not voltage limited while retaining the normal voltage or boosting the voltage on the feeder that is voltage limited.

c) Comparison of Consumers Energy approach to best industry practices

The list of controllable volt-VAR devices by Consumers Energy is consistent with devices that are installed on most electric distribution circuits operated by electric distribution utilities.

d) **Findings, conclusions, and overall assessment of Consumers Energy approach**

a. The list of controllable volt-VAR devices on Consumers Energy distribution feeders meets and, in some ways (e.g., control of voltage on individual feeder voltages), exceeds the control requirements for CVR.

b. While Consumers Energy does not currently have any "edge of network" devices, it should be possible to add these devices in the future to either a rules-based solution or ADMS model-driven solution, if needs arise (e.g., widespread electric vehicle charger deployment, addition of significant penetration of rooftop solar PV generators).

5.4 MEASUREMENT DATA COLLECTED

a) General Requirements

a. The CVR system should acquire key measurement data and equipment status information via distribution SCADA or other mechanism on a continuous "near-real-time" basis. In other words, up-to-date field information should be supplied to the CVR system at least once every 15 minutes.

b. Information supplied to the CVR system should include (as a minimum):

i. Real and reactive power flow (A, B, and C phases) measured at the substation end of the feeder.

ii. Voltage measurements (A, B, C phases) at the substation end of the feeder

iii. Voltage measurement at strategic locations on the feeder (e.g., feeder extremities)

iv. Operating status of all equipment that is monitored and controlled by CVR. This includes feeder circuit breaker and recloser status, open/closed position of all capacitor bank switches, and capacitor bank protective devices (e.g., neutral shift detection)

v. Voltage regulator tap position (if available)

c. Data "scrubbing" should be performed to identify and eliminate all data anomalies (e.g., unreasonable values, "stale" information that has not changed for an extended period) in the supplied data. Failure to detect and eliminate these data problems can result in incorrect results.

b) ESTA's understanding of the Consumers Energy approach

a. Consumers provided data from all 50 feeders on which CVR was implemented. On twenty of these feeders, demand response CVR was also conducted on selected peak load days in 2020.

b. List of variables: CVR Status, Timestamp, Phase –X kW Load, Phase –Y kW Load, Phase –Z kW Load, Phase-X secondary load voltage, Phase-Y secondary load voltage, Phase-Z secondary load voltage, Temperature, Total kW Load, Average Sub Voltage

c. Duration: varies for each feeder. "010007" feeder was the first feeder to go under voltage reduction program on August 7, 2019 and "065502" feeder was the last feeder, CVR starting on December 8, 2020. The CVR program continued until April 2021.

d. Resolution: SCADA (Supervisory Control and Data Acquisition) data provided to ESTA was recorded at a 15 min interval.

e. Data Scrubbing: A significant amount of data was scrubbed for several reasons including telemetry issues, Application issues, holidays, and data errors. Scrubbed data was excluded from this analysis.

c) Comparison of Consumers Energy approach to best industry practices

The list of measurement and equipment status information in the Consumers Energy system is consistent with devices that are installed on most electric distribution circuits operated by electric distribution utilities. However, most solutions at other utilities provide a means of obtaining near-real-time voltage feedback from AMI meters or bellwether line voltmeters. Consumers Energy does not receive such voltage feedback on a continuous basis. However, day-after voltage measurements from AMI are reviewed daily by Consumers Energy to detect any voltage problems which are subsequently corrected.

d) **Findings, conclusions, and overall assessment of Consumers Energy approach**

a. The data measurements supplied to the Consumers Energy CVR system provide the minimum amount of information that is needed for operation of the CVR system and for performing M&V of the CVR results.

b. Some data "scrubbing" was needed to eliminate data anomalies, such as "stale" data that remains constant for an extended period. However, enough data remained for performing the M&V after removing suspect data.

c. ESTA notes that the need for data scrubbing during M&V analysis is common in the industry and that the amount of data scrubbing was far less for Consumers Energy's data than the data scrubbing required for M&V purposes at other electric utilities.

d. While Consumers Energy does not currently have any "edge of network" devices, it should be possible to add these devices in the future to either a rules-based solution or ADMS model-driven solution, if needs arise (e.g., widespread electric vehicle charger deployment, addition of significant penetration of rooftop solar PV generators).

5.5 METHOD OF COMPUTING CVR FACTOR

The methods used to compute CVR factor for waste energy reduction and peak demand reduction are slightly different. Therefore, separate sections are provided below for the two operating modes.

5.5.1 CVR FACTOR FOR WASTE ENERGY REDUCTION

a) General Requirements

- M&V analysis must determine the CVR factor for individual distribution feeders with an accuracy of +/- 5% or better. CVR factor is the percentage change in power or energy attributable to voltage reduction divided by the percentage reduction in voltage.

- Separate CVR factors must be provided for Energy Waste reduction and Peak Demand reduction

- Measurement and Verification (M&V) Analysis must separate the electrical impact of voltage reduction on power or energy consumption from other factors that impact power or energy consumption. Other factors include:
  i. Ambient weather conditions and season
  ii. Day of week, time of day

- CVR voltage and load reductions were calculated by averaging all of the day "CVR On"/"CVR Off" readings and comparing the difference.

- $$CVR\ factor = \frac{(Avg.\text{ CVR Off } Load - Avg.CVR\ On\ Load) / Avg.\text{ CVR Off } Load}{(Avg.\text{ CVR Off } Voltage - Avg.CVR\ On\ Voltage) / Avg.\text{ CVR Off } Voltage}$$

b) ESTA's understanding of the Consumers Energy approach

- Consumers Energy uses a "Matching Pairs" concept for its CVR M&V analysis. The process involved comparing load measurements for a set of days on which CVR was "on" (voltage reduced) with a set of load measurements for an equal number of days when CVR was "off" (normal voltage applied).

- CVR-On data sets were compared with CVR-Off data sets having "similar" characteristics. "Similar" days are either weekdays or weekends having similar average daily temperatures:

    - **Weekdays versus Weekends:** Data sets containing weekday loads were compared with other weekdays. Weekend days were compared with other weekend days.

    - **Temperature Range:** Each data set contained load data for each "season" which includes days on which the average temperature was within a specified range. Consumers Energy determined the range of seasons based on predetermined temperature thresholds. For example, when mean temperature of the day goes beyond 65 F consistent for consecutive days, "Summer" season is considered to have begun, and it continues till threshold for "Fall" season is reached. Based on this following season ranges were identified: Start Day, End Day
        i. 2019 Summer: 8/7 to 10/1
        ii. 2019 Fall: 10/2 to 11/5
        iii. 2019/2020 Winter: 11/6 to 3/24
        iv. 2020 Spring: 3/25 to 5/22
        v. 2020 Summer: 5/23 to 9/6
        vi. 2020 Fall: 9/7 to 11/20
        vii. 2020/2021 Winter: 11/21 to 3/9

.

- Each CVR On day has a corresponding CVR Off day with the same day type (weekday or weekend) and season. An equal number of CVR On days and CVR Off days is needed for this analysis. If the number of days in each category is not the same, the M&V algorithm will exclude days from the category with higher number of days by first taking the mean load and temperature of each day and whole day and season category and eliminate the day with mean farthest from category mean.

- Once the CVR on-off cycle is completed, the load and voltage value are collected for each feeder over a resolution of 15 mins. The CVR factor is calculated by averaging all days with "CVR On"/"CVR Off" readings and comparing the difference, as shown below:

$$CVR\ factor = \frac{(Avg.\text{ CVR Off }Load - Avg.\ CVR\ On\ Load) \big/ Avg.\text{ CVR Off }Load}{(Avg.\text{ CVR Off }Voltage - Avg.\ CVR\ On\ Voltage) \big/ Avg.\text{ CVR Off }Voltage}$$

- Using this calculation, Consumers Energy found that from date 8/7/2019 to 12/31/2020, for all the CVR experiments conducted on all 50 feeders, the average CVR factor they were able achieve was 0.82, with it ranging from 1.34 to 0.07. The average voltage drop was 2.31%, while the average load drop was 1.9%.

- The Consumers Energy M&V approach assumes that the primary factors other than voltage that affect the average load on a given feeder are day of week (i.e., weekday versus weekend, holidays excluded), average ambient temperature, and season.

- Based on this assumption, the loading on a selected feeder will be the same on all weekdays in each season that have the same daily average temperature if the voltage is the same. For example, the loading on a selected feeder for two summer weekdays (Monday through Friday) that have the same average temperature will be approximately the same if normal voltage is supplied to the feeder.

- As a result of the assumptions listed above, any loading difference on two summer days with the same average temperature can be attributed to differences in applied voltage.

- To compute the CVR factor for a given feeder, Consumers Energy performed the following tasks:

  - Defined seasons as a consecutive set of days where daily average temperature is within a given range, and created separate files containing load and voltage data for each season.

  - Separated the above seasonal data files into two files: one containing only weekdays (Monday through Friday) and one containing only Weekends (Saturday and Sunday). Loading for special days and holidays was excluded from the analysis.

  - Separated the weekday file and the weekend file into two files: one file contains only loading data when voltage was reduced (CVR on) and one file containing loading data when voltage was not reduced.

  - The next step in the process was to ensure that number of “CVR On” days in each season’s weekday file is the same as the number of “CVR Off” days in each season’s weekday file.

  - Consumers Energy then computed the average daily load and the average voltage using data in the “CVR On” file and the average daily load and voltage using data from the “CVR Off” file. Then Consumers Energy computed the percentage difference in average daily load and average voltage between the On days and Off days

  - The CVR factor for the feeder in the given season is the percentage difference in feeder loading for CVR On and CVR Off days divided by the percentage difference in average voltage for CVR On days and CVR off days.

- CVR factors were computed as described above for each of the fifty feeders in the CVR demonstration. The results are shown in . As seen in T 5-6, CVR factor varied from feeder to feeder ranging from 0.07 to 1.34, with the average CVR factor for this group of feeders being 0.82.

- In 2021, Consumers Energy plans to use a new Predictive software tool called MetrixND to forecast what the load "would have been" had voltage not been reduced (i.e., normal voltage applied). Consumers Energy plans to use this load forecasting tool to derive a CVR factor for each tested circuit.

Table 5-6 CVR Factors for Each Feeder using "Matching Pairs" Method

Feeder ID	Substation	Circuit	CVR Enabled Date	Consumers CVRf
1903	Roberts Street	Bender	6/10/2020	0.99
7303	Milton	Federal Screw	1/22/2020	0.86
10007	Wealthy Street	Godfrey	8/7/2019	0.79
10106	Fremont	Reeman	11/6/2019	0.70
14301	Spring Lake	Spring Lake	3/4/2020	0.79
17301	Meridian	Towar Gardens	10/9/2019	0.87
21801	Wildwood	Yardman	5/27/2020	0.41
21802	Wildwood	Macklin	11/20/2019	1.16
23508	Beals Road	Godwin Heights	1/15/2020	0.82
28802	Michigan Center	Ballard	5/13/2020	0.90
29203	Manchester	Duncan	5/14/2020	1.34
29901	Norton	Pontaluna Road	1/22/2020	1.06
29902	Norton	Hile Road	5/13/2020	1.31
31803	East Muskegon	Quarterline Road	2/12/2020	0.84
34201	Hickory	Gateway	1/29/2020	0.07
34401	Hull Street	Lime Lake	11/13/2019	0.86
36902	Cooley	North Street	3/18/2020	0.75
41303	Terrace	Spring	10/23/2019	0.74
43502	Lake Odessa	Industrial	8/21/2019	0.72
48301	Aubil Lake	Towers	5/20/2020	0.78
50403	Oliver	King Street	1/8/2020	0.59
56802	Ramona	Blodgett	10/30/2019	0.49
60701	Getty	Marquette	6/3/2020	1.13
63403	Kilgore	Mount Everest	6/10/2020	0.99
63404	Kilgore	Timberlane	2/5/2020	0.88
63802	Neeley	Doster	5/27/2020	0.94
65502	O-at-ka	East Bay	8/12/2020	1.29
69902	Walker	Rosalie	2/12/2020	0.82
70305	Ingham	Greenwood Park	7/2/2020	1.24
72702	Burlingame	Michael	2/5/2020	0.82

73101	Mona Lake	Airport	3/18/2020	0.82
81502	Harper Road	Eifert	6/24/2020	1.33
90701	Club	Adventure	5/20/2020	0.63
90802	Oak Street	West Ganson	1/15/2020	0.66
101902	Midway	Naomi	1/8/2020	0.59
102701	Savidge	Boom Road	3/4/2020	0.74
110802	Williams	Cresent	2/19/2020	0.81
118401	Newburg	Bancroft	8/14/2019	0.92
118403	Newburg	Shiatown	5/20/2020	0.63
128802	Bennett	Jolly Road	5/27/2020	0.43
128803	Bennett	Dobie Road	2/19/2020	0.76
130301	West Road	Wood Road	3/11/2020	0.84
133501	Tallman	Wacousta	6/3/2020	1.34
133502	Tallman	Clark Road	10/16/2019	0.73
148501	Crahen	Greenbrier	5/14/2020	0.54
149502	Eleventh Street	Starr Road	6/17/2020	0.76
150002	Withey Lake	Henderson	6/17/2020	0.63
154301	Harvard Lake	Harvard Lake	6/3/2020	0.79
154901	Birchwood	Laraway Lake	3/11/2020	0.67
157802	Tremaine	Keefer Road	1/29/2020	0.56
Total				**0.82**

c) Comparison of Consumers Energy approach to best industry practices

- Regression Analysis of Day-On/Day-Off data
  - The CVR M&V approach that is most widely used in the electric utility industry involves multiple regression analysis to determine the relationship between various independent variables that typically impact load (ambient temperature, day of week, voltage level, etc.) and load.
  - The analysis is applied to data collected during CVR Day-On/Day-Off or CVR week on/week off demonstrations like the CVR pilot demonstrations conducted by Consumers Energy.
  - The resulting regression formula is used to estimate what the feeder load "would have been" on a "CVR On" day (reduced voltage) if the voltage had not been reduced.
  - The CVR factor can then be determined by comparing the actual measured loads for CVR On days against the estimated load computed using the regression formula.
- ESTA performed a regression analysis as described above using the day-on/day-off data supplied by Consumers Energy. The results of this analysis are summarized in Table 5-7 below. The CVR

factors computed using regression analysis and the Consumers Energy "matching pairs" approach was somewhat different for individual feeders. The CVR factors computed for individual feeders using regression analysis ranged from 0.2 to 1.41 (compared with the range of .07 to 1.34 for matching pairs). However, the overall average CVR factor for the entire set of CVR feeders computed using the two approaches was similar: 0.77 to regression analysis and 0.82 for matching pairs. Note that the regression analysis performed by ESTA has a modelling error of +/- 3.7%. So the range of the regression analysis is 0.74 to 0.79.

- ESTA finds that the results obtained using the two independent and significantly different approaches are comparable and consistent with results published by other electric utilities. As a result, ESTA concludes that the approach used by Consumers Energy for computing the CVR factors for Waste Energy Reduction is valid and accurate.

Table 5-7 Comparison of Feeder CVR Factors Using Matching Pairs and Regression Analysis

Feeder ID	Substation	Circuit	CVR Enabled Date	Consumers CVRf	Model Error Rate	Model CVRf	Difference
1903	Roberts Street	Bender	6/10/2020	0.99	5.49%	1.13	14%
7303	Milton	Federal Screw	1/22/2020	0.86	4.10%	0.65	25%
10007	Wealthy Street	Godfrey	8/7/2019	0.79	3.27%	0.7	11%
10106	Fremont	Reeman	11/6/2019	0.70	3.19%	0.56	20%
14301	Spring Lake	Spring Lake	3/4/2020	0.79	3.81%	1.01	28%
17301	Meridian	Towar Gardens	10/9/2019	0.87	4.42%	0.97	12%
21801	Wildwood	Yardman	5/27/2020	0.41	3.84%	0.27	34%
21802	Wildwood	Macklin	11/20/2019	1.16	3.72%	0.83	28%
23508	Beals Road	Godwin Heights	1/15/2020	0.82	3.95%	1.08	31%
28802	Michigan Center	Ballard	5/13/2020	0.90	4.08%	1	11%
29203	Manchester	Duncan	5/14/2020	1.34	4.07%	1.03	23%
29901	Norton	Pontaluna Road	1/22/2020	1.06	3.06%	1.24	17%
29902	Norton	Hile Road	5/13/2020	1.31	3.94%	1.3	1%
31803	East Muskegon	Quarterline Road	2/12/2020	0.84	3.53%	0.81	4%
34201	Hickory	Gateway	1/29/2020	0.07	4.21%	0.21	202%
34401	Hull Street	Lime Lake	11/13/2019	0.86	4.26%	1.09	27%
36902	Cooley	North Street	3/18/2020	0.75	2.92%	0.66	12%
41303	Terrace	Spring	10/23/2019	0.74	2.95%	0.74	0%
43502	Lake Odessa	Industrial	8/21/2019	0.72	3.29%	0.74	2%
48301	Aubil Lake	Towers	5/20/2020	0.78	4.84%	0.71	9%
50403	Oliver	King Street	1/8/2020	0.59	3.82%	0.46	22%
56802	Ramona	Blodgett	10/30/2019	0.49	2.12%	0.42	15%
60701	Getty	Marquette	6/3/2020	1.13	3.65%	0.81	28%

63403	Kilgore	Mount Everest	6/10/2020	0.99	3.81%	0.5	50%
63404	Kilgore	Timberlane	2/5/2020	0.88	4.28%	0.53	39%
63802	Neeley	Doster	5/27/2020	0.94	4.33%	0.9	4%
65502	O-at-ka	East Bay	8/12/2020	1.29	3.21%	0.75	42%
69902	Walker	Rosalie	2/12/2020	0.82	3.33%	0.99	21%
70305	Ingham	Greenwood Park	7/2/2020	1.24	3.12%	0.65	47%
72702	Burlingame	Michael	2/5/2020	0.82	3.45%	0.51	37%
73101	Mona Lake	Airport	3/18/2020	0.82	3.55%	0.8	2%
81502	Harper Road	Eifert	6/24/2020	1.33	5.94%	0.99	25%
90701	Club	Adventure	5/20/2020	0.63	4.39%	0.66	6%
90802	Oak Street	West Ganson	1/15/2020	0.66	3.35%	0.71	8%
101902	Midway	Naomi	1/8/2020	0.59	3.67%	0.2	66%
102701	Savidge	Boom Road	3/4/2020	0.74	3.84%	0.42	43%
110802	Williams	Cresent	2/19/2020	0.81	3.59%	0.73	10%
118401	Newburg	Bancroft	8/14/2019	0.92	3.03%	0.71	23%
118403	Newburg	Shiatown	5/20/2020	0.63	3.93%	0.69	9%
128802	Bennett	Jolly Road	5/27/2020	0.43	4.50%	0.88	106%
128803	Bennett	Dobie Road	2/19/2020	0.76	3.26%	0.64	16%
130301	West Road	Wood Road	3/11/2020	0.84	3.46%	0.32	62%
133501	Tallman	Wacousta	6/3/2020	1.34	6.28%	1.09	19%
133502	Tallman	Clark Road	10/16/2019	0.73	4.37%	0.6	18%
148501	Crahen	Greenbrier	5/14/2020	0.54	3.85%	0.84	54%
149502	Eleventh Street	Starr Road	6/17/2020	0.76	4.33%	1.07	40%
150002	Withey Lake	Henderson	6/17/2020	0.63	5.33%	1.41	124%
154301	Harvard Lake	Harvard Lake	6/3/2020	0.79	4.47%	0.92	16%
154901	Birchwood	Laraway Lake	3/11/2020	0.67	3.48%	0.61	9%
157802	Tremaine	Keefer Road	1/29/2020	0.56	4.29%	0.88	57%
Total				**0.82**	**3.90%**	**0.77**	**31%**

- Neural Net Methodology

  - ESTA has used neural net methodology to compute CVR factors with an accuracy of 2% or better, However, this method requires several years of data to “train” a model that is used to predict what the load would have been on a future date if voltage had not been reduced. Note that this approach may not be possible at this time for Consumers Energy because the CVR pilot projects have been conducted during the pandemic, which has exhibited considerably different loading patterns due to work-at-home restrictions.

d) Findings, conclusions, and overall assessment of Consumers Energy approach

a. ESTA has reviewed the Consumers Energy "Matching Pairs" M&V method and offers the following comments and conclusions.

   b. A major assumption on which the "Matching Pairs" analysis is based is that differences in average feeder loading observed in the day-on and day-off data sets are primarily due to voltage differences rather than differences in ambient temperature. For this assumption to be valid, the load must remain nearly constant with normal voltage applied for the days in each season.

   c. ESTA examined the relationship between load and ambient temperature and observed the expected relation between load and temperature for Consumers Energy CVR feeders. Figure 5-3 contains graph showing the relationship between load and ambient temperature for one of the Consumers Energy feeders in the Selected CVR feeders. As expected, the relationship is a bathtub shaped curve with sloping lines that are different for each feeder. ESTA used the bathtub curve sloping lines for each feeder to determine the approximate change of load given the range of ambient temperatures observed.

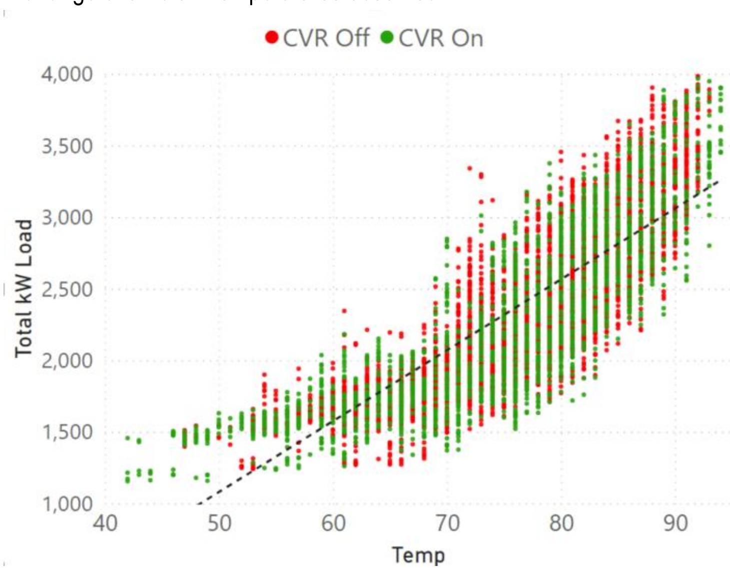

Figure 5-3 Variation of Load with Temperature on a CVR feeder

   d. The results showed that for most feeders, the feeder load changed by only a small percentage amount for the range of temperatures included in the "seasonal" data sets. Table 5-8 shows the approximate change in load that can be attributed to the temperature differences in the matching pairs data sets for weekdays in summer. Hence, ESTA concludes that average load variations in the Day-On and Day-Off datasets are primarily due to voltage reduction. This is shown in the table below for summer weekdays:

Table 5-8 Expected Change in Weekday Load for Temperature Variation in Summer

Feeder ID	Day Type	CVR Temp On	CVR Temp Off	Load Change per F	Load variation due to Temp
1903	Weekday	72.75	72.95	1.20%	-0.25%
1903	Weekend	69.93	72.28	1.21%	-2.83%
7303	Weekend	62.93	62.02	0.45%	0.41%
7303	Weekday	64.03	62.32	-0.08%	-0.14%
10007	Weekday	73.40	72.95	1.60%	0.71%
10007	Weekend	71.72	70.96	1.80%	1.35%
10106	Weekend	63.85	64.49	0.76%	-0.48%
10106	Weekday	68.05	65.97	0.49%	1.02%
14301	Weekend	71.96	71.53	3.06%	1.31%
14301	Weekday	74.25	74.09	3.16%	0.51%
21801	Weekday	72.67	73.19	1.95%	-1.00%
21801	Weekend	70.78	70.45	2.42%	0.80%
21802	Weekend	70.16	70.08	3.07%	0.24%
21802	Weekday	72.87	73.44	2.99%	-1.71%
23508	Weekend	71.41	71.82	1.97%	-0.81%
23508	Weekday	73.18	73.47	1.39%	-0.40%
28802	Weekend	70.48	70.66	3.15%	-0.55%
28802	Weekday	72.72	73.05	3.17%	-1.06%
29203	Weekend	64.99	64.81	0.86%	0.16%
29203	Weekday	70.16	67.62	0.69%	1.75%
29901	Weekend	67.19	70.77	1.93%	-6.91%
29901	Weekday	71.35	71.19	3.19%	0.53%
29902	Weekend	71.77	72.13	3.30%	-1.20%
29902	Weekday	73.54	73.89	3.55%	-1.26%
31803	Weekend	71.85	71.53	2.43%	0.78%
31803	Weekday	74.09	73.99	2.68%	0.26%
34201	Weekend	73.97	66.21	1.57%	12.18%
34201	Weekday	73.97	75.11	0.81%	-0.92%
34401	Weekend	72.47	72.14	2.91%	0.94%
34401	Weekday	73.75	74.20	2.78%	-1.26%
36902	Weekend	73.30	72.43	2.40%	2.10%
36902	Weekday	75.73	75.54	2.18%	0.41%
41303	Weekend	71.95	70.55	2.13%	2.98%
41303	Weekday	73.92	73.75	2.09%	0.34%
43502	Weekend	64.03	67.83	0.83%	-3.16%
43502	Weekday	65.77	66.23	0.40%	-0.19%
48301	Weekend	71.56	71.20	2.80%	0.99%
48301	Weekday	73.83	74.05	2.54%	-0.56%
50403	Weekend	63.91	64.08	0.53%	-0.09%
50403	Weekday	65.73	64.38	0.27%	0.36%

56802	Weekend	72.09	71.36	1.58%	1.16%
56802	Weekday	74.47	74.73	1.49%	-0.40%
60701	Weekday	71.31	70.41	2.11%	1.89%
60701	Weekend	68.43	71.97	2.28%	-8.10%
63403	Weekday	75.79	75.81	2.93%	-0.04%
63403	Weekend	74.24	75.15	3.04%	-2.78%
63404	Weekend	73.17	74.80	2.15%	-3.50%
63404	Weekday	75.19	76.15	2.16%	-2.08%
63802	Weekday	75.20	75.85	3.17%	-2.06%
63802	Weekend	72.98	73.45	3.01%	-1.40%
65502	Weekday	71.83	73.15	2.56%	-3.38%
65502	Weekend	67.69	70.88	2.41%	-7.69%
69902	Weekend	71.50	70.96	3.07%	1.65%
69902	Weekday	73.47	74.26	3.23%	-2.57%
70305	Weekday	73.03	73.80	1.70%	-1.31%
70305	Weekend	69.03	74.03	1.91%	-9.54%
72702	Weekend	71.46	71.79	2.74%	-0.92%
72702	Weekday	73.75	74.02	2.89%	-0.78%
73101	Weekend	71.96	71.53	2.95%	1.27%
73101	Weekday	74.22	74.09	3.13%	0.42%
81502	Weekday	72.71	72.89	2.37%	-0.43%
81502	Weekend	70.35	73.21	2.05%	-5.87%
90701	Weekday	74.82	73.83	2.67%	2.65%
90701	Weekend	73.01	72.59	2.45%	1.01%
90802	Weekend	70.48	70.66	2.18%	-0.38%
90802	Weekday	72.72	73.07	1.91%	-0.69%
101902	Weekend	72.57	72.41	2.23%	0.34%
101902	Weekday	75.59	75.54	2.64%	0.14%
102701	Weekend	71.96	71.53	2.52%	1.08%
102701	Weekday	74.25	74.09	2.19%	0.36%
110802	Weekend	65.83	64.66	0.61%	0.72%
110802	Weekday	64.77	67.25	0.35%	-0.88%
118401	Weekday	67.75	68.39	0.80%	-0.52%
118401	Weekend	64.39	64.74	0.73%	-0.26%
118403	Weekend	63.90	63.43	0.81%	0.38%
118403	Weekday	65.21	64.50	0.58%	0.41%
128802	Weekday	64.92	66.61	0.51%	-0.86%
128802	Weekend	64.53	63.90	0.84%	0.53%
128803	Weekend	64.35	63.33	0.86%	0.88%
128803	Weekday	64.06	65.91	0.56%	-1.04%
130301	Weekend	71.26	70.54	2.46%	1.76%
130301	Weekday	73.31	73.35	2.71%	-0.10%
133501	Weekday	75.40	74.64	4.50%	3.40%

133501	Weekend	74.51	73.13	4.79%	6.61%
133502	Weekend	72.39	70.55	3.02%	5.56%
133502	Weekday	73.90	73.58	3.22%	1.03%
148501	Weekend	71.55	70.51	1.93%	2.00%
148501	Weekday	73.71	73.71	1.93%	0.01%
149502	Weekday	76.66	77.06	2.82%	-1.14%
149502	Weekend	77.70	75.85	3.16%	5.86%
150002	Weekday	72.06	71.44	2.33%	1.44%
150002	Weekend	73.65	71.37	1.94%	4.44%
154301	Weekday	74.23	73.66	3.15%	1.77%
154301	Weekend	73.18	73.21	2.97%	-0.07%
154901	Weekend	71.45	71.64	2.66%	-0.48%
154901	Weekday	74.06	73.96	2.83%	0.29%
157802	Weekend	64.52	61.46	0.70%	2.15%
157802	Weekday	57.99	61.51	0.22%	-0.76%

e. Since the matching pair data set loading differences are primarily due to voltage reduction, ESTA believes it is acceptable and valid to use Consumers Energy's averaging technique to determine CVR factors.

f. The overall average CVR factor for the CVR feeders computed using Consumers Energy Matching Pair approach compares favorably with the overall average computed using regression analysis. ESTA believes this further confirms the approach. Significant differences in the results for individual feeders is attributable to the small number of data samples.

5.5.2 CVR FACTOR FOR PEAK DEMAND REDUCTION

This section describes the approach used for computing the Peak Demand reduction benefits. This approach is slightly different than the previously described procedure for computing the Energy Waste Reduction benefits.

a) General Requirements

a. Measurement and Verification (M&V) analysis must determine the CVR factor for individual distribution feeders with an accuracy of +/- 5% or better. CVR factor is the percentage change in power or energy attributable to voltage reduction divided by the percentage change in voltage.

b. Separate CVR factors must be provided for Energy Waste reduction and peak demand reduction.

c. Measurement and Verification (M&V) Analysis must separate the electrical impact of voltage reduction on power or energy consumption from other factors that impact power or energy consumption. Other factors include:
   i. Ambient weather conditions and season
   ii. Day of week, time of day

d. CVR voltage and load reductions were calculated by averaging all of the day "CVR On"/"CVR Off" readings and comparing the difference.

e. $CVR\ factor = \dfrac{(Avg.\text{ CVR Off }Load - Avg.CVR\ On\ Load) / Avg.\text{ CVR Off }Load}{(Avg.\text{ CVR Off }Voltage - Avg.CVR\ On\ Voltage) / Avg.\text{ CVR Off }Voltage}$

b) ESTA's understanding of the Consumers Energy approach

- The method used by Consumers Energy for computing the CVR factor for peak demand reduction is very similar to the method described above. Consumers Energy assumed the CVR factor obtained above would be the same for peak demand reduction as waste energy reduction. Then the peak demand reduction was calculated as follows:

$$Peak\ Demand\ Reduction = CVR\ Factor\ for\ waste\ energy\ reduction \times Voltage\ Reduction$$

- In 2021, Consumers Energy plans to use "MetrixND", a predictive software tool from ITRON to determine the CVR factor for Peak Shaving reduction. The analysis performed by this software tool is like the regression analysis ESTA used for determining a CVR factor for peak shaving reduction (see next Section). This software determines what the peak load "would have been" during a Peak Demand reduction event if normal voltage had been applied instead of reduced voltage. Consumers Energy plans to use measurements of the following independent variables to perform this analysis:
  - Solar irradiation and hours of sunlight on a given day.
  - Loading on recent past days
  - Dry Bulb temperature

c) Comparison of Consumers Energy approach to best industry practices

- Regression Analysis of Day-On/Day-Off data

  - The CVR M&V approach that is most widely used in the electric utility industry involves multiple regression analysis to determine the relationship between various independent variables that typically impact load (ambient temperature, day of week, voltage level, etc.) and load.

  - The analysis is applied to data collected during CVR Day-On/Day-Off demonstrations like the CVR pilot demonstrations conducted by Consumers Energy.

  - The resulting regression formula is used to estimate what the feeder load "would have been" on a "CVR On" day (reduced voltage) if the voltage had not been reduced.

  - The CVR factor can then be determined by comparing the actual measured loads for CVR On days against the estimated load computed using the regression formula.

- ESTA performed a regression analysis as described above using the day-on/day-off load data and average ambient temperature data supplied by Consumers Energy. The objective of this analysis is to determine what "would have happened" if voltage had not been reduced on the DR day in question.

- This model is trained using data when CVR status is "CVR off". This model uses inputs like voltage, temperature, heating and cooling days and temporal features like hour of the day and season. This model can account for temperature and customer behavior variations and is found to have an average error rate of 3.76%. This trained model is then used on "CVR On" hours of each feeder and demand response day to predict what the load would have been for the hours when CVR was on, if mean voltage instead of reduced voltage was applied. This predicted load is then compared with actual load to compute a mean CVR factor.

- Consumers followed a pre-determined peak reduction schedule as mentioned below:

Table 5-9 Peak Reduction Schedule

DR Date	DR Time Range	Feeder IDs
7/1/2020	1400 - 1500	050403,
7/2/2020	1400 - 1500	072702,
7/8/2020	1400 - 1600	056802, 133502, 154901
7/9/2020	1400 - 1600	090701, 041303, 007303
7/15/2020	1400 - 1700	148501, 081502, 118401, 118403, 017301
7/16/2020	1400 - 1700	128803, 034401, 110802, 157802, 149502
7/22/2020	1400 - 1800	150002, 043502, 072702, 056802, 133502, 154901, 128803, 034401, 110802, 157802, 149502
7/23/2020	1400 - 1800	050403, 090701, 041303, 007303, 148501, 081502, 118401, 118403, 017301
7/29/2020	1400 - 1800	050403, 090701, 041303, 007303, 148501, 081502, 118401, 118403, 017301
7/30/2020	1400 - 1800	150002, 043502, 072702, 056802, 133502, 154901, 128803, 034401, 110802, 157802, 149502
8/5/2020	1400 - 1800	050403, 090701, 041303, 007303, 148501, 081502, 118401, 118403, 017301
8/6/2020	1400 - 1800	150002, 043502, 072702, 056802, 133502, 154901, 128803, 034401, 110802, 157802, 149502

- Regression model is used for each of the feeder on each CVR Date along the time range mentioned in above table to predict load without CVR. Using this a CVR factor is calculated for each instance as follows:

$$CVR\ Factor = \frac{(Avg.\text{ Predicted }Load - Avg.\ CVR\ On\ Load) \big/ Avg.\text{ Predicted }Load}{(Avg.\text{ CVR Off }Voltage - Avg.\ CVR\ On\ Voltage) \big/ Avg.\text{ CVR Off }Voltage}$$

Based on this formula an average CVR factor of 1.51 is computed for all feeders on all Demand response days. As mentioned above average error rate of regression model was 3.86% so ESTA can claim that CVR factor should lie with $\pm$3.86% of 1.51 or between 1.45 and 1.56.

- The results of this analysis were compared with Peak Demand Reduction CVR factor computed by ESTA for another electric utility (utility name confidential). As seen in Figure 5-4, the Peak demand was reduced 600kW (6.5%) during a 4-hour, 15-minute voltage reduction of 4.5%. The Peak Demand CVR factor for this utility was 1.45 (6.5% / 4.5%). This is consistent with the results obtained by ESTA for Consumers Energy.

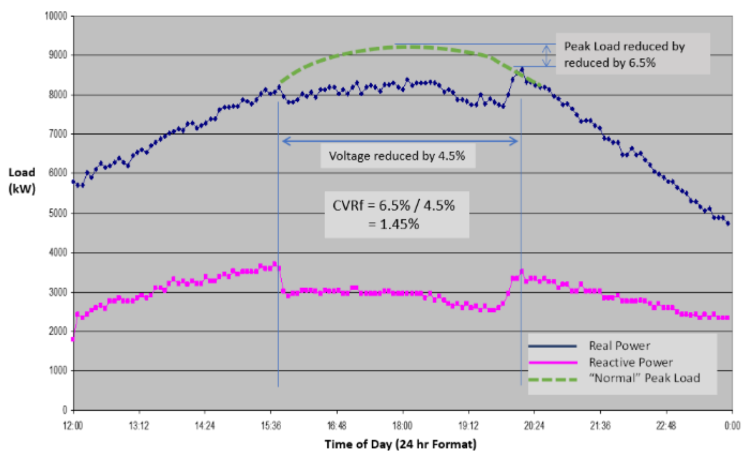

Figure 5-4 Results of Peak Demand CVR

d) Findings, conclusions, and overall assessment of Consumers Energy approach

a. ESTA has reviewed the Consumers Energy "Peak Demand Reduction" M&V method and offers the following comments and conclusions.

   b. An average CVR factor of 1.51 is computed for all feeders on all Demand response days. As mentioned above average error rate of regression model was +/- 3.89% so that the CVR factor should lie with of 1.51 or between 1.45 and 1.57

   c. Table 5-10 below shows the average Peak demand CVR factor that ESTA computed for each Consumers Energy feeder on all demand response days.

Table 5-10 Peak Demand CVR factors for Individual feeders

Feeder ID	Model Error Rate	CVR Factor
7303	4.10%	1
34401	4.26%	3.73
41303	2.95%	0.65
43502	3.29%	0.69
50403	3.82%	1.61
56802	2.12%	1.32
72702	3.45%	1.91
81502	5.94%	0.33
90701	4.39%	1.11
110802	3.59%	1.71
118401	3.03%	1.45
118403	3.93%	0.89
128803	3.26%	1.35
133502	4.37%	1.31
148501	3.85%	2.92
149502	4.33%	2.54
150002	5.33%	2.5
154901	3.48%	1.07
157802	4.39%	0.6
Average	**3.89%**	**1.51**

d. Figure 5-5 below shows the average effect of peak demand reduction for all feeders.

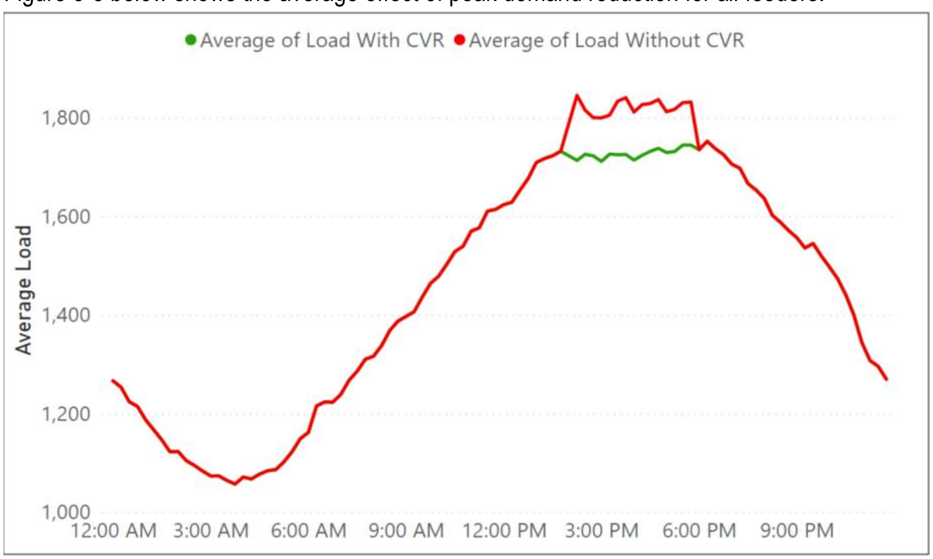

Figure 5-5 Average Peak Demand CVR Factor For Consumers Energy

6 SUMMARY OF FINDINGS CONCLUSIONS AND RECOMMENDATIONS

Following is a summary of ESTA's major findings, conclusions, and recommendations resulting from this assessment:

- **Feeder Selection:** As stated earlier in this report, the approach used by Consumers Energy to select feeders for its CVR Demonstration project far exceeds the feeder selection approach used by many other utility companies (based on ESTA experience).
  - Key characteristics of the CVR demonstration feeders selected by Consumers Energy match the characteristics of the broader set of "CVR Proposed" feeders on which CVR may be implemented in the future. While some characteristics are not the same, customer mix is very similar between the two groups. ESTA considers this to be one of the most important factors that determines the CVR factor for a given feeder.
  - As a result, ESTA believes that the selected CVR feeders represent the broader community of Consumers Energy feeders on which CVR is likely to be implemented.
  - In ESTA's opinion, it is acceptable to assume that the results obtained for the initial 50 feeders can be applied to future CVR feeders selected from the CVR Proposed feeder set.
- **CVR Solution:** The Consumers Energy CVR solution is a DSCADA rules-based solution, meaning a set of predetermined rules involving the application of Boolean logic to measurements acquired by the distribution SCADA system.
  - Most of the CVR solutions that have been successfully implemented by North American electric distribution systems are rules-based systems like what has been implemented by Consumers Energy. While this approach has some limitations, such as inability to adapt automatically to feeder reconfiguration, the approach has the benefit of simplicity, ease of operating and maintenance, and cost effectiveness, while providing the expected benefits.
  - Shortcomings of the existing approach include:
    - Lack of immediate voltage feedback to alert system operators to low or high voltage conditions on the feeder. Currently, such events may be detected the next day through manual review of voltage records from AMI. This approach is generally acceptable if major voltage deviations (e.g., voltage dips well below lower ANSI C84.1 limit) do not routinely occur.
    - Inability to adapt automatically to changing feeder configuration. Currently, Consumers Energy disables CVR if the feeder is reconfigured. While not the preferred approach, disabling CVR is acceptable if this is for a short duration (i.e., normal feeder configuration restored as quickly as possible),

- In the future, Consumers Energy should consider implementing model-driven VVO on its new ADMS. This should eliminate the shortcomings listed above.

- **Controlled Devices**

    - Consumers Energy controls switched capacitor banks and voltage regulators on its feeders. Within the industry, this is the most common complement of controlled equipment.

    - In the future, additional control requirements may apply. Examples include smart inverters and distributed generators. If these new requirements emerge at Consumers Energy, and ADMS-based, model-driven solution may be required due to the impracticality of handling these requirements with fixed Boolean logic.

- **Measurement data**

    - The measurements and equipment status information acquired by Consumers Energy for CVR purposes is adequate for meeting the basic needs of this application.

    - Some "scrubbing" was needed to eliminate questionable data (such as "stale" data measurements) collected during the CVR demonstration project. However, it is noted that data scrubbing is typically required on all M&V projects of this type, and that the amount of data scrubbing for Consumers Energy was far less than other M&V projects done by ESTA.

    - Adding near-real-time voltage measurements or low/high voltage alarms from AMI or bellwether meters would be beneficial, especially for heavily loaded feeders that are routinely operated close to the industry limits. Adding voltage feedback will enable Consumers Energy to gain additional benefits by operating with small margins (closer to voltage limits).

- **Approach to Measurement and Verification and Results Obtained**

    - The Matching Pairs M&V approach is relatively easy to understand and implement, compared to other advanced techniques (such as regression analysis and neural network modelling). As a result, it is possible to cross check the results using simple averaging to confirm the results. Another advantage is the ability to gain acceptance of the results by decision makers who do not have an advanced mathematical and statistical background.

    - ESTA performed an M&V analysis on the Consumers Energy data using multiple regression analysis that included consideration of loading, voltage, and ambient temperature. Regression analysis is the most widely used approach in the electric utility industry for CVR M&V.

    - The overall average CVR factor for the CVR feeders computed using Consumers Energy Matching Pair approach is 0.82, which compares favorably with the overall average computed using regression analysis (0.77 +/- 3.7%). We believe this further confirms the approach. Significant differences in the results for individual feeders is attributable to the small number of data samples.

- ESTA concludes that the results obtained by Consumers Energy during its CVR demonstration and analysis are valid and representative of results than can be received by implementing CVR on the CVR Proposed data set.

- ESTA computed a CVR factor for Peak Demand reduction using regression analysis to determine what “would have happened” during peak load conditions if normal voltage were applied on Demand Response days when CVR Peak Demand reduction occurred. The result of this analysis was a Peak Demand Reduction CVR factor of 1.56 +/- 3.86% on average for the 20 feeders on which Peak Reduction CVR was applied.

- Consumers Energy has assumed that the CVR factor for Peak Demand reduction is the same (0.82) as the CVR Factor for Waste Energy Reduction, which is a very conservative assumption compared to the results computed by ESTA. Based on the results of ESTA’s Peak demand CVR analysis and the results at one other electric utility (undisclosed), the results are considerably higher than the CVR factor for peak demand reduction assumed by Consumers Energy. The main reason for this difference is that the complement of equipment and appliances running during daily peak load hours is considerably different than the equipment complement running on average. For example, the amount of air conditioning load during peak load hours on a hot summer day is likely to be significantly higher than the average AC load for the day.

In 2021, Consumers Energy plans to use “MetrixND”, a predictive software tool from ITRON to determine the CVR factor for Peak Shaving reduction. The analysis performed by this software tool is like the regression analysis ESTA used for determining a CVR factor for peak shaving reduction. In ESTA’s opinion, this approach will yield much more accurate results for the Peak Demand CVR factor than the current conservative approach. ESTA strongly recommends that Consumers Energy use this approach for future analysis of peak demand CVR reduction.

Appendix A CVR BACKGROUND INFORMATION

A.1 VOLTAGE REDUCTION

As electric utilities seek to address energy efficiency and conservation portfolios, many electric distribution utilities are turning to voltage reduction to satisfy energy efficiency, demand reduction, and energy conservation objectives. Voltage reduction involves operating the distribution feeder at a voltage that is in the lower portion of the acceptable voltage range (See Figure 6-1). Electric utility experience, backed by extensive laboratory testing, has shown that many electrical loads, especially electric motors, consume less real and reactive power and perform just as well (or better) when voltage is lowered slightly. When voltage reduction is performed whenever possible (up to 24 hours per day, seven days per week), this is called “Conservation Voltage Reduction”. This is because 24-hour-per-day operation is primarily intended to promote energy conservation. If voltage reduction is used only during peak load periods for purposes of peak shaving, the term voltage reduction (VR) or voltage optimization is commonly used.

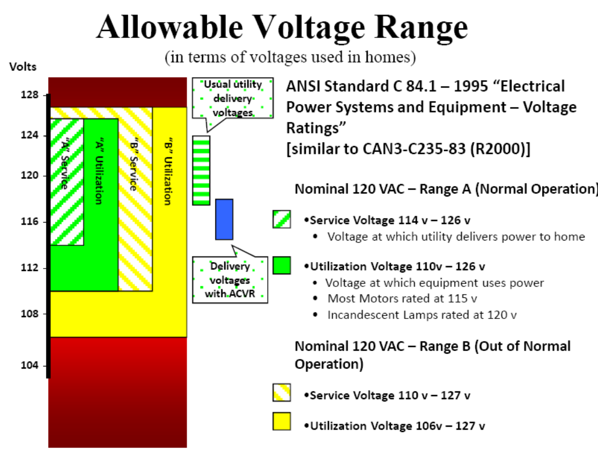

Figure 6-1 Allowable Voltage Range (per ANSI C84.1)

Many electric utilities and their associated grid management authority have used voltage reduction as a means of reducing power quickly during a peak load emergency. In the past, such voltage reductions were referred to as “brown-outs” due to the dimming effect voltage reduction may have on incandescent light bulbs. For the most part the term no longer applies as the newer generation of compact fluorescent lamps remains bright as voltage is reduced by up to five percent. Numerous utilities are planning to operate with reduced voltage on a continuous basis (for energy conservation) or during peak load periods (for demand reduction).

To implement CVR effectively with no adverse impact on consumer electrical loads, it is often necessary to implement distribution infrastructure improvements to “flatten” the voltage profile along the feeder. This allows more voltage reduction without violating minimum voltage constraints. Figure 6-2 illustrates the use of switched capacitor banks to “flatten” the voltage profile, followed by voltage reduction. The green line in this Figure 6-2 represents the starting voltage profile at one point in time along the feeder. The red line shows the impact of voltage “flattening”. In this cases the effect was achieved by switching on the three switched capacitor banks that are installed on the feeder. The brown line in Figure 6-2, shows the effect of voltage reduction on the “flattened” voltage profile. As seen in Figure 6-2, the voltage level at the end of the feeder that is furthest from the substation changes very little from the starting point. However, the voltage at all other points along the feeder are reduced considerably. This illustrates the benefit of voltage conditioning.

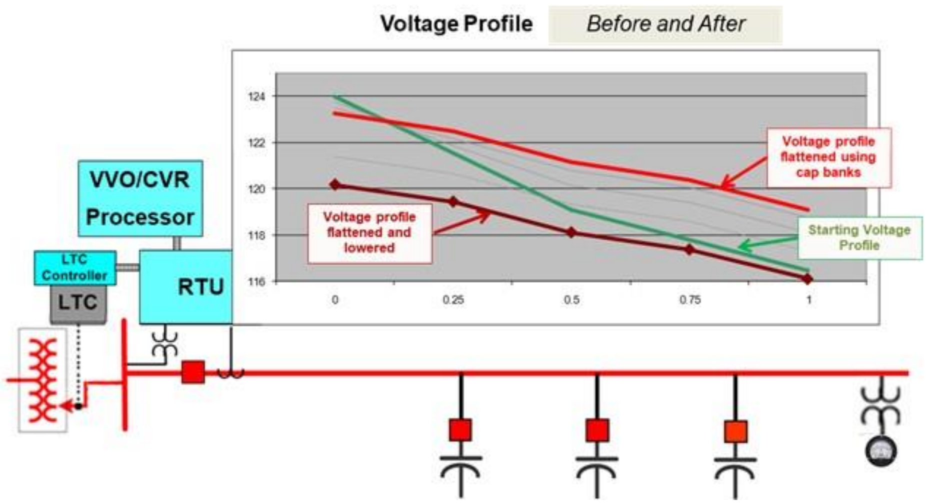

Figure 6-2- "Flattening" And "Lowering" The Voltage Profile

Many electric utilities view VR as a very attractive measure for efficiency improvement, because, in most cases, significant benefits can be achieved for a minimal investment and with no customer sacrifices. Because VR can usually be implemented without making major investments in equipment and infrastructure improvements, benefits can be achieved in the shortest possible time.

The specific benefits that can be achieved vary based on customer type (residential, commercial, industrial, etc.), time of day, day of week and season, climate zone, and other such factors. The amount of benefit is also affected by the degree to which voltage can be reduced. Feeders whose minimum voltage is near the bottom of the acceptable range will provide little or no CVR benefits, while feeders with higher distribution voltage often gain the most from CVR.

CVR benefits will be affected by new "up and coming" appliances that comprise a growing percentage of the load. Many new appliances will be equipped with electronic controls that improve the nominal efficiency of the device. Many of these controls exhibit "constant power" behavior which is not favorable for achieving CVR benefits. With constant power loads, the electricity consumed by the device stays constant as voltage is reduced. However, as the voltage is reduced, current increases which can produce higher electrical (I^2R) losses on the feeder. Due to the critical nature of the application (e.g., system emergency voltage reduction), it is important to be able to predict the outcome of voltage reduction.

A.2 SCADA "RULES-BASED" APPROACH

Consumers Energy uses one of the most common approaches to CVR: the SCADA "rules based" approach. This approach is depicted in Figure 6-3. This approach determines what volt-VAR control actions to take by applying a predetermined set of logical "rules" to a set of real time measurements from the associated substation and feeder. An example rule is: "If the voltage measured at point "X" is less than 120 volts AND the reactive power flow measured at the substation end of the feeder is greater that 900kVAR (lagging), then switch capacitor bank "1" to the ON position". These rules are determined in advance by the distribution engineers and operators using power flow analysis or general knowledge about the historical operation of the feeder.

The SCADA rules-based approach relies on intelligent controllers for interfacing with the switched capacitor banks and voltage regulators. The SCADA rules-based approach uses the Consumers Energy Distribution Supervisory

Control and Data Acquisition (DSCADA) system to interface with the field devices and intelligent controllers. The communication facilities enable the system to base its control actions on overall feeder conditions rather than just on local conditions at the site of the capacitor bank or voltage regulator. The communication facilities also enable Consumers Energy to monitor the operating status of the voltage regulators and switched capacitor banks so that appropriate actions can be taken immediately when a component failure occurs.

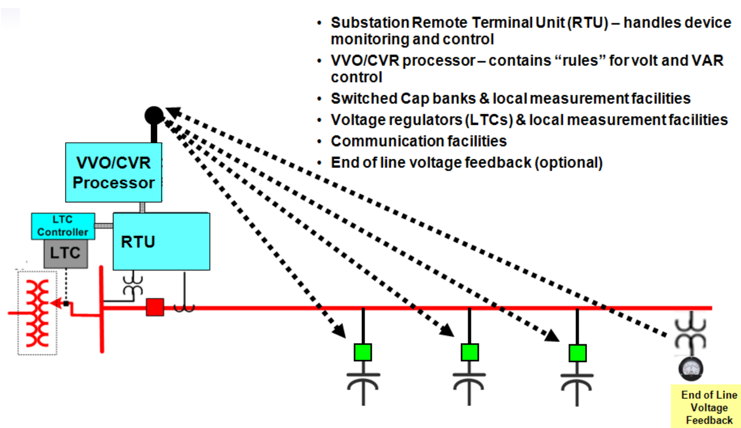

Figure 6-3 SCADA Rules Based Approach

This approach works well for the operating environment that exists on many electric utility distribution feeders today (e.g. minimal DG, infrequent changes in feeder configuration). However, in the future as the penetration of large DG units grows and advanced distribution applications (such as Fault Location Isolation and Service Restoration (FLISR)) become prevalent, the rules-based approach may lack the flexibility to address all future operating possibilities. In such cases, a more sophisticated "model-driven solution" may be needed.

A.3 CVR FACTOR EXPLAINED

CVR factor reduction (also known as load-voltage sensitivity) is an industry standard metric for identifying the effectiveness of voltage on the electric distribution system. CVR factor is given by the following formula:

CVR factor = (% change in kWh energy consumption) / (% change in voltage)

As explained in following sections, the load-voltage sensitivity of a particular electrical device depends on the electrical characteristics of the individual device which can be determined through laboratory testing. The load-voltage sensitivity or CVR factor of an entire customer premise, an entire feeder, an entire substation, or other entity containing more than one appliance, depends on the aggregate load-voltage sensitivities of the individual appliances in the entity.

A.4 LOAD-VOLTAGE SENSITIVITY OF INDIVIDUAL DEVICES

Most electrical appliances consume less electric power when voltage is reduced. The relationship between voltage and electric power for an appliance is given by the “ZIP” model of the appliance, which is a combination of the following components:

- **Constant Impedance Component (Z)** – When voltage (V) applied to a constant impedance device is reduced, the current (I in amperes) drawn by the device decreases by the same amount to keep the impedance ratio (V / I) constant. So, when voltage is reduced, the consumed power (V x I) is lowered by a significant amount. Electric heating elements in water heaters and electric stoves are examples of loads that primarily have constant impedance behavior. Incandescent light bulbs, which are becoming a thing of the past, also exhibit constant impedance behavior. Figure 6-4 below contains a graph showing test results obtained when voltage applied to an incandescent light bulb was varied. The load-voltage sensitivity is the slope of this line, which is approximately 1.6, meaning that if voltage applied to the device is reduced by 1.0%, the power consumed would be 1.6%.

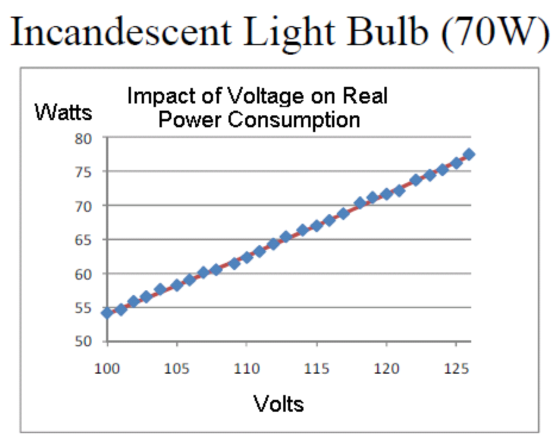

Figure 6-4 Load—Voltage Sensitivity Test Results for Light bulb

- **Constant Current Component (I)** – Constant current loads draw power in proportion to the applied voltage. That is, P= I x V, where current I is held constant. So, the power drawn by constant current loads will be lowered when voltage is reduced, but not as much as constant impedance devices. There are relatively few constant current devices that exhibit constant current behavior. Examples include welding units, smelting equipment, and electroplating processes. However, some electric vehicle chargers may exhibit constant current behavior. Normally, and EV charger exhibits a constant power behavior in which current increased as voltage is reduced to maintain a fixed power draw by the charger. However, when current reaches a maximum amount when current reaches a maximum allowable amount, the current drawn remains fixed and is clamped at the maximum as further voltage reduction occurs.

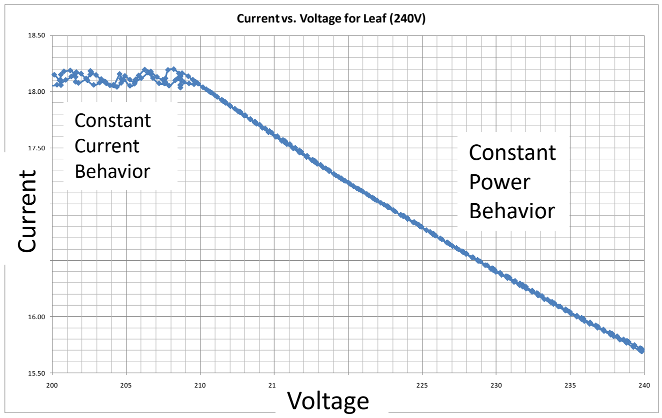

Figure 6-5 Load-Voltage Characteristic of EV Charger

- **<u>Constant Power Component (P)</u>** – Constant power loads draw the same amount of power regardless of the applied voltage. So, the CVR factor for constant power loads is zero. Computer power supplies are constant power devices as are many modern devices that used switched power supplies. Electric motors are often considered to be constant power devices. However, tests have shown that for small voltage reductions (a few percent), motors exhibit constant impedance behavior. Load-Voltage sensitivity for a computer power supply is shown in Figure 6-6 below.

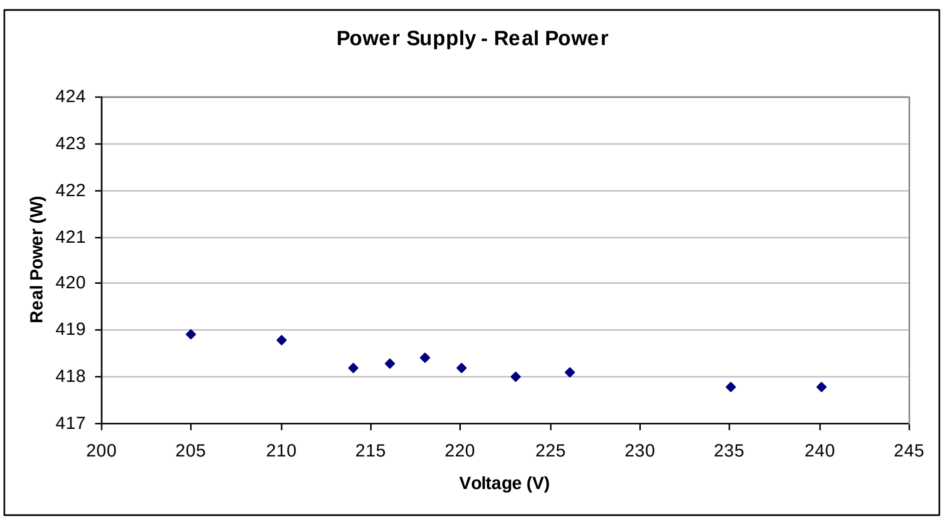

Figure 6-6 Constant Power Behavior of Computer power Supply

Commonly used electrical appliances usually exhibit individual CVR factors that are a combination of the ZIP component characteristics. Figure 6-7 below shows CVR factors for various types of electrical appliances.

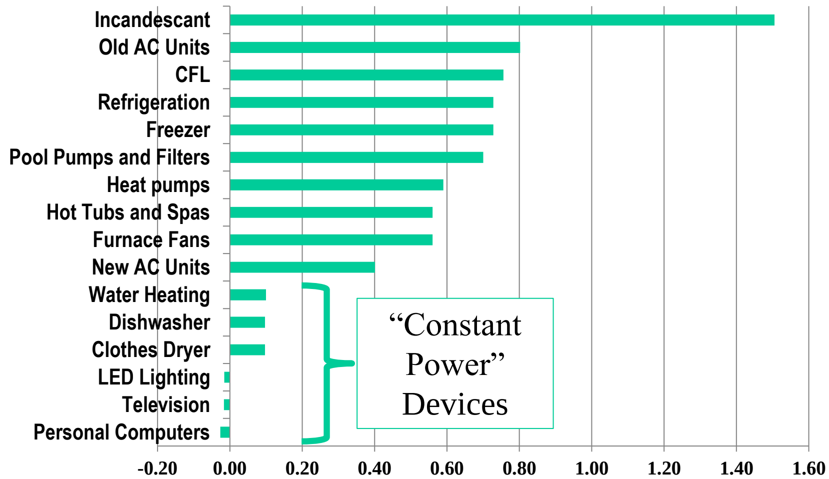

Figure 6-7 CVR Factors for Common AC Appliances

A.5 LOAD-VOLTAGE SENSITIVITY AT THE PREMISE AND FEEDER LEVEL

The power supplied to a single residential or commercial entity is the sum of the power consumed by all the individual electrical appliances within the entity. The Load-Voltage sensitivity or CVR factor for the single entity is the sum of the CVR factors for the individual types of appliances weighted by the percentage of load consumed by each appliance. Figure 6-8 and Figure 6-9 below show how the aggregate load-voltage sensitivity differs for a typical single-family residence and a commercial office building. For these examples, power consumed by each type of appliance has been obtained from RECS and CBECS data published by the US Department of Energy (DOE) for premises located in the "mixed-humid" climate zone. The energy consumed by individual appliances, and the premise CVR factor, would be different in other climate zones.

Year	State	Climate	Customer Class			
2021	New York	MIXED-HUMID	Single-Family			
SAMPLE SIZE:	60					
	Average kWh					
Enduse	Summer	Winter	Shoulder	Total kWh	LTV Factor	KWh x LTV
Clothes Dryer	91	137	160	388	0.8	310.48
Cooking	109	88	145	342	0.3	102.47
Cooling	1,305	0	278	1,583	0.5	791.38
Dishwasher	27	41	48	117	0.5	58.304
Freezer	86	69	115	270	0.3	80.977
Furnace Fans	108	40	54	202	1.23	248.02
Heating	0	131	45	176	0.1	17.552
Lighting (Incand)	100	131	158	389	1.536	597.21
Lighting (CFL)	62	81	98	242	0.748	181.08
Lighting (LED)	26	35	42	103	0.976	100.24
Other	1,428	1,144	1,901	4,473	1	4473
Hot Tubs and Spas	15	13	20	48	1	47.663
Pool Pumps and Filters	143	115	191	449	1.23	552.43
Personal Computers	136	179	215	530	0.1	53.04
Refrigeration	449	360	598	1,407	0.3	422.23
Television	437	352	582	1,371	0.1	137.11
Water Heating	0	0	0	0	0.1	0
	4,524	**2,914**	**4,650**	**12,088**	**Aggregate LTV**	**0.6761**

Figure 6-8 CVR Factor for a typical Single Family Residence

Year	State	Climate	Customer Class			
2021	New York	MIXED-HUMID	Office			
SAMPLE SIZE:	82					
	Average kWh (Total End Use Energy / Total Number of Premises)					
Enduse	Summer	Winter	Shoulder	Total kWh	LTV Factor	KWh x LTV
Computer Use	29,402	38,671	48,579	116,653	0.1	11665.3
Cooking	119	157	197	472	0.3	141.7
Cooling	41,113	0	10,261	51,375	0.5	25687.3
Heating	50	12,627	4,941	17,618	0.2	3523.7
Lighting	62,108	81,685	102,613	246,407	0.748	184312.3
Miscellaneous Use	24,692	32,476	40,796	97,964	1	97964.0
Office Equipment	15,026	19,761	24,824	59,611	0.2	11922.1
Refrigeration	4,507	5,928	7,448	17,884	0.4	7153.5
Ventilation	14,992	19,718	24,769	59,479	0.7	41635.6
Water Heating	1,166	1,533	1,927	4,626	0.1	462.6
	193,177	**212,556**	**266,356**	**672,088**	**Aggregate LTV**	**0.57205**

Figure 6-9 CVR Factor for a Typical Office building

Similarly, the CVR factor for an entire feeder or substation is the weighted sum of the CVR factors for the individual customers connected to the feeder or substation. In this case, the weighting factor is the percentage of total feeder power consumed by each entity.

It can be concluded that the load-voltage sensitivity depends only on the types of appliances and equipment served and the portion of energy consumed by each type of appliance. In other words, two entities (premises, feeders, substations, etc.) that supply the same types of appliances and energy consumption per appliance will have the same CVR factor.

As explained above, aggregate load-voltage sensitivity depends on appliance type and climate zone. If all Consumers Energy substations and feeders are in the same mixed-humid climate zone, then CVR factor varies only by the customer mix (e.g., residential, commercial, industrial) served by the feeder or substation.

A.6 CVR "BENEFITS" FOR DIFFERENT TYPES OF FEEDERS

While the load-voltage sensitivity is nearly the same for a given set of appliances in a given climate zone, the energy conservation <u>benefits</u> (kWh reduction) for a given feeder or substation will depend on the following items:

- <u>The amount of voltage reduction that is possible without violating voltage limits.</u> A larger voltage reduction will result in larger kWh savings. The possible voltage reduction on short, lightly loaded feeders is usually greater than the possible voltage reduction on longer, heavily loaded feeders (which may be voltage-limited). For example, reducing the voltage by 2% on a 1.0 MWh load with a 0.7 CVR factor will reduced the consumed energy by 1.4%; if voltage can only be reduced by 1%, then kWh savings would be half that amount.

- <u>The total energy consumption by the entity.</u> A one percent voltage reduction on a heavily loaded entity will produce a greater kWh reduction than a lightly loaded entity. For example, reducing the voltage by 2% on a 1.0 MWh load with a 0.7 CVR factor will reduced the consumed energy by 1.4% of 1.0 MWh; a 2% voltage reduction on a 2.0 MWh load would save 1.4% of 2.0 MWh (twice the benefit).

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of an Integrated Resource Plan	)	Case No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	
	)	

EXHIBITS

OF

EUGÈNE M.J.A. BREURING

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21090
Exhibit No.: A-93 (EMB-1)

Witness: EMBreuring
Date: June 2021

Historical & Forecasted Annual Electric Deliveries *
Reference Case: Base Case (A1.2)
(GWh)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
Line No.	**Year**	**Residential**	**Commercial**	**Industrial**	**Other *****	**Wholesale**	**Total**
1	2016 Hist	12,474	11,972	12,382	188	357	37,372
2	2017 Hist	12,485	12,761	11,748	179	365	37,538
3	2018 Hist	12,450	12,786	11,568	170	364	37,339
4	2019 Hist	12,452	12,653	11,215	161	342	36,824
5	2020 Hist	13,105	11,870	9,641	149	363	35,127
6	2021 Fcst	12,380	12,581	11,058	167	359	36,546
7	2022 Fcst	12,516	12,414	11,051	167	361	36,509
8	2023 Fcst	12,335	12,453	11,226	167	362	36,544
9	2024 Fcst	12,385	12,346	11,226	167	364	36,488
10	2025 Fcst	12,315	12,255	11,222	167	31	35,991
	CAGR (2020 - 2025)	-1.23%	0.64%	3.08%	2.38%	-38.96%	0.49%
	CAGR (2016 - 2025)	-0.14%	0.26%	-1.09%	-1.25%	-23.84%	-0.42%
11	2026 Fcst	12,484	12,183	11,240	167	0	36,074
12	2027 Fcst	12,612	12,210	11,319	167	0	36,309
13	2028 Fcst	12,753	12,154	11,306	167	0	36,381
14	2029 Fcst	12,773	12,317	11,471	167	0	36,729
15	2030 Fcst	12,866	12,260	11,492	167	0	36,786
16	2031 Fcst	12,896	12,684	11,961	167	0	37,709
17	2032 Fcst	12,792	12,763	12,150	167	0	37,873
	CAGR (2020 - 2032)	-0.20%	0.61%	1.95%	0.98%	-----	0.63%
	CAGR (2026 - 2032)	0.41%	0.78%	1.31%	0.00%	-----	0.81%
18	2033 Fcst	12,631	13,090	12,551	167	0	38,440
19	2034 Fcst	12,494	13,049	12,619	167	0	38,330
20	2035 Fcst	12,361	13,005	12,681	167	0	38,215
21	2036 Fcst	12,258	12,979	12,766	167	0	38,170
22	2037 Fcst	12,117	12,920	12,844	167	0	38,049
23	2038 Fcst	12,005	12,879	12,942	167	0	37,993
24	2039 Fcst	11,899	12,836	13,049	167	0	37,951
25	2040 Fcst	11,817	12,806	13,162	167	0	37,952
	CAGR (2020 - 2040)	-0.52%	0.38%	1.57%	0.59%	-----	0.39%
	CAGR (2033 - 2040)	-0.95%	-0.31%	0.68%	0.00%	-----	-0.18%

* Historicial electric deliveries are weather-adjusted (calendar).
** Forecasted deliveries are based on Spring 2020 Forecast (cycle-billed)
*** "Other" consists of Streetlighting and Interdepartmental.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21090
Exhibit No.: A-94 (EMB-2)
Page: 1 of 1
Witness: EMBreuring
Date: June 2021

Historical & Forecasted Monthly Peak Demands
Reference Case: Base Case (A1.2)
(GW)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
Line No.	**Year**	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	***Peak***	***Avg***
1	2016 Hist	5.75	5.54	5.42	5.15	6.32	7.36	7.91	8.23	7.86	5.41	5.33	5.92	*8.23*	*6.35*
2	2017 Hist	5.79	5.53	5.33	5.06	5.92	7.50	7.63	7.14	7.55	5.47	5.32	5.86	*7.63*	*6.18*
3	2018 Hist	5.86	5.55	5.17	5.11	7.61	7.69	8.08	7.59	7.87	6.07	5.39	5.48	*8.08*	*6.45*
4	2019 Hist	5.75	5.52	5.50	5.00	4.90	6.79	8.04	7.20	6.63	5.62	5.43	5.60	*8.04*	*6.00*
5	2020 Hist	5.33	5.27	4.87	4.20	6.52	7.38	8.22	7.93	6.03	4.84	5.08	5.29	*8.22*	*5.91*
6	2021 Fcst	5.60	5.45	5.34	5.17	5.83	7.23	7.84	7.60	7.05	5.42	5.38	5.67	*7.84*	*6.13*
7	2022 Fcst	5.59	5.39	5.36	5.20	5.83	7.26	7.87	7.58	7.06	5.40	5.37	5.66	*7.87*	*6.13*
8	2023 Fcst	5.59	5.37	5.34	5.20	5.83	7.24	7.81	7.59	7.06	5.43	5.37	5.66	*7.81*	*6.13*
9	2024 Fcst	5.60	5.54	5.40	5.29	5.83	7.29	7.82	7.59	7.13	5.36	5.32	5.66	*7.82*	*6.15*
10	2025 Fcst	5.51	5.34	5.26	5.13	5.76	7.16	7.70	7.50	6.99	5.35	5.29	5.58	*7.70*	*6.05*
Average (2016 - 2025)		5.64	5.45	5.30	5.05	6.04	7.29	7.89	7.60	7.12	5.44	5.33	5.64	*7.89*	*6.15*
11	2026 Fcst	5.52	5.36	5.31	5.16	5.77	7.23	7.79	7.52	7.01	5.34	5.29	5.62	*7.79*	*6.08*
12	2027 Fcst	5.55	5.38	5.34	5.19	5.81	7.26	7.83	7.55	7.03	5.38	5.33	5.65	*7.83*	*6.11*
13	2028 Fcst	5.56	5.50	5.36	5.20	5.82	7.28	7.84	7.57	7.05	5.39	5.34	5.66	*7.84*	*6.13*
14	2029 Fcst	5.60	5.43	5.39	5.25	5.87	7.33	7.89	7.61	7.09	5.43	5.39	5.71	*7.89*	*6.17*
15	2030 Fcst	5.61	5.44	5.40	5.25	5.89	7.34	7.89	7.63	7.10	5.44	5.39	5.72	*7.89*	*6.17*
16	2031 Fcst	5.74	5.57	5.52	5.37	6.01	7.47	8.03	7.78	7.23	5.56	5.52	5.85	*8.03*	*6.30*
17	2032 Fcst	5.77	5.71	5.55	5.40	6.04	7.51	8.07	7.82	7.25	5.60	5.55	5.88	*8.07*	*6.35*
Average (2026 - 2032)		5.62	5.49	5.41	5.26	5.89	7.35	7.91	7.64	7.11	5.45	5.40	5.73	*7.91*	*6.19*
18	2033 Fcst	5.84	5.67	5.62	5.48	6.12	7.60	8.15	7.91	7.35	5.68	5.63	5.96	*8.15*	*6.42*
19	2034 Fcst	5.83	5.66	5.61	5.46	6.12	7.59	8.14	7.90	7.34	5.67	5.62	5.95	*8.14*	*6.41*
20	2035 Fcst	5.83	5.64	5.60	5.45	6.11	7.58	8.13	7.90	7.32	5.66	5.60	5.95	*8.13*	*6.40*
21	2036 Fcst	5.83	5.75	5.60	5.46	6.11	7.59	8.13	7.91	7.32	5.67	5.60	5.95	*8.13*	*6.41*
22	2037 Fcst	5.82	5.61	5.57	5.44	6.11	7.57	8.11	7.90	7.31	5.65	5.59	5.94	*8.11*	*6.39*
23	2038 Fcst	5.82	5.60	5.58	5.43	6.11	7.57	8.10	7.90	7.32	5.65	5.59	5.94	*8.10*	*6.38*
24	2039 Fcst	5.82	5.59	5.57	5.43	6.12	7.57	8.10	7.91	7.32	5.65	5.58	5.94	*8.10*	*6.38*
25	2040 Fcst	5.82	5.71	5.58	5.44	6.13	7.58	8.11	7.92	7.34	5.67	5.59	5.95	*8.11*	*6.40*
Average (2033 - 2040)		5.83	5.66	5.59	5.45	6.12	7.58	8.12	7.91	7.33	5.66	5.60	5.95	*8.12*	*6.40*

Electric Bundled Peak Demand Forecast Sensitivities
(GW)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	**Year**	**Reference Case Base Case A1**	**Reference Case Base Case A1.2**	**MPSC Base**	**High Growth**	**High EWR**	**50 % ROA Shift**	**Advanced Tech.**	**Advanced Tech. (revised)**
1	2021	7,316	7,316	7,316	7,423	7,316	7,577	7,318	7,839
2	2022	7,352	7,352	7,352	7,530	7,352	7,611	7,358	7,878
3	2023	7,293	7,293	7,293	7,612	7,293	7,555	7,309	7,832
4	2024	7,301	7,301	7,290	7,755	7,267	7,555	7,259	7,771
5	2025	7,173	7,173	7,139	7,663	7,071	7,402	7,020	7,532
6	2026	7,266	7,267	7,208	7,640	7,093	7,445	7,072	7,586
7	2027	7,384	7,305	7,308	7,798	7,158	7,544	7,110	7,531
8	2028	7,397	7,318	7,297	7,845	7,101	7,528	7,034	7,457
9	2029	7,489	7,366	7,371	7,976	7,141	7,601	7,049	7,420
10	2030	7,509	7,367	7,376	8,038	7,122	7,602	7,012	7,344
11	2031	7,659	7,500	7,517	8,236	7,247	7,746	7,122	7,416
12	2032	7,793	7,531	7,628	8,408	7,317	7,851	7,181	7,372
13	2033	7,789	7,594	7,623	8,505	7,309	7,857	7,153	7,392
14	2034	7,770	7,553	7,589	8,566	7,250	7,830	7,091	7,315
15	2035	7,932	7,540	7,735	8,810	7,371	7,987	7,194	7,234
16	2036	7,975	7,537	7,774	8,958	7,405	8,026	7,217	7,179
17	2037	7,981	7,494	7,788	9,078	7,433	8,054	7,240	7,128
18	2038	7,995	7,476	7,790	9,183	7,415	8,056	7,228	7,072
19	2039	8,020	7,469	7,808	9,302	7,425	8,078	7,230	7,022
20	2040	8,085	7,474	7,879	9,478	7,507	8,148	7,310	6,997
21	CAGR(2021-2040)	0.53%	0.11%	0.39%	1.29%	0.14%	0.38%	-0.01%	-0.60%

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-21090
Exhibit No.: A-96 (EMB-4)
Page: 1 of 1
Witness: EMBreuring
Date: June 2021

Electric Bundled Generation Requirements Sensitivities
(GWh)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	**Year**	**Reference Case Base Case A1**	**Reference Case Base Case A1.2**	**MPSC Base**	**High Growth**	**High EWR**	**50 % ROA Shift**	**Advanced Tech.**	**Advanced Tech. (revised)**
1	2021	35,312	35,312	35,312	36,400	35,312	37,326	35,337	35,327
2	2022	35,221	35,221	35,221	36,852	35,221	37,220	35,275	35,251
3	2023	35,150	35,150	35,151	37,308	35,153	37,173	35,223	35,191
4	2024	35,133	35,135	35,056	37,732	34,902	37,060	34,890	34,854
5	2025	34,509	34,515	34,277	37,456	33,813	36,260	33,621	33,586
6	2026	34,567	34,576	34,182	37,856	33,416	36,148	33,047	33,009
7	2027	35,319	34,776	34,782	38,955	33,722	36,748	33,160	32,574
8	2028	35,429	34,891	34,738	39,402	33,386	36,684	32,656	32,070
9	2029	35,950	35,115	35,109	40,271	33,472	37,074	32,564	31,680
10	2030	36,104	35,139	35,176	40,831	33,390	37,131	32,379	31,230
11	2031	37,029	35,943	36,010	42,167	34,066	38,052	32,955	31,558
12	2032	37,853	36,006	36,688	43,329	34,489	38,808	33,223	31,047
13	2033	37,848	36,512	36,639	43,814	34,368	38,781	33,067	31,169
14	2034	37,830	36,357	36,531	44,208	34,104	38,674	32,713	30,550
15	2035	38,794	36,004	37,373	45,533	34,743	39,650	33,195	29,670
16	2036	39,090	35,974	37,651	46,370	34,997	39,953	33,456	29,331
17	2037	39,203	35,727	37,775	47,041	35,161	40,103	33,643	28,847
18	2038	39,327	35,639	37,848	47,637	35,150	40,180	33,582	28,411
19	2039	39,457	35,559	37,924	48,237	35,135	40,263	33,520	27,986
20	2040	39,893	35,556	38,397	49,257	35,698	40,781	34,159	27,819
21	CAGR(2021-2040	0.64%	0.04%	0.44%	1.60%	0.06%	0.47%	-0.18%	-1.25%

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

EXHIBITS

OF

TERESA E. HATCHER

ON BEHALF OF

CONSUMERS ENERGY COMPANY

June 2021

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
IRP Proposed Course of Action - 15% RPS Forecast

Case No.: U-21090
Exhibit No.: A-97 (TEH-1)
Page: 1 of 1
Witness: TEHatcher
Date: June 2021

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
					Total RECs from Current Year							
Line No.	Year	Jurisdictional Calendar Year Retail Sales (MWh)	RPS Target	RECs Required for RPS	Existing, EOCs, and Market Purchase	IRP Proposed Course of Action Build Plan	PPA	Total RECs Received	Total RECs Received / Current Year Retail Sales	Banked RECs Beginning of Year	Banked RECs Total	Banked RECs post compliance
1	2020	31,446,239	12.5%	4,168,550	1,184,821	995,475	1,108,253	3,288,549	10%	3,767,920	7,056,469	2,887,919
2	2021	32,287,657	15.0%	4,912,147	1,162,492	1,440,250	1,185,191	3,787,933	12%	4,647,648	8,435,581	3,523,434
3	2022	32,264,994	15.0%	4,822,092	1,161,063	1,440,179	1,366,741	3,967,983	12%	3,523,434	7,491,417	2,669,325
4	2023	32,239,613	15.0%	4,799,945	1,184,808	2,456,995	1,826,015	5,467,817	17%	2,669,325	8,137,142	3,337,197
5	2024	32,190,878	15.0%	4,839,613	1,205,502	2,941,592	2,310,408	6,457,501	20%	3,337,197	9,794,698	4,955,085
6	2025	32,034,781	15.0%	4,834,774	1,212,295	3,532,702	2,899,530	7,644,527	24%	4,955,085	12,599,612	7,764,838
7	2026	32,148,678	15.0%	4,823,264	1,202,006	3,935,184	3,301,505	8,438,694	26%	7,764,838	16,203,532	11,380,268
8	2027	32,356,580	15.0%	4,818,717	1,035,068	4,336,529	3,700,455	9,072,052	28%	11,380,268	20,452,320	15,633,603
9	2028	32,437,285	15.0%	4,827,002	795,344	4,908,241	4,269,900	9,973,485	31%	15,633,603	25,607,088	20,780,086
10	2029	32,720,088	15.0%	4,847,127	736,205	5,477,124	4,828,797	11,042,126	34%	20,780,086	31,822,212	26,975,085
11	2030	32,775,075	15.0%	4,875,698	703,305	6,043,011	5,384,013	12,130,329	37%	26,975,085	39,105,414	34,229,716
12	2031	33,515,810	15.0%	4,896,622	607,782	6,484,539	5,788,522	12,880,843	38%	34,229,716	47,110,560	42,213,938
13	2032	33,613,798	15.0%	4,950,549	599,054	6,649,302	5,405,662	12,654,017	38%	42,213,938	54,867,954	49,917,405
14	2033	34,028,088	15.0%	4,995,234	589,927	6,734,443	5,058,958	12,383,328	36%	49,917,405	62,300,733	57,305,499
15	2034	33,899,454	15.0%	5,057,885	587,365	6,801,165	4,987,767	12,376,297	37%	57,305,499	69,681,796	64,623,911
16	2035	33,768,822	15.0%	5,077,067	587,256	6,973,367	5,159,482	12,720,104	38%	64,623,911	77,344,016	72,266,949
17	2036	33,699,169	15.0%	5,084,818	588,535	7,436,387	5,622,016	13,646,938	40%	72,266,949	85,913,886	80,829,068
18	2037	33,557,413	15.0%	5,068,372	587,042	7,992,591	6,177,739	14,757,373	44%	80,829,068	95,586,441	90,518,069
19	2038	33,474,351	15.0%	5,051,270	586,937	8,546,021	6,730,688	15,863,647	47%	90,518,069	106,381,716	101,330,446
20	2039	33,401,024	15.0%	5,036,547	580,148	9,096,683	7,280,872	16,957,704	51%	101,330,446	118,288,150	113,251,603
21	2040	33,369,284	15.0%	5,021,639	576,656	9,644,598	7,828,310	18,049,564	54%	113,251,603	131,301,166	126,279,527

(d): 2018 = 10% as stated in PA 295 Section 27; 2019 - 2040 as stated in PA 342 Section 28 (the previous 3-year rolling average multiplied by current year compliance requirement)
(h)=(e)+(f)+(g)
(i)=(h)/(b)
(k)=(h)+(j)
(l)=(k)-(d)

Existing = Company Owned Renewable Generation Assets
EOCs =
RECs = Renewable Energy Credits
PPA = Power Purchase Agreement
RPS = Renewable Energy Credit Portfolio Standard
Assumptions:
All PCA COD (Commercial Operation Date) assumes May 31 of a given year.
Cross Winds Energy Park Phase II, COD: 2018, nameplate 43.7MW, 0% RECs for CE RPS, 100% RECs for LCREP (Large Customer Renewable Energy Program).
Cross Winds Energy Park Phase III, COD: 2020, nameplate 75.9MW, 0% RECs for CE RPS, 100% RECs for LCREP (Large Customer Renewable Energy Program) starting from 2021.
Crescent Wind COD: 10/22/2020, nameplate 166MW, 100% RECs for CE RPS.
Gratiot Wind COD: 11/16/2020, nameplate 150MW, 100% RECs for CE RPS.
Heartland Wind Planned COD: 12/31/2022, nameplate 198MW, 100% RECs for CE RPS.
The Cumulative Capacity Additions Solar Total is produced by the proposed course of action solar build plan through 2040.
The REC model assumes CE receives 0% RECs from "new" PURPA solar projects.
The REC model assumes CE receives 100% RECs from Non-PURPA solar projects regardless of the ownership structure.
CE Solar Gardens 10% RECs for CE RPS.

All “New Contracts w/ Existing PURPA QFs” do not contribute any RECs to CE.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company
IRP Proposed Course of Action - 35% Goal Outlook

Case No.: U-21090
Exhibit No.: A-98 (TEH-2)

Witness: TEHatcher
Date: June 2021

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
Line No.	Year	Jurisdictional Calendar Year Retail Sales (MWh)	EE Savings (MWh)	Energy Efficiency (%)	EWR Credits	EWR (%)	Existing, EOCs, and Market Purchase (RECs)	Existing and Market Purchase (%)	IRP Proposed Course of Action Build Plan (RECs)	Build (%)	PPA	PPA%	RECs Received%	RECs to Purchase	EE+RECs	Percent of Goal
1	2020	31,446,239	5,201,504	16.54%	147,185	0.47%	1,184,821	3.77%	995,475	3.17%	1,108,253	3.52%	10.46%	0	8,490,053	27.00%
2	2021	32,287,657	5,916,693	18.32%	230,830	0.71%	1,162,492	3.60%	1,440,250	4.46%	1,185,191	3.67%	11.73%	0	9,704,626	30.06%
3	2022	32,264,994	6,628,539	20.54%	227,467	0.70%	1,161,063	3.60%	1,440,179	4.46%	1,366,741	4.24%	12.30%	0	10,596,522	32.84%
4	2023	32,239,613	7,339,478	22.77%	226,723	0.70%	1,184,808	3.68%	2,456,995	7.62%	1,826,015	5.66%	16.96%	0	12,807,295	39.73%
5	2024	32,190,878	7,966,956	24.75%	145,414	0.45%	1,205,502	3.74%	2,941,592	9.14%	2,310,408	7.18%	20.06%	0	14,424,457	44.81%
6	2025	32,034,781	8,555,165	26.71%	109,374	0.34%	1,212,295	3.78%	3,532,702	11.03%	2,899,530	9.05%	23.86%	0	16,199,691	50.57%
7	2026	32,148,678	9,127,764	28.39%	94,659	0.29%	1,202,006	3.74%	3,935,184	12.24%	3,301,505	10.27%	26.25%	0	17,566,458	54.64%
8	2027	32,356,580	9,710,597	30.01%	104,104	0.32%	1,035,068	3.20%	4,336,529	13.40%	3,700,455	11.44%	28.04%	0	18,782,649	58.05%
9	2028	32,437,285	10,297,064	31.74%	109,246	0.34%	795,344	2.45%	4,908,241	15.13%	4,269,900	13.16%	30.75%	0	20,270,549	62.49%
10	2029	32,720,088	10,864,562	33.20%	86,967	0.27%	736,205	2.25%	5,477,124	16.74%	4,828,797	14.76%	33.75%	0	21,906,689	66.95%
11	2030	32,775,075	11,447,766	34.93%	103,756	0.32%	703,305	2.15%	6,043,011	18.44%	5,384,013	16.43%	37.01%	0	23,578,096	71.94%
12	2031	33,515,810	11,927,548	35.59%	0	0.00%	607,782	1.81%	6,484,539	19.35%	5,788,522	17.27%	38.43%	0	24,808,391	74.02%
13	2032	33,613,798	12,412,605	36.93%	0	0.00%	599,054	1.78%	6,649,302	19.78%	5,405,662	16.08%	37.65%	0	25,066,622	74.57%
14	2033	34,028,088	12,945,755	38.04%	36,032	0.11%	589,927	1.73%	6,734,443	19.79%	5,058,958	14.87%	36.39%	0	25,329,082	74.44%
15	2034	33,899,454	13,617,357	40.17%	175,956	0.52%	587,365	1.73%	6,801,165	20.06%	4,987,767	14.71%	36.51%	0	25,993,654	76.68%
16	2035	33,768,822	14,298,386	42.34%	195,808	0.58%	587,256	1.74%	6,973,367	20.65%	5,159,482	15.28%	37.67%	0	27,018,491	80.01%
17	2036	33,699,169	15,152,611	44.96%	372,534	1.11%	588,535	1.75%	7,436,387	22.07%	5,622,016	16.68%	40.50%	0	28,799,548	85.46%
18	2037	33,557,413	15,904,026	47.39%	272,645	0.81%	587,042	1.75%	7,992,591	23.82%	6,177,739	18.41%	43.98%	0	30,661,399	91.37%
19	2038	33,474,351	16,631,305	49.68%	249,635	0.75%	586,937	1.75%	8,546,021	25.53%	6,730,688	20.11%	47.39%	0	32,494,952	97.07%
20	2039	33,401,024	17,375,449	52.02%	261,133	0.78%	580,148	1.74%	9,096,683	27.23%	7,280,872	21.80%	50.77%	0	34,333,152	102.79%
21	2040	33,369,284	18,100,339	54.24%	245,138	0.73%	576,656	1.73%	9,644,598	28.90%	7,828,310	23.46%	54.09%	0	36,149,903	108.33%

(g): Exhibit A-97 (TEH-1) titled "IRP Proposed Course of Action - 15% RPS Forecast" Col (e).
(i): Exhibit A-97 (TEH-1) titled "IRP Proposed Course of Action - 15% RPS Forecast" Col (f).
(k): Exhibit A-97 (TEH-1) titled "IRP Proposed Course of Action - 15% RPS Forecast" Col (g).
(d)=(c)/(b)
(f)=(e)/(b)
(h)=(g)/(b)
(j)=(i)/(b)
(l)=(k)/(b)
(m)=(h)+(j)+(l)
(o)=(c)+(g)+(i)+(k)+(n)
(p)=(d)+(m)

Assumption:

Per the Company’s settlement agreement for the 2017 EWR reconciliation filing in Case No. U-20028, EWR savings are only included for a given year when the EWR savings exceed 1.5%, and the savings forecasted for years 2031 and 2032 are below 1.5%. Therefore, Column (e), rows 12 and 13 show zero.