OLSON, BZDOK & HOWARD

August 21, 2019

Ms. Barbara Kunkle
Acting Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

Via E-Filing

RE: MPSC Case No. U-20471

Dear Ms. Kunkle:

The following is attached for paperless electronic filing:

Direct Testimony of Douglas Jester on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club

Exhibits MEC-53 through MEC-63

Proof of Service

Sincerely,

Digitally signed by Lydia Barbash-Riley
DN: cn=Lydia Barbash-Riley, email=lydia@envlaw.com, c=US
Date: 2019.08.21 19:33:22 -04'00'

Lydia Barbash-Riley
lydia@envlaw.com

xc: Parties to Case No. U-20471

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE Electric Company** for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief.	U-20471 ALJ Sally L. Wallace

DIRECT TESTIMONY OF DOUGLAS JESTER

ON BEHALF OF MICHIGAN ENVIRONMENTAL COUNCIL, NATURAL RESOURCES DEFENSE COUNCIL, AND SIERRA CLUB

August 21, 2019

TABLE OF CONTENTS

<u>I. INTRODUCTION AND QUALIFICATIONS</u>

Q. Please state for the record your name, position, and business address.

A. My name is Douglas B. Jester. I am a Partner of 5 Lakes Energy LLC, a Michigan limited liability corporation, located at Suite 710, 115 W Allegan Street, Lansing, Michigan 48933.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of Michigan Environmental Council ("MEC"), Natural Resources Defense Council ("NRDC"), Sierra Club ("SC"), Energy Innovation Business Council ("EIBC"), and Institute for Energy Innovation ("IEI").

Q. Please summarize your experience in the field of electric utility regulation.

A. I have worked for more than 20 years in electricity industry regulation and related fields. My work experience is summarized in my resume, provided as Exhibit MEC-53.

Q. Have you testified before this Commission or as an expert in any other proceeding?

A. I have previously testified before the Michigan Public Service Commission in the following cases:

- Case U-17473 (Consumers Energy Plant Retirement Securitization);
- Case U-17096-R (Indiana Michigan 2013 PSCR Reconciliation);
- Case U-17301 (Consumers Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17302 (DTE Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17317 (Consumers Energy 2014 PSCR Plan);
- Case U-17319 (DTE Electric 2014 PSCR Plan);
- Case U-17671-R (UPPCO 2015 PSCR Reconciliation);

- Case U-17674 (WEPCO 2015 PSCR Plan);
- Case U-17674-R (WEPCO 2015 PSCR Reconciliation);
- Case U-17679 (Indiana-Michigan 2015 PSCR Plan);
- Case U-17688 (Consumers Energy Cost of Service and Rate Design);
- Case U-17689 (DTE Electric Cost of Service and Rate Design);
- Case U-17698 (Indiana-Michigan Cost of Service and Rate Design);
- Case U-17735 (Consumers Energy General Rates);
- Case U-17752 (Consumers Energy Community Solar);
- Case U-17762 (DTE Electric Energy Optimization Plan);
- Case U-17767 (DTE General Rates);
- Case U-17792 (Consumers Energy Renewable Energy Plan Revision);
- Case U-17895 (UPPCO General Rates);
- Case U-17911 (UPPCO 2016 PSCR Plan);
- Case U-17911-R (UPPCO 2016 PSCR Reconciliation);
- Case U-17990 (Consumers Energy General Rates);
- Case U-18014 (DTE General Rates);
- Case U-18089 (Alpena Power PURPA Avoided Costs);
- Case U-18090 (Consumers Energy PURPA Avoided Costs);
- Case U-17911-R (UPPCO 2016 PSCR Reconciliation);
- Case U-18091 (DTE PURPA Avoided Costs);
- Case U-18092 (Indiana Michigan Power Company PURPA Avoided Costs);
- Case U-18093 (Northern States Power PURPA Avoided Costs);
- Case U-18094 (Upper Peninsula Power Company PURPA Avoided Costs);
- Case U-18095 (Wisconsin Public Service Company PURPA Avoided Costs);

- Case U-18096 (Wisconsin Electric Power Company PURPA Avoided Costs);
- Case U-18224 (UMERC Certificate of Necessity);
- Case U-18255 (DTE Electric General Rates);
- Case U-18322 (Consumers Energy General Rates);
- Case U-18406 (UPPCO 2018 PSCR Plan);
- Case U-18408 (UMERC 2018 PSCR Plan);
- Case U-18419 (DTE Certificate of Necessity);
- Case U-20111 (UPPCO TCJA Adjustment);
- Case U-20134 (Consumers Energy General Rates);
- Case U-20150 (UPPCO RDM Complaint);
- Case U-20162 (DTE Electric General Rates);
- Case U-20165 (Consumers Energy IRP);
- Case U-20276 (UPPCO General Rates);
- Case U-20229 (UPPCO PSCR Plan); and
- Case U-20350 (UPPCO IRP).

Additionally, I testified as an expert witness before the Public Utilities Commission of Nevada in Case No. 16-07001 concerning the 2017-2036 integrated resource plan of NV Energy; and before the Missouri Public Service Commission in Cases Nos. ER-2016-0179, ER-2016-0285, and ET-2016-0246 concerning residential rate design and electric vehicle ("EV") policy, revenue requirements, cost of service, and rate design. I testified before the Kentucky Public Service Commission in Case No. 2016-00370 concerning municipal street lighting rates and technologies, and the Massachusetts Department of Public Utilities in Case Nos. DPU 17-05 and DPU 17-13 concerning EV charging infrastructure program design and cost recovery.

I have also testified as an expert witness on behalf of the State of Michigan before the Federal Energy Regulatory Commission in cases relating to the relicensing of hydro-electric generation, and have participated in state and federal court cases on behalf of the State of Michigan, concerning electricity generation matters, which were settled before trial.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following Exhibits:

- MEC-53: Resume of Douglas Jester
- MEC-54: DTE response to MECNRDCSC-3.85
- MEC-55: Combined Heat and Power (CHP) Roadmap for Michigan
- MEC-56: U-20165 Exhibit EIB-3
- MEC-57: U-20350 Direct Testimony of Gradon R. Haehnel and Exhibit A-34
- MEC-58: DTE Response to MECNRDCSC-8.32
- MEC-59: Reanalysis of DTE Capacity Starting Point
- MEC-60: Section 4 of NIPSCO IRP Report
- MEC-61: U-18091 Stanczak Testimony
- MEC-62: U-18232 Exhibit A-3
- MEC-63: U-20343 Direct Testimony of Terri L. Schroeder

II. OVERVIEW OF CASE AND TESTIMONY

Q. Please summarize the major elements of this case from your perspective.

A. In this case, DTE requests that the Commission:

A. Approve DTE Electric's Integrated Resource Plan by approving the Proposed Course of Action as the most reasonable and prudent means of meeting the Company's energy and capacity needs:

B. Find that DTE does not have a persistent capacity need for the next ten (10) years;

C. Pre-approve DTE Electric's proposed Energy Waste Reduction and Volt-VAR Optimization capital costs, commencing within three years following the Commission's approval of the Company's Integrated Resource Plan; and

D. Grant DTE Electric any and further relief as is just and reasonable.[1]

In its Application, DTE Electric describes its Proposed Course of Action ("PCA") as consisting of two parts, "the near-term PCA covering years 2020-2024 and the flexible PCA covering years 2025-2035."[2] DTE Electric also refers to the near-term PCA as the defined PCA, and further describes it as including:

a. Additional 11 MW of solar plus storage pilot projects;
b. Additional 693 MW of wind energy;
c. Additional Voluntary Green Pricing (VGP) program renewables (MIGreenPower) between 465 MW and 715 MW depending upon subscription levels;
d. Acceleration of previously announced retirement of the Trenton Channel Power Plant to 2022;
e. Acceleration of previously announced retirement of St. Clair Power Plant Unit 7 to 2022;
f. Accelerated retirement of St. Clair Unit 1 to 2019;
g. River Rouge Unit 3 will end the use of coal in 2020, and will continue to operate until 2022 on recycled industrial gases and natural gas;
h. Increase Energy Waste Reduction ("EWR") programs to achieve annual energy savings to 1.65% in 2020 and 1.75% in 2021;
i. Increase Demand Response ("DR") programs to 859 MW by 2024; and
j. Conduct Conservation Voltage Reduction and Volt-Var Optimization

---

[1] U-20471 DTE Electric Application, pages 11-12.

[2] U-20471 DTE Electric Application, page 2.

("CVR/VVO") pilot program by 2020.[3]

DTE Electric further explains that its flexible PCA "contains commitments by DTE Electric to reach two renewable targets in the years 2025-2030, but leaves several issues to be determined in the next IRP:

a. The Company will continue to build renewables to support our clean energy and carbon reduction goals, and expects to add 525 MW of solar between 2025–2030, with another 2000 MW of solar by 2040;
b. The EWR program levels will be analyzed in subsequent IRPs, but it is expected that the 1.75% annual reduction level of EWR that begins in 2021 would at least be continued through 2040;
c. DR program levels will be analyzed in subsequent IRPs, but it is expected that the 859 MW that is expected to be achieved by 2024 will at least be maintained at that level through 2040;
d. Building on the momentum of our current VGP programs, we have included up to 675 MW of voluntary renewable energy between 2025 and 2030;
e. Belle River Units 1 and 2 are currently expected to retire in 2029 and 2030 respectively, but that retirement timing will be reevaluated in the next IRP;
f. Monroe Power Plant is planned for retirement by 2040, but that retirement timing will be reevaluated in the next IRP;
g. CVR/VVO will be analyzed in subsequent IRPs (50 MW by 2030 included in two of the four potential pathways in the flexible years of the PCA);
h. Additional generation resources will be analyzed in the next IRP. There is a combined cycle gas addition in two of the four potential pathways in the flexible years of the PCA. The size of the potential gas addition would be a 414 MW 1x1 combined cycle. In the two plans that do not have combined cycle additions, there are other resources selected to fill the capacity need in 2030."[4]

DTE Electric further contends that its "defined PCA for years 2020-2024 is fully integrated and requires approval in its entirety; the flexible PCA for years 2025-2035 is by its nature undefined and may be separately approved or rejected."[5] DTE Electric requests pre-approval of capital costs for "EWR, DR, and CVR/VVO that the Company will commence

[3] U-20471 DTE Electric Application, pages 2-3.

[4] U-20471 DTE Electric Application, pages 3-4.

[5] U-20471 DTE Electric Application, page 4.

within three years of the Commission's approval of the Company's IRP and PCA"[6] and further lists these costs as:

a. $103 million in projected EWR capital costs in 2020-2022;
b. $24 million of projected DR capital costs beginning May 1, 2020 through December 31, 2022, which is incremental to the DR spend requested in DTE Electric's current rate case, U-20162; and
c. $0.7 million in cumulative capital costs for the CVR/VVO program from 2019 to 2020, related to the CVR/VVO pilot.[7]

Q. What is the scope of your testimony?

A. First, I observe several deficiencies in DTE Electric's IRP analysis, based on which I conclude that DTE Electric has not proposed an IRP that demonstrably represents the most reasonable and prudent means of meeting energy and capacity needs.

Secondly, I examine DTE Electric's claim that it "does not have a persistent capacity need for the next ten (10) years," which has consequences for this IRP and for matters outside this case.

Thirdly, I examine what can be understood about DTE Electric's "avoided costs", based on this IRP filing, for the purposes of voluntary green pricing ("VGP") program rates and of power purchase agreements ("PPAs") with qualifying facilities ("QFs") pursuant to the Public Utility Regulatory Policies Act[8] ("PURPA").

Fourthly, I explain that competitive generation resource acquisition allowing multiple technologies and procurement models is necessary for reasonable and prudent resource selection and should therefore be used in any future IRP process.

---

[6] U-20471 DTE Electric Application, page 9.

[7] U-20471 DTE Electric Application, pages 9-10.

[8] Public Law 95-617, 92 Stat 3117.

Finally, I explain that DTE Electric considered storage in a very limited way and did not consider the distribution of energy resources in this IRP, and that the Commission should revise its IRP guidelines to require a utility to better address these topics in future.

III. DEFICIENCIES OF DTE ELECTRIC'S IRP FILING

Q. You indicated that there are several deficiencies in DTE Electric's IRP filing. What are those deficiencies?

A. The principal deficiencies that I have identified are:

- DTE Electric's IRP modeling is premised on meeting "capacity needs" rather than "energy and capacity needs"
- DTE Electric failed to issue a request for proposals for new generation in support of this IRP
- DTE Electric failed to reasonably consider combined heat and power as a resource
- DTE used excessive near-term costs for solar generation
- DTE Electric modeled solar resources using the output profile and capacity credits for a fixed-tilt system even though they represented that they used a single-axis tracking system
- DTE Electric modeled storage in only a primitive way

Other witnesses have identified additional deficiencies or mistakes.

A. DTE ELECTRIC'S IRP FILING IS BASED ON "CAPACITY NEEDS" RATHER THAN "ENERGY AND CAPACITY NEEDS"

Q. Explain how DTE Electric's IRP modeling is premised on meeting "capacity needs" rather than "energy and capacity needs"?

A. DTE witness Mikulan explains the Company's approach to an IRP as being based on capacity needs:

> To conduct an IRP process, planning and modeling must be performed to determine if currently available resources meet future customer needs. If a capacity shortfall is forecasted, potential resource options need to be analyzed, with a range of input assumptions, in order to formulate cost-effective resource portfolios.[9]

Her entire testimony then proceeds on this premise. Further, the primary software used by DTE in its modeling for this IRP, Strategist©, is commonly referred to as a "capacity additions" model. Through discovery, DTE confirmed that its modeling was premised on adding capacity only when there was a capacity shortfall. Exhibit MEC-54.

Q. Why is modeling premised on meeting "energy and capacity needs" better than modeling based on merely meeting "capacity needs"?

A. Unlike DTE's approach, an IRP based on "energy and capacity" would potentially add a resource at a time when there is no immediate capacity shortfall, because doing so reduces the net present value of revenue requirement compared to other alternatives, including the alternative of waiting until there is a capacity need. This could happen with any resource whose variable cost of energy generation is less than the marginal cost of energy generation in the generation portfolio. Wind and solar, with near-zero variable costs of generation, are likely candidates for selection, even when there is no immediate capacity need, in an

[9] U-20471. Revised Direct Testimony of Laura K. Mikulan, page LKM-7.

"energy and capacity" selection. Such selection does not require that the full cost of the wind or solar resource per unit energy be less than the marginal cost of energy in the portfolio, only that the avoided costs of energy is less than the cost of acquiring the resource earlier than if driven by capacity need. Modeling based only on "capacity need" rather than "energy and capacity" is a flawed practice when important resource options have near-zero variable costs of generation and life-cycle costs that are competitive with fuel-based generation.

Further, the question for the Commission in reviewing an IRP pursuant to 2016 PA 341 Section 6t as stated in paragraph (8)(a) is whether "[t]he proposed integrated resource plan represents the most reasonable and prudent means of meeting the electric utility's **energy and capacity** needs…"[10] (Emphasis added). The question is not whether the integrated resource plan is the most reasonable and prudent means of meeting the utility's capacity needs. 2016 PA 341 Section 6t requires in paragraph (5)(k) that the utility provide "an analysis of the cost, capacity factor, and viability of all reasonable options available to meet projected energy and capacity needs[.]" By modeling only resources to meet "capacity needs", DTE Electric has manifestly failed to address statutory IRP requirements.

Q. In this case, DTE developed its plan based on "capacity need' modeling but then chose to accelerate the development of many of the wind and solar resources ahead of when capacity was needed. Does DTE's approach obviate your concern about using a "capacity need" approach instead of an "energy and capacity" approach?

A. No. It potentially improves their plan but does not guarantee that they develop the chosen

[10] MCL 460.6t(8)(a) (emphasis added).

resources at the optimum time (producing the lowest net present value revenue requirement), nor that they chose the optimum (least net present value revenue requirement) resource portfolio. The optimum timing of resource development in an "energy and capacity" approach is a complicated question best determined through modeling. DTE did not calculate the accelerated development dates through modeling, and therefore those dates are almost certainly not the optimal timing to acquire these resources.

Further, when a resource is optimally acquired earlier than when it is needed to satisfy a capacity constraint it means that such a resource has lower net cost than a similar resource acquired at the time of capacity need. This implies that the accelerated build of the resource provides it a comparative advantage with respect to other resource options and might result in selecting more of it. As a result, DTE's method of modeling based on "capacity need" and then developing resources earlier likely leads to a suboptimal, more costly mix of resources.

Q. Did you examine whether modeling on an "energy and capacity" basis in this IRP would produce a different result that modeling on the basis of "capacity need"?

A. Yes. Witness Avi Allison and I requested evaluation of this matter by Witnesses George Evans, and by arrangement through EIBC/IEI I also requested evaluation by ELPC Witness Anna Sommer.[11]

Strategist has a feature called "superfluous' resources that allow it to choose specific resources on an "energy and capacity" basis rather than a "capacity need" basis. Because Strategist is minimizing the net present value of required revenue whether or not a

[11] See U-20471. Direct Testimony of Anna Sommer.

"superfluous" resource is allowed and the "superfluous" resource will not be selected unless it reduces the revenue requirement, but a "capacity need" will always be satisfied, an "energy and capacity" modeling approach will never be more costly than a "capacity need" modeling approach and may be an improvement. Both Evans and Sommer used Strategist to test this matter by allowing a superfluous wind resource.

Evans evaluated a single superfluous wind block in a run otherwise specified by Witness Allison. That run is designated in Evans' testimony as his case 4 and is on the Belle River early retirement sensitivity of DTE's Reference Scenario with 1.75% Tiered EWR and 465 MW VGP. This modeling run is discussed by Evans[12] and by Allison[13] in their testimony. This single run demonstrates that DTE's "capacity need" approach produces materially worse results than an "energy and capacity" approach. It also demonstrates that more rapid development of wind and solar resources than proposed by DTE will reduce net present value of revenue requirements.

As Ms. Sommer testifies,[14] she evaluated the use of a superfluous resource by using DTE Electric's Reference scenario with the resource assumptions modeled in response to Staff request STDE 2.3-b. This was a case where Strategist was allowed to optimize resource selection without assuming resources not already approved while adding resources only when there is a "capacity need." Sommer made one superfluous wind resource available only in 2021, using the resource characterization that DTE labeled WP21. Strategist chose

[12] See U-20471. Direct testimony of George Evans, page 17; Exhibit MEC-7.

[13] See U-20471. Direct testimony of Avi Allison, pages 32-45.

[14] See U-20471. Direct testimony of Anna M. Sommer.

that resource, demonstrating that adding a wind resource at a time when there is not a "capacity need" can reduce the net present value of required revenue. In this instance, DTE's case had $14,346,133,000 net present value of required revenue, and addition of the one superfluous wind resource reduced the net present value of required revenue to $14,315,136,000 for savings of $30,997,000. Sommer refers to this run as "STDE 2.3-b 2004 Reference Case Superfluous WP21" in her testimony. This result demonstrates that a "capacity need" approach to IRP modeling is likely to produce a plan that is inferior to an "energy and capacity" approach.

B. DTE ELECTRIC FAILED TO ISSUE A REQUEST FOR PROPOSALS FOR NEW GENERATION IN SUPPORT OF THIS IRP

Q. Why did DTE decide not to issue a request for proposals in support of this IRP?

A. In its testimony in this case, DTE Electric asserts that "[g]iven the Company does not anticipate a need for additional capacity in the short-term planning horizon, there is no need or requirement to issue an RFP to third parties to supply capacity resources."[15]

Q. Is the absence of a capacity need in the short-term planning horizon relevant for whether the Company should have issued an RFP to third parties to supply capacity resources?

A. No. In making this argument, the Company is apparently referring to a portion of 2016 PA 341, Section 6t (6), which reads "Before filing an integrated resource plan under this section, each electric utility whose rates are regulated by the commission shall issue a request for proposals to provide any new supply-side generation capacity resources needed

[15] U-20471. Direct Testimony of Sharon G. Pfeuffer, page SGP-30, lines 1-3.

to serve the utility's reasonably projected electric load, applicable planning reserve margin, and local clearing requirement for its customers in this state and customers the utility serves in other states during the initial 3-year planning period to be considered in each integrated resource plan to be filed under this section."[16] The Company apparently reads this provision as not requiring issuance of an RFP if they do not have a "capacity need" during the initial 3-year planning period to be considered in this IRP. I note, however, that this provision of 2016 PA 341 requires a request for proposals "to provide **any** new supply-side generation capacity resource needed to serve the utility's reasonably projected load.…" (Emphasis added). Generation resources to meet specific requirements, such as renewable energy standards and supply for VGP programs, are "needed to serve the utility's reasonably projected load" and thereby trigger this specific requirement for a request for proposals.

Second, 2016 PA 341 Section 6t (8) directs the Commission to approve the IRP only if "[t]he proposed integrated resource plan represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs."[17] If the Commission determines that competitive solicitation of energy resources is reasonably likely to have produced more competitive pricing, improved diversity of generation supply, or is otherwise a more reasonable and prudent means to meet DTE Electric's energy needs even absent a near-term capacity requirement, the Commission should determine that the DTE Electric's IRP does not represent the most reasonable and prudent means of meeting the

[16] MCL 460.6t(6).

[17] MCL 460.6t(8)(a).

energy and capacity needs because it was developed absent an RFP and competitive solicitation.[18]

Finally, the Commission should consider that pursuant to 2016 PA 341, Section 6w, DTE must annually demonstrate that it controls capacity to meet its resource adequacy obligations four years out.[19] DTE's interpretation of the provision in 2016 PA 341 Section 6t(6) requires the use of a request for proposals to provide any new supply-side generation capacity resources **only** when it has a capacity need within three years following approval of an IRP, hence four years after filing an IRP. Under DTE's interpretation of 2016 PA 341, Section 6t, DTE will never be required to issue a request for proposals in support of an IRP while it is in compliance with Section 6w.

Q. DTE justified its decision not to issue and RFP by asserting that it does not have a capacity need in the short-term planning horizon. Is that assertion correct?

A. No. Exhibit A-18 lists 1,240 MW of renewable resources to be built by 2023 that are not specified as from particular resources. Pursuant to 2016 PA 341, Section 6t(6), these resources must be acquired pursuant to a request for proposals.

As I show later in this testimony, DTE has a capacity need for PY 2023-24. To acquire capacity in time for it to be available in PY 2023-24, the owner will almost certainly need to begin construction in 2022, inside of the three-year period following this IRP. I conclude

[18] The Commission should also note that it was dissatisfied with DTE's use of an extremely limited RFP in the Blue Water Energy Center Certificate of Necessity case U-18419. See page 106 the Commission Order of April 27, 2018.

[19] MCL 460.6w(1).

that even by DTE's criteria, it should have issued a request for proposals.

Q. Explain the significance for IRP results of DTE's decision not to issue a request for proposals in support of this IRP?

A. In addition to being based on inaccurate premises as discussed above, DTE's decision not to issue a request for proposals deprived DTE and thereby the Commission and intervenors of accurate information that would be needed to determine if DTE's proposals are prudent and reasonable.

Operationally, the IRP does not really serve to determine the resources that the utility will acquire years from now, but what resources it will acquire in the next few years. DTE acknowledges that "it makes sense to have a determined or fixed PCA for the first five years…"[20] The analysis of subsequent paths serves to inform the utility, Commission, and other stakeholders about the consequences for future options of the actions to be taken now. Authorization of cost recovery for short-term actions based on the IRP requires that those actions be determined prudent and reasonable. Thus, in my view, good practice in the IRP is to offer the model a full selection of near-term resources based on actual offers or specific project estimates so as to determine the near-term economics of available near-term resources, as well as an array of future resource options in order to explore the sensitivity of immediate resource selections to projections about future conditions. In many respects, DTE's IRP has inverted this logic, by assuming resources in the starting point for the IRP that have not yet been approved,[21] limiting resource acquisition largely to the future based

[20] U-20471 Application, page 8.

[21] See my later discussion of DTE's capacity position.

on projected capacity need, and failing to use a request for proposals to identify concrete near-term options at known costs.

The analysis of "superfluous" resources that I discuss earlier in this testimony shows potential economic value from incremental wind and solar resources in the near future absent any capacity need. This analysis, however, was premised on generic solar and wind resources as modeled by DTE and not based on the actual costs of solar and wind resources that might be on offer to DTE. The results may therefore be incorrect. Issuance of a request for proposals provides clarity about the costs and performance of resources currently available in the market and aids proper modeling of options.

Later in this testimony, I also explain that DTE's failure to issue a request for proposals underlies deficiencies in its consideration of combined heat and power resources, and of solar resources.

I urge the Commission to direct DTE and other utilities that future IRPs must be premised on issuance of a request for proposals to identify concrete resource options for analysis in the IRP. Absent responses to a request for proposals, intervenor's and the Commission's ability to evaluate the Proposed Course of Action is compromised.

Q. You made arguments earlier in your testimony that DTE is required to issue a request for proposals in preparing an IRP and that issuing a request for proposals is important for the accuracy of the IRP. Are there additional reasons that the Commission should require DTE Electric to use competitive resource selection when

acquiring generation resources?

A. Yes. This is a question of prudence. Competitive bidding has long been viewed as definitively producing the least-cost, or best-value depending on selection criteria, provision of goods or services. When utilities primarily purchased large power plants chosen from a very limited range of technologies, and with long development times, a certificate of necessity proceeding and competitive selection of engineering, technology, and construction satisfactorily demonstrated prudence. With increasing use of renewables and other generators of relatively small size, in which design details and siting can be varied, with shorter development schedules, and with manageable ownership risks, the Commission should be looking to new standards of prudence. In particular, competitive selection of resources can transfer most development and construction risks to competitive providers and the alternative of using power purchase agreements creates competition in cost of capital and related taxation. Competitive solicitation that specifies what the utility needs for its customers, rather than the specific generation resource technology and design also provides the opportunity to compare definitive options for various technologies. For these reasons, the Commission should be expecting DTE and other regulated utilities to rely predominantly on competitive solicitation, open to different business models and some range of technologies, to acquire needed generation resources. So long as competitive solicitation is open, transparent, and fairly administered, the utility can compete in such a solicitation.

Q. Is there precedent in Michigan for requiring competitive solicitations for generation resources?

A. Yes, the Commission recently endorsed this approach for Consumers Energy in U-20165. More recently in DTE's Renewable Energy Plan Case No. U-18232, the Commission adopted the ALJ's view with respect to resources for compliance with renewable energy standards, and presumably for VGP program resources:

> DTE Electric's rationale for its plan to meet all updated renewable energy needs through company-owned facilities appears to be based on a misinterpretation of Act 295 as amended by Act 342. As originally enacted, section 33 of Act 295, formerly MCL 460.1033, provided that "[a]t the electric provider's option, up to but no more than 50% of the renewable energy credits" could come from renewable energy systems developed by and owned by the electric utility or developed by a third party or parties for transfer to utility ownership, while "[a]t least 50% of the renewable energy credits shall be from renewable energy contracts that do not require transfer of ownership" to the electric utility. This provision was eliminated by 2008 PA 342, and MCL 460.1028(3) now states:
>
> > Subject to subsection (5), each electric provider shall meet the renewable energy credit standards with renewable energy credits obtained by 1 or more of the following means: (a) Generating electricity from renewable energy systems for sale to retail customers. (b) Purchasing or otherwise acquiring renewable energy credits with or without the associated renewable energy.
>
> DTE Electric argues based on this revision that DTE Electric now has unfettered discretion to choose to pursue only company-owned renewable energy generation: … This argument is erroneous because as discussed above, MCL 460.1022(5) requires the company's plan to be reasonable and prudent.[22]

In the Commission's Order of December 20, 2017 in cases U-18461 and U-15896, in which the Commission established IRP filing guidelines and guidance, the Commission responded to DTE's request in that docket to exempt certain generation resources from competitive solicitation:

---

[22] U-18232. Proposal for Decision of May 21, 2019, pages 39-40. *See also* U-18232. Commission Order of July 18, 2019, pages 23-24 (discussing DTE's failure to "adequately explain why it failed to consider any option other than company-owned generation" and that DTE "could have made an attempt to consider REC purchases associated with PURPA contracts under different scenarios but failed to do so.").

> DTE Electric comments that requests for proposals (RFPs) for small capacity resources and renewable energy (RE) resources governed by 2008 PA 295 (Act 295) should be exempt from the IRP filing requirements. The company requests that the following language be added to this section: "Each electric utility whose rates are regulated by the Commission shall issue a request for proposals (RFP) to provide any new greater than 50 MW [megawatts], non-renewable supply-side capacity resources . . . ." DTE Electric's initial comments, p. 1 (emphasis in original).
>
> The Commission declines to adopt DTE Electric's proposed language because Act 341 does not set forth an exemption for small capacity and RE resources governed by Act 295. In addition, it is beneficial for a utility to receive updated costs for RE, including solar and battery storage that Page 5 U-15896 et al. may be less than 50 MW, and issuing an RFP is a useful way for a utility to garner this information. The Commission notes that, under the current language of this section, a utility has the ability to exclude a long-term power purchase agreement (PPA) from the RFP process. To avoid this type of restriction, the Commission adds the following language to the end of the section:
>
>> e) The RFP shall allow for proposals to provide new supply-side capacity in the form of a purchase power agreement for a period that is the lesser of the study period or of the useful life of the resource type proposed.[23]

Having made that decision, the Commission should not in the present case sanction yet another attempt by DTE to avoid competitive solicitation or generation resources.

C. DTE ELECTRIC FAILED TO REASONABLY CONSIDER COMBINED HEAT AND POWER AS A RESOURCE

Q. What is combined heat and power?

A. Cogeneration, or combined heat and power (CHP) is the simultaneous generation of electricity and useful thermal energy from a single source of fuel, located at or near the point of energy use. Electricity is primarily used on site as a substitute for power provided by a utility, with any excess electricity generation potentially sold onto the grid. The

[23] U-18461. Commission Order of December 20, 2017, pages 4-5; U-15896. Commission Order of December 20, 2017, pages 4-5.

thermal energy can be used to support process applications or human comfort through the production of steam, hot water, hot air, refrigeration, or chilled water. CHP systems typically reach fuel efficiencies of 65% to 80%.[24]

Q. Explain how DTE's consideration of combined heat and power in this IRP was unreasonable?

A. The Company makes a very limited and cursory assessment of the projected energy and capacity that could be purchased or produced from a CHP resource. According to Witness Mikulan, CHP was one of the technologies that was screened out as "uneconomic" based on the levelized cost of energy.[25] DTE derived this estimated cost from modeling a "generic" CHP unit.[26] She further explains that DTE screened out CHP even as it was advancing the Dearborn CHP on the basis that "While a CHP can be a very efficient technology, the units tend to be very location specific in that they require participation of a host customer with a need for both steam and electricity. The Company's marketing team is open to working with potential partners to develop CHP in our service area, however due to the specificity of each project, CHP was not conducive to selection on a generic basis in an IRP, as wind blocks, solar blocks, or utility scale gas units are."[27]

Q: What options did DTE have to find potential partners to develop CHP in its service area with a Request for Proposals, or a customer survey?

A. As I explain below, DTE could have surveyed its large customers to assess their interest in

---

[24] U.S. EPA. 2017. Methods for Calculating CHP Efficiency. Available from: https://www.epa.gov/chp/methods-calculating-chp-efficiency.

[25] U-20471. Revised Direct Testimony of Laura K. Mikulan, page LKM-66, lines 8-16.

[26] U-20471. Revised Direct Testimony of Laura K. Mikulan, page LKM-66, lines 20-21.

[27] U-20471. Revised Direct Testimony of Laura K. Mikulan, page LKM-66, line 18 through LKM-67, line 3.

CHP. DTE also could have created a request for proposals that allowed CHP to be responsive. Such a request for proposals might have caused CHP developers to partner with potential customers and present such concrete proposals to DTE, who could then have evaluated these in its IRP modeling. DTE's failure to issue RFPs or conduct a customer survey eliminated these opportunities and deprived intervenors and the Commission of potentially insightful details.

Q. What are the benefits of CHP to electric power users?

A. CHP is an efficient, resilient technology application that offers many potential benefits to both the system owner and the grid as a whole. When properly configured to operate independently from the grid, CHP systems can provide critical power reliability for businesses and critical infrastructure facilities while providing electric and thermal energy to the sites on a continuous basis, resulting in daily operating cost savings. A more resilient energy supply also prevents lost business productivity and decreases the likelihood of crippling power outages. By installing properly sized and configured CHP systems, Michigan facilities can effectively insulate themselves from a grid failure, providing continuity of critical services and freeing power restoration efforts to focus on other facilities in periods of emergency. This results in electricity cost savings, reduced losses due to power outages, and increased reliability.

Q. What are the potential benefits of CHP to the grid?

A. CHP can be both a supply-side resource and demand-side resource, resulting in a reduced need for additional grid and resource investments, reduced energy waste, enhanced cost-effectiveness of energy efficiency, reduced strain on the grid, and improved reliability and resiliency. By avoiding electric line losses and capturing much of the thermal energy normally wasted in power generation to provide heating and cooling to factories and businesses, CHP significantly reduces the total primary fuel needed to supply energy services, reducing air emissions and saving fuel and money.

Q. What are the potential benefits of CHP to a utility?

A. CHP represents an opportunity for electric utilities to help their customers decrease energy waste. There are also opportunities for electric utilities to engage customers with CHP as part of their resource planning, advanced transmission and distribution system planning processes. Through more robust customer engagement, electric utilities can harness the numerous ways in which CHP can benefit the grid, including helping to avoid the need for new generation, transmission and distribution infrastructure and easing grid congestion when demand for electricity is high by avoiding transmission and distribution losses associated with conventional electricity supply.

Q. Did DTE consider any of those benefits of CHP in this IRP?

A. Not visibly.

Q. Have you done any analysis of the potential use of CHP in DTE's service territory?

A. Yes. In February 2018, along with my colleagues at 5 Lakes Energy and other project partners, I completed a report for the Michigan Energy Office on behalf of the Michigan Agency for Energy and the U.S. Department of Energy entitled the "Combined Heat and Power (CHP) Roadmap for Michigan." This report is attached as Exhibit MEC-55. While that report does not identify the opportunity by utility, it is reasonable to estimate that about half of the opportunity is in DTE Electric's service territory.

Q. What did you find with respect to the economically viable potential to deploy CHP in

Michigan?

A. We found, assuming various fuel and technology costs, that the economic potential for new installed CHP in Michigan varies from 722 MW to 2,360 MW. In our reference scenario, economic potential for CHP in Michigan is about 1,014 MW electric generation capacity. Steam turbines, combustion turbines, and reciprocating engines above some threshold size appear profitable in each scenario with the minimum size threshold being lower under higher natural gas pricing and when renewables aren't available. The results of this modeling are show in the Table 8 of Exhibit MEC-55. Opportunities for deploying these CHP resources in Michigan are concentrated in the industrial chemical production, large public colleges and universities, solid waste facilities, automotive factories, pulp and paper mills, and agricultural processing plants.

Q. Would the economic potential for CHP in Michigan increase if we considered the economic benefits of increased resiliency.

A. Yes. According to our research, consideration of resilience value increases CHP potential by 591 MW above the 1,014 MW that would be profitable without consideration of resilience value using our reference case for gas and technology costs.

Q. Are you concerned about emissions from the use of gas in CHP?

A. Yes, but where gas is already used or going to be used as a heating fuel or in a stand-alone gas-fired generation unit, CHP will usually produce significantly less incremental emissions per unit of electricity generation. My view is not that DTE should include CHP in its Proposed Course of Action, but that it should have fully and properly evaluated that option as potentially superior to a gas-fired generation plant.

Q. In your opinion, what should DTE Energy have done to assess the potential for CHP in its service territory prior to the IRP filing?

A. DTE should have surveyed its industrial, commercial, and university customers to assess their interest in CHP and the economic viability of CHP systems at those potential sites. It should also have allowed an opportunity for CHP projects to be proposed in response to a request for proposals in support of this IRP. Instead of simply modeling a "generic" CHP unit, DTE Energy should have then used survey and RFP responses to provide a real, grounded assessment of the economic viability of CHP systems. This viable level of CHP penetration should have then been used as an input into the IRP modeling.

D. DTE USED EXCESSIVE NEAR-TERM COSTS FOR SOLAR GENERATION

Q. What is the best source for information on the costs of solar resources?

A. For the near-term, offers from market participants, in response to a Request for Proposals. DTE doesn't have that because they failed to issue a Request for Proposals in preparation of this IRP.

Q. What source did DTE use instead?

A. DTE used industry-standard, publicly available sources to obtain costs for "generic" solar resources. In particular, they relied primarily on the National Renewable Energy Laboratory's Annual Technology Baseline ("NREL ATB").[28] In the Commission's stakeholder processes to develop IRP guidance, I was a proponent of using such publicly available sources and particularly the NREL ATB for cost projections. I continue to support

[28] U-20471. Exhibit A-3 Revised, Table 14.3.1 on page 115.

this practice for identifying future cost projections to use in IRP modeling.[29] However, for near-term resource options, actual local market information in the form of offers from market participants is clearly superior.

Q. Since DTE did not issue a Request for Proposals to obtain cost information, on what basis do you assess that DTE used excessive near-term costs for solar generation?

A. My assessment that DTE's assumed utility-scale solar is more costly than current, actual solar costs, is based on both my understanding from many direct communications with market participants and also on record evidence.

Q. What cost did DTE attribute to utility-scale solar in its modeling?

A. Each resource has a stream of costs over time, some classified as capital and others as operating costs, and different resources have different life-lengths, so cost comparisons are typically done by comparing Levelized Cost of Electricity ("LCOE"). I will follow that practice here.

DTE used LCOE for resource screening and as inputs to the Strategist modeling. DTE presents the LCOE of various technologies in its reference scenario in Exhibit A-3, Section 14, Figure 14.4.1 in 2024. In that Figure, they show levelized cost for single-axis tracking solar as \$80 per MWh without tax credits and \$69 per MWh with tax credits. Since these are less than the comparable \$89 per MWh without tax credits and \$77 per MWh with tax credits for fixed-tilt solar, they screened out fixed-tilt solar from further consideration.[30]

[29] I note that the practice recommended by the Commission of using a percentage reduction or increase of the entire forecast in sensitivity analyses is not appropriate as uncertainty about the future generally increases over time and near-term information is more certain.

[30] U-20471. Exhibit A-3 Revised, Table 14.4.2, page 118.

DTE also presented LCOE calculations for additional scenarios in Exhibit A-4, Appendices M and N. In the Commission-defined BAU scenario, DTE calculated the LCOE of single-axis tracking solar to be the same $80 per MWH without tax credits and $69 per MWh with tax credits, because in this scenario they used the same assumptions regarding solar technologies as in the DTE Reference scenario. In the Commission-defined ET and EP scenarios, DTE calculated the LCOE for a single-axis tracking solar system to be $58 per MWh without tax credits and $51 per MWh with tax credits.

Because tax credits for solar are currently available, the appropriate LCOE for comparison to current market pricing is $69 per MWh for the Reference and BAU cases and $51 per MWh for the ET and EP cases.

Q. What record evidence is available that solar is less costly than DTE assumed?

A. There is ample evidence on the lower cost of solar where a utility solicited competitive proposals.

In U-20165, in which I was a testifying witness, Consumers Energy provided the results from competitive bidding for utility-scale solar that was conducted in 2018.[31] Based on the bidding results, Consumers found the weighted average PPA proposal pricing to be a rate of $49.10/MWh, including energy, capacity, and RECs. Since $49.10 per MWh is a weighted average of PPA proposals, there were proposals for even less. Exhibit EIB-3 in Case U-20165 was sponsored by Michigan Energy Innovation Business Council witness

[31] Exhibit MEC-56. Case U-20165. Exhibit EIB-3 (LSS-3).

Laura S Sherman and consists of a discovery response from Consumers Energy to EIBC. Exhibit EIB-3 (LSS-3) from U-20165 is provided here as Exhibit MEC-56.

In addition to providing relevant pricing information for PPAs, Exhibit MEC-56 also shows the results for Consumers Energy's competitively solicited build and transfer solar projects, which are conceptually similar to DTE's approach. The weighted average levelized cost of those proposals for projects coming into service in the next three years was $73.92/MWh, which is slightly above DTE's LCOE for single-axis tracking solar of $69/MWh for a unit to come into service in 2024. Given cost trends in the solar industry, it is likely that pricing in 2024 will be lower than projected by DTE. Based on this evidence, I conclude that competitively bid solar PPAs would provide solar costs substantially below those modeled by DTE.

In U-20350, in which I am also a witness, UPPCO proposes to enter a 25-year PPA for energy, capacity, and RECs from a 125 MW solar system to be located in the Upper Peninsula of Michigan.[32] The facility is to be online by May 2022, which is only two years earlier than the timing of the DTE LCOE presented in Exhibits A-3 and A-4. UPPCO's proposal resulted from a request for proposals that anticipated a 20 MW solar system but was sufficiently favorable that UPPCO proposes this larger PPA. Public Exhibit A-34 (GRH-16) from the UPPCO proceeding shows that the levelized annual revenue requirement for this solar PPA is $42.63 per MWh. Selected portions of Haehnel's testimony and Exhibit A-34 from U-20350 are included in Exhibit MEC-57.

[32] Exhibit MEC-57. U-20350. 2 TR 43-48. Direct Public Testimony of Gradon R. Haehnel, page 12 line 5 through page 17, line 21.

Northern Indiana Public Service Company ("NIPSCO") recently completed an IRP for which they solicited competitive proposals for renewable generation.[33] They summarize results on page 56 of their IRP report, presenting the following table:

	Technology	# of Bids	Bid MW (ICAP)	# of Projects	Project MW	Average Bid Price	Pricing Units	Comments
Asset Sale or Option	Combine Cycle Gas (CCGT)	7	4,846	4	3,055	$959.61	$/kW	
	Combustion Turbine (CT)	1						
	Solar	9	1,374	5	669	$1,151.01	$/kW	
	Wind	8	1,807	7	1,607	$1,457.07	$/kW	
	Solar + Storage	4	705	3	465	$1,182.79	$/kW	
	Wind + Solar + Storage	1						
	Storage	1						
Purchase Power Agreement	Combine Cycle Gas (CCGT)	8	2,715	6	2,415	$7.86	$/kW-Mo	+ fuel and variable O&M
	Solar + Storage	7	1,055	5	755	$5.90	$/kW-Mo	+ $35/MWh (Average)
	Storage	8	1,055	5	925	$11.24	$/kW-Mo	
	Solar	26	3,591	16	1,911	$35.67	$/MWh	
	Wind	6	788	4	603	$26.97	$/MWh	
	Fossil	3	1,494	2	772	N/A		Structure not amenable to price comparison
	Demand Response	1						
	Total	**90**	**20,585**	**59**	**13,247**			

NIPSCO reported average bid cost per MWh from solar PPAs at $35.67.

On the basis of this evidence, it is my opinion that the market cost of utility-scale solar is currently below that assumed by DTE in all scenarios, including the ET and EP scenarios that were constructed to reflect lower costs for solar. The Commission should therefore give greater weight to the ET and EP scenario results in its consideration of this IRP.

[33] The full NIPSCO IRP is available from their web site, at https://www.nipsco.com/our-company/about-us/regulatory-information/irp. Section 4 of their IRP report is provided as Exhibit MEC-60.

Q. Did DTE evaluate the combination of solar with storage?

A. Yes, Witness Mikulan describes the evaluation of storage with solar in the ET scenario. According to her description, this was done by assuming that the Investment Tax Credit (ITC) that is available for solar generation also applied to the battery system and that transmission losses would be eliminated. Although this was a reasonable first effort, it does not reflect that solar developers have developed ways of adjusting the design of this combination using smaller inverters (higher module to inverter ratios) and other component sizing so that the cost of the combination is also lower than simple summation of the costs of the solar and battery systems. DTE would have benefitted from these advances in design had the Company issued a request for proposals that included the combination of solar and storage.

Q. Can we derive a reasonable estimate of the costs of solar combined with battery storage, using publicly available information?

A. Perhaps best known is an "all-source solicitation" by Public Service Company of Colorado, results of which were made available in early 2018. A report on that solicitation that was provided to the Colorado Public Utility Commission by Public Service Company of Colorado is available.[34] The following table copied from that report

[34] 2017 All-Source Solicitation 30-day Report (Public Version) in CPUC Proceeding No. 16A-0396E, available from https://www.documentcloud.org/documents/4340162-Xcel-Solicitation-Report.html.

presents the results:

ATTACHMENT A - PUBLIC VERSION Page 9 of 11

RFP Responses by Technology

Generation Technology	# of Bids	Bid MW	# of Projects	Project MW	Median Bid Price or Equivalent	Pricing Units
Combustion Turbine/IC Engines	30	7,141	13	2,466	$ 4.80	$/kW-mo
Combustion Turbine with Battery Storage	7	804	3	476	6.20	$/kW-mo
Gas-Fired Combined Cycles	2	451	2	451	[redacted]	$/kW-mo
Stand-alone Battery Storage	28	2,143	21	1,614	11.30	$/kW-mo
Compressed Air Energy Storage	1	317	1	317	[redacted]	$/kW-mo
Wind	96	42,278	42	17,380	$ 18.10	$/MWh
Wind and Solar	5	2,612	4	2,162	19.90	$/MWh
Wind with Battery Storage	11	5,700	8	5,097	21.00	$/MWh
Solar (PV)	152	29,710	75	13,435	29.50	$/MWh
Wind and Solar and Battery Storage	7	4,048	7	4,048	30.60	$/MWh
Solar (PV) with Battery Storage	87	16,725	59	10,813	36.00	$/MWh
IC Engine with Solar	1	5	1	5	[redacted]	$/MWh
Waste Heat	2	21	1	11	[redacted]	$/MWh
Biomass	1	9	1	9	[redacted]	$/MWh
Total	430	111,963	238	58,283		

Although these results do not translate directly to Michigan because of significant differences in solar conditions, it is likely that the ratio of the cost of solar with battery to solar without battery will approximate the expected results. In these Colorado bids, solar with storage is about 22% more expensive than solar without storage. Applying this ratio to the Consumers Energy weighted average solar PPA price of $49.10/MWh yields a rough price estimate of $59.91 per MWh for a solar system with battery storage., which is lower than DTE's assumed cost of single-axis tracking solar without storage.

Average prices for seven solar plus storage bids in response NIPSCO's RFP were $35/MWH plus $5.90 per kW-month.[35] Given NIPSCO's location with only slightly better solar conditions that DTE, this would also serve as a reasonable estimate of the cost to DTE of a solar plus storage PPA.

E. DTE ELECTRIC MODELED SOLAR RESOURCES USING THE OUTPUT PROFILE AND CAPACITY CREDITS FOR A FIXED TILT SYSTEM EVEN THOUGH THEY REPRESENTED THAT THEY USED A SINGLE-AXIS TRACKING SYSTEM

Q. Do you have additional concerns about DTE's modeling of solar resources in this IRP?

A. Yes. DTE has inaccurately represented both the pattern of hourly output from a single-axis tracking solar system and has substantially understated the capacity credit that MISO would recognize for such a system.

Q. Please explain how they inaccurately represented the pattern of hourly output from a single-axis tracking solar system?

A. The solar output from a solar module is higher under given sun conditions when the sunlight is more nearly perpendicular to the surface of the solar module. A fixed-tilt system is fixed in place, and in order to maximize energy output, is commonly tilted somewhat toward the south and facing due-south. It produces maximum output around noon of each day and is less both before and after. A tracking system rotates through the day so that it more directly faces the sun through most of the day. At noon, a tracking system will be

[35] See page 56 of NIPSCO's IRP report in Exhibit MEC-60.

approximately as productive as a fixed-tilt system but at other times of the day, the tracking system will have greater output than a fixed-tilt system would.

Exhibit MEC-58 consists of DTE's response to discovery on this topic. As explained there, "A capacity factor of 22.9% was used for single axis tracking systems, and a lower capacity factor of 18.5% was used for fixed tilt systems in the LCOE screening. The desired capacity factor was applied to the same hourly solar shape and the resulting annual solar energy scaled to be consistent with the desired capacity factor. Upon completion of the modeling, it was identified that the shape used was that of fixed tilt, as opposed to single-axis tracking solar."[36] This illustrates that DTE used the hourly generation profile of a fixed-tilt system even though they claimed to be modeling a single-axis tracking system.

Q. If DTE scaled the total output from a fixed-tilt system to match the total output expected from a single-axis tracking system rather than using the generation profile of a single-axis tracking system, is that consequential to the IRP?

A. Yes. In the remainder of MEC-58, not quoted above, DTE presents an argument that it ran certain modeling cases with a single-axis tracking generation profile, compared the results to the scaled fixed-tilt system, and determined that the differences were minimal. However, this analysis neglects that the fixed-tilt generation profile and the single-axis tracking system produce substantially different capacity credits as a percentage of system nominal size and DTE did not make that adjustment.

Q. Why do fixed-tilt and single-axis tracking solar systems produce different capacity

---

[36] Exhibit MEC-58, Response to MECNRDCSCDE-8.32.

credits?

A. In this IRP, DTE have assigned capacity credit to all solar systems by adjusting nameplate capacity to ZRCs based on an initial 50% effective load carrying capacity which then declines by 2% per year beginning in 2024 until it reaches 30% in 2033 and remains 30% thereafter.[37] Company Witness Mikulan explains this in her testimony:

> The IRP modeling assumed a solar ELCC of 50% through 2023, and declining 2% each year until 2033, ending at 30%. This practice is consistent with MISO forecasts of declining solar ELCC, driven primarily by higher levels of solar penetration shifting net peak load periods to later in the day when solar generation has decreased. Declining ELCC is not a function of solar generation performance, but rather the ability of such generation to meet peak load requirements. Existing facilities - which today maintain ELCC values of approximately 50% - are expected to experience a similar decline.[38]

This assumption that the Effective Load Carrying Capacity for a solar system is presently 50% is only approximately correct for a fixed-tilt system and is wrong for a single-axis tracking system. MISO's practices for determining the capacity credit of a solar system are defined in their Business Practices Manual 11, Section 4.2.3.5.1, which reads

> Solar photovoltaic (PV) resources will have their annual UCAP value determined based on the 3 year historical average output of the resource for hours ending 15, 16, and 17 EST for the most recent Summer months (June, July, and August). Market Participants will need to supply this historical data to MISO by October 31 of each year in order to have their UCAP value determined. Market Participants will use the template found on the MISO website (Planning > Resource Adequacy (Module E) > Planning Resource Auction) to submit the 3 year historical average output data. Solar PV resources that are new, upgraded or returning from extended outages shall submit all operating data for the prior Summer with a minimum of 30 consecutive days, in order to have their capacity registered with MISO. Resources

---

[37] Such calculations for determining the Company's capacity position are in Workpaper LMK-37, for example.

[38] U-20471. Revised Direct Testimony of Laura K. Mikulan, page LKM-50 line 19 through page LKM-51 line 2.

with less than 30 days of metered values would receive the class average of 50% for its Initial Planning Year.[39]

As is obvious, MISO does not credit solar capacity at 50% as assumed by DTE in this IRP, but assigns capacity credit based on actual output between 2pm and 5pm EST (3pm to 6pm EDT) for the months of June, July, and August.

Since a south-facing fixed-tilt system has maximum output at mid-day and lower output morning and afternoon, but the single-axis tracking system maintains comparatively stable output over much of the daylight period, it is unsurprising that a single-axis tracking system will have greater capacity credit than a fixed-tilt system.

Q. What would be an appropriate Effective Load Carrying Capacity for a single-axis tracking system?

A. In order to illustrate the significance of this, I used NREL's System Advisor Model,[40] which is widely used by solar analysts to model the performance of solar systems. I modeled using a default system configuration with nameplate DC capacity of 20 MW and nameplate AC capacity of 16.94 MW, using typical meteorological year weather data for Cass City, Michigan which is located in Michigan's "Thumb". I used this system configuration with a southward tilt of 30 degrees with both the fixed-tilt and single-axis tracker configurations. I then used the modeled hourly system output to determine annual energy output and output during the hours used by MISO to determine capacity credits. I then divided the capacity credit by 16.94, the nameplate AC capacity, to determine

[39] Available from https://cdn.misoenergy.org//BPM%20011%20-%20Resource%20Adequacy110405.zip.

[40] Available from https://sam.nrel.gov.

Effective Load Carrying Capacity as a percentage of nameplate capacity. The following table summarizes the results.

System Type	Fixed-Tilt	Single-Axis Tracking
Annual Energy	27,762 MWH	36,018 MWh
Capacity Credit	9.179 MW	11.690 MW
Effective Load-Carrying Capacity	54.2%	69.0%
Capacity Credit/ Annual Energy	.33062 MW/MWH	.32455 MW/MWH

Q. How significant to the IRP is this change in solar capacity credit?

A. Higher solar effective load carrying capacity could affect the IRP modeling in two ways.

In a scenario where solar is selected as a capacity resource and the quantity of solar is determined by capacity need, the model would achieve the same amount of capacity credit with a smaller amount of nameplate solar capacity. If the solar has an Effective Load Carrying Capacity of 69% rather than 50%, then the amount of solar required to achieve a given amount of capacity would be reduced by 1-.50/.69 = 27.5% of the amount needed with an Effective Load Carrying Capacity of 50%, The cost of solar per unit capacity credit would similarly be reduced by about 27.5%, but this would also reduce the energy output by 27.5% at some cost for replacement energy. Of course, a 27.5% lower cost of capacity for solar is likely to cause solar to be selected as a capacity resource in more modeled circumstances.

In a scenario where the nameplate amount of solar is chosen to produce a fixed amount of energy, such as to comply with a renewable energy standard or supply a VGP program, then using a single-axis tracking system rather than a fixed tilt system also leads to acquiring less solar nameplate resource. In my example, a fixed amount of energy would require only 27,762/36,018 = 77% as much solar nameplate capacity in single-axis tracking systems and fixed-tilt systems. Since the ratio of capacity credit to annual energy is nearly the same for both system designs, the resulting capacity credit would also be about 75.6% as much for the single-axis tracking as for fixed-tilt systems to produce the same amount of annual energy.

Unfortunately, since DTE scaled the energy output of a fixed-tilt system to match that of a single-axis tracking system but did not also adjust the Effective Load Carrying Capacity, the effect is to give insufficient capacity credit relative to the amount of energy produced. In modeling scenarios where solar deployment is driven by energy requirements, they have attributed approximately 27% too little capacity to that solar, requiring that additional capacity of some type be acquired at some cost. The type and cost of that capacity varies widely amongst scenarios. In modeling scenarios where solar deployment is driven by capacity requirements, they have attributed too much energy to solar with a given amount of capacity credit but have made solar appear to be more expensive as a capacity resource than it actually is. These effects are simply too complex to trace out with redoing all of DTE's modeling.

Witness Avi Allison also considered this issue. He constructed a solar profile using the tool PVWatts, which is also an NREL tool that has the same underlying solar model as System Advisor Model. He used Detroit as the location of the modeled solar array. The minor differences between his and my profile and capacity credits are primarily due to this locational difference and, since any significant amount of solar generation is likely to be distributed throughout DTE territory the variation is realistic. Allison testifies to one modeling run showing that using a correct profile and capacity credit is material, consistent with my view that this is a significant modeling issue and that correcting it would require redoing all of DTE's modeling.

As I explained above, DTE's examination of this issue, reported in their discovery response that is included as Exhibit MEC-58, is unavailing because they did not correct the capacity credit associated with a single-axis tracking system as opposed to a fixed-tilt system.

Q. What is your overall conclusion regarding DTE's IRP modeling based on their assumptions about solar costs and performance?

A. Because near-term selection of resources to meet renewable energy standards and clean energy goals depends very much on comparative costs of different resources and DTE's solar cost estimates are significantly above market prices, DTE's modeling cannot be relied upon to select near-term generation resources.

Because longer-term selection of resources to meet capacity requirements depends on the cost of capacity net of earnings on energy (the difference between marginal cost of energy and variable costs of energy from the given resource) and DTE's treatment of solar capacity is so significantly wrong, DTE's modeling cannot be relied upon to project future resource selection.

Because DTE overestimated costs and underestimated performance of solar, DTE submitted an IRP that very likely underestimates the level of solar that DTE should pursue in the near term and in the long term.

F. DTE ELECTRIC MODELED STORAGE IN ONLY A PRIMITIVE WAY

Q. Please review how DTE evaluated storage in this case.

A. DTE included Ludington Pumped Storage Plant as an existing resource and included its operations in its IRP modeling. In addition, DTE evaluated new lithium-ion battery storage as a bulk power resource, providing energy arbitrage. As I discussed above, they also considered battery storage "integrated" with solar generation although their modeling of that "integration" was limited to applying the Investment Tax Credit for solar to the battery storage and assuming no transmission losses for use of the battery. However, the modeling of the battery was based on bulk power price arbitrage and not linked to the solar system.[41]

Q. In what way do you consider this approach to have been primitive?

A. DTE modeled storage for energy arbitrage, moving energy supply from one time to another based on energy cost. They did not model battery operations that were "aware" of capacity value of a charged battery, of the increase in capacity credit to a solar plus storage system that schedules battery discharge to maximize solar Effective Load Carrying Capacity, nor of the demand reduction potential, for purposes of resource adequacy, of battery storage behind the meter. They also did not consider any values of storage other than in the bulk power system.

[41] U-20471. Revised Direct Testimony of Laura K. Mikulan, page LKM-104, line 3 through LKM-105 line 15.

IV. DTE ELECTRIC'S CAPACITY POSITION

Q. What would be the significance of a Commission determination that DTE does not have a persistent capacity need for the next ten years?

A. In its Application in this case, DTE Electric raises this matter in the context of PURPA, in that it is one of three items addressed by the Company under the common heading of "CAPACITY NEED AVOIDED COSTS AND STANDARD OFFER CAP", and DTE's statements with respect to the other two items explicitly concern PURPA.[42] In the context of PURPA, capacity need potentially affects the avoided costs that limit compensation to PURPA qualifying facilities.

Apparently unmentioned by DTE in this case, but important for the outcome of this IRP, is that capacity need and avoided capacity costs potentially affect the terms of the voluntary green pricing programs offered by DTE,[43] which DTE gives considerable weight in this IRP.

As I discussed above, DTE also justified its decision not to issue a request for proposals in preparation of this IRP based on their claim that they lack a capacity need in the next three years, so that decision is also potentially implicated by a Commission determination that DTE does not have a persistent capacity need for the next ten years.

---

[42] U-20471. DTE Electric Application, page 10.

[43] Exhibit MEC-63. U-20343. Direct Testimony of Terri L. Schroeder, page TLS-11, lines 1-14.

Q. Please explain DTE's position on the relevance to PURPA avoided costs of the absence of a persistent capacity need in the next ten years?

A. The Commission is currently considering a determination of DTE's avoided costs for PURPA QFs in Case No. U-18091. In that case, DTE's position is that "[i]f a persistent capacity need does not exist, then there is no new plant construction or long-term purchase contract to defer, and therefore no avoided cost associated with such deferral."[44] In Consumers Energy's PURPA avoided cost case U-18090, the Commission had determined that a 10-year horizon should be used to determine whether a capacity need existed that would warrant payment of avoided capacity costs, but in the most recent remand of U-18091, the Commission asked the parties to address this planning horizon. In that case, DTE took the position that the capacity need horizon should be 5 years.[45] A determination in this IRP case that the Company does not have a persistent need for capacity in the next ten years may raise the argument that the Company has no obligation to pay avoided capacity costs to QFs. It also should be noted that "persistent capacity need" is a phrase apparently invented by DTE and, to my knowledge, does not appear in PURPA law or regulations and does not have a specific legal meaning.

---

[44] Exhibit MEC-61. 6 TR 634. U-18091. Direct Testimony of Don M. Stanczak on Remand, page DMS-9, lines 19-21.

[45] Exhibit MEC-61. 6 TR 636. U-18091. Direct Testimony of Don M. Stanczak on Remand, page DMS-11, lines 1-20.

Q. Do you agree that absence of a persistent capacity need for the next ten years would absolve the Company from an obligation to pay avoided capacity costs to PURPA QFs?

A. No. If the Company does not have a capacity need at the time a PURPA QF establishes a legally enforceable obligation for the Company to purchase power from the QF, and does not forecast a capacity need during some fixed period thereafter, it does not absolve the Company from paying avoided capacity costs at such time as the Company does have a capacity need. Indeed, when the Company has a capacity need that the PURPA QF can satisfy or partially satisfy, and if the PURPA QF has established a legally enforceable obligation for the Company to acquire that capacity, then the Company is obligated to do so at a price not to exceed the avoided cost of capacity.

In my view, the question of the time horizon for determination of a capacity need has become a "red herring" which misleads the Company with respect to its PURPA obligations. If the Company has a projected capacity need at any date in the future without the addition of additional non-PURPA generation resources, a PURPA contract that extends beyond the date of that capacity need must include compensation to the PURPA QF for the capacity it offers that will satisfy any portion of that need, at a price up to the Company's avoided cost of capacity. This is true whether the capacity need is temporary or persistent.

In an environment in which there may be many PURPA QFs seeking to establish a legally enforceable obligation for the Company to acquire capacity, it will benefit the Company and the Commission to establish a clear rule of priority for payment for avoided capacity cost. It is my recommendation that the Commission do so by establishing a queue of capacity offers that the Company must accept in queue order to fulfill any future capacity need and that the queue be based on the order in which legally enforceable obligations for the Company to purchase power from the QFs are established. In order to comply with PURPA, it is my further view that Company cannot be allowed to "jump queue" by constructing Company-owned capacity or by contracting for non-Company capacity without first honoring the prior right of PURPA QFs in the queue to provide capacity to the Company at the Company's avoided capacity cost.

Q. Do you recommend that the Commission determine, for PURPA purposes, that the Company does not have a capacity need for some specific period?

A. No. Such a decision is not relevant for PURPA and would perpetuate the misconception that it is. I make further recommendations regarding the determination of avoided costs for PURPA contracts later in my testimony.

The present circumstance is similar to one about which the Commission has previously commented.

> With respect to new PURPA contracts, the Commission agrees with Mr. Jester's observation that:
>
> > The interplay between PURPA avoided cost proceedings and consideration of utility proposals for Certificates of Necessity or through Integrated Resource Planning raises the potential for conflict, requiring careful consideration in all relevant proceedings, including this one. If the utility states in its PURPA proceedings that it does not forecast capacity needs from PURPA qualifying facilities because it has plans to acquire non-PURPA capacity, while at the same time the utility states in a Certificate of Necessity proceeding that it does not forecast PURPA resources in its integrated resource planning and therefore must build other resources, were the Commission to accept both statements,

> this may result in sanctioned discrimination by the utility against PURPA qualifying facilities and fully undermine PURPA's intent.[46]

I show later in my testimony that DTE in this case, as in U-18419, again asserted an absence of capacity need by assuming what it intends to do and concluding on that basis that it has no capacity need.

Q. What is the significance of capacity need and avoided capacity costs for the Company's VGP programs?

A. The Company is required to offer VGP programs pursuant to 2016 PA 342 Section 61, which reads

> Sec. 61. An electric provider shall offer to its customers the opportunity to participate in a voluntary green pricing program under which the customer may specify, from the options made available by the electric provider, the amount of electricity attributable to the customer that will be renewable energy. If the electric provider's rates are regulated by the commission, the program, including the rates paid for renewable energy, must be approved by the commission. The customer is responsible for any additional costs incurred and shall accrue any additional savings realized by the electric provider as a result of the customer's participation in the program. If an electric provider has not yet fully recovered the incremental costs of compliance, both of the following apply:
>
> (a) A customer that receives at least 50% of the customer's average monthly electricity consumption through the program is exempt from paying surcharges for incremental costs of compliance.
>
> (b) Before entering into an agreement to participate in a commission-approved voluntary green pricing program with a customer that will not receive at least 50% of the customer's average monthly electricity consumption through the program, the electric provider shall notify the customer that the customer will be responsible for the full applicable charges for the incremental costs of compliance and for participation in the voluntary renewable energy program as provided under this section.[47]

[46] U-18419. Commission Order of April 27, 2018, page 78.

[47] MCL 460.1061.

In U-20343, the Commission approved the Company's VGP pilot program for large customers using a construct in which customers pay their normal tariff rate for power, pay additional costs reflecting the cost of renewable generation resources constructed and operated to supply the VGP program, and receive a bill credit based on avoided costs of energy and capacity attributable to the renewable generation that serves the VGP program. In this construct, the customer's obligation to pay for the cost of the renewable resources dedicated to the VGP program assures that "[t]he customer is responsible for any additional costs incurred,"[48] while bill credits for avoided costs of energy and capacity should assure that "[t]he customer … shall accrue any additional savings realized by the electric provider as a result of the customer's participation in the program."[49] Thus, the proper determination of avoided costs attributable to renewable generation for the VGP program is essential both for fairness to the participating customers and compliance with law. To the extent that avoided costs depend on capacity need, it is essential that the Commission properly determine capacity need that can be satisfied by VGP resources.

Q. Is a ten-year time horizon for persistent capacity need the appropriate basis to determine credits for the VGP program?

A. No. Under the Company's VGP program as approved as a pilot program,[50] customers may contract to participate in the program for 5, 10 or 20 years. Avoided capacity costs

[48] *Id.*

[49] *Id.*

[50] U-20343. Commission Order of January 18, 2019, page 6.

attributable to the VGP resources should therefore be included in the credits for program participants when their contracts include periods of avoided capacity costs.

Q. How do claims for capacity credits by PURPA QFs and obligations to provide capacity credits to VGP program participants interact?

A. If a VGP program resource is provided by a QF, then treatment of capacity credit should be straightforward, with the QF being paid for capacity and VGP program participants, who will be paying the costs of the QF PPA, receiving bill credits for supplying that capacity.

If the VGP program resource is owned or contracted by the Company by a method other than a PURPA contract, then it will have been acquired because a PURPA resource was not available to fulfill the VGP program requirements; otherwise PURPA obligations would require the Company to use a PURPA resource to meet its VGP resource requirements. Thus, any VGP resource that is not a PURPA QF will likely have been acquired before any PURPA QF contracts that would require the Company to pay the QF for capacity; the VGP resource should take precedence in being credited for meeting the Company's capacity need and the VGP program participants should be credited for supplying that capacity since they will be paying the Company's costs for providing that resource.

Q. Please summarize your recommendation to the Commission regarding the Company's request that the Commission determine that DTE does not have a

persistent capacity need for the next ten years.

A. The Commission should not make such a determination, as that determination is not relevant for any identifiable purpose and will cause confusion with respect to the decisions the Commission must make in this case and in other cases.

The Commission should make PURPA avoided cost decisions in light of projected capacity need and avoided capacity costs during the period to be included in a PURPA contract, whenever that need is projected to occur and whether or not that need is temporary or persistent. I make further recommendations regarding the determination of PURPA avoided costs later in my testimony.

The Commission should make VGP bill credit decisions in light of projected capacity need and related avoided costs during the period to be included in the VGP customer contract, whenever that need is projected to occur and whether or not that need is temporary or persistent. I make further recommendations regarding the determination of VGP bill credits based on avoided costs later in my testimony.

Q. How does DTE Electric represent its capacity position in support of the proposition that it has no capacity need for the next ten years?

A. The Company's capacity position is developed primarily in the testimony of Laura K. Mikulan.[51] According to Ms. Mikulan, the Company made an initial assessment of the Company's capacity position in June 2018, which served as the "Starting Point" of IRP

[51] U-20471. Revised Direct Testimony of Laura K. Mikulan, Section II, page LKM-20 line 11 through page LKM-24 line 10.

optimization modeling. It then reassessed that information in February 2019, just before filing in this case, which it refers to as the "Current State" and used in modeling the PCA. Starting Point and PCA resources are shown in nominal terms in Exhibit A-5, particularly the table on pages 3 and 4. The Starting Point (2018) Projected Capacity Position measured in Zonal Resource Credits ("ZRC") for purposes of compliance with the current resource adequacy construct of the Midcontinent Independent System Operator ("MISO), of which DTE is a member, are shown in Exhibit A-6. The PCA (2019) Projected Capacity Position under each of the PCA pathways presented by DTE in this case are then illustrated using ZRCs in Exhibit A-7. Both Exhibits use MISO Planning Years, which run from June 1 of the first year in the planning year label through May 31 of the second year in the planning year label. Both Exhibits show a "bottom line" surplus or deficiency of UCAP MW, which are for practical purposes equivalent to ZRCs in this case. Confidential Workpapers for Exhibits A-6 and A-7 were also provided to intervenors by the Company.

Exhibit A-6 as presented by the Company represents that the Company has a surplus of 1 ZRC in PY 2018-19, a surplus of 0 ZRC in PY 2023-24, varying larger ZRC surpluses in every other year until PY 2029-2030, and a substantial ZRC deficiencies in all subsequent years except PY 2038-39 and PY 2039-40. Ms. Mikulan discusses the dynamics and layout of this Exhibit.[52]

[52] U-20471. Revised Direct Testimony of Laura K. Mikulan, page LKM-20 line 22 through LKM-22 line 17.

Q. Does Exhibit A-6 support DTE Electric's position that it does not have a capacity need for ten years?

A. No. Exhibit A-6 shows a significant capacity need in the final year (PY 2029-30) of the ten-year planning horizon. In addition, there are several defects in the Company's claim through Exhibit A-6 that it has no capacity need until PY 2029-30.

Q. What are those defects in Exhibit A-6?

A. Exhibit MEC-59 shows various adjustments to the Company's Exhibit A-6 that I discuss below. Lines 1-37 of Exhibit MEC-59 are identical to the same line numbers of Company Exhibit A-6. Adjustments are shown in subsequent lines.

Close examination of the workpaper used by the Company to prepare Exhibit A-6 shows permanent additions of 7 MW in PY 2020-21 and 16 MW in PY 2023-24 that are included in Line 9 of Exhibit A-6, labeled as "Company-Owned, In-State, Non-Intermittent, ZRC" and are unexplained by testimony. Subtraction of these from the Company's net position as shown in Line 37 of Exhibit A-6 causes the Company to have a capacity deficiency of 23 MW ZRC in PY 2023-24. This subtraction is shown in Line 38 of Exhibit MEC-59. Although this deficiency is overcome by other changes in subsequent years and the Company would thereby show a surplus until PY 2029-30, it is notable that the Company chose to acquire permanent resources at these times even as it claims that it should not have to accept and pay for capacity from PURPA QFs during the same time periods. These unexplained capacity additions are just enough to conveniently ensure that DTE shows no capacity need until Belle River retirements begin.

Close examination of the workpaper used by the Company to prepare Exhibit A-6 also shows that it includes 32 MW ZRC permanently added beginning in PY 2020-21 for the Dearborn CEP, cost recovery for which was addressed by the Commission in U-20162. Since that plant was partially approved by the Commission in U-20162, it is appropriate to include those 32 MW ZRC in the Initial Position used in Exhibit A-7, but it was not at the time that Exhibit A-6 is purported to represent. Excluding those 32 MW in the Company's capacity position in PY 2020-21 and thereafter would have caused the Company to have a capacity deficit of 57 MW ZRC in PY 2023-24 and a capacity surplus of only 3 MW ZRC in PY 2024-25. Considering these 32 MW ZRC in the Company's capacity position with respect to any PURPA QF claim of a legally enforceable obligation established prior to the conclusion of U-20162 subverts that PURPA QF's claim. Now that it has been accepted by the Commission, I do not think the Commission is better informed by excluding it from the Company's Starting Point capacity position so I have not made an adjustment in preparing Exhibit MEC-59.

Exhibit A-6 also shows in Line 15 the ZRCs the Company projects certain "Company-Owned, In-State, Intermittent, ZRC" resources, which represents the ZRCs from its cumulative Company-owned wind and solar projects, as shown in non-confidential Workpaper LKM-37. In that workpaper, various wind resources are adjusted from nameplate capacity to ZRCs based on an 11.7% effective load carrying capacity factor. In that workpaper, various solar resources are adjusted from nameplate capacity to ZRCs based on an initial 50% effective load carrying capacity which then declines by 2% per year beginning in 2024 until it reaches 30% in 2033 and remains 30% thereafter. Later in my testimony, I address the effective load carrying capacity of solar resources, but for purposes of examining the Company's claim that it does not have capacity need in the next ten years, I am focusing on the wind and solar resources used by the Company in constructing Exhibit A-6 and have used the Company's method for calculating wind and solar ZRCs.

Q. What renewable resources does the Company include in its Starting Point capacity position as shown in exhibit A-6?

A. In Exhibit MEC-59, I show the cumulative ZRCs from Company-Owned wind resources from Workpaper LMK-37 in Line 39 and the cumulative nameplate capacity of Company-Owned wind resources in Line 41. I also show the cumulative ZRCs from Company-Owned solar resources from Workpaper LMK-37 in Line 47.[53]

Q. Is it appropriate to include all of these renewable resources in the Company's starting point for purposes of determining its capacity need?

A. No, only those resources already approved for cost recovery by the Commission are appropriate to include because any other resources only reflect the Company's intent and not its approved position. To my knowledge, at the time this case was filed, none of the solar resources shown on Line 47 of Exhibit MEC-59 had been approved nor have they been subsequently approved by the Commission, so I also identify those in Line 48 as solar ZRCs included in Line 15 of Exhibit A-6 that have not been approved by the Commission.[54] To my knowledge, at the time that DTE formulated its Starting Point

[53] A minor adjustment was necessary for the Company's failure in Exhibit A-6 to apply diminishing ELCC to the solar resources included in Line 17 and to align years with planning years.

[54] An 11 MW solar plus storage pilot was approved in U-18232, but that is apparently included in Line 17 of Exhibit A-6 and Exhibit MEC-54.

capacity position as represented in Exhibit A-8, it had approximately the 454 MW of Company-Owned wind resources shown in the PY 2018-19 column. To facilitate examination of the wind resources included in the subsequent years of the Company's Starting Point capacity position, I computed incremental nominal wind capacity in Line 42 of Exhibit MEC-59.

Work papers in support of Exhibit A-6 did not readily provide identification of the specific wind resources included in future years of the Company's Starting Point analysis, so I compared the incremental nominal wind capacity in Line 42 to those listed In Exhibit A-18 by Witness Schroeder and to the Company-Owned wind facilities identified in Exhibit A-3 filed by the Company in its Renewable Energy Plan Case, U-18232. The incremental 161 MW in PY 2019-20 in this case corresponds to 161.3 MW shown for the Pine River Wind Park. The incremental 169 MW in PY 2020-21 in this case corresponds to 168.8 MW shown in U-18232 for an unspecified 2019 Future Wind Build and in A-18 for the 168 MW Polaris Wind Park.[55] The incremental 310 MW in PY 2021-22 in this case reasonably corresponds to 300 MW shown in U-18232 for an unspecified 2020 Future Wind Build. The incremental 215 MW in PY 2022-23 in this case reasonably corresponds to 225 MW shown in U-18232 and A-18 for an unspecified 2021 Future Wind Build. The incremental 150 MW in PY 2023-24 in this case corresponds to 150 MW shown in U-18232 for unspecified 2022 Future Wind Build. Subsequent incremental wind resources included in DTE Electric's Starting Point for this case are not accounted for in the Company's Renewable Energy Plan but are shown in Exhibit A-18.

[55] Exhibit MEC-62, U-18232 Exhibit A-3.

As of the filing in this case, only the Pine River Wind Park had been previously approved by the Commission. In its July 18, 2019 meeting, the Commission issued an Order in U-18232 in which it determined that three wind parks would be approved. These were the Isabella I Park with 197 MW nameplate capacity, the Isabella II Park with 186 MW nameplate capacity, and the Fairbanks contract with 72.45 MW. Thus, subsequent to the Company's formulation of its 2018 Starting Point, the Commission approved 455.45 MW nameplate capacity for cost recovery.[56] Line 43 of Exhibit MEC-59 shows Incremental Commission-Approved, Company-Owned Wind Nominal Capacity, while Line 44 accumulates those quantities. Line 45 shows ZRCs for Commission-Approved, Company-Owned wind resources that were included in Line 15 of Exhibit A-6, and Line 46 shows the wind ZRCs in Line 15 that have not been approved by the Commission.

Line 49 of Exhibit MEC-59 shows the Company's 2018 Starting Point including those resources subsequently approved by the Commission in its July 18, 2019 Order in U-18232. Line 51 of Exhibit MEC-59 shows the Company's 2018 Starting Point prior to the Commission's July 18, 2019 Order in U-18232.

Q. Based on the analysis you just presented, did the Company accurately represent that it did not have a persistent capacity need for ten years at the time it filed its

[56] U-18232. Commission Order of July 18, 2019, pages 31-32.

Application in this case?

A. No. For purposes of the Integrated Resource Plan, it had a 2018 Starting Point capacity need of 82 MW in PY 2023-24, 55 MW in PY 2024-25, 6 MW in PY 2025-26, and 389 MW in PY 2029-30.

For purposes of determining avoided costs for any PURPA QFs who established legally enforceable obligations for DTE to purchase power from them during the period between the Commission's Order in U-18419 and the Commission's Order in U-18232, DTE had capacity needs for which QFs should be able to be compensated for avoided costs in the amounts of 82 MW in PY 2023-24, 55 MW in PY 2024-25, 6 MW in PY 2025-26, and 389 MW in PY 2029-30. For purposes of determining avoided costs for PURPA QFs who established legally enforceable obligations for DTE to purchase power from them after the Commission's Order in U-18232, DTE had a 2018 Starting Point capacity need of 29 MW in PY 2023-24, 2 MW in PY 2024-25, and 336 MW in PY 2029-2030.

For purposes of determining appropriate credits in VGP programs, it is necessary to further calculate the ZRCs included in the Company's capacity position that derive from VGP program resources, as the avoided costs of capacity attributable to such program resources should be considered in determining participant credits in VGP programs. In U-18232, DTE modeled its renewable energy plan based on 300 MW wind resources dedicated to the VGP program.[57] In the present case, DTE also represents that 300 MW wind resources to be added in 2020 for the VGP programs were included in its 2018 Starting Point.[58] I

[57] U-18232. Commission Order of July 18, 2019, page 3.

[58] U-20471. Exhibit A-5 and U-20471 Exhibit A-18 line 81.

therefore subtracted an additional 35 MW[59] from the Company's capacity position as shown in Line 49 to calculate Line 52 of Exhibit MEC-59. This shows that without the 35 ZRCs provided by the VGP program resources, DTE has a 2018 Starting Point ZRC deficiency of 64 MW in PY 2023-24, 37 MW in PY 2024-25, 371 MW in PY 2029-30 and larger amounts thereafter. Since these ZRC deficiencies all exceed 35 MW ZRCs that are being contributed by VGP customers, those VGP customers should be compensated for those ZRCs through appropriate bill credits for the avoided cost of capacity in those years, provided that the customer's contract includes those years.

Q. How would you characterize DTE's capacity position as of its Application for this proceeding?

A. The Company's capacity position is somewhat volatile, but in surplus for the next few years as it completes the Blue Water Energy Center and retires several old coal units. Beginning in PY 2023-24, it has a modest capacity need for two or three years, a modest surplus for about three years, and a substantial persistent capacity need thereafter.

I also note that while DTE developed its IRP around a projected capacity need resulting from its currently planned 2029 and 2030 retirement date for Belle River, DTE would begin replacing that capacity several years earlier.[60] Although DTE discusses this build-out as though it is specific to renewables and customer programs, a similar lead time is required for large fossil plants; the Blue Water Energy Center was under construction about 4 years before the final retirement of the resources it will replace. Thus, an explicit capacity need

[59] 35 MW is the approximate result of 300 MW wind with an 11.7% effective load carrying capacity.

[60] See, for example U-20471. Revised Direct Testimony of Laura K. Mikulan, page LKM-83, lines 4-11.

in 2029 translates to capacity acquisition beginning in about 2025 or 2026. I therefore conclude that DTE has a persistent need to acquire new capacity beginning in PY 2023-24, ramping up to its proposed replacement of Belle River in 2029 and 2030.

Q. How do you recommend that the Commission assess the Company's capacity position going forward for purposes of compliance with PURPA?

A. With respect to PURPA, the Commission should take two steps. First, it should establish that avoided capacity costs are not based on the Company's capacity position as of the time a legally enforceable obligation is established by a QF. Rather, avoided capacity costs are based on projected capacity needs at various times during the life of a PPA with a QF, with avoided capacity costs attributed to the QF at those times when, but for the QF and any subsequently acquired capacity resource, there would be a capacity need. In doing so, the Commission should establish a clear priority system for various QFs and Company-Owned or contracted resources such that the right of a QF to capacity compensation is not lost to subsequently approved PURPA contracts or Company-controlled resources. Normal lead times and ramp-up of capacity acquisition should be considered in determining avoided capacity costs for PURPA purposes with QFs able to receive avoided capacity costs during the utility's normal lead time between new capacity development and subsequent capacity retirement.

Second, with respect to PURPA capacity needs, the Commission should recognize that the capacity position applicable to a QF is determined at the time the QF establishes a legally enforceable obligation and expect the Company to include a clear assessment of the queue of PURPA QFs as a basis for any request for approval of Company-Owned resources.

Q. How do you recommend that that the Commission assess the Company's capacity position for purposes of determining participant credits in VGP programs?

A. The Commission should establish that the Company is required to use ZRCs for any VGP resources before those of any subsequently acquired capacity resource, as needed to satisfy the Company's resource adequacy requirements. The Commission should further direct the Company to include such calculations in all subsequent VGP program filings and to appropriately credit program participants for the avoided cost of capacity attributable to VGP program resources.

V. DTE ELECTRIC'S "AVOIDED COSTS"

Q. Why are "avoided costs" an important aspect of an IRP?

A. "Avoided costs" are important to the Commission and DTE primarily for the purposes of (1) determining an appropriate credit for participants in VGP programs and (2) determining appropriate payments to PURPA QFs. "Avoided costs" are also important in other Commission activities, such as EWR planning and calculation of the associated Michigan Energy Measures Database that is used to keep score in EWR programs. A potentially important application of "avoided costs" is in the comparison of proposals in an "all sources" competitive selection, since simple cost comparison will not suffice for choosing amongst alternatives in such a process. In all of these contexts, "avoided costs" simply provide a measure of the utility costs that are not incurred if the action in question is taken versus if that action is not taken.

"Avoided costs" are appropriately determined by modeling the course of action that would be taken by the utility with and without the action in question. The difference between these, excluding the costs of the action in question then measures "avoided costs". In the PURPA literature, this approach is referred to as the Partial Displacement Differential Revenue Requirements method.[61] In the cited manual, this method is described as

> Under a revenue requirement differential method, the system revenue requirement without the QF is subtracted from the system revenue requirement with the QF. This assumes that the addition of the QF or QFs will reduce the utility's system revenue requirement. Also, this method assumes that the utility is subject to rate base/rate-of-return regulation for the generation facilities, where a revenue requirement is being determined and can be used as the basis. This method essentially calculates both energy and capacity (when required) cost simultaneously. Also required is the use of a planning expansion model to run scenarios both with and without the QF or QFs, and then a financial planning model to determine the revenue requirements under each scenario.[62]

The tie between this method and the modeling methods used in an IRP is obvious.

Q. Are there other methods that are not so closely tied to IRP modeling?

A. Yes. There are several, and in some circumstances they are as good as the Partial Displacement Differential Revenue Requirements method, but in general this method does better in addressing multiple technologies with different mixtures of capacity and energy, different dispatch patterns, and different investment timing.

Q. Briefly, how would the Partial Displacement Differential Revenue Requirements method be applied to determining "avoided costs" for a PURPA QF?

A. An IRP modeling tool would be prepared with the appropriate load forecast, existing resources, planned retirements, and approved new resources. The tool would then be used

---

[61] See, for example, the 2014 PURPA Title II Compliance Manual prepared by Robert Burns and Ken Rose for the American Public Power Association, Edison Electric Institute, national Association of Regulatory Utility Commissioners, and the National Rural Electric Cooperative Association, available from https://pubs.naruc.org/pub/B5B60741-CD40-7598-06EC-F63DF7BB12DC.

[62] *Id.* at page 35.

to optimally select a future course of action beyond these "given" actions, with and without the QF and assuming that the QF has no cost. The difference in revenue requirements would be the "avoided costs" of the QF. It would be possible to tailor the QF payment stream to the stream of annual avoided revenue requirements, but it would generally be sufficient to match the net present value of QF payments to the net present value of the differential revenue requirements.

Q. Are there any important complications in using the Partial Displacement Differential Revenue Requirements method to determine the "avoided costs" for a PURPA QF?

A. Yes. There are three that I wish to highlight.

First, the IRP modeling must be appropriately responsive to the presence or absence of the QF. If the model is used in such a way that future utility course of action is "hardwired" and does not respond to the presence or absence of the QF, then this method is not in fact informing the Commission about the avoided costs of the QF.

Second, when the utility's future course of action includes a lumpy investment, such as the 414 MW combined cycle plant included by DTE in some scenarios in this IRP, then some care is needed. A single QF may not change that investment, while multiple QFs combined would. If each QF is evaluated independently, then the cost of building that large, lumpy investment will not be avoided by any QF and will not be included in the QF's "avoided cost". If the QFs are evaluated serially, then the QF that triggers removing the large, lumpy investment will be credited with the "avoided cost" when in fact it was a result of cumulative acceptance of QFs. To properly deal with this circumstance, the Commission will need to assess whether the aggregate QF market is likely to displace the anticipate lumpy investment by the utility and shape the analysis accordingly.

Third, the Commission has recognized that utility resource planning should be informed by a range of scenarios about market conditions, fuel costs, technology costs, and policies that would affect optimal utility resource selection. This is necessary because the future is inherently uncertain and it is important to assess the risk profile of immediate investments. The same logic applies to PURPA QFs. QF "avoided costs" will vary by scenario, so even a Partial Displacement Differential Revenue Requirements method will need to include exploration of scenarios to determine the risk to the utility and its customers with and without the QF.

Q. Briefly, how would the Partial Displacement Differential Revenue Requirements method be applied to determine bill credits for VGP program participants?

A. In many ways, this question is similar to the question of determining "avoided costs" for PURPA QFs. VGP program participants are paying for one or more renewable resources that produce "avoided costs" for the utility, and should be credited for those "avoided costs" When the VGP resources are to be acquired in the future to serve anticipated program beneficiaries, the analytical issues are almost identical to the determination of PURPA QF "avoided costs". However, as the program matures and includes resources that were acquired in the past, it will be necessary to determine the 'avoided costs' of those resources that have already been acquired. If "avoided costs" of the existing resources were determined when those resources were required, those "avoided costs" cannot just be used going forward, because the present and the future as we see it now are unlikely to be the same as the projection of the present that was used to determine "avoided costs" when the

VGP resources were acquired. It may, therefore, be necessary to develop a method that accounts for "embedded avoided costs."

Q. Briefly, how would the Partial Displacement Differential Revenue Requirements method be applied to EWR program planning and evaluation?

A. Again, the basic logic would remain the same. The "avoided costs" going forward can be determined by this method for several increments of EWR program level and, if necessary, for different program emphases. Those "avoided costs" can then be used as the basis for EWR program planning and evaluation.

Q. Briefly, how would the Partial Displacement Differential Revenue Requirements method be applied in an "all-source" solicitation of generation proposals?

A. There are two options for this application. The first would be to evaluate each proposal by modeling the change in other future revenue requirements in much the same way that I described for PURPA QFs. The other would be to either model various technologies in this way or use the method to assign value to hypothetical "pure" capacity and energy resources, with attention to different timing of delivery, in order to establish an evaluation scoring method.

Q. Is it possible to apply the Partial Displacement Differential Revenue Requirements method within this IRP case?

A. No. First, the deficiencies of modeling in this case would invalidate any results. Second, there are no modeling runs in this case that properly incorporate exactly those resources that exist or have been fully approved by the Commission and then "optimize" subsequent resource selection. This case may result in additional approvals, which would then need to be incorporated into any forward-looking analysis of avoided costs. Third, it would be unreasonable to expect either the Company or intervenors to evaluate "avoided costs" in the context of the IRP case that is already complex and burdensome to the parties.

Q. What do you recommend to the Commission regarding the determination of "avoided costs" based on this or any IRP?

A. The Commission has already determined that it should conduct a periodic review of PURPA "avoided costs" in separate cases for that purpose. I recommend that the Commission consider scheduling those cases to follow soon after completion of an IRP case, and consider broadening the scope of such cases to include determining a utility's "avoided costs" for all purposes for which the Commission would routinely find that information useful, including PURPA QF contracts, VGP pricing, demand-side program planning and evaluation, and competitive resource selection. In such a proceeding, the Commission could consider other methods but should consider results from applying the Partial Displacement Differential Revenue Requirement

VI. STORAGE AND DISTRIBUTED RESOURCES IN FUTURE IRPs

Q. You indicated that DTE did not adequately evaluate storage and distributed energy resources in this IRP. Please explain.

A. DTE should be commended for both examining storage options in this IRP[63] and for including an effort to estimate the value of avoided distribution transmission and

[63] U-20471. Revised Direct Testimony of Laura K. Mikulan, throughout.

distribution capacity value for the EWR program.[64] My concerns about these analyses is that they were not adequately structured to support integration of the IRP with distribution system planning or other decisions that will be before the Commission. Accordingly, I am not deeply examining the particular conclusions in this IRP regarding storage, nor suggesting that fuller consideration of distributed energy resources would have led to different results in this IRP. Rather, I am recommending an approach that should be used in future IRPs to better address these types of resources.

Q. Please review how DTE evaluated storage in this case.

A. DTE included Ludington Pumped Storage Plant as an existing resource and included its operations in its IRP modeling. In addition, DTE evaluated new lithium-ion battery storage as a bulk power resource, providing energy arbitrage. As I discussed above, they also considered battery storage "integrated" with solar generation although their modeling of that "integration" was limited to applying the Investment Tax Credit for solar to the battery storage and assuming no transmission losses for use of the battery. However, the modeling of the battery was based on bulk power price arbitrage and not linked to the solar system.[65] They did not model battery operations that were "aware" of capacity value of a charged battery, of the increase in capacity credit to a solar plus storage system that times battery discharge to maximize solar Effective Load Carrying Capacity, nor of the demand reduction potential, for purposes of resource adequacy, of battery storage behind the meter.

[64] U-20471. Direct Testimony of Yujia Zhou, Part II, page YZ-18, line 13 through page YZ-24, line 23.

[65] U-20471. Revised Direct Testimony of Laura K. Mikulan, page LKM-104, line 3 through LKM-105 line 15.

Q. Please review how DTE evaluated distributed energy resources in this case.

A. Aside from the limited reference to CHP that I previously discussed, DTE included behind-the-meter distributed generation as a factor in its sales forecast. They also referenced existing PURPA contracts as distributed generation. However, aside from treating behind-the-meter generation and existing PURPA contracts as external factors to be accounted for in the IRP, they did not analytically embrace distributed generation as a resource option.

Q. What should be the key considerations in evaluating storage in future IRPs?

A. Aside from pumped storage, storage is primarily of modest size and inherently somewhat distributed. Distribution strategies are therefore potentially important in evaluating storage. An IRP is primarily concerned with bulk power and I do not recommend incorporating detailed geographical analysis in an IRP. However, it will be very helpful to include in future IRPs those aspects of storage strategy that affect the bulk power system. These are primarily (1) the operating rule set for the storage, and (2) position in the transmission and distribution system voltage hierarchy.

The operating rule set for storage is perhaps best characterized based on who has operational control and what they are incented to optimize with storage. In my opinion, the relevant options are:

A. Storage behind-the meter, optimized to minimize the customer's power bill. The most likely purpose of such storage will be to reduce demand charges, though arbitrage between time-of-use periods may also occur.

B. Storage behind-the-meter with generation, again optimized to minimize the customer's power bill but reflecting the economics of retaining power on site rather than discharging it to the grid.

C. Storage integrated with generation, optimized for generator net revenue, which will likely include both rescheduling power release to the grid to increase capacity credit and to arbitrage wholesale price variation. In the case of a generator subject to a PPA, the compensation terms of the PPA will define the owner's optimization plan.

D. Grid-integrated storage, optimized for net revenue in the wholesale market including energy and ancillary services but not capacity value

E. Utility-controlled storage, which will be optimized for capacity credit as part of a utility's resource adequacy plan but otherwise operate as grid-integrated storage optimized for net energy market revenue

Position in the transmission and distribution system hierarchy should reflect two aspects of storage performance.

(1) Generically, storage that is connected at transmission, either on its own or in conjunction with generation, is not analytically different than generation with some interesting features. Storage in the distribution system can reschedule energy delivery over the distribution system from periods of high power flow to periods of lower power flow in the local distribution system. This rescheduling can reduce energy losses in distribution (though at the cost of battery storage system losses) and reduce voltage drop by reducing peak current levels. This can either allow circuits to have greater economic reach or allow

distribution system components to be smaller. Aside from the difference in operational rule sets outlined above, the effects of storage on distribution system operations and investments are not much different whether in front of or behind the meter. I therefore recommend that storage be analyzed as interconnected at transmission, primary distribution (at multiple voltage levels if needed to represent the utility's distribution system, and at secondary level.

(2) In specific locations, these can relieve the utility of distribution system upgrade requirements.

In an IRP, where geography should not be a focus of the analysis, it is nonetheless important to account for other benefits of storage when calculating whether the storage is beneficial in the bulk power system. I therefore recommend that bulk power analysis for storage connected to the distribution system be done with storage at each voltage level, sized to that level and that the value to the distribution system in general and as relief to a local constraint be included in the valuation of the storage. These storage locations would, in general, be cross-tabulated with the operating rule sets listed above.

Q. What should be the key considerations in evaluating distributed generation in future IRPs?

A. Considerations for evaluating distributed generation would be very similar to those for storage. Operating rule sets are likely to be simpler for distributed generation, though system design and sizing may well be shaped ownership and consequent optimization rules. Location on the transmission and distribution network will have similar effects as with storage. Further, as storage becomes cheaper, integration of storage with generation will become more common, so analysis should generally be of a combination of generation and storage. I therefore recommend using the same structure outline above to establish a resource typology for analysis in the IRP.

VII. RECOMMENDATIONS AND CONCLUSION

Q. Please summarize your recommendations to the Commission.

A. I recommend that the Commission conclude that DTE was wrong to approach this IRP from the perspective of "capacity need" rather than seeking the most reasonable and prudent plan to serve "energy and capacity needs".

I recommend that the Commission reject DTE's reasoning that it did not need and was not required to issue a request for proposals in preparing for this IRP, both because consideration of proposals in response to such a request is essential to determining whether DTE's Proposed Course of Action is the most reasonable and prudent and because the underlying claim that it did not have a capacity need in the next three years is not accurate.

I recommend that the Commission find that the IRP analysis was deficient in important respects. On that basis, I further recommend that the Commission cannot conclude that DTE's Proposed Course of Action is the most reasonable and prudent means of meeting the Company's energy and capacity needs without remedying the issues outlined in my testimony.

I recommend that the Commission decline to determine that DTE Electric has no persistent capacity need for the next ten years, both because this is not a relevant request for the

Commission to determine in this case and because it does not accurately portray DTE's capacity position.

I further recommend that the Commission find that the capacity credits associated with the VGP program are contributing toward meeting DTE's capacity needs in most years after they become operational and direct that DTE include the full avoided costs of that capacity in determining the VGP tariff credits in its next VGP case.

To the extent that DTE has near-term renewable energy requirements, I recommend that the Commission direct DTE to accept PURPA contracts for those QFs that have established legally enforceable obligations and acquire any further required renewable resources through issuance of a request for proposals that is open to any resource that satisfies the relevant standard or program requirements. In order to compare different resources in such a bidding process, the Commission will need to decide what value to give capacity. I recommend giving full weight to capacity, as DTE's capacity position is not in persistent surplus over the next several years or over the likely duration of any resulting contract.

The Commission has previously determined that DTE must submit and the Commission will consider "avoided costs" for PURPA contracts every two years. "Avoided costs" are also relevant for VGP pricing, demand-side program planning and evaluation, and competitive resource selection. Determining "avoided costs" for these purposes within an IRP is problematic, so I recommend that the Commission consider consolidating its "avoided cost" cases and schedule them to follow the utility's IRP proceeding. In such a proceeding, the Commission can be informed about "avoided costs" by applying the Partial Displacement Differential Revenue Requirement based on the modeling done for the preceding IRP.

Finally, I recommend that the Commission amend its IRP guidelines to provide better direction to utilities for consideration of storage and distributed energy resources.

Q. Does that complete your testimony?

A. Yes.

Douglas B. Jester

Personal Information

Contact Information:

115 W Allegan Street, Suite 710
Lansing, MI 48933
517-337-7527
djester@5lakesenergy.com

Professional experience

January 2011 – present 5 Lakes Energy

Partner

Co-owner of a consulting firm working to advance the clean energy economy in Michigan and beyond. Consulting engagements with foundations, startups, and large mature businesses have included work on public policy, business strategy, market development, technology collaboration, project finance, and export development concerning energy efficiency, smart grid, renewable generation, electric vehicle infrastructure, and utility regulation and rate design. Policy director for renewable energy ballot initiative and Michigan energy legislation advocacy. Supported startup of the Energy Innovation Business Council, a trade association of clean energy businesses. Expert witness in utility regulation cases. Developed integrated resource planning models for use in ten states' compliance with the Clean Power Plan.

February 2010 - December 2010 Michigan Department of Energy, Labor and Economic Growth

Senior Energy Policy Advisor

Advisor to the Chief Energy Officer of the State of Michigan with primary focus on institutionalizing energy efficiency and renewable energy strategies and policies and developing clean energy businesses in Michigan. Provided several policy analyses concerning utility regulation, grid-integrated storage, performance contracting, feed-in tariffs, and low-income energy efficiency and assistance. Participated in Pluggable Electric Vehicle Task Force, Smart Grid Collaborative, Michigan Prosperity Initiative, and Green Partnership Team. Managed development of social-media-based community for energy practitioners. Organized conference on Biomass Waste to Energy.

August 2008 - February 2010 Rose International

Business Development Consultant - Smart Grid

- Employed by Verizon Business' exclusive external staffing agency for the purpose of providing business and solution development consultation services to Verizon Business in the areas of Smart Grid services and transportation management services.

December 2007 - March 2010 Efficient Printers Inc

President/Co-Owner

- Co-founder and co-owner with Keith Carlson of a corporation formed for the purpose of acquiring J A Thomas Company, a sole proprietorship owned by Keith Carlson. Recognized as Sacramento County (California) 2008 Supplier of the Year and Washoe County (Nevada) Association for Retarded Citizens 2008 Employer of the Year. Business operations discontinued by asset sale to focus on associated printing software services of IT Services Corporation.

August 2007 - present IT Services Corporation

President/Owner

- Founder, co-owner, and President of a startup business intended to provide advanced IT consulting services and to acquire or develop managed services in selected niches, currently focused on developing e-commerce solutions for commercial printing with software-as-a-service.

2004 – August 2007 Automated License Systems

Chief Technology Officer

- Member of four-person executive team and member of board of directors of a privately-held corporation specializing in automated systems for the sale of hunting and fishing licenses, park campground reservations, and in automated background check systems. Executive responsible for project management, network and data center operations, software and product development. Brought company through mezzanine financing and sold it to Active Networks.

2000 - 2004 WorldCom/MCI

Director, Government Application Solutions

- Executive responsible in various combinations for line of business sales, state and local government product marketing, project management, network and data center operations, software and product development, and contact center operations for specialized government process outsourcing business. Principal lines of business were vehicle emissions testing, firearm background checks, automated hunting and fishing license systems, automated appointment scheduling, and managed application hosting services. Also responsible for managing order entry, tracking, and service support systems for numerous large federal telecommunications contracts such as the US Post Office, Federal Aviation Administration, and Navy-Marine Corps Intranet.
- Increased annual line-of-business revenue from $64 million to $93 million, improved EBITDA from approximately 2% to 27%, and retained all customers, in context of corporate scandal and bankruptcy.
- Repeatedly evaluated in top 10% of company executive management on annual performance evaluations.

1999-2000 Compuware Corporation

Senior Project Manager

- Senior project manager, on customer site with five project managers and team of approximately 80, to migrate a major dental insurer from a mainframe environment to internet-enabled client-server environment.

1995 - 1999 City of East Lansing, Michigan

Mayor and Councilmember

- Elected chief executive of the City of East Lansing, a sophisticated city of 52,000 residents with a council-manager government employing about 350 staff and with an annual budget of about $47 million. Major accomplishments included incorporation of public asset depreciation into budgets with consequent improvements in public facilities and services, complete rewrite and modernization of city charter, greatly intensified cooperation between the City of East Lansing and the East Lansing Public Schools, significant increases in recreational facilities and services, major revisions to housing code, initiation of revision of the City Master Plan, facilitation of the merger of the Capital Area Transportation Authority and Michigan State University bus systems, initiation of a major downtown redevelopment project, City government efficiency improvements, and numerous other policy initiatives. Member of Michigan Municipal League policy committee on Transportation and Environment and principal writer of league policy on these subjects (still substantially unchanged as of 2009).

1995-1999 Michigan Department of Natural Resources

Chief Information Officer

- Executive responsibility for end-user computing, data center operations, wide area network, local area network, telephony, public safety radio, videoconferencing, application development and support, Y2K readiness for Departments of Natural Resources and Environmental Quality. Directed staff of about 110. Member of MERIT Affiliates Board and of the Great Lakes Commission's Great Lakes Information Network (GLIN) Board.

1990-1995 Michigan Department of Natural Resources

Senior Fisheries Manager

- Responsible for coordinating management of Michigan's Great Lakes fisheries worth about $4 billion per year including fish stocking and sport and commercial fishing regulation decisions, fishery monitoring and research programs, information systems development, market and economic analyses, litigation, legislative analysis and negotiation. University relations. Extensive involvement in regulation of steam electric and hydroelectric power plants.
- Served as agency expert on natural resource damage assessment, for all resources and causes.
- Considerable involvement with Great Lakes Fishery Commission, including:
    - Co-chair of Strategic Great Lakes Fishery Management Plan working group

- Member of Lake Erie and Lake St. Clair Committees
- Chair, Council of Lake Committees
- Member, Sea Lamprey Control Advisory Committee
- St Clair and Detroit River Areas of Concern Planning Committees

1989-1990 American Fisheries Society

Editor, North American Journal of Fisheries Management

- Full responsibility for publication of one of the premier academic journals in natural resource management.

1984 - 1989 Michigan Department of Natural Resources

Fisheries Administrator

- Assistant to Chief of Fisheries, responsible for strategic planning, budgets, personnel management, public relations, market and economic analysis, and information systems. Department of Natural Resources representative to Governor's Cabinet Council on Economic Development. Extensive involvement in regulation of steam electric and hydroelectric power plants.

1983-present Michigan State University

Adjunct Instructor

- Irregular lecturer in various undergraduate and graduate fisheries and wildlife courses and informal graduate student research advisor in fisheries and wildlife and in parks and recreation marketing.

1977 – 1984 Michigan Department of Natural Resources

Fisheries Research Biologist

- Simulation modeling & policy analysis of Great Lakes ecosystems. Development of problem-oriented management records system and "epidemiological" approaches to managing inland fisheries.
- Modeling and valuation of impacts power plants on natural resources and recreation.

Education

1991-1995 Michigan State University
PhD Candidate, Environmental Economics
Coursework completed, dissertation not pursued due to decision to pursue different career direction.

1980-1981 University of British Columbia
Non-degree Program, Institute of Animal Resource Ecology

1974-1977 Virginia Polytechnic Institute & State University
MS Fisheries and Wildlife Sciences
MS Statistics and Operations Research

1971-1974 New Mexico State University
BIS Mathematics, Biology, and Fine Arts

Citizenship and Community Involvement

Youth Soccer Coach, East Lansing Soccer League, 1987-89

Co-organizer, East Lansing Community Unity, 1992-1993

Bailey Community Association Board, 1993-1995

East Lansing Commission on the Environment, 1993-1995

East Lansing Street Lighting Advisory Committee, 1994

Councilmember, City of East Lansing, 1995-1999

Mayor, City of East Lansing, 1995-1997

East Lansing Downtown Development Authority Board Member, 1995-1999

East Lansing Transportation Commission, 1999-2004

East Lansing Non-Profit Housing and Neighborhood Services Corporation Board Member, 2001-2004

Lansing – East Lansing Smart Zone Board of Directors, 2007-present

Council on Labor and Economic Growth, State of Michigan, by appointment of the Governor, May 2009 – May 2012

East Lansing Downtown Development Authority Board Member and Vice-Chair, 2010 – present.

East Lansing Brownfield Authority Board Member and Vice-Chair, 2010 – present.

East Lansing Downtown Management Board and Chair, 2010 – 2016

East Lansing City Center Condominium Association Board Member, 2015 – present.

Douglas Jester
Specific Energy-Related Accomplishments

Unrelated to Employment

- Member of Michigan SAVES initial Advisory Board. Michigan SAVES is a financing program for building energy efficiency measures initiated by the State of Michigan Public Service Commission and administered under contract by Public Sector Consultants. Program launched in 2010.
- Member of Michigan Green Jobs Initiative, representing the Council for Labor and Economic Growth.
- Participated in Lansing Board of Water and Light Integrated Resource Planning, leading to their recent completion of a combined cycle natural gas power plant that also provides district heating to downtown Lansing.
- In graduate school, participated in development of database and algorithms for optimal routing of major transmission lines for Virginia Electric Power Company (now part of Dominion Resources).
- Commissioner of the Lansing Board of Water and Light, representing East Lansing. December 2017 – present.

For 5 Lakes Energy

- Participant by invitation in the Michigan Public Service Commission Smart Grid Collaborative, authoring recommendations on data access, application priorities, and electric vehicle integration to the grid.
- Participant by invitation in the Michigan Public Service Commission Energy Optimization Collaborative, a regular meeting and action collaborative of parties involved in the Energy Optimization programs required of utilities by Michigan law enacted in 2008.
- Participant by invitation in Michigan Public Service Commission Solar Work Group, including presentations and written comments on value of solar, including energy, capacity, avoided health and environmental damages, hedge value, and ancillary services.
- Participant by invitation in Michigan Senate Energy and Technology Committee stakeholder work group preliminary to introduction of a comprehensive legislative package.
- Participant by invitation in Michigan Public Service Commission PURPA Avoided Cost Technical Advisory Committee.
- Participant by invitation in Michigan Public Service Commission Standby Rate Working Group.
- Participant by invitation in Michigan Public Service Commission Street Lighting Collaborative.
- Participant by invitation in State of Michigan Agency for Energy Technical Advisory Committee on Clean Power Plan implementation.
- Conceived, obtained funding, and developed open access integrated resource planning tools (State Tool for Electricity Emissions Reduction aka STEER) for State compliance with the Clean Power Plan:
  - For Energy Foundation - Michigan and Iowa
  - For Advanced Energy Economy Institute – Arkansas, Florida, Illinois, Ohio, Pennsylvania, Virginia
  - For The Solar Foundation - Georgia and North Carolina
- Presentations to Michigan Agency for Energy and the Institute for Public Utilities Michigan Forum on Strategies for Michigan to Comply with the Clean Power Plan.
- Participant in Midcontinent Independent Systems Operator stakeholder processes on behalf of Michigan Citizens Against Rate Excess and the MISO Consumer Representatives Sector, including Resource Adequacy Committee, Loss of Load Expectation Working Group, Transmission Expansion Working Group, Demand Response Working Group, Independent Load Forecasting Working Group, and Clean Power Plan Working Group.
- Expert witness before the Michigan Public Service Commission in various cases, including:

- Case U-17473 (Consumers Energy Plant Retirement Securitization)
- Case U-17096-R (Indiana Michigan 2013 PSCR Reconciliation)
- Case U-17301 (Consumers Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17302 (DTE Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17317 (Consumers Energy 2014 PSCR Plan);
- Case U-17319 (DTE Electric 2014 PSCR Plan);
- Case U-17674 (WEPCO 2015 PSCR Plan);
- Case U-17679 (Indiana-Michigan 2015 PSCR Plan);
- Case U-17689 (DTE Electric Cost of Service and Rate Design);
- Case U-17688 (Consumers Energy Cost of Service and Rate Design);
- Case U-17698 (Indiana-Michigan Cost of Service and Rate Design);
- Case U-17762 (DTE Electric Energy Optimization Plan);
- Case U-17752 (Consumers Energy Community Solar);
- Case U-17735 (Consumers Energy General Rates);
- Case U-17767 (DTE General Rates);
- Case U-17792 (Consumers Energy Renewable Energy Plan Revision);
- Case U-17895 (UPPCO General Rates);
- Case U-17911 (UPPCO 2016 PSCR Plan);
- Case U-17990 (Consumers Energy General Rates); and
- Case U-18014 (DTE General Rates);
- Case U-17611-R (UPPCO 2015 PSCR Reconciliation);
- Case U-18089 (Alpena Power PURPA Avoided Costs);
- Case U-18090 (Consumers Energy PURPA Avoided Costs);
- Case U-18091 (DTE PURPA Avoided Costs);
- Case U-18092 (Indiana Michigan Electric Power PURPA Avoided Costs);
- Case U-18093 (Northern States Power PURPA Avoided Costs);
- Case U-18094 (Upper Peninsula Power Company PURPA Avoided Costs);
- Case U-18095 (UMERC PURPA Avoided Costs);
- Case U-18224 (UMERC Certificate of Necessity);
- Case U-18255 (DTE General Rate Case);
- Case U-18322 (Consumers Energy General Rate Case).

- Expert witness before the Public Utilities Commission of Nevada in
  - Case 16-07001 (NV Energy 2017-2036 Sierra Pacific Integrated Resource Plan)
- Expert witness before the Missouri Public Service Commission in
  - Case ER-2016-0179 (Ameren Missouri General Rate Case)
  - Case ER-2016-0285 (KCP&L General Rate Case)
  - Case ET-2016-0246 (Ameren Missouri EV Policy)
- Expert witness before the Kentucky Public Service Commission
  - Case 2016-00370 (Kentucky Utilities General Rate Case)
- Expert witness before the Massachusetts Department of Public Utilities in
  - Case 17-05 (Eversource General Rate Case)
  - Case 17-13 (National Grid General Rate Case)
- Coauthored “Charge without a Cause: Assessing Utility Demand Charges on Small Customers”
- Currently under contract to the Michigan Agency for Energy to develop a Roadmap for CHP Market Development in Michigan, including evaluation of various CHP technologies and applications using STEER Michigan as an integrated resource planning tool.
- Under contract to NextEnergy, authored “Alternative Energy and Distributed Generation” chapter of Smart Grid Economic Development Opportunities report to Michigan Economic Development Corporation and assisted authors of chapters on “Demand Response” and “Automated Energy Management Systems”.
- Developed presentation on “Whole System Perspective on Energy Optimization Strategy” for Michigan Energy Optimization Collaborative.
- Under contract to NextEnergy, assisted in development of industrial energy efficiency technology development strategy.

- Under contract to a multinational solar photovoltaics company, developed market strategy recommendations.
- For an automobile OEM, developed analyses of economic benefits of demand response in vehicle charging and vehicle-to-grid electricity storage solutions.
- Under contract to Pew Charitable Trusts, assisted in development of a report of best practices for electric vehicle charging infrastructure.
- Under contract to a national foundation, developed renewable energy business case for Michigan including estimates of rate impacts, employment and income effects, health effects, and greenhouse gas emissions effects.
- Assisted in Michigan market development for a solar panel manufacturer, clean energy finance company, and industrial energy management systems company.
- Under contract to Institute for Energy Innovation, organized legislative learning sessions covering a synopsis of Michigan's energy uses and supply, energy efficiency, and economic impacts of clean energy.

For Department of Energy Labor and Economic Growth

- Participant in the Michigan Public Service Commission Energy Optimization Collaborative, a regular meeting and action collaborative of parties involved in the Energy Optimization programs required of utilities by Michigan law enacted in 2008.
- Lead development of a social-media-based community for energy practitioners in Michigan at www.MichEEN.org.
- Drafted analysis and policy paper concerning customer and third-party access to utility meter data.
- Analyzed hourly electric utility load demonstrating relationship amongst time of day, daylight, and temperature on loads of residential, commercial, industrial, and public lighting customers. Analysis demonstrated the importance of heating for residential electrical loads and the effects of various energy efficiency measures on load-duration curves.
- Analyzed relationship of marginal locational prices to load, demonstrating that traditional assumptions of Integrated Resource Planning are invalid and that there are substantial current opportunities for cost-effective grid-integrated storage for the purpose of price arbitrage as opposed to traditionally considered load arbitrage.
- Developed analyses and recommendations concerning the use of feed-in tariffs in Michigan.
- Participated in Pluggable Electric Vehicle Task Force and initiated changes in State building code to accommodate installation of vehicle charging equipment.
- Organized December 2010 conference on Biomass Waste to Energy technologies and market opportunities.
- Participated in and provided support for teams working on developing Michigan businesses involved in renewable energy, storage, and smart grid supply chains.
- Developed analyses and recommendations concerning low-income energy assistance coordination with low-income energy efficiency programs and utility payment collection programs.
- Drafted State of Michigan response to a US Department of Energy request for information on offshore wind energy technology development opportunities.
- Assisted in development of draft performance contracting enabling legislation, since adopted by the State of Michigan.

For Verizon Business

- Analyzed several potential new lines of business for potential entry by Verizon's Global Services Systems Integration business unit and recommended entry to the "Smart Grid" market. This recommendation was adopted and became a major corporate initiative.
- Provided market analysis and participation in various conferences to aid in positioning Verizon in the "Smart Grid" market. Recommendations are proprietary to Verizon.

- Led a task force to identify potential converged solutions for the “Smart Grid” market by integrating Verizon’s current products and selected partners. Established five key partnerships that are the basis for Verizon’s current “Smart Grid” product offerings.
- Participated in the “Smart Grid” architecture team sponsored by the corporate Chief Technology Officer with sub-team lead responsibilities in the areas of Software and System Integration and Network and Systems Management. This team established a reference architecture for the company’s “Smart Grid” offerings, identified necessary changes in networks and product offerings, and recommended public policy positions concerning spectrum allocation by the FCC, security standards being developed by the North American Reliability Council, and interoperability standards being developed by the National Institute of Standards and Technology.
- Developed product proposals and requirements in the areas of residential energy management, commercial building energy management, advanced metering infrastructure, power distribution monitoring and control, power outage detection and restoration, energy market integration and trading platforms, utility customer portals and notification services, utility contact center voice application enablement, and critical infrastructure physical security.
- Lead solution architecture and proposal development for six utilities with solutions encompassing customer portal, advanced metering, outage management, security assessment, distribution automation, and comprehensive “Smart Grid” implementation.
- Presented Verizon’s “Smart Grid” capabilities to seventeen utilities.
- Presented “Role of Telecommunications Carriers in Smart Grid Implementation” to 2009 Mid-America Regulatory Conference.
- Presented “Smart Grid: Transforming the Electricity Supply Chain” to the 2009 World Energy Engineering Conference.
- Participant in NASPInet work groups of the North American Energy Reliability Corporation (NERC), developing specifications for a wide-area situational awareness network to facilitate the sharing and analysis of synchrophasor data amongst utilities in order to increase transmission reliability.
- Provided technical advice to account team concerning successful proposal to provide network services and information systems support for the California ISO, which coordinates power dispatch and intercompany power sales transactions for the California market.

For Michigan Department of Natural Resources

- Determined permit requirements under Section 316 of the Clean Water Act for all steam electric plants currently operating in the State of Michigan.
- Case manager and key witness for the State of Michigan in FERC, State court, and Federal court cases concerning economics and environmental impacts of the Ludington Pumped Storage Plant, which is the world’s largest pumped storage plant. A lead negotiator for the State in the ultimate settlement of this issue. The settlement was valued at $127 million in 1995 and included considerations of environmental mitigation, changes in power system dispatch rules, and damages compensation.
- Managed FERC license application reviews for the State of Michigan for all hydroelectric projects in Michigan as these came up for reissuance in 1970s and 1980s.
- Testified on behalf of the State of Michigan in contested cases before the Federal Energy Regulatory Commission concerning benefit-cost analyses and regulatory issues for four different hydroelectric dams in Michigan.
- Reviewed (as regulator) the environmental impacts and benefit-cost analyses of all major steam electric and most hydroelectric plants in the State of Michigan.
- Executive responsibility for development, maintenance, and operations of the State of Michigan’s information system for mineral (includes oil and gas) rights leasing, unitization and apportionment, and royalty collection.
- In cooperative project with Ontario Ministry of Natural Resources, participated in development of a simulation model of oil field development logistics and environmental impact on Canada’s Arctic slope for Tesoro Oil.

MPSC Case No.:	U-20471
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-3.85
Respondent:	L. K. Mikulan
Page:	1 of 1

Question: Suppose that a new generation resource can be owned and operated or that power can be purchased through a new long-term contract at less than the cost of energy (as measured by LMP) that would be displaced by that resource but the Company has no capacity need. Explain how that resource would have been treated in the Company's IRP modeling and whether it would have been selected for inclusion in the PCA.

Answer: If an alternative technology has better than market value, it would have been rated highly in the market valuation screening. In the Strategist optimization modeling, a resource would have not been selected because there was no capacity need. However, knowing that the resource was economic, it can be forced into a modeling run or run in Strategist as a "superfluous" unit to verify that the value of the alternative positively impacted the build plan economics.

An example of such a resource was the CVR/VVO program. The program rated highly in the market valuations, was not selected in the optimization due to in part to its small size, therefore was not selected as an optimized resource so it was subsequently forced into the PCA for pathways A and C.

The voluntary renewables programs were also forced into the PCA pathways.

Attachments: *N/A*

CHP

ROADMAP FOR MICHIGAN

Prepared for the Michigan Energy Office on behalf of the Michigan Agency for Energy and the US Department of Energy

February 2018

Project Team

The **Michigan Energy Office** (MEO) is within the **Michigan Agency for Energy** (MAE). MAE is a government agency within the Michigan Department of Licensing and Regulatory Affairs. MAE coordinates, analyzes, advises on, and advocates for the state's policies, programs, and proposals related to energy. The MEO is a recognized State Energy Office by the federal Department of Energy. MEO encourages and informs energy policy and technology and program development by facilitating partnerships, administering grant funds, and providing statewide education, outreach opportunities and stakeholder collaboratives.

5 Lakes Energy (5LE) is a Michigan-based policy consulting firm dedicated to advancing policies and programs that promote clean energy, sustainability and the environment. The team has decades of experience in research, modeling and analysis. From public policy design to reviewing policy implementation around the country and world, 5 Lakes Energy has the deep knowledge base necessary to review, analyze, and recommend models for optimizing the deployment of clean energy.

Sustainable Partners LLC (SPART) was formed in 2011 to develop and finance alternative and renewable energy projects and provide related consulting services to major industrial and commercial energy users. SPART excels at building consensus among stakeholders, leading cross-functional teams, and ensuring accountability, while helping clients thoroughly evaluate energy options and implement sustainable projects through advisory services and direct capital investment.

The **Energy Resources Center** (ERC), established in 1973 at the University of Illinois at Chicago, is an interdisciplinary public research center bringing experts from across the fields of electric, mechanical and environmental engineering, in addition to economics, public policy, and bioenergy. The ERC manages the U.S. Department of Energy's Midwest CHP Technical Assistance Partnership (TAP), which provides services to twelve Midwest states, including Michigan.

NextEnergy is one of the nation's leading accelerators of advanced energy and transportation technologies, businesses and industries. NextEnergy drives technology demonstration and commercialization, delivers industry and venture development services, and provides an authoritative voice in the public sector. Founded in 2002 as 501(c)(3) nonprofit organization, NextEnergy has helped attract more than $1.6 billion of new investment, including programs in excess of $160 million in which NextEnergy has directly participated.

Authors

David Baker………………..Energy Resources Center
Rand Dueweke…………...Sustainable Partners
Cliff Haefke………..……… Energy Resources Center
Douglas Jester……………..5 Lakes Energy
Pam Landes………………..Sustainable Partners
Graeme Miller……………. Energy Resources Center
Greg Northrup…………...Sustainable Partners
Jean Redfield………..…… NextEnergy
Gina Schrader…..………..NextEnergy
Jamie Scripps…..…………5 Lakes Energy

About the Report

The Combined Heat and Power (CHP) Roadmap for Michigan is a collaborative effort to accelerate the adoption of CHP in Michigan through three objectives:

1. Identify and evaluate CHP technologies and applications with a potential for adoption in Michigan;
2. Assess, measure, and determine the cost and value of CHP in Michigan's future energy mix;
3. Listen, educate, and advocate for the inclusion of CHP based upon economic, environmental, and system benefits.

Project partners worked to identify strategies to remove transactional, market, finance and policy barriers to CHP deployment. Project partners also worked to leverage proven methodology to map and engage the Michigan-specific CHP supply chain. This report shares results and recommendations that can be utilized to accelerate the adoption of CHP in Michigan and achieve the resulting economic benefits.

Acknowledgements

This report and the work described were supported by the U.S. Department of Energy and the Michigan Agency for Energy through the Michigan Energy Office under Award No. DE-EE0006226.

The authors gratefully acknowledge the assistance of the stakeholders in the CHP ecosystem who generously shared their time and expertise in completing surveys, participating in interviews, attending events, and providing other related information.

Glossary of Acronyms

5LE – 5 Lakes Energy, LLC

CHP – Combined heat and power

CI – Commercial/industrial

CIBO – Council of Industrial Boiler Owners

CODE2 – Cogeneration Observatory and Dissemination Europe

CPM – Continuous process manufacturing

CPP – Clean Power Plan

DE – Digital economy

DOE – United States Department of Energy

DTE – DTE Electric Company (formerly Detroit Edison)

EIA – United States Energy Information Administration

EPA – United States Environmental Protection Agency

EPRI – Electric Power Research Institute

ERC – Energy Resources Center

EWR – Energy Waste Reduction

F&ES – Fabrication and essential services

GDP – Gross domestic product

GW – Gigawatt

HHV – Higher heating value

IEI – Institute for Energy Innovation

IRP – Integrated Resource Plan

ITC – Investment tax credit

kW – Kilowatt

kWh – Kilowatt-hour

LHV – Lower heating value

Michigan EIBC – Michigan Energy Innovation Business Council

MISO – Midcontinent Independent System Operator

MMBtu – Million British thermal units

MPSC – Michigan Public Service Commission

MW – Megawatt

MWh – Megawatt-hour

NEP – New Energy Policy

NREL – National Renewable Energy Laboratory

NYSERDA – New York State Energy Research and Development Authority

PACE – Property Assessed Clean Energy

PURPA – Public Utilities Regulatory Policies Act

RAP – The Regulatory Assistance Project

REC – Renewable energy credit

RPS – Renewable Portfolio Standard

SPART – Sustainable Partners, LLC

STEER – State Tool for Electricity Emissions Reduction

TAP – Technical Assistance Partnership

WHP – Waste heat to power

WMAEE – West Michigan Association of Energy Engineers

Contents

Executive Summary

Michigan has the opportunity to capture enormous benefits by embracing optimal levels of combined heat and power (CHP) generation in its future energy mix. CHP provides a path to make Michigan businesses more competitive by lowering and stabilizing energy costs, reducing strain on the electric grid, improving on-site reliability and resiliency, and lowering harmful greenhouse gas emissions. Yet many studies have shown that CHP is a vastly underutilized energy resource across the country due to a combination of policy barriers, market impediments, and other factors. Michigan intends to be a leader in advancing CHP deployment and this CHP Roadmap is a significant initial step in that effort.

CHP is *the* most fuel-efficient way to produce and utilize both electric and thermal energy from a single fuel source. CHP adoption across Michigan offers a low-cost approach to new electricity generation and uses highly skilled Michigan labor and technology to develop, implement, and operate projects.

Governor Snyder has made smart energy policy a top priority for Michigan, emphasizing the need to reduce energy waste and increase reliability. A confluence of executive and legislative interest in energy policy, coupled with recognition of the potential of CHP to participate in meeting Michigan's energy needs, means the time is right to accelerate CHP deployment in Michigan.

The CHP Roadmap for Michigan differs from previous projects by applying a cutting-edge integrated resource modeling tool to determine least-cost deployment of CHP resources. This model – the State Tool for Electricity Emissions Reduction (STEER) – calculates the least-cost resource portfolio to satisfy electricity demand and various reliability and environmental constraints based on projections of demand, fuel prices, technology price and performance, taxes, and other factors. Depending on natural gas prices and the availability of renewable energy resources, STEER recommended an optimal level of additional CHP deployment in Michigan ranging from 722 MW to 1,014 MW by 2030.

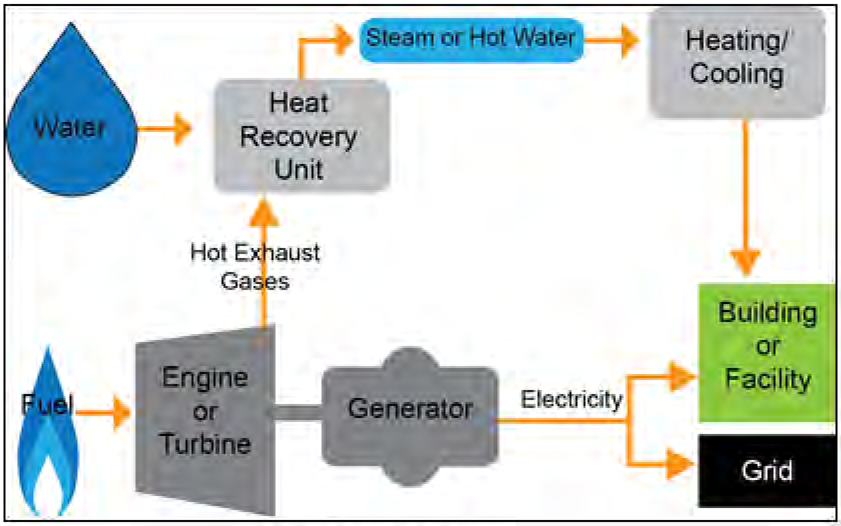
Parallel to this modeling effort, an intensive analysis of Michigan's CHP-related supply and value chains provides insight to support state-level policy analyses and recommendations. Michigan firms have a robust ability to participate throughout the CHP value chain with the majority of economic impact being realized by using the pool of talent based in Michigan companies to design and implement CHP projects.

Finally, the Michigan CHP Roadmap provides a series of prioritized public policy recommendations that will put Michigan on a path to a CHP-friendly future, including recommendations to:

- Offer financing and incentives for CHP in order to reduce the payback period for CHP projects;
- Promote Property Assessed Clean Energy (PACE) financing and on-bill financing for CHP;
- Consider best practices in utility standby rates and PURPA avoided cost/buyback rates;
- Fully value CHP when considering the costs and benefits of distributed energy resources;
- Update interconnection standards to better align with new technologies and best practices;
- Incorporate CHP as a resource in Michigan utility energy waste reduction (EWR) plans;
- Require utility integrated resource plans (IRPs) to consider CHP as both a supply-side and demand-side resource;
- Collaborate closely with expert organizations, such as the Midwest CHP Technical Assistance Program (TAP), to promote CHP assistance.

Background

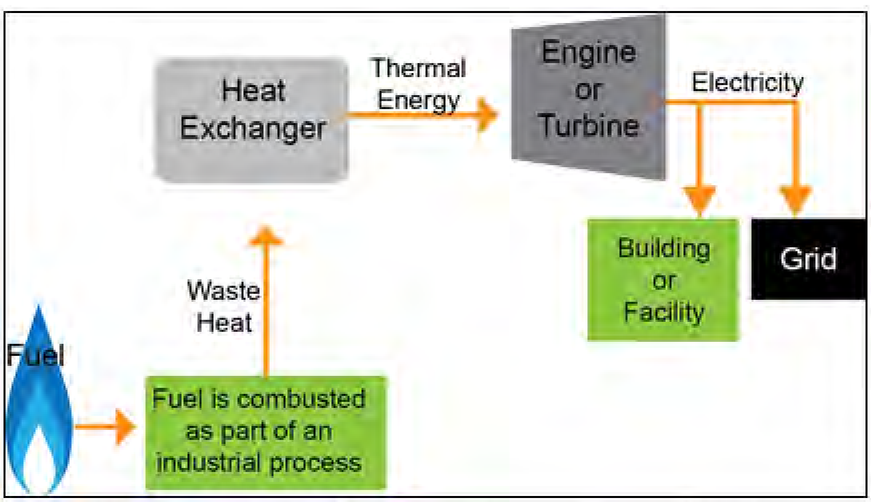
CHP is the simultaneous generation of electricity and useful thermal energy from a single source of fuel, located at or near the point of energy use. Electricity is primarily used on site as a substitute for utility-provided power, with any excess generation potentially sold onto the grid. The thermal energy can be used to support process applications or human comfort through the production of steam, hot water, hot air, refrigeration, or chilled water.



CHP Topping Cycle

Installed CHP systems typically achieve total energy efficiencies of 65% to 80%, compared to a weighted average of only about 45% to 60% for conventional separate heat (via boilers/furnaces) and power generation (via central utility plants). By avoiding electric line losses and utilizing much of the thermal energy normally wasted in power generation, CHP significantly reduces the total primary fuel needed to supply energy services, reducing greenhouse gas emissions and saving fuel and money. CHP systems can range in size from 5 kilowatts (kW; the demand of a typical single-family home) to several hundred Megawatts (MW; the demand of a very large industrial plant).

CHP technology can be deployed quickly, with few geographic limitations, and can utilize a variety of fuels, both fossil and renewable. CHP may not be widely recognized outside industrial, commercial, institutional, and utility circles, but it has quietly been providing highly efficient electricity and process heat throughout the United States for decades to vital industries, large employers, urban centers, critical infrastructure like hospitals and wastewater treatment plants, and university campuses.



CHP Bottoming Cycle: Waste Heat to Power (WHP)

Methodology

The methodology employed throughout the Roadmap was developed with the objective of replicability in other states. To achieve this objective, project partners relied on:

- U.S. Department of Energy (DOE) state-by-state CHP technical potential projections,
- U.S. Environmental Protection Agency (EPA) data on CHP economics and performance across a range of technologies and generating capacities, and
- U.S. Energy Information Administration (EIA) data for Michigan's existing power plant portfolio

According to DOE, Michigan has nearly 5 GW of CHP technical potential at more than 10,000 sites across 17 industrial and 24 commercial sectors. This potential, on a capacity basis, is roughly evenly split between industrial candidates in the transportation equipment, chemicals, primary metals, paper and food sectors; and commercial candidates in the commercial office building, higher education, hospital, retail location, and multifamily housing sectors.

The EPA provides cost and performance data for the five CHP technologies which comprise 99% of existing installations: reciprocating engines, steam turbines, combustion turbines, microturbines and fuel cells. Data from DOE, EPA and EIA serve as a major proportion of the input required for the STEER model to dynamically identify which CHP configurations are economically viable across a wide variety of scenarios. This analysis narrows the scope of Michigan's technical potential to only include those projects that are economically viable given Michigan's overall power generation portfolio.

Mapping of the Michigan CHP supply and value chain utilized methodology previously developed to support creation of the Michigan "Clean Energy Roadmap." Boundaries for supply and value chain mapping were determined through market research and market analysis based on likely economic impact to the state of Michigan arising from deployment of CHP projects. Market segments where Michigan companies are currently participating in the CHP supply or value chain were given principal consideration for surveys and interviews. A directory of Michigan supply and value chain firms has been created and will be distributed to foster collaboration and promote CHP deployment.

In customizing and prioritizing proposed solutions for Michigan, project partners considered the estimated proportion of potential projects affected, perception of barrier magnitude by stakeholders, and the ease/practicality of achieving change in the short term. Focus was placed on those barriers that are most significant to restricting deployment of CHP across Michigan and to which attainable solutions exist. These include 1) a lack of access to low-cost capital; 2) prohibitive utility rates; 3) failure to fully embrace CHP in energy waste reduction and integrated resource planning; and (4) a lack of awareness or familiarity with CHP. For the most part, solutions take the form of legislative change or regulatory relief, modification of utility rate structures, and financial incentives.

Finally, deployment of the Roadmap involves the ongoing effort to educate CHP stakeholders, and especially end-users, on the merits of CHP. Project partners engaged with over 300 individuals through outreach and education efforts related to the development of the Roadmap. Project partners are working with the Michigan Agency for Energy to expand outreach and assistance over the next several years as a critical step toward achieving the goal of accelerating the deployment of CHP in Michigan.

State Tool for Electricity Emissions Reduction (STEER)

The STEER model was used to assess, measure, and determine the cost and value of CHP as one of multiple resources in Michigan's future energy mix. In our primary application of STEER, we considered the net value of CHP to the economy by considering the cost of installing and operating various CHP systems, the value of the heat produced by CHP measured as the cost of supplying heat in the least-cost way other than CHP, and the value of electricity produced by the CHP system measured as the marginal cost of producing electricity absent the CHP system.

Because we determined that standby rates are one of the principal barriers to CHP adoption and may be amenable to policy adjustments, we also used STEER to evaluate the effect of standby rates on the economic potential for CHP in Michigan. Further, because resilience of CHP site host operations is an important benefit of CHP that is not reflected in standard electric power system evaluations, we also used STEER to evaluate the additional economic potential for CHP in Michigan if site hosts would not otherwise choose to build CHP but sufficiently valued resilience to enable them to build CHP. Consideration of resilience value increases the potential deployment of CHP in sectors where loss of power is most consequential and can significantly increase CHP potential beyond the levels that would be supported only by power sector value. Based on our analysis of Michigan potential, resilience value could increase CHP potential by around 60%. Standby rates, on the other hand, substantially reduce the profitability of CHP ownership and thereby reduce potential CHP deployment by 50% or more.

STEER modeling indicates that steam turbines, gas combustion turbines, and reciprocating engines appear profitable above some size threshold size in each scenario. Conversely, microturbines and fuel cells do not appear economically viable.

Scenarios with higher natural gas prices and higher cost of renewable resources in the future both tend to lower the minimum size threshold for the more viable CHP technologies, thereby expanding the number of potential installation sites in Michigan.

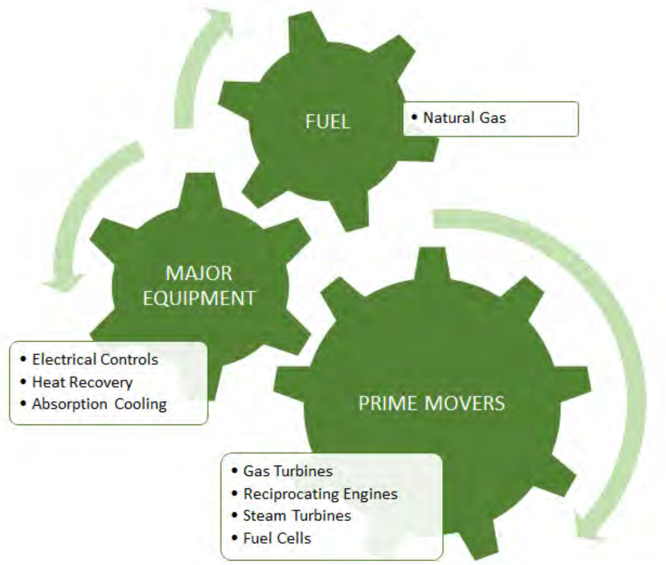
About half the sites where steam turbines are economically feasible are colleges and universities, confirming that this sector should be an important part of end-user outreach and education. We also note that this result does not necessarily mean that combustion turbines and reciprocating engines would not be suitable for many of these applications.

In our reference scenario, economic potential for CHP in Michigan is about 1,014 MW electric generation capacity with direct investment of about $865.6 million, annual direct O&M activity of about $67.6 million, annual economic profit of about $109.5 million, annual fuel cost savings of $94.7 million, and annual air emissions reductions of 662 tons CO_2 per year, 379 tons NO_x per year, and 39 tons SO_x per year.

In various scenarios, assuming various fuel and technology costs, the economic potential for new installed CHP in Michigan varies from 722 MW to 2,360 MW.

Michigan Supply and Value Chain

Demand for CHP projects in both the private and public sector is primarily driven by an economic comparison of the costs and benefits of CHP versus the costs and benefits of current operations. This status quo typically entails electric generation at a utility-owned power plant and thermal energy generation on-site by end-user-owned boilers or furnaces.

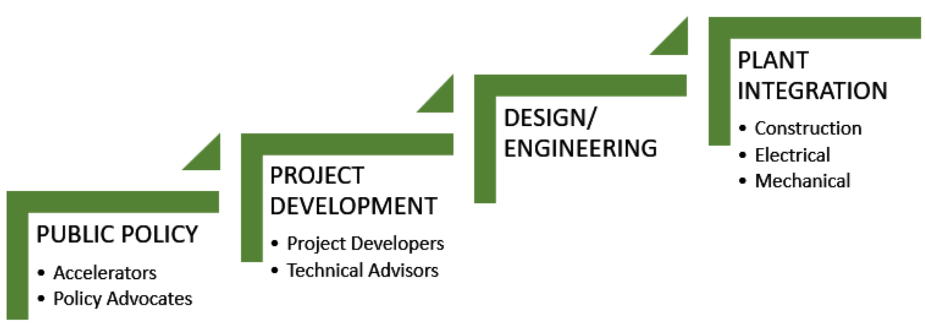


The **CHP supply chain** consists of the physical equipment and fuel required for the CHP system to operate. The major sectors of the CHP supply chain include CHP end-user applications, prime mover manufacturers and distributors, major equipment manufacturers and distributors, and fuel suppliers and brokers.

While Michigan manufacturers cannot realistically tap into prime mover manufacturing, there are a handful of Michigan companies that manufacture some of the major ancillary equipment that may be found in CHP projects but are not part of the prime mover systems. And manufacturers of both prime movers and other equipment execute sales, engineering, and service functions through Micihgan-based distributors.

Fuel supply and price can be controlled via 5 to 10 year contracts in most industrial and commercial locations, with costs currently near historic lows. This ability to control commodity costs significantly mitigates investment risk. In some regions of the state, particularly rural areas and the Upper Peninsula, the infrastructure for handling large volumes of natural gas is inadequate or nonexistent. Biomass-based fuel sources may be utilized but require significant additional effort on the part of the project developer. In the Upper Peninsula, unless a potential CHP project is located in one of the few major cities or along the east-west natural gas transmission corridor, fuel supply may be an impossible hurdle to overcome.

Michigan firms have a robust ability to participate throughout the **CHP value chain**, which consists of the intellectual capital and skilled trades required to develop, design, engineer, finance, install, and integrate CHP systems. The major sectors of the value chain include policy advocates and accelerators, project developers and technical advisors, design/engineering firms, and plant integration contractors. The majority of the economic impact of CHP will be realized by using this pool of talent based in Michigan companies to design and implement projects.



Barriers to CHP in Michigan

CHP has the potential to be a significant, reliable, cost-effective, and environmentally protective contributor to Michigan's energy mix. However, those interested in installing CHP projects face a number of obstacles. In order to fulfill the promise of energy waste reduction (EWR) in Michigan through optimal deployment of CHP, these barriers should be examined and understood in general, and in light of the unique circumstances facing Michigan energy users.

While CHP can save a system owner money in the long run, there are a few economic barriers that could prevent a CHP project from moving forward in the first place. The relatively high upfront cost of installing a CHP system can be a barrier in itself. Additionally, a lack of sufficient access to financing options can prevent otherwise cost-effective installations. CHP developers must navigate a complex landscape of project financing alternatives and provide detailed project information in order to attract investors. Inadequate information can cause project delays, leading investors to offer less favorable financial terms, or even decline a CHP investment opportunity all together.

Regulatory barriers can dramatically affect a CHP project's bottom line and projected payback period. An overarching barrier that affects the valuation of CHP throughout regulatory and policy discussions stems from the failure to account for the full value of CHP, including qualities such as resilience. Ignoring grid-wide and societal benefits affects how CHP is portrayed in standby rates, avoided cost rates, energy waste reduction standards and integrated resource planning. Standby rates, or charges a utility customer pays for the utility to provide backup service in case of a scheduled or unscheduled CHP system outage, can be so high as to completely undermine the economic viability of a proposed CHP system. Beyond standby rates, avoided cost or buyback rates under the Public Utility Regulatory Policies Act of 1978 (PURPA) may be insufficient to make a CHP project worthwhile. Interconnection processes can be lengthy, cumbersome and costly. Where states have embraced energy waste reduction (EWR) goals or standards, a failure to incorporate CHP, or to properly calculate energy savings from participating CHP systems, will lead to less than ideal deployment numbers. Finally, even as regulators and utilities embrace a longer-term resource planning approach, integrated resource planning (IRP) models often fail to recognize the value of CHP as both a supply side and demand side resource, resulting in CHP being overlooked in utility long-range resource plans.

Each of these barriers – which are often dependent on geography, project size and technology, utility constraints, and the prevailing regulatory climate – adds to the risk and cost associated with a potential CHP project. And since CHP is not regarded as part of most end-users' core business focus, it is often subject to higher investment hurdle rates than competing internal options.

Given the substantial capital investment involved in developing a CHP project, and in light of the benefits offered by more robust deployment of CHP, it is vitally important that these risks and costs be mitigated through thoughtful policies and incentives to avoid preventing CHP projects that would otherwise make good sense for Michigan businesses and the state's future energy mix.

Michigan businesses interested in CHP have access to the U.S. DOE's Midwest CHP Technical Assistance Partnership (TAP), managed by the Energy Resources Center and based in Chicago, Illinois. The Midwest CHP TAP promotes greater adoption of clean and efficient energy generation and use through CHP, district energy, and waste heat recovery. The Midwest CHP TAP provides a number of resources to potential CHP end-users including free or low-cost technical advisory services.

Roadmap for CHP Deployment

There is strong interest and capability for Michigan to move closer to optimal levels of CHP deployment. Currently, Michigan is home to over 3,300 MW of installed CHP capacity, and STEER indicates that ideal levels of CHP in Michigan include between 722 MW to 2,360 MW of new installed capacity. In order to pursue a greater role for CHP in Michigan's future energy mix, these recommendations reflect lessons learned from stakeholder surveys, interviews, Midwest CHP TAP experience and expertise, and best practices from other states.

1. **Offer financial incentives for CHP.** Payback period is critical to the development of a CHP project. Efforts to reduce the payback period of CHP by either defraying some of the initial upfront cost through a grant or offering a production incentive would be beneficial in addressing this barrier.
2. **Promote Property Assessed Clean Energy (PACE) financing and On-Bill Financing (OBF) for CHP.** PACE financing eliminates the high upfront cost and spreads the repayment over a long enough term that the annual savings generated from the CHP project exceed the PACE payments starting in the very first year. With OBF, the customer's costs of energy waste reduction retrofits or equipment are amortized and added to savings resulting from the measures on the customer's utility bill.
3. **Consider best practices in utility standby rates and PURPA avoided cost/buyback rates.** Standby rates are difficult are to interpret and navigate and negatively impact a CHP project's bottom line. The need for a revised approach to standby rates in Michigan stands as a prime example of a barrier to CHP that can be readily reduced or eliminated.
4. **Fully value CHP when considering the costs and benefits of distributed energy resources.** Michigan's current distributed generation program is targeted at small installations and does not include CHP. Future consideration of the costs and benefits of distributed energy resources should include CHP and attempt to capture its full value, including the value of resilience.
5. **Update interconnection standards to better align with new technologies and best practices.** Michigan's new energy law (passed in December 2016, PA341 and PA342) gives the MPSC authority to revisit and update the interconnection technical standards. Other states in the Midwest have recently revised their interconnection standards for small electrical generations to follow best practices and reflect the proposed standards in FERC Orders 792 and 792-A.
6. **Incorporate CHP as a resource in Michigan utility energy waste reduction (EWR) plans.** When allowed as an eligible measure, CHP can improve a utility's ability to meet energy reduction goals and further increase CHP deployment.
7. **Require utility IRP's to consider CHP as both a supply-side and demand-side resource.** This would help ensure that these complicated projects are allotted equivalent analyses as other resources.
8. **Collaborate closely with expert organizations (e.g. the Midwest CHP TAP) to promote CHP assistance.** These resources can be enormously helpful for those interested in developing CHP projects.

Moving Michigan Forward

Michigan is poised to move forward toward optimal levels of CHP development. According to the U.S. DOE, Michigan has nearly 5 GW of CHP technical potential at more than 10,000 sites across 17 industrial and 24 commercial sectors. STEER model results indicate that ideal levels of new CHP in Michigan, as a least-cost resource option, range between 722 MW to 2,360 MW.

This increase in CHP deployment will enhance Michigan's efforts to lead on energy waste reduction among other states. Currently, Michigan ranks 7th in the nation for potential annual CO_2 reductions from industrial energy efficiency and CHP and waste heat to power (WHP). In the 2017 American Council for an Energy Efficient Economy (ACEEE)Energy Efficiency Scorecard, Michigan was ranked 14th (tied with Arizona, Delaware, Iowa, New Jersey, New Mexico, Ohio, Texas, and Wisconsin) in the CHP category, slightly lower than its overall energy efficiency rank of 11th.

Demonstrating leadership in CHP development will serve to both reinforce and grow Michigan's demonstrated commitment to energy waste reduction. According to the Michigan Public Service Commission, regarding energy waste reduction overall, "For 2015, Michigan utility providers successfully complied with the energy savings targets laid out in PA 295. Providers met a combined average of 121 percent of their electric energy savings targets and 117 percent of their natural gas energy savings targets – one percent of retail sales for electric providers, and 0.75 percent of retail sales for gas providers. Energy Optimization programs across the state accounted for electric savings totaling over 1.1 million MWh (megawatt hours) and natural gas savings totaling over 4.58 million Mcf (thousand cubic feet) for program year 2015." CHP could be key to continuing to meet strong energy savings targets in the future. A single CHP system can offer the efficiency savings of many smaller energy efficiency projects. Given that some utilities are reporting a lower availability of cheap ("low hanging") energy efficiency savings opportunities in the commercial and industrial sector, CHP can offer deep savings at a very low cost, enhancing the overall cost-effectiveness of energy efficiency portfolios.

Execution of the Michigan CHP Roadmap will likely have significant impacts on the levels of CHP deployed in Michigan. For example, by addressing the CHP barrier of standby rates, STEER results using the EIA Reference Case indicate that Michigan could see an increase of 345 MW of CHP capacity built.

Additionally, CHP incentive programs in other states have seen dramatic results in additional CHP capacity coming online. The NYSERDA CHP incentive program has had an enormous market impact in New York. Between 2013 and 2016, the NYSERDA program has provided incentives to over 150 sites with a cumulative total capacity of over 70 MW. Similarly, in Illinois, the impact of the public sector CHP incentive was immediately felt, with the incentive program receiving 17 applications providing 31 MW of capacity. Through implementation of the Michigan CHP Roadmap, well-crafted CHP incentive programs could have similar positive effects on CHP development in Michigan.

Building on its strong commitment to energy waste reduction, Michigan is well-positioned to take advantage of the opportunities offered by increased CHP development in the state. By implementing the Michigan CHP Roadmap, the state can expand its energy waste reduction vision to include the many benefits of CHP, helping businesses to achieve their cost-savings and energy reliability goals. With key revisions to programs and policy, CHP has the potential to be a significant, reliable, cost-effective, and environmentally protective contributor to Michigan's energy mix.

1 Introduction

Michigan has the opportunity to capture enormous benefits by embracing optimal levels of combined heat and power (CHP) generation in the state's future energy mix. CHP provides a path to make Michigan businesses more competitive by lowering and stabilizing energy costs, reducing strain on the electric grid, improving on-site reliability and resiliency, and lowering harmful greenhouse gas emissions. Yet many studies have shown that CHP is a vastly underutilized energy resource across the country due to a combination of policy barriers, market impediments, and other factors. Michigan intends to be a leader in advancing CHP deployment and this Roadmap is a significant initial step in that effort.

Also known as cogeneration, CHP involves using one power system to generate both electricity and heat simultaneously from a single fuel source, and is the most fuel-efficient way to produce and utilize both electric and thermal energy. CHP systems typically reach fuel efficiencies of 65% to 80%, while the average efficiency of utility-scale electric generation has remained near 35% percent since the 1960s.[1]

CHP adoption across Michigan offers a low-cost approach to new electricity generation and uses highly skilled Michigan labor and technology to develop, implement, and operate projects. CHP is likely to enhance the competitiveness of Michigan's manufacturing, commercial, and institutional sectors, while lessening the need for new investments in utility transmission and distribution infrastructure.

Governor Snyder has made smart energy policy a top priority for Michigan, emphasizing the need to reduce energy waste and increase reliability. Through his leadership, the state remains focused on meeting its energy needs while protecting the environment and reducing customers' energy bills. Late in 2016, Governor Snyder signed into law an important package of energy legislation (MCL 460.6t(5)(g)), which accomplishes the following:

- Reduces energy waste by providing incentives for utilities to enhance current energy waste reduction programs;
- Ensures a reliable energy supply by requiring all electric providers to have adequate resources, using a market-driven approach;
- Allows customers to finance energy waste reduction projects through an itemized charge on utility bills; and
- Requires utilities' Integrated Resource Plans (IRPs) to include the projected energy and capacity purchased or produced by the utility from CHP resources, ensuring the use of reliable, cost-effective, and environmentally friendly energy.

This confluence of executive and legislative interest in formulating new energy policy, coupled with recognition of the potential of CHP to participate in meeting Michigan's energy needs, means the time is right to optimize and accelerate the deployment of CHP in Michigan.

This project differs from previous projects by applying cutting-edge integrated resource modeling tools to determine least-cost deployment options for CHP resources. The project team quantitatively modeled

[1] U.S. EPA. 2017. *Methods for Calculating CHP Efficiency*. https://www.epa.gov/chp/methods-calculating-chp-efficiency.

the optimized deployment of CHP in Michigan using a modified version of the State Tool for Electricity Emissions Reduction (STEER) model. STEER is an integrated resource planning model that calculates the least-cost resource portfolio to satisfy electricity demand and various reliability and environmental constraints based on projections of demand, fuel prices, technology price and performance, taxes, and other factors. STEER was used to assess, measure, and determine the cost and value of CHP as one of multiple resources in Michigan's future energy mix. Depending on natural gas prices and the availability of renewable energy resources, STEER recommended an optimal level of additional CHP deployment in Michigan ranging from 722 Megawatts (MW) to 1.014 Gigawatts (GW) by 2030.

In developing the Michigan CHP Roadmap, the STEER model was also customized to consider the impact of the value of resilience and standby rates on projected CHP deployment. Results showed that consideration of CHP's resilience value increases the potential deployment of CHP in sectors where loss of power is most consequential and can significantly increase CHP potential beyond the levels that would be supported by only the power sector value. According to STEER, resilience value could increase CHP potential by around 60%. On the other hand, standby rates, which apply to most grid-connected CHP projects, substantially reduce the profitability of CHP ownership and thereby reduce potential CHP deployment by 50% or more.

Parallel to this modeling effort, an intensive analysis of Michigan's CHP-related supply and value chains provides insight to support policy analyses and recommendations. Evaluation of the CHP supply and value chains in Michigan indicates a robust ability by Michigan firms to participate throughout the CHP value chain, with the majority of the economic impact of CHP being realized by using this pool of talent based in Michigan companies to design and implement CHP projects.

Finally, the Michigan CHP Roadmap provides a series of prioritized public policy recommendations that will put Michigan on a path to a CHP-friendly future, including recommendations to:

- Offer financial incentives for CHP in order to reduce the payback period for CHP projects;
- Promote Property Assessed Clean Energy (PACE) financing and encourage local communities to adopt PACE programs;
- Include CHP as eligible for on-bill financing;
- Include the full value of CHP (including the value of resilience) when considering the costs and benefits of distributed energy resources (DER), such as in a "Value of DER Study;"
- Consider best practices in utility standby rates and PURPA avoided cost/buyback rates;
- Update interconnection standards to better align with new technologies and best practices;
- Incorporate CHP as a resource in Michigan utility energy waste reduction (EWR) plans;
- Use a societal cost test for calculating energy savings from CHP in EWR plans;
- Require utilities to consider in integrated resource planning (IRP) the demand-side savings from utility-owned CHP and on-site CHP as both a supply-side and demand-side resource;
- Enable commercial and industrial property owners to utilize shared CHP assets under flexible terms;
- Collaborate closely with expert organizations, such as the Midwest CHP Technical Assistance Program (TAP), to promote CHP outreach and education in Michigan.

1.1 Project Goal

The goal of this project was to create a multifaceted, cohesive, replicable program that will help drive the adoption and deployment of CHP in Michigan. To do this, the project assessed the full range of CHP technologies and applications and used recently developed analytical capabilities to model the energy and cost savings derived from integrating CHP technologies into Michigan's power system. This project enlisted and mobilized the primary CHP supply and value chain constituencies – engineering, procurement, construction, and supply– to educate policymakers, legislators, utilities, and potential industrial and commercial end-users on the economic and environmental benefits of CHP technologies.

The actions steps completed during 2016 and 2017 to achieve this goal were:

- Model least-cost, optimized deployment of CHP as a clean, reliable, and fuel efficient energy resource in Michigan;
- Conduct field research, surveys and interviews, to obtain a complete picture of the economic development opportunity of CHP in Michigan, mapping both the supply and value chains;
- Use modeling results to explore and prioritize gaps and opportunities in the supply and value chains, while also using case studies and other data obtained from supply and value chain mapping effort to further refine data in modeling scenarios;
- Employ modeling results and supply and value chain maps to tell the complete story of CHP in Michigan, including key opportunities for how policymakers can eliminate barriers to help achieve the ideal level of cost-effective CHP deployment for the state;
- Engage with stakeholders throughout the state to build education and awareness among potential CHP end-users and value chain members who would be active during CHP project design, development, engineering, and construction stages.

2 Background

2.1 Combined Heat and Power (CHP)

CHP is the simultaneous generation of electricity and useful thermal energy from a single source of fuel, located at or near the point of energy use. Electricity is primarily used on-site as a substitute for utility-provided power. The thermal energy can be used to support process applications or human comfort through the production of steam, hot water, hot air, refrigeration, or chilled water.

Installed CHP systems typically achieve total energy efficiencies of 65% to 80%, compared to a weighted average of only about 45% to 60% for conventional separate heat (via boilers/furnaces) and power generation (via central utility plants).[2] By avoiding electric line losses and capturing much of the thermal energy normally wasted in power generation to provide heating and cooling to factories and businesses, CHP significantly reduces the total primary fuel needed to supply energy services, reducing air emissions and saving fuel and money.

[2] U.S. EPA. 2017. *Methods for Calculating CHP Efficiency*. https://www.epa.gov/chp/methods-calculating-chp-efficiency.

CHP systems can range in size from 5 kilowatts (kW; the demand of a typical single-family home) to several hundred MW (the demand of a very large industrial plant).[3] In general, the more efficiently the thermal energy can be utilized, the greater the net overall efficiency of the CHP system. Because fuel costs are the primary expenses for operational CHP systems, the more efficient the system is, the less fuel it consumes, and in turn, the less money the end-user likely spends on energy.

CHP technology can be deployed quickly, with few geographic limitations, and can be powered using a variety of fossil fuels and renewable resources. CHP may not be widely recognized outside industrial, commercial, institutional, and utility circles, but it has quietly been providing highly efficient electricity and process heat throughout the United States for decades to vital industries, large employers, urban centers, critical infrastructure like hospitals and wastewater treatment plants, and university campuses.

2.2 CHP Processes: Topping and Bottoming Cycle

There are two types of CHP processes -- topping cycle and bottoming cycle.[4] In a topping cycle CHP system, as depicted in **Figure 1**, fuel is consumed by a prime mover such as a gas turbine or reciprocating engine, generating electricity or mechanical power. Energy normally lost in the prime mover's hot exhaust or cooling systems is recovered to provide process heat, hot water, space heating, and/or cooling for the facility. Optimal topping CHP systems are typically designed and sized to meet a facility's baseload thermal demand. Heat production may offset energy requirements previously met with water heaters and steam boilers. The electric requirements of on-site air conditioning and refrigeration units may be offset by using absorption chiller technology to produce cold water or refrigerant.

[3] Cuttica, J. J. and Haefke C. May 14, 2009. U.S. DOE Industrial Technologies Program. *Combined Heat and Power: Is It Right For Your Facility?* Webcast Series. https://energy.gov/sites/prod/files/2013/11/f4/webcast_2009-0514_chp_in_facilities_2.pdf.
[4] U.S EPA. 2016. *What is CHP?* https://www.epa.gov/chp/what-chp.

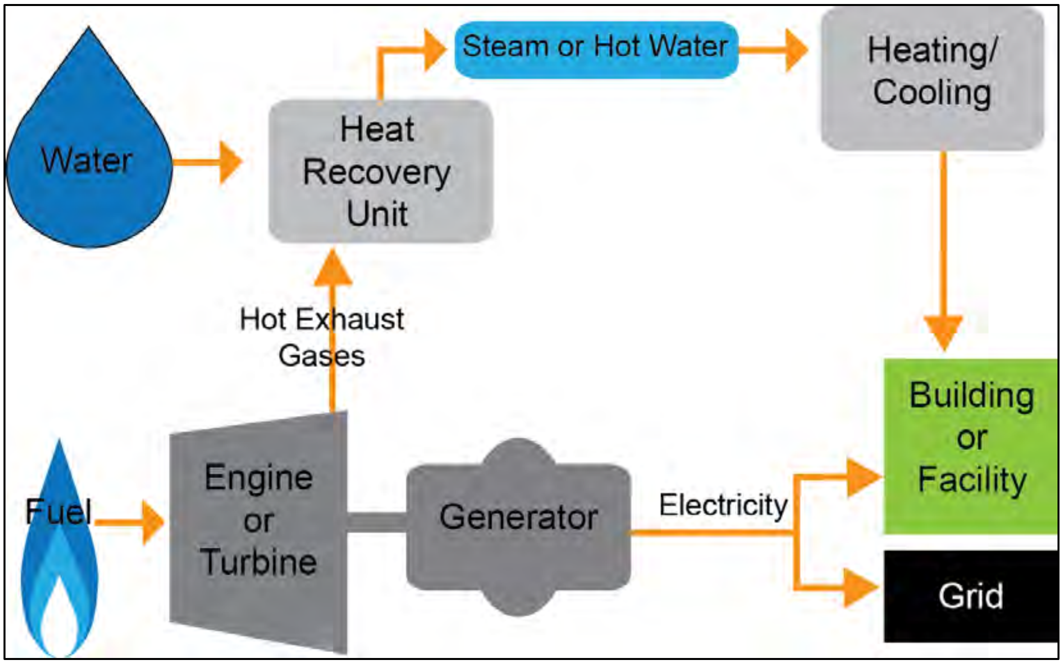


Figure 1: CHP Topping Cycle: Gas Turbine or Reciprocating Engine with Heat Recovery[5]

The bottoming cycle CHP process, which is alternatively known as waste heat to power (WHP), is depicted in **Figure 2**. In WHP, fuel is first used to provide thermal input to a furnace or other high temperature industrial process, and a portion of the heat rejected from the process is then recovered and used for power production, typically in a waste heat boiler/steam turbine system. WHP systems are a particularly beneficial form of CHP in that they utilize heat that would otherwise be wasted from an existing thermal process to produce electricity, without directly consuming additional fuel.

[5] Ibid.

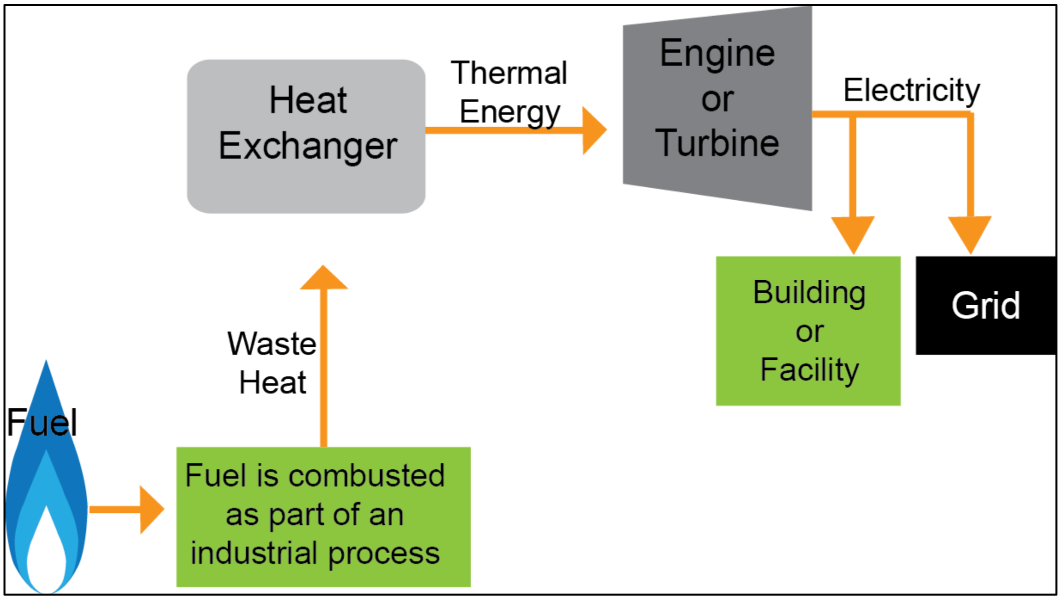


Figure 2: CHP Bottoming Cycle: Waste Heat to Power[6]

Topping cycle CHP installations may provide the local source of power generation around which microgrids can be designed. A microgrid is a group of interconnected power loads and distributed energy resources (DERs) such as CHP systems, solar panels, and batteries within clearly defined electrical boundaries that acts as a single controllable entity (micro-utility) with respect to the grid. A microgrid can connect and disconnect from the macro-utility grid to enable it to operate in both grid-connected or island-mode, providing distinct performance, resiliency, and economic benefits to energy users if managed and coordinated efficiently. Increased deployment of CHP in Michigan could present more opportunities for the development of microgrids, particularly in industrial parks or similar business clusters.[7]

[6] U.S EPA. 2016. *What is CHP?* https://www.epa.gov/chp/what-chp.
[7] Jones, D. and Tidball, R. ICF. 2016. *CHP for Microgrids: Resiliency Opportunities Through Locational Analysis*. https://www.icf.com/-/media/files/icf/white-papers/2016/energy-chp-microgrids.pdf.

2.3 Prime Mover Technologies

The United States Environmental Protection Agency (EPA) published a report in March 2015, which catalogs the various types of CHP technology.[8] According to the EPA, the five most common prime movers are fuel cells, gas turbines, micro gas turbines (microturbines), reciprocating engines, and steam turbines. Combined, these technologies comprised 97% of installations and 99% of CHP capacity installed in the U.S in 2016. **Table 1** provides a summary of the breakdown of prime movers for units under 100 MW – encompassing greater than 99.9% of all potential projects.

Fuel cells are the most recent of these innovations, and the least adopted, while steam turbines have been commonplace for over a century. Reciprocating engines, gas turbines, and microturbines comprise the bulk of new CHP installations.[9]

Prime Mover	Sites	Share of Sites	Capacity (MW)	Share of Capacity
Reciprocating Engine	2,194	51.9%	2,288	2.7%
Gas Turbine*	667	15.8%	53,320	64.0%
Boiler/Steam Turbine	734	17.4%	26,741	32.1%
Microturbine	355	8.4%	78	0.1%
Fuel Cell	155	3.7%	84	0.1%
Other	121	2.9%	806	1.0%
Total	**4,226**	**100.0%**	**83,317**	**100.0%**

Table 1: Economic Potential for CHP Units Less than 100 MW[10]

Installed capital costs for these technologies vary significantly depending on the scope of the plant equipment, geographical area, competitive market conditions, special site requirements, emissions control requirements, and prevailing labor rates. Prime mover packages themselves decline in cost, on an electrical capacity basis, only slightly as systems increase in scale. However, ancillary equipment such heat recovery steam generators (HRSG), gas compressors, water treatment systems, and electrical equipment achieve much lower costs per unit of electrical output as the systems become larger.

The description of each prime mover technology provided below is a summary of information provided in the EPA Catalog of CHP Technologies.[11] The U.S. Department of Energy (DOE) Midwest CHP TAP also describes the five prime mover technologies in additional detail.[12]

[8] U.S. EPA. 2017. *Catalog of CHP Technologies*. http://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf.
[9] Ibid.
[10] Ibid.
[11] Ibid.
[12] U.S. DOE Midwest CHP Technical Assistance Partnerships (TAP). http://www.midwestchptap.org.

Reciprocating Engines

Reciprocating internal combustion engines are the most widespread technology for power generation up to 5 MW. These engines start quickly, follow electric load well, and generally are highly reliable. They are effective in applications that require hot water or low-pressure steam as the heat carrier. Natural gas is the typical fuel, but propane, landfill gas, or biogas can also be used.

There are nearly 2,400 reciprocating engine CHP installations in the United States, accounting for 54% of the total number of installed CHP systems and nearly 2.4 GW, or 3%, of total capacity. Individual engine units range in size from less than 50 kW up to 10 MW. In Michigan, 30 sites utilize reciprocating engine technology, accounting for nearly 60 MW of capacity. Common applications for reciprocating engine CHP systems include universities, hospitals, water treatment facilities, industrial facilities, commercial buildings, and multi-family dwellings.

Routine maintenance of reciprocating engines is required after approximately 2,000 hours of operation to ensure optimal engine performance. Engine overhauls are required every 32,000 to 64,000 hours of operation, depending on service, and typically include a complete inspection and rebuild of components to restore the reciprocating engine to nearly original or current (upgraded) performance standards. Engine maintenance costs can vary significantly depending on the quality and diligence of the preventative maintenance program and operating conditions.

Gas Combustion Turbines

Gas combustion turbines (also referred to simply as gas turbines or combustion turbines) are available in sizes ranging from 1 MW to more than 300 MW. They produce high-quality heat that can be used to generate steam for on-site use. In large applications, typically above 40 MW, the steam can be used to drive a steam turbine, generating additional electricity, in an arrangement known as “combined cycle.”

In CHP applications, gas turbines typically have favorable economics for system sizes greater than 5 MW. Gas turbines account for 52 GW of installed CHP capacity in the United States, representing 64% of the total installed CHP capacity. Michigan features 19 gas turbine installations and an aggregate installed capacity of 2.8 GW, which represents over 80% of Michigan’s 3.4 GW of installed CHP capacity. Gas turbines are well suited for industrial CHP applications because the high temperature gas turbine exhaust can either be used to generate high pressure steam or used directly for heating or drying.

Routine maintenance practices include predictive maintenance, plotting trends, performance testing, vibration analysis, and preventive maintenance procedures. Typically, routine inspections are required every 4,000 hours of operation to ensure that the turbine is free of excessive vibration due to worn bearings and rotors or damaged blade tips. A gas turbine overhaul is needed every 25,000 to 50,000 hours of operation, depending on service, and typically includes a complete inspection and rebuild of components to restore the gas turbine to nearly original or current (upgraded) performance standards. Gas turbine maintenance costs can vary significantly depending on the quality and diligence of the preventative maintenance program and operating conditions and reliance on the turbine distributor to supply the required labor.

Steam Turbines

Steam turbines are a mature technology and have been used since the 1880s for electricity production. These systems burn fuel in a boiler to generate high-pressure steam that is transferred to a turbine that powers a generator. Steam turbine-based CHP systems are most often used in medium- and large-scale industrial or institutional facilities with high thermal loads, and where solid or waste fuels are readily available for combustion in the boiler.

Most of the electricity generated in the United States is produced by steam turbines in central station power plants. Steam turbines are also commonly used for CHP installations, of which there are 699 sites in the United States. These steam turbine CHP installations have an average capacity of 37 MW and a combined capacity of 26 GW, representing 32% of total installed CHP capacity. In Michigan, steam turbines are installed at 31 sites, accounting for 500 MW of capacity. The majority of these CHP steam turbines are at industrial plants, commercial buildings with high thermal loads, and district heating sites.

Microturbines

Microturbines are relatively small combustion turbines that can use gaseous or liquid fuels. They produce hot water or low-pressure steam for a variety of applications, including potable water heating, absorption chillers and desiccant dehumidification equipment, space heating, process heating, and other building uses.

Microturbines emerged as a CHP option in the 1990s, evolving from the technology used in turbochargers and auxiliary power units which are lightweight and have few moving parts. Individual microturbines range in size from 30 to 330 kW and can be integrated to provide modular packages with capacities exceeding 1,000 kW. There are over 360 sites in the United States that currently use microturbines for CHP, accounting for over 8% of the total number of CHP sites and 92 MW, or 0.1%, of aggregate capacity. In Michigan, 5 sites utilize an aggregate 1.6 MW of microturbine CHP technology.

Fuel Cells

Fuel cells use an electrochemical process similar to a battery to convert the chemical energy of hydrogen into water and electricity. In CHP applications, heat is generally recovered in the form of hot water or low-pressure steam.[13] The hydrogen can be obtained from natural gas, coal gas, methanol, and other hydrocarbon fuels. Fuel cells are highly efficient, quiet, and clean running.

There are 126 fuel cells installed in the United States that are configured for CHP operation, accounting for a combined capacity of 67 MW, or less than 0.1% of total US CHP capacity. None are currently installed in Michigan. The majority of these fuel cells are used in commercial and institutional buildings (such as universities, hospitals, nursing homes, hotels, and office buildings) where there is a relatively

[13] Rajalakshmi, N. and Dhathathreyan, K. S. 2008. *Present Trends in Fuel Cell Technology Development*. Nova Publishers, p. 104.

high coincident demand for electricity and thermal energy. Fuel cell capital costs have decreased in recent years, leading to an increase in the adoption of this technology in CHP projects. As in any CHP application, thermal load displacement can improve operating economies of a fuel cell system.

2.4 Reliability and Resiliency Benefits

Aging U.S. electricity infrastructure presents a significant concern to commercial and industrial (CI) facilities in meeting their power needs, as grid outages become increasingly frequent. The Electric Power Research Institute (EPRI) estimates that over $150 billion per year is lost by U.S. industries due to electric network (reliability) problems.[14]

When properly configured to operate independently from the grid, CHP systems can provide critical power reliability for businesses and critical infrastructure facilities while providing electric and thermal energy to the sites on a continuous basis, resulting in daily operating cost savings.[15] A more resilient energy supply also prevents lost business productivity and decreases the likelihood of crippling power outages. By installing properly sized and configured CHP systems, Michigan facilities can effectively insulate themselves from a grid failure, providing continuity of critical services and freeing power restoration efforts to focus on other facilities in periods of emergency.

There are a number of ways in which CHP systems can be configured to meet the specific reliability needs and risk profiles of various customers, and to offset the capital cost investment for traditional backup power measures. Most CI facilities and even some non-CI facilities have backup generators on-site to supply electricity in the case of an outage. While the presence of a CHP system may not override the necessity, or in some sectors the legal requirement to have a backup generator, CHP systems provide regular benefits to their host facilities, rather than just during emergencies. Some advantages that CHP systems have over backup generators include:[16]

- Backup generators are seldom used and can often be poorly maintained. This can result in operational problems during an actual emergency. Most CHP systems run daily and are typically better maintained.
- Backup generators rely on a finite supply of fuel on site, generally enough supply to last only a few hours or days, after which fuel deliveries are required. Most CHP systems have a permanent source of fuel on demand. For example, in the case of CHP systems powered by natural gas, most natural gas infrastructure is underground and rarely impacted by severe weather events.
- Backup generators may take time to start up after a grid failure. This lag time, even though it may be brief, can result in the shutdown of critical systems. In some cases, backup generators not permanently located on-site must be delivered to the sites where they are needed, leading to further delays.

---

[14] Rouse, G. and Kelly, J. Galvin Electricity Initiative. 2011. *Electric Reliability: Problems, Progress, and Policy Solutions.* http://www.galvinpower.org/sites/default/files/Electricity_Reliability_031611.pdf.

[15] Hampson, A., et al. ICF International. Prepared for Oak Ridge National Laboratory. 2013. *Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities.* https://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_critical_facilities.pdf.

[16] Ibid.

- Backup generators by and large typically rely on diesel fuel, a fuel which emits greater quantities of air pollutants compared to natural gas. The majority of CHP systems burn natural gas, thereby emitting less pollution in addition to significantly greater efficiencies and lower fuel costs.
- Backup generators only supply electricity; whereas, CHP systems supply thermal loads (heating, cooling, chilled water) as well as electricity to keep facilities operating as usual.

In a CHP system designed for reliability, the electric grid serves as the first level of backup to the CHP system. When the CHP system is down, the grid supplies the entire electricity load to the plant. In the unlikely event that both the CHP system and the grid are down at the same time, standby generators could be used to maintain critical loads. In certain applications, the value of this additional reliability can outweigh all other factors in the investment decision.

The requirements for a CHP system to deliver power reliability are straightforward. While CHP systems may or may not be designed to provide a facility's entire power demand, CHP can be configured to maintain critical loads in the event of a utility grid outage. To implement this capability, additional costs are often required including engineering, controls, labor and materials. The engineering required to analyze the existing electrical system, determine critical loads, provide a design and determine cost to provide back-up power from the system, may be extensive. A CHP system designed to supply the entire power needs of a facility during an outage may need to be oversized compared to the optimal design or require redundant units that would add to the cost.

2.5 CHP Market Summary

The DOE published a report in March 2016, which outlines the current status and technical potential for CHP for each state.[17] DOE data indicate that the U.S. currently has about 85 GW of CHP-based electric capacity installed, which represents nearly 9% of total installed electric capacity. Installed CHP systems generate about 505 million megawatt-hours (MWh) of electricity each year, or more than 12% of total U.S. 2016 generation. Compared to the average fossil-based electricity generation, this CHP portfolio eliminates 240 million metric tons of carbon dioxide emissions each year (equivalent to the emissions from 40 million cars).[18]

In Michigan, the total installed CHP capacity of 3.4 GW generates about 27 million MWh of electricity each year distributed among 87 locations and represents roughly 24% of total statewide generation. These CHP facilities provide power and thermal energy to users across a range of CI market sectors. The industrial chemicals sector is best represented, with 1,600+ MW of generation spread across 12 sites and is led by the state's largest CHP facility, Dow Corning's 1,370 MW plant in Midland.[19] Beyond

[17] U.S. DOE. 2016. *Combined Heat and Power (CHP) Technical Potential in the United States*. https://www.energy.gov/eere/amo/downloads/new-release-us-doe-analysis-combined-heat-and-power-chp-technical-potential.

[18] State and Local Energy Efficiency Action Network. U.S. DOE. 2013. *Guide to the Successful Implementation of State Combined Heat and Power Policies*. p. 4. https://www4.eere.energy.gov/seeaction/system/files/documents/see_action_chp_policies_guide.pdf.

[19] We note that this facility is an extreme outlier in Michigan in terms of its size and scale.

industrial chemicals, the major users of CHP technology in Michigan are large public colleges and universities, pulp and paper mills, solid waste facilities, automotive factories, and agricultural processing plants.

The DOE Combined Heat and Power Installation Database, cataloging all operating CHP facilities in the nation, is publicly available online.[20] Nationwide investment in CHP declined in the early 2000s due to changes in the wholesale market for electricity and increasingly volatile natural gas prices. For example, in Michigan, from 2011 through 2015, only 10 CHP projects were commissioned, representing just 120 MW of capacity.

However, CHP's potential role as a clean energy source for the future is much greater than these recent market trends would indicate. Multiple factors point toward continued levels of CHP market penetration, including continued technological advancements reducing capital costs, new business and investment models, favorable incentives and policies, continued desire for low emissions profiles, and a recognition of the resiliency and reliability advantages of distributed energy.

Efficient on-site CHP represents a largely untapped resource that exists in a variety of energy-intensive industries and businesses. DOE estimates the technical potential for additional CHP at existing industrial facilities is slightly less than 65 GW and the technical potential for CHP at commercial and institutional facilities is slightly more than 65 GW, for a national total of about 130 GW.[21] A 2009 study by McKinsey & Company estimated that 50 GW of CHP in industrial and large commercial and institutional applications could be deployed at reasonable returns under then current equipment and energy prices.[22] These estimates of both technical and economic potential are likely greater today given the improved outlook in natural gas supply and pricing.

CHP deployment can also lead directly to greater deployment of renewable energy resources. Many renewable energy projects, such as biomass and solar, are often of an insufficient scale to be financially viable as stand-alone projects. Renewable fuels such as biogas or landfill gas can be co-fired with natural gas to enable larger scale, more cost-effective CHP installations than supply constraints of the renewable fuel might otherwise allow. A combined, larger-capacity solar/CHP project in some applications will yield an investment which is economically-viable, whereas neither solar nor CHP as smaller-capacity stand-alone projects are viable due to large fixed electrical grid interconnection costs.

The framework for a robust Michigan CHP industry is currently in place. As will be discussed in Section 5 of this Michigan CHP Roadmap, existing Michigan companies are well-positioned to supply the intellectual capital and skilled trades required to develop, design, finance, install/construct/integrate, operate, and maintain CHP systems. Economic value is primarily realized by employing the state's talent

---

[20] U.S. DOE. 2016. *Combined Heat and Power Installation Database*. https://doe.icfwebservices.com/chpdb/.
[21] State and Local Energy Efficiency Action Network. U.S. DOE. 2013. *Guide to the Successful Implementation of State Combined Heat and Power Policies*. p. 4.
https://www4.eere.energy.gov/seeaction/system/files/documents/see_action_chp_policies_guide.pdf.
[22] Granade, H. C., et al. McKinsey & Company. 2009. *Unlocking Energy Efficiency in the U.S. Economy*.
https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&ved=0ahUKEwipv7eB0-TYAhUEG6wKHet5DycQFggpMAA&url=https%3A%2F%2Fwww.mckinsey.com%2Fclient_service%2Felectric_power_and_natural_gas%2Flatest_thinking%2F~%2Fmedia%2F204463a4d27a419ba8d05a6c280a9.

pool and fuel suppliers throughout each project's 20- to 30-year useful lifecycle. Michigan companies are not particularly well-positioned to manufacture the principal energy equipment. But they will find opportunities in ancillary equipment manufacturing as well as in distribution and maintenance of both domestic and internationally-sourced CHP equipment.

2.6 Current Status of CHP Policy in Michigan

Historically, there have been a variety of policies and incentives in place to encourage the use of CHP. An enduring example is the DOE CHP TAPs, formerly called the Clean Energy Application Centers (CEACs), which promote and assist in transforming the market for CHP across the country. Services include market opportunity analyses, education and outreach, and technical assistance. Michigan is served by the Midwest CHP TAP, managed through the Energy Resources Center at the University of Illinois at Chicago.[23]

The federal Business Energy Investment Tax Credit (ITC) previously provided a non-refundable tax credit equal to 10% of expenditures related to CHP systems up to 50 MW in capacity that exceeded 60% energy efficiency. This credit expired at the end of 2016 and renewal is very unlikely.

At the state level, the Michigan legislature passed significant energy legislation at the end of 2016, including provisions affecting cogeneration. Public Act (PA) 341 of 2016 set criteria to be considered in an individual utility Integrated Resource Plan (IRP) filing with the Michigan Public Service Commission (MPSC). As of April 2017, CHP must be considered in a utility's IRP, which must be filed with the MPSC no later than April 2019. Specifically, a utility IRP must include the projected energy and capacity purchased or produced by the utility from a cogeneration resource (MCL 460.6t(5)(g)).

Also as part of this energy legislation, as of April 2017, renewable-fueled steam generation is included in the definition of "renewable energy."[24] However, PA 342 of 2016 also repealed Section 43 of PA 295, which provided that advanced cleaner energy credits could be created by cogeneration and Section 27, which provided the ability to substitute advanced cleaner energy credits for renewable energy credits. As a result, cogeneration does not qualify as renewable energy and can no longer be used to meet the requirements of the RPS under PA 342. [25] Despite their significance, these recent legislative changes are not expected to significantly affect the level of CHP deployment in Michigan.

One area of positive progress in Michigan is Property Assessed Clean Energy (PACE) financing, which is currently available in 23 Michigan counties and 2 large cities (Grand Rapids and Wyoming). PACE for CHP creates a system in which private sector loans are made to property owners to pay for up to 100% of

[23] U.S. DOE. Office of Energy Efficiency and Renewable Energy. 2017. *CHP Technical Assistance Partnerships (CHP TAPs)*. https://www.energy.gov/eere/amo/chp-technical-assistance-partnerships-chp-taps.

[24] According to PA 342 of 2016, one Renewable Energy Credit (REC) will be issued for each MWh of electricity generated, including the steam equivalent of a MWh of electricity. RECs are the currency of the Michigan Renewable Portfolio Standard (RPS).

[25] PA 295 of 2008, Section 27 generally limits the combined use of energy optimization credits and advanced cleaner energy credits to 10% of an electric provider's renewable energy credit standard. However, this limitation does not appear to have impacted the development of cogeneration based on electric provider's responses to this question as part of their annual reporting to the MPSC.

CHP investments, with repayment of those loans occurring through a "special assessment" on the site's property taxes. This mechanism allows for CHP investments without any up-front capital investment by the property owner, substantially mitigating financial risk while leveraging the return on investment. If the property is sold, the special assessment remains with the property. Additional information on PACE program attributes and participating local governments can be found in **Attachment A**.

2.7 Recent Efforts to Examine Standby Rates for CHP

From January 2016 through February 2017, the MPSC staff hosted a working group on standby rates. The Association of Businesses Advocating for Tariff Equity (ABATE), Michigan Energy Innovation Business Council (Michigan EIBC), Alliance for Industrial Efficiency, Electricity Consumers Resource Council, Midwest Cogeneration Association, Consumers Energy Company and DTE Energy Company all submitted comments to the MPSC staff to inform the final working group report, issued in June 2017.

In the MPSC staff's first standby rate working group report, published in August 2016, the purpose of the workgroup was described as the following:

> Ensuring that utility standby service tariffs are appropriately recovering only the costs attributable to the self-generation customer can result in complex analysis and billing. There is some concern in the self-generation community that standby rates in Michigan may not be set appropriately – particularly for small-scale CHP and intermittent resources such as solar and wind generation, but also in some cases for large-scale CHP. With the burgeoning interest in these types of projects by potential self-generation customers and project developers, greater understanding of these complicated standby service tariffs is essential. It is an opportune time to determine whether the current standby service tariffs reflect the cost of serving self-generation customers with CHP or solar and address concerns of the self-generation community.[26]

As part of the working group process, Michigan utility standby rates for CHP sites were analyzed and compared to the standby rates of other utilities in the Midwest.[27] The analysis found that standby charges experienced in Michigan are relatively high, potentially posing a barrier to CHP deployment.[28] Further, the analysis found that standby tariffs in Michigan can be confusing and difficult for customers to navigate.[29] While no formal requirements came out of the working group process, the MPSC staff issued several recommendations related to standby rate best practices.[30]

Coming out of the MPSC staff standby rate working group, engagement in the overall discussion of standby rates continued, and some interested parties went on to pursue formal intervention in utility general rate cases as a means of continuing to raise concerns about the effect of standby rates on CHP installations. Outside of formal intervention, businesses and associations have expressed their support

---

[26] Michigan Public Service Commission Staff. 2016. *Standby Rate Working Group August 19, 2016 Report*. http://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-376753--,00.html.
[27] 5 Lakes Energy. 2016. *Consumers Energy: Standby Rate Tariff Scenarios*. http://www.michigan.gov/documents/mpsc/5LE_Standby_Rate_Scenarios_10182016_538289_7.pdf.
[28] Ibid.
[29] Ibid.
[30] Michigan Public Service Commission Staff. 2017. *Standby Rate Working Group Supplemental Report June 2017*. http://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-376753--,00.html.

for standby rate reform through comments and sign-on letters submitted to the MPSC.[31] As utilities continue to refine and develop the ways in which they interact with customers with CHP projects, there will likely continue to be attention paid to aligning standby rates with best practices, and making sure these rates reflect a utility's cost of service.

2.8 Roadmap Purpose

The purpose of the CHP Roadmap is to help drive the adoption and deployment of CHP in Michigan through an assessment of CHP technologies and applications, use of integrated resource planning (IRP) modeling to determine the energy and cost savings derived from integrating CHP technologies into Michigan's power system, identification and cataloging of CHP business constituencies, and education of policymakers, legislators, utilities, business, and industrial nd-users on the economic and environmental benefits of CHP technologies.

Against the backdrop of Michigan's energy legislation passed in December 2016, renewed interest in distributed generation such as CHP, and recent efforts to examine elements of rate design affecting distributed generation resources, there is a desire to better understand the opportunities and barriers to CHP deployment in Michigan, and to identify a path forward. In order to examine how CHP can contribute to Michigan's future energy mix on a least-cost basis, the STEER model is utilized, with the benefit of an enhanced CHP suite of technologies and applications. The results of this modeling effort show that CHP can play an important, cost-effective role in Michigan's future energy mix. In parallel with this modeling effort, the policy and regulatory barriers to greater CHP penetration are identified, along with recommended solutions to address these barriers in Michigan.

A strong stakeholder engagement process is key to optimizing deployment of CHP in Michigan. The development of the CHP Roadmap has involved state energy, environmental, economic development, and regulatory agencies, as well as participation from utilities, universities, trade associations, project developers, equipment suppliers, engineering firms, and current and prospective CHP end-users. These stakeholders have helped to refine the barriers, identify potential solutions, and recommend best practices most suitable for Michigan. The process of working closely with stakeholders on policy development and education also represents an important first step in increasing education and outreach about the benefits and opportunities offered by CHP. Building on this foundation, and with the aid of the information contained in the CHP Roadmap, Michigan's CHP education and outreach effort can continue into the future, encouraging and supporting optimized CHP deployment in the years to come.

---

[31] Michigan Public Service Commission Staff. 2017. Public comments. http://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-376753--,00.html.

2.9 Prior Studies

A number of important CHP studies have been conducted. According to the DOE, "states, utilities, and non-governmental organizations across the country have commissioned analyses over the years to identify potential energy savings (typically for electricity) available within their jurisdictions. These studies can be used to fulfill a variety of needs, including energy efficiency program planning, state goal setting, utility resource planning, and other priorities."[32]

Among the most useful in identifying opportunities for both energy savings and economic development have been studies of CHP potential. These studies quantify the size of particular resource, such as MW of CHP development, under different scenarios and within a specific geography. According to the American Gas Association (AGA), "estimates on the untapped potential of CHP in the United States vary considerably depending on how 'potential' is defined and calculated. While investment in CHP applications has remained low since 2005, recent market activity suggests the potential for a rebound in CHP development powered by three critical drivers: 1) the changing outlook for natural gas supply and price; 2) environmental regulatory pressures on power plants and industrial boilers, and 3) growing federal and state policymaker support."[33]

CHP potential studies can be viewed as a subset of energy efficiency potential studies, which according to the American Council for an Energy-Efficient Economy (ACEEE), fall into three categories:

- Technical potential studies, which describe an ideal scenario that sums all energy efficiency measures that are feasible given technology limitations;
- Economic potential studies, which describe the fraction of the technical potential that is cost-effective;
- Achievable potential studies, which describe the fraction of the economic potential that is attainable given actual program infrastructure and both societal and market limitations.[34]

Importantly, according to the Alliance for Industrial Efficiency (AIE), "technical potential provides an estimation of market size constrained only by technological limits – the ability of CHP technologies to fit customer energy needs. It does not include economic or other considerations relevant to a decision to invest in CHP."[35]

In terms of CHP potential in the state of Michigan, there have been an array of different estimates throughout the years. In 2007, "Michigan's 21st Century Electric Energy Plan" – a study modeling technical and economic potential of a number of different energy resources, with a view toward evaluation of policy initiatives – examined Michigan's short and long term electric needs through 2025. The Plan utilized extensive modeling to enhance the understanding of Michigan's energy needs and to verify policy initiatives, and sought to advance the goals of supporting economic development,

---

[32] U.S. DOE. Office of Energy Efficiency and Renewable Energy. 2017. *Energy Efficiency Potential Studies Catalog*. https://www.energy.gov/eere/slsc/energy-efficiency-potential-studies-catalog.

[33] ICF International, Inc. Prepared for the American Gas Association (AGA). 2013. *The Opportunity for CHP in the United States*. p. ES-1. https://www.aga.org/research/reports/the-opportunity-for-chp-in-the-us---may-2013/.

[34] American Council for an Energy Efficient Economy (ACEEE). *Efficiency Potential and Market Analysis*. https://aceee.org/topics/efficiency-potential-and-market-analysis.

[35] Alliance for Industrial Efficiency (AIE). 2015. *Combined Heat and Power (CHP) as a Compliance Option under the Clean Power Plan*. https://alliance4industrialefficiency.org/resources/chp-as-a-compliance-option-under-the-clean-power-plan/.

improving environmental quality and promoting resource diversity, while ensuring reliable electric power.[36] With regard to CHP potential, The Plan stated:

> Modeling indicates a potential for at least 1,100 MW, and up to 2,700 MW, of new electric power capacity development in Michigan from renewable resources with another 180 MW available from combined heat and power, or CHP. Forecasting in this area is particularly problematic, in light of the rapid pace of technological advancements and policy changes that will affect renewables. It is thus important to revisit renewable resource modeling on a regular basis and to expand the renewable portfolio when appropriate.[37]

In May 2013, ICF International, Inc. (ICF) prepared for the AGA a study titled "The Opportunity for CHP in the United States."[38] Table 2 illustrates the state-by-state economic potential for CHP units less than 100 MW in size. The study found that there was 803 MW of CHP potential in Michigan in the 5-10 year payback range, and 3605 MW of CHP potential in the >10 year time frame.[39]

State	Technical Potential by Payback Range, MW			Total Technical Potential	State	Technical Potential by Payback Range, MW			Total Technical Potential
	Minimal Potential, Payback >10 yrs	Moderate Potential, Payback 5-10 yrs	Strong Potential, Payback <5yrs			Minimal Potential, Payback >10 yrs	Moderate Potential, Payback 5-10 yrs	Strong Potential, Payback <5yrs	
Alabama	1,512	416	0	1,928	Missouri	2,532	0	0	2,532
Alaska	0	52	130	181	Montana	343	0	0	343
Arizona	1,561	134	0	1,695	Nebraska	718	26	0	744
Arkansas	1,384	0	0	1,384	Nevada	999	0	0	999
California	2,807	8,283	735	11,826	New Hampshire	0	497	74	571
Colorado	1,211	208	0	1,419	New Jersey	1,159	2,301	341	3,801
Connecticut	0	796	621	1,417	New Mexico	493	76	0	569
Delaware	254	144	0	398	New York	0	5,993	3,367	9,360
Dist of Columbia	321	0	0	321	North Carolina	3,726	632	0	4,358
Florida	2,541	2,098	104	4,744	North Dakota	324	0	0	324
Georgia	3,256	555	0	3,811	Ohio	5,951	0	0	5,951
Hawaii	77	212	86	376	Oklahoma	1,295	0	0	1,295
Idaho	469	0	0	469	Oregon	1,472	0	0	1,472
Illinois	4,626	727	0	5,354	Pennsylvania	4,972	1,143	0	6,115
Indiana	2,705	0	0	2,705	Rhode Island	203	198	35	436
Iowa	1,573	0	0	1,573	South Carolina	1,962	386	0	2,348
Kansas	1,126	96	0	1,222	South Dakota	332	0	0	332
Kentucky	1,607	932	0	2,539	Tennessee	2,143	594	0	2,737
Louisiana	1,864	658	0	2,523	Texas	5,716	1,836	384	7,935
Maine	582	237	0	820	Utah	881	0	0	881
Maryland	1,450	306	0	1,756	Vermont	0	282	12	293
Massachusetts	282	2,078	466	2,826	Virginia	2,570	490	0	3,060
Michigan	3,605	803	0	4,408	Washington	2,201	0	0	2,201
Minnesota	2,230	327	0	2,557	West Virginia	545	244	0	789
Mississippi	1,086	274	0	1,360	Wisconsin	2,859	1,114	0	3,973
					Wyoming	166	110	0	275
					U.S. Total	81,691	35,257	6,355	123,303

Table 2: Economic Potential for CHP Units Less than 100 MW[40]

[36] Lark, P. J. Michigan Public Service Commission. 2007. *Michigan's 21st Century Electric Energy Pl*an. p. 1. https://www.michigan.gov/documents/mpsc/21stcenturyenergyplan_185274_7.pdf.
[37] Ibid., p. 26.
[38] ICF International, Inc. Prepared for the American Gas Association (AGA). 2013. *The Opportunity for CHP in the United States*. p. ES-1. https://www.aga.org/research/reports/the-opportunity-for-chp-in-the-us---may-2013/.
[39] Ibid.
[40] Ibid.

According to the study, projects with greater than 10 year projected payback periods have minimal potential; the range of 5-10 years for payback represents moderate potential; and a project payback of less than 5 years is considered to have strong potential.[41] This finding underscores a major barrier to CHP deployment in Michigan the payback period, which is further discussed in Sections 6 and 7 of this report.

More recently, the U.S. DOE estimated that “Michigan has 4,987 MW of CHP technical potential capacity identified at 10,370 sites.”[42] The DOE Technical Potential study notes that “the outlook for increased CHP use is bright as policymakers at the federal and state level are recognizing the potential benefits and the role that this technology could play in providing clean, reliable, cost-effective energy services to industry and businesses.”[43]

Internationally, there is a major CHP roadmapping effort underway throughout the European Union. Pursuant to Cogeneration Directive (2004/8/EC) European Union member states have “identified their cogeneration potential out to 2020 but many have failed or are failing to make progress on cogeneration despite the wide range of support measures which are in place.”[44] The CODE2 project aims to support the development of 27 National Cogeneration Roadmaps[45] and one European Cogeneration Roadmap. The project will also “develop ‘How-to’ guides focused on understanding the cogeneration legislation and business case to simplify first steps for new users.”[46] A major goal of the CODE2 project is to recommend policy measures to increase the deployment of CHP in participating nations.[47] For example, as part of the CODE2 project, a study titled “Final CHP Roadmap Ireland” was published in November 2014. This Final CHP Roadmap Ireland draws from a previous study called “Cogeneration Potential in Ireland” published in 2009 by Sustainable Energy Authority of Ireland. This earlier study estimated CHP potential in 2020 across multiple scenarios using historic patterns of deployment and the effects of various policies. The 2014 “Final CHP Roadmap Ireland” was further updated in 2016 by a study titled “Combined Heat and Power in Ireland: 2016 Update,” which provided an update on Ireland’s installed CHP capacity and associated energy savings and carbon reductions.[48]

---

[41] Lark, P. J. Michigan Public Service Commission. 2007. *Michigan’s 21st Century Electric Energy Pl*an. p. ES-2. https://www.michigan.gov/documents/mpsc/21stcenturyenergyplan_185274_7.pdf.
[42] U.S. DOE. 2016. *Combined Heat and Power (CHP) Technical Potential in the United States*. p. 56. https://www.energy.gov/eere/amo/downloads/new-release-us-doe-analysis-combined-heat-and-power-chp-technical-potential.
[43] Ibid., p. 1.
[44] Cogeneration Observatory and Dissemination Europe. 2014. http://www.code2-project.eu/about/.
[45] Countries covered by the CODE2 Project include Austria, Belgium, Bulgaria, Cyprus, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovakia, Slovenia, Spain, Sweden, United Kingdom. CHP Roadmaps are available at http://www.code2-project.eu/code-regions/.
[46] Cogeneration Observatory and Dissemination Europe. 2014. http://www.code2-project.eu/about/.
[47] Ibid.
[48] Howley, M. and Holland, M. Sustainable Energy Authority of Ireland. 2016. *Combined Heat and Power in Ireland: 2016 Updat*e. https://www.seai.ie/resources/publications/Combined%20Heat%20and%20Power%20in%20Ireland%20Update%202016.

The "Final CHP Roadmap Ireland" was developed to better understand market and policy factors affecting CHP penetration, map supply and value chain opportunities for manufacturers and project implementers, and determine ways to accelerate deployment. In this way, the "Final CHP Roadmap Ireland" is similar to this Michigan CHP Roadmap. A key difference, however, is that the Michigan CHP Roadmap benefits from the STEER model's rigorous CHP technology and application suite, which allows for characterization of a range of CHP technologies and sizes, and dispatch of individual CHP units on an hourly basis. The Michigan CHP Roadmap also contains a substantial stakeholder outreach and education component.

Overall, the Michigan CHP Roadmap project builds upon these prior studies by adding a perspective that is specific to the challenges and opportunities of Michigan. The Michigan CHP Roadmap methodology makes use of the market-based perspective of private-sector project developers, and has the benefit of a quantitative modeling capability that differentiates among CHP technologies. Finally, the Michigan CHP Roadmap also makes initial strides toward educating a diverse array of stakeholders in order to effect long-term change, and lays the groundwork for this education and outreach to continue.

3 Methodology

The methodology employed throughout this study was developed with the objective of being replicable by other states. To achieve this objective, project partners relied on economic data provided by the U.S. EPA[49] and on technical potential data provided by the U.S. DOE[50] to evaluate CHP technologies and applications. Analytical modeling of this data within Michigan's overall energy portfolio was achieved by leveraging the STEER model, which can be adapted by other states or developed independently. Mapping of the Michigan CHP supply and value chain utilized methodology previously developed to support creation of the Michigan "Clean Energy Roadmap."[51] Recommendations to mitigate solutions are based on a quantitative assessment of the impact on CHP deployment under a variety of utility rate and public incentive scenarios. Finally, deployment of the CHP Roadmap involves the ongoing effort to educate CHP stakeholders, and especially end-users, on the merits of CHP, and to provide them with a directory of firms operating in the CHP space to facilitate project development with local partners. (A directory of Michigan CHP Supply/Value Chain Participants is contained in **Attachment B**.)

---

[49] U.S. EPA. 2017. *Catalog of CHP Technologies*. http://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf.
[50] U.S. DOE. 2016. *Combined Heat and Power (CHP) Technical Potential in the United States*. https://www.energy.gov/eere/amo/downloads/new-release-us-doe-analysis-combined-heat-and-power-chp-technical-potential.
[51] Michigan Agency for Energy. 2016. Clean Energy Roadmap. http://www.michigan.gov/documents/energy/2016-03-09_CER_Full_526941_7.pdf.

3.1 Technology Roadmapping

STEER can dynamically model Michigan's electricity system on an hourly basis by dispatching electricity resources based on lowest marginal cost, and has the advantage of representing a range of supply-side and demand-side resource options at the level of individual electric generating units (see Section 4). This modeling, which we will alternatively refer to as "technology roadmapping," provides a rigorous capability to quantify the optimal cost CHP potential in Michigan.

STEER is populated with U.S. Energy Information Administration (EIA) data of Michigan's existing portfolio of power plants and various modules of fossil-fueled and renewable generating units that can be deployed as needed to meet hourly energy and capacity requirements out to the year 2030. Modifications were made to include an expanded, more detailed suite of CHP prime mover technologies, system sizes, and operating characteristics.

STEER modifications required the establishment of criteria to evaluate prime mover technologies for the suite of CHP options. As discussed in Section 2.3, because 99% of total installed CHP capacity is comprised of reciprocating engines, combustion turbines, microturbines, steam turbines and fuel cells, the project team decided to limit its focus to just these five technologies.

Project partners identified and evaluated CHP technologies and applications as a prelude to modifying the STEER model in order to achieve the following goals:

- Quantify Michigan CHP technical potential by prime mover type;
- Quantify industry average cost and performance data for each prime mover type;
- Extrapolate these data to Michigan prime mover technical potential.

U.S. DOE defines technical potential as "an estimation of market size constrained only by technological limits – the ability of CHP technologies to fit customer energy needs without regard to economic or market factors." This provides a valid upper boundary of CHP deployment in Michigan, with actual deployment levels being lower due to economic factors that can be represented as inputs to the STEER model that act to constrain deployment below technical potential.

According to DOE, Michigan has nearly 5 GW of CHP technical potential at more than 10,000 sites across 17 industrial and 24 commercial sectors (specific identifying data for each of the 10,000 sites is not available from DOE).[52] This potential, on a capacity basis, is roughly evenly split between 17 industrial sectors and 24 commercial sectors, as depicted in **Figure 3**. However, nearly 80% of the 10,000 sites are commercial locations, which tend to have much lower CHP capacity potential than industrial sites.

According to DOE, there are 2.2 GW of industrial on-site CHP potential primarily in the transportation equipment, chemicals, primary metals, paper, and food sectors. Another 2.0 GW of commercial CHP technical potential exists primarily at commercial office buildings, colleges and universities, hospitals, retail locations, and multifamily housing sectors. Michigan also has 700 MW of CHP potential

[52] U.S. DOE. 2016. *Combined Heat and Power (CHP) Technical Potential in the United States*. https://www.energy.gov/eere/amo/downloads/new-release-us-doe-analysis-combined-heat-and-power-chp-technical-potential.

deployment at 2 district energy sites and 150 MW of waste heat to power (WHP) potential identified at 36 sites primarily in the oil and gas extraction, refining, stone/clay/glass, and primary metals sectors.[53]

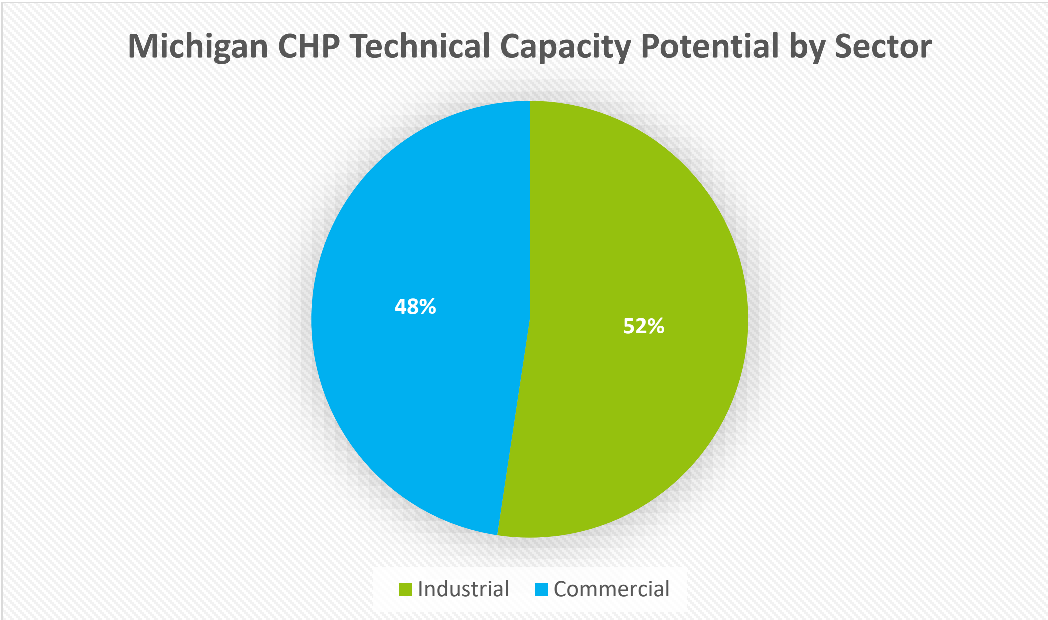


Figure 3: Michigan CHP Technical Capacity Potential by Sector[54]

Beyond commercial and industrial business types, the DOE database also quantifies the technical CHP potential in Michigan, by number of sites and capacity potential, according to annual operating hours (7,500 hours/full-time versus 4,500 hours/part-time) and project size classification (50 to 500 kW, 500 kW to 1 MW, 1 MW to 5 MW, 5 MW to 20 MW, and 20+ MW).[55]

For STEER customization, the DOE's CHP technical potential data for Michigan needed to be broken down one level further, from the total number of CHP sites and capacity (per project size range), to differentiate among the five prime mover types. To complete this task, the project team relied on EPA CHP cost and performance data for the prime movers across the spectrum of available capacities, along with project members' collective experience with public and private-sector CHP projects as necessary to make assumptions about market and pricing trends. Table 3 summarizes which prime movers were considered for CHP systems of various scale.

[53] Ibid.
[54] Ibid.
[55] Ibid.

Table 3: Prime Mover Technologies by System Capacity[56]

Capacity	Fuel Cell	Microturbine	Reciprocating Engine	Combustion Turbine	Steam Turbine
50 kW – 500 KW	X	X	X		
500 kW – 1 MW		X	X		
1 MW – 5 MW		X	X	X	
5 MW – 20 MW			X	X	X
> 20 MW				X	X

In their "Catalog of CHP Technologies,"[57] the EPA compiled cost and performance data for twenty-four CHP technology and size combinations as indicated in Table 4.

Table 4. EPA Technology and System Size Combinations[58]

Prime Mover Technology	System Sizes (kW)	EPA Catalog Reference
Fuel Cell	0.7, 1.5, 300, 400, 1400	Table 6-3
Microturbine	30, 65, 200, 250, 333, 1000	Table 5-2
Reciprocating Engine	100, 633, 1121, 3326, 9341	Table 2-2
Combustion Turbine	3510, 7520, 10680, 21730, 45607	Table 3-5
Steam Turbine	500, 3000, 15000	Table 4-2

Project partners extrapolated, via simple regression modeling, the cost and performance data for the EPA's 24 technology/size combinations indicated in Table 4, to include an additional 33 technology/size combinations. These 33 reflect the average CHP system size based on DOE technical potential in Michigan, across each of the five technologies and five capacity categories indicated in Table 3.

Table 5 lists all 57 resource options that are now available in the STEER model's CHP suite. The extrapolated data in combination with the EPA provided data provide the basis for technical analysis of CHP in the STEER model.

56 Ibid.
57 U.S. EPA. 2017. *Catalog of CHP Technologies*. http://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf.
58 Ibid.

Table 5. STEER Model CHP Resource Options

Prime Mover Technology	System Sizes (kW)
Fuel Cell	0.7, 1.5, 78, 124, 179, 300, 400, 1400
Microturbine	30, 65, 78, 124, 179, 200, 250, 333, 427, 597, 710, 1000, 1083
Reciprocating Engine	78, 100, 124, 179, 427, 597, 633, 710, 1083, 1121, 1800, 2093, 3326, 8000, 8758, 9341
Combustion Turbine	2093, 3510, 5000, 7520, 8000, 8758, 10680, 21730, 31000, 35867, 45607
Steam Turbine	500, 3000, 8000, 8758, 9091, 15000, 25000, 31000, 35867

Since STEER is a model of the electrical system and CHP provides heat-related benefits to the site host, STEER assumes that CHP systems will be sized to meet host thermal requirements. STEER treats the required capital and fuel costs for production of heat as the same with or without CHP. Thus, it can use the incremental capital and fuel costs associated with adding electricity production as the marginal cost of CHP generation of electricity.

This modified version of STEER containing these 57 CHP options can now dynamically identify which CHP configurations are economically viable across a wide variety of scenarios, narrowing the scope of Michigan's 5 GW/10,000 site technical potential to only include those projects that should be implemented based on economics and in consideration of Michigan's overall electricity generation portfolio.

3.2 Valuing Reliability and Resiliency

There have been many attempts to assess the cost of unreliable electricity. Reports by EPRI and DOE have estimated the cost of electricity outages at $30 to $400 billion per year.[59] According to the Lawrence Berkeley National Laboratory (LBNL), economic losses from unreliable electricity and power outages total approximately $80 billion per year.[60] However, even this figure is disputed as too low because it does not include the cost of food spoilage, dispatching police and fire personnel, evacuating and securing senior citizens and ancillary damage, such as the kind caused by sump pump failure.[61] While difficult to quantify, the full extent of power outage costs are undoubtedly quite large.

While everyone understands the value of power reliability and infrastructure resiliency, there are few, if any, proposed methodologies for monetizing that value. The data that exist regarding outage costs are largely aggregated between all customer classes among a wide geography and include economic loses as

[59] Primen. Submitted to the Electric Power Research Institute. 2001. *The Cost of Power Disturbances to Industrial and Digital Economy Companies*. http://www.energycollection.us/Energy-Reliability/Cost-Power-Disturbances.pdf.
[60] LaCommare, K. H., and Eto, J. H. Lawrence Berkeley National Laboratory. 2004. *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers*. https://emp.lbl.gov/sites/all/files/lbnl-55718.pdf.
[61] Rouse, G. and Kelly, J. Galvin Electricity Initiative. 2011. *Electric Reliability: Problems, Progress, and Policy Solutions.* http://www.galvinpower.org/sites/default/files/Electricity_Reliability_031611.pdf.

well as personal loses. Further complicating this effort is the fact that power resiliency creates both private and public benefits. In fact, there are three important categories when discussing resiliency costs and benefits:

- Private Resiliency for Private Benefit;
- Public Resiliency for Public Benefit;
- Private Resiliency for Public Benefit.

Public resiliency benefits are important specifically because of their relationship to maintaining critical infrastructure and the public well-being. However, it is difficult to monetize the value of resiliency in critical infrastructure where an outage may lead to human harm and even death. On the other hand, private benefits, such as reduced or eliminated economic loss can be easier and more ethical to monetize. Though public resiliency, especially as it relates to critical infrastructure, is very important, it was out of the scope of this project to attempt to create a methodology to monetize the value of public resiliency. Using existing research and literature, however, it is feasible to monetize the value of private benefits from private resiliency.

In 2001 and 2013, EPRI published studies that quantified the cost of power disturbances to industrial and digital economy firms using direct surveys. This report, titled "The Cost of Power Disturbances to Industrial & Digital Economy Companies," provides the best available data to quantify the value of electric resiliency for private benefit. The report focuses on three economic sectors particularly sensitive to power outages within the U.S. economy:[62]

- **The digital economy (DE).** This sector includes firms that rely heavily on data storage and retrieval, data processing, or research and development operations. Specific industries include telecommunications, data storage and retrieval services (including collocation facilities or Internet hotels), biotechnology, electronics manufacturing, and the financial industry.
- **Continuous process manufacturing (CPM).** This sector includes manufacturing facilities that continuously feed raw materials, often at high temperatures, through an industrial process. Specific industries include paper, chemicals, petroleum, rubber and plastic, stone, clay, and glass, and primary metals.
- **Fabrication and essential services (F&ES).** This sector includes all other manufacturing industries, plus utilities and transportation facilities such as railroads and mass transit, water and wastewater treatment, and gas utilities and pipelines.

These three sectors account for roughly 2 million business establishments in the U.S. While this comprises only 17 percent of U.S. businesses by establishment, these same sectors comprise approximately 40 percent of U.S. gross domestic product (GDP). Disruptions in each of these sectors – but especially DE and F&ES – have an almost immediate effect on other sectors that depend on the services they provide. According to the EPRI report, the U.S. economy is losing between $104 billion and $164 billion a year to outages and another $15 billion to $24 billion to power quality phenomena.[63]

[62] Primen. Submitted to the Electric Power Research Institute. 2001. *The Cost of Power Disturbances to Industrial and Digital Economy Companies*. http://www.energycollection.us/Energy-Reliability/Cost-Power-Disturbances.pdf.
[63] Ibid.

Michigan is estimated to be losing between $3.765 billion and $5.971 billion per year in annual outage costs for all sectors.

However, in relation to the total economic losses stemming from power outages these figures are most likely on the low end of the spectrum because they do not include the loses stemming from outages to critical infrastructure. These data only include business losses, which in general, do not include the cost of potential loss of life, loss of communications, loss of critical infrastructure, and loss of evacuation routes. No doubt the cost of these aspects would outweigh those from the business sector, but as previously stated, there is no data available monetizing the value of public resiliency benefits.

While it is relatively easy to approximate the annual outage cost by state or economic sector it is much more difficult to translate that monetary loss into a resiliency value. Certainly, DE, F&ES and CPM businesses with on-site generation such as CHP would benefit from the increased resiliency provided by such applications. Difficulty arises, however, when monetizing individual resiliency benefits using nationwide, aggregate numbers.

In order to include the benefits of CHP resiliency into the STEER model it was necessary to calculate a dollar value per kilowatt of CHP installed for power resiliency. Using the data provided in the EPRI report and summarized in Figure 4, an average annual cost was assigned to all businesses within the DE, CPM and F&ES sectors. It was only necessary, however, to consider the Standard Industrial Classification (SIC) codes within each economic category with any CHP technical potential. CHP technical potential was assigned to each SIC code using DOE data discussed in Section 2.5. This aggregate CHP potential was then divided by potential CHP sites per SIC code to arrive at the average capacity per potential site. Using average CHP capacity by SIC code it was possible to assign a technology type and corresponding duration before a major maintenance overhaul based on the EPA Catalog of CHP Technologies.[64] This lifespan duration is not equal to the equipment lifespan but, rather, the average duration before a major overhaul is required. Because the equipment overhaul costs are not included in the STEER model, we felt it best to calculate resiliency benefits over the average timespan before any major overhaul is required. Resiliency benefits beyond this original duration could be calculated using the cost of the overhaul and the anticipated longevity of the CHP system at that point.

[64] U.S. EPA. 2017. *Catalog of CHP Technologies*.
http://www.epa.gov/sites/production/files/2015-07/documents/catalog_of_chp_technologies.pdf.

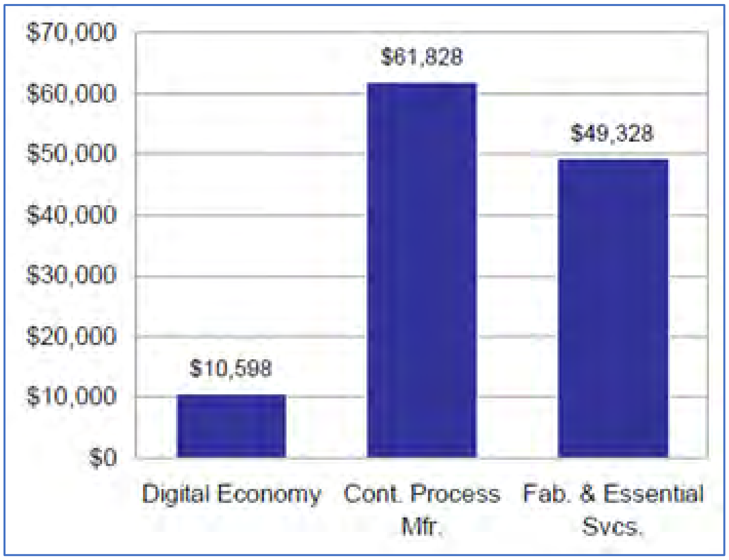


Figure 4: Average Annual Per-Establishment Cost of Outage by Sector

The value of resiliency was calculated by summing the annual outage costs over each CHP lifespan and using an 8% weighted average cost of capital[65] to determine the net present cost of outages. This net present cost was divided by the average CHP capacity per SIC code to arrive at a gross value of resiliency on a dollar per kW installed basis. As the CHP installed costs within the STEER model do not include additional costs related to resiliency (black start, islanding mode, etc.), an estimation of those costs was required. According to Oak Ridge National Laboratory, adding resiliency features to CHP installations costs approximately 10% of the total installed costs.[66]

The difference between these two figures is the net value of resiliency on a dollar per kW installed. Technically, this does not capture the value of resiliency, *per se.* Nevertheless, it does capture the costs of power outages per kW of CHP installed capacity on a net present value basis. However, absent other methodologies or guidelines, this approach best reflects an accurate monetization of the private resiliency benefits necessary to avoid costly power outages. The final results are presented in Table 6.

[65] While each SIC code might have an average weighted average cost of capital, 8% was used for simplicity.
[66] Hampson, A., et al. ICF International. Prepared for Oak Ridge National Laboratory. 2013. *Combined Heat and Power: Enabling Resilient Energy Infrastructure for Critical Facilities.* https://www1.eere.energy.gov/manufacturing/distributedenergy/pdfs/chp_critical_facilities.pdf.

Table 6. Value of CHP Resiliency

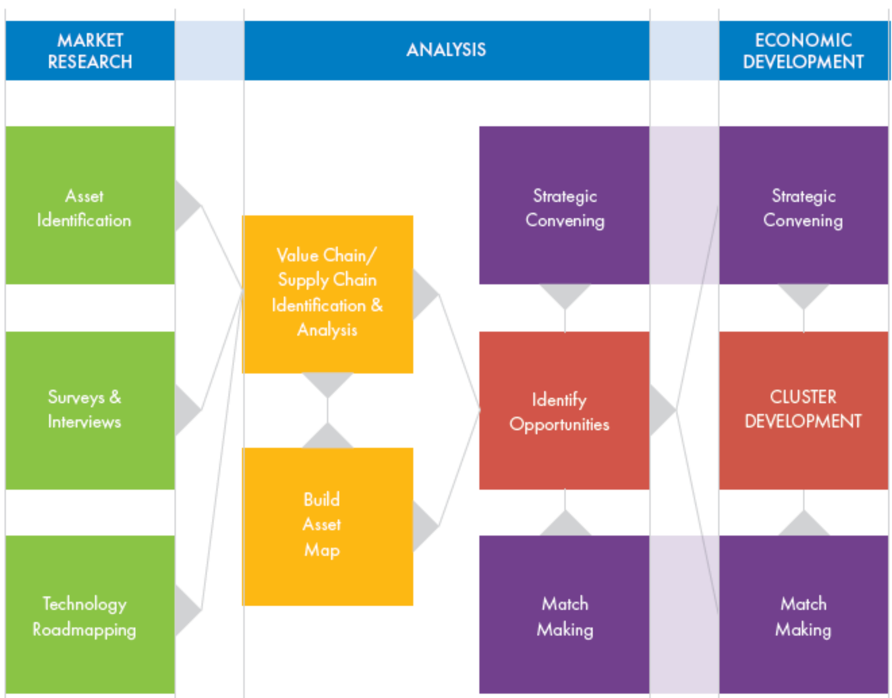
Sectors by SIC Code	Average Annual Outage Costs	CHP Technical Potential (kW)	CHP Technical Potential (Sites)	Average kW per Site	Technology Type	Average CHP Lifespan	Present Value of Outage costs per CHP lifespan	Gross value of resiliency $/kW Installed	Costs of Resiliency Equipment $/kW Installed	Net Value of Resiliency $/kW Installed
Digital Economy	$ 10,598.00									
7374		27,948 kW	70	399 kW	RECIP	9	$66,204.52	$ 165.82	$ 230.00	$ (64.18)
38		915 kW	5	183 kW	MT	5	$42,314.74	$ 231.28	$ 230.00	$ 1.28
8051		42,672 kW	313	136 kW	MT	5	$42,314.74	$ 310.38	$ 230.00	$ 80.38
8062		193,064 kW	171	1,129 kW	RECIP	9	$66,204.52	$ 58.64	$ 160.00	$ (101.36)
Continuous Process Manufacturing	$ 61,828.00									
26		211,885 kW	104	2,037 kW	CT	6.25	$295,104.35	$ 144.85	$ 300.00	$ (155.15)
28		572,452 kW	284	2,016 kW	CT	6.25	$295,104.35	$ 146.40	$ 300.00	$ (153.60)
29		69,484 kW	20	3,474 kW	CT	6.25	$295,104.35	$ 84.94	$ 300.00	$ (215.06)
30		88,300 kW	333	265 kW	RECIP	9	$386,232.59	$ 1,456.57	$ 230.00	$ 1,226.57
32		16,923 kW	4	4,231 kW	CT	6.25	$295,104.35	$ 69.75	$ 300.00	$ (230.25)
33		255,213 kW	169	1,510 kW	CT	6.25	$295,104.35	$ 195.42	$ 300.00	$ (104.58)
Fabrication and Essential Services	$ 49,328.00									
43		2,344 kW	24	98 kW	MT	5	$196,952.40	$ 2,016.63	$ 230.00	$ 1,786.63
4581		6,977 kW	11	634 kW	RECIP	9	$308,146.49	$ 485.86	$ 180.00	$ 305.86
49		8,283 kW	16	518 kW	RECIP	9	$308,146.49	$ 595.20	$ 230.00	$ 365.20
20		186,019 kW	273	681 kW	RECIP	9	$308,146.49	$ 452.23	$ 180.00	$ 272.23
22		6,406 kW	23	279 kW	RECIP	9	$308,146.49	$ 1,106.40	$ 230.00	$ 876.40
25		662 kW	7	95 kW	MT	5	$196,952.40	$ 2,081.30	$ 230.00	$ 1,851.30
27		5,526 kW	38	145 kW	MT	5	$196,952.40	$ 1,354.34	$ 230.00	$ 1,124.34
34		18,129 kW	149	122 kW	MT	5	$196,952.40	$ 1,618.71	$ 230.00	$ 1,388.71
35		15,673 kW	17	922 kW	RECIP	9	$308,146.49	$ 334.25	$ 180.00	$ 154.25
37		618,436 kW	529	1,169 kW	RECIP	9	$308,146.49	$ 263.58	$ 160.00	$ 103.58
39		490 kW	6	82 kW	MT	5	$196,952.40	$ 2,411.02	$ 230.00	$ 2,181.02

3.3 Supply and Value Chain Mapping

Boundaries for the supply and value chain mapping component of this Michigan CHP Roadmap were determined through a combination of market research and market analysis. The primary criteria for setting boundaries were the significance to the state of Michigan in terms of economic activity arising from deployment of CHP projects and feasibility given the resources and timeframe of this project. Any market segments where Michigan companies are currently participating in the CHP supply or value chain were given principal consideration for surveys, interviews, and database development. Segments where Michigan companies are not competing but perhaps could compete, under the right value proposition, were also analyzed.

The supply and value chain mapping methodology was adapted from the approach used in developing the Michigan Agency for Energy's (MAE) "Clean Energy Roadmap" published in 2016.[67] That effort, focused on Michigan and Northeast Ohio, developed strategies for accelerating energy efficient or energy waste reduction technologies and developing technology roadmaps for several energy intensive, clean energy manufacturing processes to reduce the energy cost of these processes. The project was split into three components: market research, market analysis, and economic development, as depicted in **Figure 5**.

Figure 5: Clean Energy Roadmap Methodology[68]



[67] Michigan Agency for Energy. 2016. Clean Energy Roadmap. http://www.michigan.gov/documents/energy/2016-03-09_CER_Full_526941_7.pdf.
[68] Ibid.

Market Research

The first step of the mapping methodology -- market research -- included asset identification, surveying and interviewing market participants, and technology roadmapping.

Michigan companies – "assets" – that could potentially participate in the CHP supply and value chain, through a clear supply or value proposition, were identified by project partners through internet research, project partners' knowledge base, and aggregation of attendance lists from the 2015, 2016 and 2017 Michigan CHP Conferences, as well as via additional contacts obtained through Institute for Energy Innovation (IEI) industrial energy efficiency (IEE) roundtables. This baseline asset list was supplemented by attendee lists from other CHP-related events, such as the Smart Solutions for the Upper Peninsula event (July 14, 2016), the Combined Heat and Power Opportunities for Michigan Healthcare Providers Detroit Event (August 22, 2016), and referrals from those in the supply and value chain.

Survey and interview questions were developed by project partners based on prior survey and interview work that had been completed to support the MAE's "Clean Energy Roadmap." The project team conducted 21 detailed interviews with representatives of firms active in the various sectors of Michigan's CHP supply and value chain, and received detailed survey results from 107 individuals working at firms throughout these sectors. Many more information gathering conversations were conducted with supply and value chain participants by members of the project team throughout the course of this study.

Participants in the Michigan CHP supply and value chain who volunteered for interviews include the following, with their principal role in the CHP supply and value chain indicated:

- Michigan Caterpillar (prime mover distributor)
- W.W. Williams (prime mover distributor)
- Solar Turbines (prime mover distributor)
- Varnum Law (legal)
- CMS Enterprises (investor)
- Petros PACE Finance (investor)
- Ford Dearborn campus (end-user)
- Dow Chemical (end-user)
- Scenic View and Brook View dairy farms (end-user)
- Midland Cogeneration Venture (end-user)
- Opterra Energy (developer)
- Cogen Consultants (developer)
- DTE Gas (fuel supplier)
- Michigan Public Service Commission (regulators/policymakers)
- GEM Energy (design/engineering)
- Ghafari & Associates (design/engineering)
- Fishbeck, Thomson, Carr & Huber (design/engineering)
- Newkirk Electric/Theka (engineering/component supplier)

- Kendall Electric/Eaton (component supplier)
- Waukesha-Pierce (component supplier)
- EMP Corp (component supplier)

The project team also received 68 detailed survey responses from firm representatives who attended the annual Michigan CHP Conference in either 2015, 2016, or 2017. The survey was deployed on the following dates:

1. 9/14/2016 – First deployment sent to attendees of 2015 and 2016 CHP Conferences
2. 9/22/2016 – Survey reminder sent
3. 10/26/2016 – Survey link was shared with Michigan's New Energy Policy (NEP) stakeholder group
4. 7/24/2017 – Survey sent to attendees of 2015, 2016 and 2017 CHP Conferences
5. 8/14/2017 – Survey reminder sent

Digging deeper into potential opportunities for Michigan manufacturers to produce the high-value CHP equipment and/or prime mover components, further research was completed to ascertain whether there are any realistic economic opportunities for Michigan companies. This was pursued through:

1. Qualifying the market opportunity for a typical Michigan manufacturing firm;
2. Interviewing procurement gatekeepers at prime mover and major component manufacturers;
3. Identifying and qualifying the legal, regulatory, and financial barriers to market entry;
4. Assessing what Michigan could potentially do through state incentives or other mitigating strategies to help Michigan's manufacturing firms enter and compete in this market.

In aggregate, these market research efforts enabled the project team to better understand the full spectrum of challenges and opportunities facing CHP deployment in Michigan from a supply and value chain perspective and qualify the economic opportunities for Michigan businesses to participate.

Market Analysis

To identify likely gaps and opportunities for Michigan companies, the second step of the mapping methodology -- market analysis -- entailed identification of the specific industry segments within the CHP supply and value chains and classification of the Michigan CHP market participants into those sectors.

Project partners defined the **CHP supply chain** as the physical equipment and fuel required for the CHP system to operate. The CHP supply chain contains four major sectors of participants:

- CHP end-user applications;
- Prime mover manufacturers and distributors;
- Major equipment manufacturers and distributors;
- Fuel suppliers and brokers.

Project partners defined the **CHP value chain** as the intellectual capital and skilled trades required to develop, design, engineer, finance, install, and integrate CHP systems. The CHP value chain contains four major sectors of participants:

- Public policy advocates and accelerators;
- Project developers and technical advisors;
- Design/engineering firms;
- Plant integration contractors.

All firms identified as participating in the Michigan CHP supply and value chains were classified by project partners into one of these major sectors. Where a firm might participate across multiple sectors, preference was given to the sector in which it was deemed that the greatest impact would likely be realized for the business.

Economic Development

In the case of the MAE's "Clean Energy Roadmap," economic development was the third and final step of the mapping methodology and entailed strategic convening and match-making of Michigan companies who participate in the supply and value chains for the purpose of manufacturing new products. However, this approach is not well-suited for increasing the deployment of CHP energy projects, which are driven primarily by individual end-user interest, understanding, and their financial and technical ability to implement projects with the support of local and regional supply and value chain participants. For this reason, project partners expanded upon the economic development methodology used previously by MAE. For the Michigan CHP Roadmap, economic development includes not only the matchmaking component, which is accomplished through compiling, distributing, and periodically updating the directory of Michigan supply and value chain participants, but also proactive outreach to potential CHP end-users and their industry associations to discuss the merits of CHP.

End-users typically focus on their core business and take energy for granted. In project partners' experience, few have a clear understanding of CHP on both its technical and economic merits. End-users must be educated and engaged to explore CHP opportunities for their facilities, as it is their ultimate interest (or lack of interest) in the technology, coupled with their expectations for economic benefit that will drive (or stall) CHP project deployment.

The task of education has historically fallen on CHP equipment distributors who understand the technology well. However, these equipment distributors are often unable to accurately assess the economic impact of CHP systems on the end-user in an unbiased fashion. By helping prospective end-users fully recognize the range of benefits afforded by CHP, including implementation of projects and reinvestment of end-users' energy savings into growth or expansion of their core businesses, will create opportunities for economic development.

3.4 Barrier Identification

Project partners collected data through three approaches In order to recommend targeted solutions to mitigate barriers to CHP deployment:

1. The project team conducted detailed research to understand the barriers and market impediments, which in most cases are well-documented by prior studies;
2. The project team aggregated in-house data acquired through public- and private-sector technical assistance activities and project development experience;
3. The project team surveyed and interviewed the major market participants including CHP developers, equipment manufacturers, end-users, regulatory officials, and other invested stakeholders.

Throughout 2016 and 2017, Michigan stakeholders interested in CHP development were surveyed and interviewed as to their perceptions of the major barriers facing CHP in the state. As was described in Section 3.3, a comprehensive survey was deployed at five separate intervals between September 14, 2016 and August 14, 2017 to over 200 recipients. There were 107 survey respondents in total, representing the full spectrum of stakeholders including utilities, government officials, economic development specialists, CHP developers, engineering firms, advocates and end-users. Additionally, more than two dozen in-depth interviews took place with representatives from government, utilities, law firms, finance experts, CHP developers, engineering/design firms, and major energy users. Results from these survey and interview responses shed light on stakeholder perceptions regarding the major barriers impeding CHP development in Michigan. **Attachment C** contains survey and interview data reflecting respondents' perceptions as to the magnitude of potential barriers to CHP in Michigan.

Upon review of the survey and interview responses received from a broad array of Michigan stakeholders, key barriers to deployment of CHP in Michigan have been identified as: 1) a lack of access to low-cost capital; 2) utility rates; 3) failure by the electric utilities to fully embrace CHP in EWR and IRP programs; and (4) a lack of awareness/familiarity with CHP.

Identifying solutions to the barriers and market impediments of CHP adoption will help to enlarge the pool of CHP projects that meet minimum criteria for technical and economic viability within STEER, which models CHP as a least-cost resource in Michigan's future energy mix, and thereby enable increased CHP deployment. In customizing and prioritizing proposed solutions for Michigan, project partners considered the estimated proportion of potential projects affected, perception of barrier magnitude by stakeholders, and the ease/practicality of achieving change in the short term. Focus was placed on those barriers which are most significant to restricting deployment of CHP across Michigan and to which attainable solutions exist. For the most part, solutions take the form of legislative change or regulatory relief, modification of utility rate structures, and financial incentives.

3.5 Stakeholder Engagement in Roadmap Deployment

Project partners have engaged policymakers, utilities, state agencies, the MPSC, business and industrial trade associations, non-governmental organizations (NGOs), and end-users with regard to the development of this CHP roadmap, through presentations and engagement with, among others: the state's New Energy Policy (NEP) Stakeholder Group, the Michigan CHP Conferences at Oakland University (2016) and Grand Valley State University (2017), IEE roundtables hosted by IEI in Marquette, Kalamazoo, and Ann Arbor, an event focusing on CHP in healthcare in Detroit, and outreach to the state's Collaborative Development Council.

The 2016 Michigan CHP Conference took place at Oakland University on May 10, 2016. There were over 120 attendees representing component manufacturers, developers, end-users and potential end-users, and governmental leaders. This followed-up on the success of the first ever Michigan CHP Conference, held in Lansing in 2015, which drew nearly 200 attendees. Panel discussions at the 2016 conference focused on technology, case studies, project development, financing and policy.

On June 20, 2016, project partners presented at the NEP Stakeholder Group Meeting in Lansing. Stakeholders were asked to engage around the following questions: "What barriers are impeding the adoption of CHP technology in Michigan?" and "Where do you see the greatest opportunity for distributed CHP energy production?" A follow-up webinar was conducted on October 24, 2016 to gain further feedback on the project.

IEI hosted two roundtables focused on IEE and CHP: one in Marquette on July 15, 2016 and the other in Kalamazoo on August 22, 2016. These roundtables provided an opportunity for project partners to engage with current and potential end-users and policymakers, and provided a productive forum for education around a variety of aspects affecting CHP implementation in the state.

In August 2016, the Energy Resources Center organized an event focused on CHP in healthcare in Detroit. The workshop, titled "Combined Heat and Power Opportunities for Michigan Healthcare Providers," highlighted the steps necessary for end-users to implement a successful CHP project, from initial screening to equipment installation. The workshop also outlined the complimentary technical assistance provided by DOE CHP TAP to end-users interested in CHP solutions.

In December 2016, team members from Sustainable Partners, LLC (SPART) led a CHP presentation before the Collaborative Development Council, a group comprised of 18 economic development practitioners representing regions across the state. The purpose of the presentation was to provide general education about CHP, and also enlist the group's assistance in facilitating end-user outreach in 2017. Additionally, Douglas Jester of 5 Lakes Energy (5LE) presented to the Council of Industrial Boiler Owners (CIBO) on the potential challenges and opportunities surrounding CHP. The Energy Resource Center also presented on CHP to DTE Gas in November 2016, and to the West Michigan Association of Energy Engineers (WMAEE) in December 2016.

Proactive stakeholder engagement continued through year two of the project. On February 23, 2017 and April 25, 2017, Jamie Scripps of 5LE presented to the Alliance for Industrial Efficiency (AIE) and to the American Forest & Paper Association (AF&PA) on standby rates as a potential barrier to CHP deployment. In May 2017, project partners presented to MAE on the supply/value chain mapping aspects of the project. In the summer, project partners engaged with stakeholders through the 2017 Michigan CHP Conference held on June 28, 2017 in Grand Rapids.

In September 2017, Greg Northrup of SPART participated as an exhibitor on behalf of the CHP Roadmap Project at the Michigan Society for Healthcare Engineering (Mi-SHE) annual meeting in Traverse City. Also in September 2017, Jamie Scripps of 5LE presented to the Electricity Consumers Resource Council (ELCON) on standby rates as a potential barrier to CHP deployment. Additionally, in partnership with IEI, project partners presented on the CHP Roadmap and solicited feedback from stakeholders at a UP Energy Roundtable in Marquette on September 19, 2017, and at a CHP Roundtable in Ann Arbor on December 11, 2017.

Project partners engaged with over 300 unique individuals through outreach and education efforts related to the development of the CHP Roadmap.[69] Through this outreach process, in addition to receiving valuable insight, the project team has increased awareness in CHP and built a network of stakeholders interested in participating the future of CHP in Michigan.

4 State Tool for Electricity Emissions Reduction (STEER)

One objective of this project was to identify and evaluate CHP technologies and applications with a potential for adoption in Michigan. In support of this objective, the project team quantitatively modeled the optimized deployment of CHP in Michigan using a modified version of the STEER model. Because CHP simultaneously provides heat and power, the potential for CHP adoption is partly determined by the number and size of sites that have heat requirements that can be met by CHP.

STEER was used to assess, measure, and determine the cost and value of CHP as one of multiple resources in Michigan’s future energy mix. In the primary application of STEER, the model considered the net value of CHP in the economy by considering the cost of installing and operating various CHP systems, the value of the heat produced by CHP measured as the cost of supplying heat in the least-cost way other than CHP, and the value of electricity produced by the CHP system measured as the marginal cost of producing electricity absent the CHP system. Determining the value of CHP in the electric power system is the province of STEER. Thus, the selection of CHP technologies by STEER is a projection of the economic potential for CHP in Michigan. The actual division of costs and benefits amongst CHP site hosts and utilities depends on policy and particularly on utility rates as applied to customers with CHP.

Because we determined that standby rates are one of the principal barriers to CHP adoption that may be amenable to policy adjustments, STEER was used to evaluate the effect of standby rates on the economic potential for CHP in Michigan. Further, because resilience of CHP site host operations is an important benefit of CHP that is not reflected in standard electric power system evaluations, STEER was used to evaluate the additional economic potential for CHP in Michigan if site hosts would not otherwise choose to build CHP but sufficiently valued resilience to do so. Consideration of resilience value increases the potential deployment of CHP in sectors where loss of power is most consequential and can significantly increase CHP potential beyond the levels that would be supported only by power sector value. Based on STEER analysis of Michigan potential, resilience value could increase CHP potential by

[69] Total calculated through aggregation and removal of duplicates from attendance lists for 2015, 2016 and 2017 Michigan CHP Conferences, and 2016 and 2017 IEI roundtables. This total is conservative and does not include anonymous survey respondents.

around 60%. Standby rates, on the other hand, substantially reduce the profitability of CHP ownership and thereby reduce potential CHP deployment by 50% or more.

As described in detail in the following sections, STEER modeling indicates that steam turbines, gas combustion turbines, and reciprocating engines appear profitable above some size threshold size in each scenario. Conversely, microturbines and fuel cells do not appear economically viable. In addition, STEER indicates that higher natural gas prices and higher cost of renewable resources in the future both tend to lower the minimum size threshold for the more viable CHP technologies, thereby expanding the number of potential installation sites in Michigan.

Furthermore, approximately half of sites where steam turbines are economically feasible are on college and university campuses, confirming that this sector should be an important part of end-user outreach and education. However, this result does not necessarily mean that combustion turbines and reciprocating engines would also not be suitable for these facilities.

In the STEEER reference scenario, economic potential for CHP in Michigan is about 1,014 MW electric generation capacity with direct investment of about $865.6 million, annual direct O&M activity of about $67.6 million, annual economic profit of about $109.5 million, annual fuel cost savings of $94.7 million, and annual air emissions reductions of 662 tons carbon dioxide (CO_2) per year, 379 tons nitrous oxide (NO_x) per year, and 39 tons sulfur oxide (SO_x) per year. In other STEER scenarios, assuming different fuel and technology costs, the economic potential for CHP in Michigan varies from 722 MW to 1,014 MW.

4.1 Model Overview

STEER is an integrated resource planning model that calculates the least-cost resource portfolio to satisfy electricity demand and various reliability and environmental constraints based on projections of demand, fuel prices, technology price and performance, taxes, and other factors.

To give state lawmakers, regulators, and stakeholders the ability to evaluate Clean Power Plan compliance approaches with the benefit of reliable integrated resource planning data, 5LE, in collaboration with the University of Michigan, originally developed the STEER model with funding from the Energy Foundation and Advanced Energy Economy Institute. The principal purpose of theSTEER model is to facilitate stakeholder access to data and integrated resource planning analysis. The STEER model automatically calculates the least-cost compliance and implementation strategies to serve forecast demand and comply with reliability and environmental standards, along with projected cost to electricity users, given certain policy options and electricity demand and price forecasts. All data, inputs, and formulae are visible to and changeable by the user. The Michigan version of the STEER model is available for download online.[70]

STEER is based on hourly load data for 24 representative days of the year and forecasts future loads out to 2030, considering changes in load profile that result from selected energy efficiency/EWR programs.

[70] Advanced Energy Economy. 2017. *State Tool for Electricity Reduction (*STEER). https://info.aee.net/steer.

STEER builds on a trend forecast of load with adjustments to accommodate forecasted adoption of electric vehicles and demand response, storage, and smart grid programs.

STEER contains performance data for each utility-scale electric generating unit in Michigan, including the multiple units in each power plant, and for aggregated small-scale generation either “behind-the meter” or integrated to the distribution system. It calculates the least-cost dispatch of these generating units to satisfy load for each hour, then calculates coal usage, natural gas usage, variable costs, carbon emissions, sulfur oxide emissions, nitrous oxide emissions, and mercury emissions based on that dispatch plan.

The STEER dispatch model also derives locational marginal prices for selection of least-cost resource additions. These locational marginal prices have been verified by comparisons to historical data. If an environmental policy (such as annual CO_2 emissions limits or NO_x limits to reduce summer ozone levels) is applied to dispatch, the model calculates dispatch, locational marginal price, and incremental cost of operating the power system accordingly.

STEER adds generation resources when needed to satisfy load, meet capacity reserve margin standards, or to satisfy a constraint on emissions. When adding generation resources, the STEER model considers technologies including natural gas combustion turbines and combined cycle plants, nuclear electricity generation, biomass co-firing in existing coal plants, hydropower, wind power, utility-scale and distributed solar photovoltaic generation, biomass combustion, and cogeneration. Required revenue to recover investment costs and operating expenses, as well as capacity and energy value of new generation resources is considered when those are chosen for addition to the generation portfolio. STEER follows the standard utility planning practice of valuing capacity at the cost of new entry of a natural gas combustion turbine, when capacity is needed. In utility operations, energy production is planned from a generating unit only when the output from all units that are cheaper to operate is insufficient to meet demand. The value of energy from each generating unit is the cost of electricity from the marginal generating unit at each time a generating unit operates.

To address capacity limitations, if the model finds that capacity requirements to satisfy the forecasted load, plus necessary reserve requirements, are not being met based on economic selection of another resource, it adds new natural gas combustion turbine capacity to the generation fleet. This occurs because, of the available generation technologies, such combustion turbines require the lowest capital investment per unit capacity. Economic selection of another technology occurs when the higher investment in the technology is offset by lower operating costs or emissions compliance. This method assures adequate capacity at least-cost even if the combustion turbine capacity itself is not “profitable” as a power system resource.

STEER allows for improvements in the fuel efficiency of existing generation plants, often referred to as “heat rate improvements.” Costs and effects of heat rate improvements at existing plants default to the assumptions made by EPA in developing the draft Clean Power Plan. However, a STEER user is free to make plant-specific assumptions.

STEER does not automatically retire power plants, but allows the user to specify plant retirements and to attribute these retirements as due to compliance with environmental regulations or as retirements that would occur anyway. STEER facilitates user decisions about plant retirements by providing the capacity factors, dispatch order, air pollutant emissions, and other information that a user might consider in making retirement decisions. Upon retirement, the STEER model reflects the avoided fixed and variable cost of plant operations and the costs of replacement capacity and energy. Remaining book value is assumed to be securitized and accounted for in utility revenue and rate forecasts.

Since utility practices and regulation rarely lead to capacity additions based purely on economic value, if additional capacity is not needed, STEER does not add capacity unless capacity is needed. However, a user can quickly determine such economic additions by retiring plants that do not “earn” their fixed and operating costs and allowing STEER to select the best available demand-side or generation option.

Renewable resource options are based on inventories of renewable resource potentials developed by the National Renewable Energy Laboratory (NREL). Wind and solar generation are based on hourly site-specific data from NREL’s Eastern Wind Integration Transmission Study and System Advisory Model, respectively. Capacity factors, capacity credits, and hence power system value of wind and solar generation are the result of calculations using site-specific data rather than general assumptions. Hydropower resources are representative of small hydropower facilities operated run-of-river using typical Michigan streamflow. Biomass resources are grouped into eight categories running from municipal waste and landfill gas through timber residuals.

Energy efficiency or energy waste reduction measures included in the model, their costs, and their achievable potential are taken from the Michigan Energy Efficiency Potential Study performed by GDS Associates in 2013 and released as part of Governor Snyder’s “Ensuring Michigan’s Future” report series in November 2013.[71] These measures include 190 applications used by residential, commercial, and industrial customers. For purposes of modeling effects on load profiles, we classified each measure as affecting all load or peak load. In STEER, the user can specify whether the model should consider all achievable cost-effective energy efficiency or constrain these programs to a spending cap of 2% of utility revenues, as was evaluated by GDS.

In addition to these features of Michigan’s power system, the STEER model also incorporates the operation of the Ludington Pumped Storage Plant and the possibility of power imports and exports subject to current transmission limitations established by the regional transmission organizations. A STEER user can make changes to the import and export capacity limits.

4.2 Strengths and Weaknesses

By utilizing STEER, the project team was able to take advantage of an existing, Excel-based tool designed for use by anyone with a standard laptop or desktop computer. Also, STEER provides an appropriate granularity of analysis for this project because it represents Michigan’s electricity system at the level of individual generating units dispatched hourly. This level of detail is well suited for capturing the different

[71] GDS Associates, Inc. Prepared for the Michigan Public Service Commission. 2013. *Michigan Electric and Natural Gas Energy Efficiency Potential Study*. http://www.michigan.gov/documents/mpsc/mi_ee_potential_study_rep_v29_439270_7.pdf.

sizes, operating characteristics, and costs of a range of CHP technologies. Finally, STEER's existing suite of cogeneration units provided a framework that could be readily expanded to include multiple prime mover technologies and system sizes to yield a more realistic set of CHP options for the model to deploy.

As with any model, simplifications have been made. STEER assumes there are no binding transmission constraints within Michigan. The model might replace generation from a fossil fuel plant with, for example, renewables located in an area that lacks adequate transmission interconnections, requiring additional transmission. New natural gas and biomass plants are not assigned to specific locations, so their locations can also reflect transmission availability and support requirements. That said, model results do not appear to be distorted as a result of this simplification.

In addition, the model calculates the least-cost plan for the single year, chosen by the user, and does not aggregate year-by-year results over a period of time. For example, the model might calculate that the least-cost plan uses a new natural gas combined cycle plant based on projected conditions in 2020. However, based on projected conditions in 2030, the model may calculate that a combination of wind generation and cogeneration is more cost-effective. The model does not attempt to resolve these differences by solving the dynamic programming problem of how best to act over the full life-cycle of each generator although that analysis can be performed by using the model to analyze results year-by-year and evaluating the life-cycle results. As such, the results of the model from any given year should be viewed in the context of long-term utility and regulatory planning, including underlying changes in the cost of fossil fuels used for generation and the desirability of hedging against volatility in fossil fuel prices.

With these simplifications in mind, STEER represents a useful strategic planning tool for regulators and stakeholders alike, enabling consideration of a wide range of alternatives and providing transparency as to the model's calculations in a particular scenario. STEER users may rely on the existing publicly available data that is included in the model or the data can be replaced with more granular information if desired. Stakeholders can use this tool for analysis and comparison with analyses produced by utility companies and other stakeholders.

4.3 Model Adaptation

The original version of STEER already included a limited selection of natural gas-fired, combustion turbine cogeneration systems available for deployment. As described in Section 3.1, for this project, this existing suite of CHP options was expanded to reflect a wider range of prime mover technologies, system sizes, and fuel types. This enables the ability to run more sophisticated modeling scenarios that consider the characteristics of different types of CHP applications. The result is a more realistic picture of the scale of CHP deployment that is possible in Michigan, subject to various factors such as future fuel prices, policy decisions such as the structure of standby rates, and other elements that affect the overall cost of building and operating CHP systems. The results presented throughout this report are based on the modified version of STEER.

During activities related to the customization of the STEER Model as described in detail within the technology roadmapping methodology in Section 3.1, project partners incorporated CHP technologies for inclusion in Michigan's generation portfolio based on the performance characteristics and costs published by EPA with potential deployment numbers and capacities published by DOE. These included various sizes of reciprocating engines, gas turbines, steam turbines, microturbines and fuel cells. In order to evaluate CHP's value to the electric power system, we found the "electric-only" costs of each CHP application by subtracting from both the investment cost and the operating cost of CHP the cost of producing a comparable amount of heat from an efficient natural gas boiler.

STEER evaluates the potential deployment of each CHP technology in the same way that it evaluates all new generation options. First, it computes the required annual revenue for investment per unit of the technology based on the investment cost, depreciation schedule, cost and shares of debt and equity, property and use taxation, and income taxation using rates that are representative of Michigan utilities. Second, STEER calculates the capacity and energy value of each generation option when placed into dispatch competition with all existing or previously selected generation resources. This allows calculation of "unmet required revenue," which is the required annual revenue for investment less the capacity and energy value the resource would provide if built. In principle, this is the same as determining whether the new resource would be profitable in a wholesale power supply market. If "unmet required revenue" is negative, then the plant would be profitable based solely on wholesale power market revenues and capacity values. If "unmet required revenue" is positive, then it would fail to recover its costs with a reasonable return on investment from its power output and would only be built if it provided additional value, such as resilience benefits to its host. Third, STEER calculates avoided emissions of CO_2, NO_x and SO_x by calculating the reduced use of the marginal generating unit in each hour due to deployment of a potential new resource and the consequent reduction of emissions from that marginal unit, offset by any emissions from the potential new resource. Finally, STEER chooses which generation resources to deploy by ranking them in order from the lowest to highest "unmet required revenue" per unit environmental mitigation and going as far down this list as necessary to both meet required load and satisfy the aggregate statewide environmental constraints established by the user. If the environmental constraints are lax, this produces essentially the same result as ranking them from lowest to highest "unmet required revenue" per unit of power generation.

Because new generation resources are only added when needed, in deference to the existing generation resources, it is possible that options with a negative (profitable) "unmet revenue requirement" will not be chosen by STEER. STEER might choose a resource that has a positive (unprofitable) "unmet revenue requirement" if necessary to meet the emissions constraints. For purposes of CHP deployment, any technology with a negative "unmet revenue requirement" would be viable in the marketplace absent discriminatory utility policy and without an emissions constraint.

4.4 Assumptions

As with all integrated resource planning, assumptions or projections about future conditions are the bases for analysis. The STEER model provides means to determine an optimum course of action given those projections, but the projections of future conditions are determined external to the model. Projections of conditions such as load growth, fuel prices, and technology prices are provided to the model as independent parameters but are not actually independent. Best practice when using a model is therefore to use multiple scenarios reflecting possible "states of the world" in order to understand the variation of modeling results and the risks associated with a potential course of action. Because of the large number of parameters that are incorporated into STEER, it is possible to construct many scenarios.

Because any investment in CHP will need to be viable for an extended period, we evaluated the role of CHP in 2030. For purposes of preliminary evaluation of the viability of CHP technologies in Michigan, we constructed and used several scenarios. In each case, we assume current law including Michigan's EWR resource standard and Renewable Portfolio Standard (RPS), the availability of federal production or investment tax credits, tax rates, etc. We also assumed announced plans to retire power plants, consistent with the retirements used by MAE in its modeling of Clean Power Plan compliance.[72]

"Spark spread" – the difference between the price of electricity and the cost of fuel to produce electricity – is widely understood to be one of the most critical factors in the economic viability of CHP projects. In order to evaluate this factor in a logically consistent way, we used natural gas price forecasts from three scenarios provided in the U.S. DOE Energy Information Administration (EIA) 2016 Annual Energy Outlook.[73]

In preparing the annual outlook, EIA uses econometric models that statistically identify the "linkages between the prices of various fuels." Their scenarios, designed principally to identify the effects of variation in natural gas supply, are the Reference Case, the High Oil and Gas Resource Case ("High Resource Case"), and the Low Oil and Gas Resource Case ("Low Resource Case"). The High Resource Case produces lower fuel price forecasts and the Low Resource Case produces higher fuel price forecasts than the Reference Case. These forecasts, in 2016 dollars per Million British thermal units (MMBtu) of heat content, are shown through 2030 in Table 7.

The other principal non-policy factor besides fuel prices that would be likely to materially affect "spark spread" and hence CHP project economics, is the price of electricity. STEER forecasts the hourly wholesale price of electricity given fuel prices, existing generation resources, and the least-cost selection of new generation resources. STEER projects the price of electricity using the embedded costs of legacy generation, projected costs of new generation resources, and projected costs of fuel used in either existing or new generation resources. The assumptions used in STEER, other than fuel prices, that are most likely to affect the future price of electricity are the costs of renewable generation technologies. In order to assess the effects of these projections, we used each of the fuel price scenarios noted above in combination with two alternative assumptions about renewable technology. One alternative assumes that renewable generation costs continue to decline at the rates that have occurred over the last five years, while the second alternative simply excludes new renewables from the STEER analysis, simulating that they are not economically competitive. This range of scenarios provides a corresponding range of CHP deployment outcomes, reflecting appropriate uncertainty about the future.

[72] These retirements were not based on requirements of the Clean Power Plan. Rather they reflected the knowledge and opinions of staff of the Michigan Public Service Commission and Michigan Agency for Energy about expected retirements of existing generating units based on age and other environmental requirements.
[73] U.S. EIA. 2016. *Annual Energy Outlook 2016 with projections to 2040*. https://www.eia.gov/outlooks/aeo/pdf/0383(2016).pdf.

Table 7. EIA Price Forecasts through 2030[74]

	Reference Case Fuel Forecast (2016$/MMBtu)				High Gas and Oil Resource Case Fuel Forecast (2016$/MMBtu)				Low Oil and Gas Resource Case Fuel Forecast (2016$/MMBtu)			
Year	Distillate Fuel Oil	Residual Fuel Oil	Natural Gas	Steam Coal	Distillate Fuel Oil	Residual Fuel Oil	Natural Gas	Steam Coal	Distillate Fuel Oil	Residual Fuel Oil	Natural Gas	Steam Coal
2014	$ 23.19	$ 20.00	$ 5.04	$ 2.27	$ 23.19	$ 20.01	$ 4.93	$ 2.27	$ 23.19	$ 20.01	$ 5.00	$ 2.27
2015	$ 15.26	$ 10.13	$ 3.29	$ 2.28	$ 15.26	$ 10.13	$ 3.29	$ 2.28	$ 15.26	$ 10.13	$ 3.29	$ 2.28
2016	$ 11.95	$ 8.09	$ 3.02	$ 2.14	$ 11.95	$ 8.09	$ 2.93	$ 2.15	$ 11.95	$ 8.09	$ 3.05	$ 2.13
2017	$ 14.33	$ 9.30	$ 3.53	$ 2.18	$ 14.58	$ 9.39	$ 3.32	$ 2.18	$ 14.17	$ 9.20	$ 3.65	$ 2.17
2018	$ 16.22	$ 10.57	$ 3.81	$ 2.23	$ 15.94	$ 10.40	$ 3.58	$ 2.20	$ 15.81	$ 9.89	$ 4.03	$ 2.26
2019	$ 17.26	$ 12.65	$ 4.18	$ 2.28	$ 16.96	$ 12.47	$ 3.81	$ 2.23	$ 17.22	$ 12.40	$ 4.55	$ 2.31
2020	$ 17.75	$ 13.25	$ 4.54	$ 2.31	$ 17.44	$ 13.00	$ 3.83	$ 2.24	$ 17.86	$ 13.14	$ 5.15	$ 2.36
2021	$ 18.10	$ 13.74	$ 4.57	$ 2.31	$ 17.76	$ 13.44	$ 3.68	$ 2.22	$ 18.52	$ 13.94	$ 5.48	$ 2.38
2022	$ 18.36	$ 14.12	$ 4.53	$ 2.32	$ 18.06	$ 13.93	$ 3.58	$ 2.23	$ 18.87	$ 14.45	$ 5.99	$ 2.39
2023	$ 18.69	$ 14.52	$ 4.56	$ 2.33	$ 18.55	$ 14.39	$ 3.60	$ 2.23	$ 19.27	$ 14.83	$ 6.32	$ 2.40
2024	$ 19.00	$ 14.78	$ 4.68	$ 2.33	$ 19.08	$ 14.87	$ 3.69	$ 2.24	$ 19.60	$ 15.22	$ 6.82	$ 2.40
2025	$ 19.48	$ 15.41	$ 4.81	$ 2.33	$ 19.47	$ 15.48	$ 3.76	$ 2.24	$ 20.07	$ 15.86	$ 7.34	$ 2.41
2026	$ 19.84	$ 15.95	$ 4.93	$ 2.33	$ 20.06	$ 16.41	$ 3.85	$ 2.25	$ 20.52	$ 16.49	$ 7.69	$ 2.41
2027	$ 20.04	$ 16.05	$ 5.05	$ 2.32	$ 20.07	$ 16.24	$ 3.97	$ 2.24	$ 20.74	$ 16.62	$ 8.00	$ 2.41
2028	$ 20.06	$ 16.09	$ 5.16	$ 2.31	$ 20.30	$ 16.60	$ 4.10	$ 2.23	$ 20.95	$ 16.77	$ 8.17	$ 2.42
2029	$ 20.31	$ 16.32	$ 5.25	$ 2.30	$ 20.64	$ 17.11	$ 4.14	$ 2.23	$ 21.28	$ 17.01	$ 8.33	$ 2.42
2030	$ 20.75	$ 16.63	$ 5.29	$ 2.30	$ 21.25	$ 17.42	$ 4.07	$ 2.22	$ 21.77	$ 17.41	$ 8.37	$ 2.42

[74] U.S. EIA. 2016. *Annual Energy Outlook 2016 with projections to 2040.* https://www.eia.gov/outlooks/aeo/pdf/0383(2016).pdf.

4.5 Power System Modeling Results

Using the EIA 2016 Annual Energy Outlook Reference Case and allowing STEER to choose renewables to meet generation requirements, STEER produced the results for the various CHP technologies that are shown in **Attachment D**. In this scenario, steam turbines of any size, combustion turbines larger than 20 MW capacity, and reciprocating engines larger than 3 MW capacity are profitable. Michigan technical potential for these CHP technologies totals 1.014 GW but only 722 MW at 70 sites are built because the additional capacity was not required.

Using the EIA 2016 Annual Energy Outlook Reference Case without allowing STEER to choose renewables to meet generation requirements, STEER produced the results for the various CHP technologies that are shown in **Attachment E**. In this scenario, the same CHP technologies as in the scenario with renewables are profitable, but because renewable capacity was not allowed to be chosen by STEER, all 1.014 GW of profitable CHP technologies at 103 sites are chosen.

Using the EIA 2016 Annual Energy Outlook High Resource Case and allowing STEER to choose renewables to meet generation requirements, STEER produced the results for the various CHP technologies that are shown in **Attachment F**. Natural gas prices are lower in this scenario, but CHP is generally competing with combined cycle natural gas in the dispatch order, so that the price of electricity is also lower. As a result, the same technologies are profitable as in the Reference Case: steam turbines of any size, combustion turbines larger than 20 MW capacity, and reciprocating engines larger than 3 MW capacity. However, because the price of natural gas is lower in this scenario, fewer renewables are selected and more of the profitable CHP capacity is built. Just like the Reference case, the profitable CHP technologies have Michigan potential totaling 1.014 GW at 103 sites, but in this case all 1.014 GW are chosen.

Using the EIA 2016 Annual Energy Outlook High Resource Case without allowing STEER to choose renewables to meet generation requirements, STEER produced the results for the various CHP technologies that are shown in **Attachment G**. In this scenario, the same CHP technologies are profitable as in the preceding scenario and are chosen as in the High Resource Case but with renewables excluded, primarily because with the low natural gas prices projected in this case, incremental renewables are not chosen.

Using the EIA 2016 Annual Energy Outlook Low Resource Case and allowing STEER to choose renewables to meet generation requirements, STEER Michigan CHP produced the results for the various CHP technologies that are shown in **Attachment H**. With the higher natural gas prices used in this scenario, the relative fuel efficiency of CHP generation as compared to combined cycle and electricity-only combustion turbines causes a wider range of CHP technologies to be profitable, including steam turbines of any size, combustion turbines 8 MW capacity and larger, and reciprocating engines 1 MW capacity and larger. Michigan technical potential for these profitable technologies totals 2.36 GW at 816 sites. However, with higher natural gas prices, substantial renewables are chosen and the selected amount of cogeneration is still only 1.014 GW.

Using the EIA 2016 Annual Energy Outlook Low Resource Case without allowing STEER to choose renewables to meet generation requirements, STEER produced the results for the various CHP technologies that are shown in **Attachment I**. As is generally true, the same set of CHP technologies is profitable in this scenario as in the previous scenario. Without renewables available in this scenario, STEER builds the entire 2.36 GW of profitable CHP generation technologies at 816 sites. This scenario results in the most amount of CHP being chosen by the STEER model.

Across a fairly broad range of scenarios, neither microturbines nor fuel cells appear economically viable for broad application in Michigan. Steam turbines, combustion turbines, and reciprocating engines above some threshold size appear profitable in each scenario with the minimum size threshold being lower under higher natural gas pricing and when renewables aren't available.

The CHP technologies that appear viable based on STEER modeling results based solely on their value to the power system have potential in specific economic sectors. Table 8 summarizes the number of sites in each sector for which there appear to be viable technologies, where a range reflects the results in the various scenarios described above.

Table 8. STEER CHP Evaluation Results

Sector	Steam Turbine		Combustion Turbine		Reciprocating Engine	
	MW	Sites	MW	Sites	MW	Sites
Food/Beverages	8	1	25	3	24-90	3-36
Lumber/Wood	-	-	7	1	6-36	1-16
Paper/Pulp	40	1	79-87	2-3	8-50	1-21
Chemicals	64	3	88-194	2-13	108-244	11-66
Petroleum Refining	-	-	-	-	0-16	0-8
Rubber/Plastics	-	-	-	-	0-17	0-9
Stone/Clay/Glass	-	-	5	1	5-12	1-3
Primary Metals	39	1	58-71	2-3	13-67	1-26
Machinery/Comp Equip	-	-	-	-	0-3	0-2
Transportation Equip	25	3	101-182	4-14	80-231	10-87
Gas Processing	-	-	-	-	0-6	0-2
Refrigerated Warehouses	-	-	-	-	1	1
Wastewater Treatment	-	-	-	-	2	1
Commercial Office Bldgs	-	-	-	-	0-172	0-284
Multifamily Housing	-	-	-	-	0-17	0-16
Hotels	-	-	-	-	0-24	0-15
Data Centers	-	-	-	-	0-13	0-8
Hospitals	-	-	0-21	0-3	7-131	1-57
Colleges/Universities	101	8	31-70	1-6	41-128	5-37
Prisons	-	-	-	-	0-50	0-34
Military Facilities	-	-	-	-	0-7	0-3
Airports	-	-	-	-	0-4	0-2
Museums	-	-	-	-	0-2	0-1
Government Buildings	-	-	5	1	0-30	0-16

4.6 Resilience

The preceding analysis using STEER does not assign any value to the potential contribution of CHP to site or community resilience in case of an extended grid outage, nor to the avoidance of costs related to outages of any length. For some CHP host sites, this resilience value can be decisive. We therefore extended STEER to account for the additional CHP potential associated with the resilience value of CHP.

Resilience value does not lead to increased deployment of a CHP technology that would be developed anyway based on only its power system value. Thus incremental CHP potential due to resilience value will result when CHP is not profitable based purely on the avoided cost of electricity. In these cases, the profitability gap is overcome by the value of resilience to the CHP host. Since resilience value varies amongst potential hosts, our extension of STEER to address resilience value was conducted primarily to include calculations of the minimum resilience value that would lead a potential CHP host to build a CHP resource that is otherwise not profitable, identify the application sectors likely to have resilience value at least as large as the threshold, and estimate the additional potential for CHP in those sectors.

The results of resilience calculations based on the EIA 2016 Annual Energy Outlook Reference Case fuel prices and considering additional use of renewables in the power system (corresponding to the assumptions in Attachment D) are shown in **Attachment J**. Consideration of CHP resilience value enables the potential use of smaller combustion turbines and reciprocating engines than would be profitable based solely on heat and power system value, and also enables the potential use of some microturbines.

Under the assumptions of Attachments D and J, consideration of resilience value increases CHP potential by 591 MW above the 1,014 MW that would be profitable without consideration of resilience value.

4.7 Standby Rates

The primary analysis using STEER examined the fundamental value of CHP in Michigan's power supply. Host decisions to adopt CHP, however, are often determined by the terms of utility tariffs rather than by power system value. The principal difference between these is the application of standby rates, which is one of the primary barriers to CHP adoption. We therefore extended our analysis using STEER to examine the effect of standby rate tariffs on CHP potential.

In order to incorporate the economic effects of standby rates on CHP potential, it was necessary to model the avoided costs as created by Michigan standby rates. The avoided cost assesses the financial relationship between the aggregate price of electricity before and after the installation of customer-sited CHP.

As a metric for evaluation, we used the guidelines and methodology presented by the EPA CHP partnership in the paper "Standby Rates for Customer-sited Resources: Issues, Considerations, and the Elements of Model Tariffs"; specifically, the EPA's concept and application of the avoided rate.[75] This

[75] Regulatory Assistance Project. Prepared for the U.S. EPA. Office of Atmospheric Programs, Climate Protection Partnerships Division. 2009. *Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs*. https://www.epa.gov/sites/production/files/2015-10/documents/standby_rates.pdf.

metric is useful because it reduces the economic and financial impact created by standby rates to a simple percentage figure that can easily be incorporated into the STEER model.

The concept of avoided rate evaluates the financial impacts of standby rates on distributed generation systems by comparing the per kWh cost of full-requirements customers to that of otherwise comparable standby customers. Ideally, a decrease in electricity purchased from the utility would be commensurate with a decrease in monthly electric costs. If a customer reduces their purchased electricity by 50% they would expect their bill to decrease by a similar amount. However, there are some utility system costs appropriately billed to the customer that are not reduced by the same percentage and limit the bill reduction. These manifest as standby charges and the question of whether or not they are reasonable is beginning to be the subject of rate cases before the MPSC.

Standby rates can increase electric demand charges even when a customer decreases overall electric consumption, thus negating many economic benefits to the customer. The avoided rate is a metric that measures the amount of savings per kWh a distributed generation customer receives when not purchasing electricity from the utility. In essence, it compares the value of a purchased kWh to the value of an avoided kWh. This rate requires the comparison between the electricity costs to a facility when on a full-requirements rate and the electricity costs to a facility when on a standby rate.

The avoided rate model analyzes the extent that standby rates allow distributed generation customers to avoid electric charges. After modeling each facility's usage during one year it is possible to aggregate all charges into a simple cost per kWh. This aggregate cost includes the cost of generation, transmission, distribution, demand, taxes and all applicable riders for both full-requirements and standby rates. The avoided rate is calculated by dividing the money not paid to the utility by the electricity not purchased from the utility. When the avoided rate closely matches the full-requirements rate, the user experiences increased savings.

For example, if a hypothetical facility purchases 1,000,000 kWh of electricity per year from the utility at an aggregate cost of $0.10 per kWh, the facility will pay a total cost of $100,000. If this same facility installs a CHP system that reduces their need for purchased electricity to 500,000 kWh per year, in an ideal economic situation, the annual bill would be half the normal bill, or $50,000. Under this ideally constructed scenario, the avoided rate from the 500,000 kWh *not* purchased would be $0.10 ($50,000/500,000 kWh). Thus, this situation would have an avoided rate equivalent to the full requirement rate.

There are limitations in using the avoided rate metric, however. Though simple to calculate and communicate, the avoided rate metric can over-simplify situations. The economic effect of standby rates is largely related to the specific attributes and operating schedules of a customer's generator. Given the diversity of potential CHP hosts in Michigan, the avoided rate represents a simplified generalization for these actual CHP hosts. A more specific calculation would be needed to assess an individual CHP project.

Project partners modeled the avoided rates of Consumers Energy and DTE Energy using energy usage data provided during a March 14, 2016 workshop on standby rates. Based on these data, Consumers Energy's standby rate results in an avoided rate between 81%-85% depending on the size of the CHP customer while DTE Energy's standby rate results in an avoided rate between 71%-77%. According to the EPA, avoided rates below 90% may pose an economic barrier to otherwise financially feasible CHP implementation. The results of this modelling are shown in Table 9.

Since standby rates primarily apply to the capacity of the CHP system, the ratio of the cost of standby rates to CHP system capacity is an appropriate measure of the effect of standby rates on the profitability of a CHP system. Based on the avoided rates of DTE Energy and Consumers Energy, STEER projected that standby rates in 2030 would impose costs of about $88,000 per MW capacity of a CHP system. In STEER, this additional cost of capacity reduced the profitability of all CHP technologies. Some CHP technologies were still profitable, despite the standby rate cost, while more marginal CHP technologies became unprofitable. The technologies that became unprofitable in the face of standby rates depend on the scenario under which they are evaluated.

The effect of standby rates on STEER Michigan CHP potential results using the EIA 2016 Annual Energy Outlook Reference Case and allowing STEER to choose renewables to meet generation requirements (corresponding to the assumptions of Attachment D) is shown in **Attachment K**. Standby charges had the effect of making combustion turbines below 40 MW and reciprocating engines below 9 MW unprofitable, thereby reducing CHP potential by 669 MW from the 1,014 MW that would be available under the same scenario but without standby charges.

Table 9. Utility Standby Rate Impact

Utility	Site Peak Load	CHP Capacity	Total Required kWh	Generated kWh	Full Requirements Bill	Standby Bill	Full Requirements $/kWh	Avoided Rate $/kWh	Avoided Rate Percentage
Consumers	7,000 kW	3,500 kW	44,623,000 kWh	27,594,000 kWh	$ 3,128,000.00	$ 1,489,000.00	$ 0.070	$ 0.059	85%
	1,000 kW	450 kW	5,889,000 kWh	3,548,000 kWh	$ 503,000.00	$ 259,000.00	$ 0.085	$ 0.069	81%
DTE Energy	8,000 kW	5,000 kW	51,544,000 kWh	30,926,400 kWh	$ 3,280,000.00	$ 1,756,000.00	$ 0.064	$ 0.049	77%
	1,000 kW	282 kW	3,917,000 kWh	2,350,200 kWh	$ 318,000.00	$ 183,000.00	$ 0.081	$ 0.057	71%

4.8 Analysis

As noted previously, STEER modeling indicated that steam turbines, gas combustion turbines, and reciprocating engines appear profitable above some size threshold size in each scenario. Conversely, microturbines and fuel cells do not appear economically viable. Assuming higher natural gas prices and higher cost of renewable resources in the future both tend to lower the minimum size threshold for the more viable CHP technologies, thereby expanding the number of potential installation sites in Michigan.

Consideration of resilience value increases the potential deployment of CHP in sectors where loss of power is most consequential and can significantly increase CHP potential beyond the levels that would be supported only by power sector value. Based on STEER analysis of Michigan potential, resilience value could increase CHP potential by around 60%. Standby rates, on the other hand, substantially reduce the profitability of CHP ownership and thereby reduce potential CHP deployment by 50% or more.

Developing CHP to its economic potential will provide a number of benefits to Michigan. Since economic potential varies with projections of technology and fuel costs, and other factors, STEER estimated the primary benefits using the EIA 2016 Annual Energy Outlook Reference Case for fuel prices and was allowed to choose renewables to meet generation requirements (corresponding to assumptions of Attachment D). If built, these CHP installations would produce about $109.5 million per year in profit above the level required to recover cost of capital. Such profit due to outperforming the marginal unit in the economy is considered a significant benefit to society and, if accruing to CHP hosts, increases the likelihood that they remain in their primary business in Michigan.

STEER estimates building 1,014 MW CHP of the types chosen in this scenario would require direct investment of about $865.7 million and annual non-fuel operations and maintenance of about $67.6 million. These expenditures are themselves costs to the site host but are income to suppliers and generate additional economic activity in Michigan. The amount of direct and indirect economic activity in Michigan and the consequent employment depends on the degree to which Michigan-based businesses are able to participate in the supply and value chains for CHP systems.

Fuel efficiency of CHP systems, in contrast to separately produced heat and electricity using natural gas as a fuel is a benefit to Michigan. STEER estimates building and operating 1,014 MW CHP of the types chosen in this scenario would save about 11.3 million MMBtus per year, representing a net cost savings to Michigan's economy of about $94.7 million per year. This reduction in fuel usage would also reduce air emissions by 662 tons of CO_2 per year, 379 tons of NO_x per year, and 39 tons of SO_x per year.

5 Michigan Supply and Value Chain

The primary objectives of mapping the Michigan CHP supply and value chains were to:

1. Identify the companies who are positioned to facilitate Michigan CHP projects – these firms are members of the Michigan supply and value chains;
2. Develop a digital directory of the identified companies and distribute to potential end-users to market CHP and expedite project discovery and implementation;
3. Evaluate segments of the supply and value chains where there may be barriers to CHP deployment due to a lack of Michigan firms operating in that space;
4. Assess the economic impact to Michigan arising from CHP deployment.

Mapping efforts built on the results of technology roadmapping presented in Section 3.1 and the conclusions of STEER modeling discussed in Section 4.8. Mapping utilized stakeholder engagement activities to assess end-user appetite for CHP and the supply and value chain enthusiasm for participating in CHP projects, with the goal of ultimately driving CHP education, project development, and implementation.

Demand for CHP projects in both the private and public sector is primarily driven by an economic comparison of the costs and benefits of CHP versus the costs and benefits of end-user current operations. This status quo typically entails electric generation at a utility-owned power plant and thermal energy generation on-site by end-user-owned boilers or furnaces. Thus, in order for demand for CHP to increase, the economics must become more favorable than the status quo. Market economics are affected by a number of factors, including:

- Delivered energy cost trends
- End-user energy efficiency or energy waste reduction targets
- Technological performance or cost improvements
- Fuel resource supply and pricing trends
- Utility regulations and incentives
- Government legislation and incentives

5.1 Supply Chain Mapping

As discussed in Section 3.4, project partners have defined the **CHP supply chain** as the physical equipment and fuel required for the CHP system to operate. The major sectors of the CHP supply chain include CHP end-user applications, prime mover manufacturers and distributors, major equipment manufacturers and distributors, and fuel suppliers and brokers.

Prime movers include gas turbines, reciprocating engines, steam turbines, and fuel cells. Project partners have confirmed that there are businesses operating in Michigan that manufacture, distribute, or provide maintenance services to each of these four types of prime movers.

Major equipment was grouped into three subsectors: electrical controls, heat recovery, and absorption cooling. Electrical controls and heat recovery are common to nearly all CHP applications, although the implementation may vary considerably. Absorption cooling is utilized in projects where there is demand for chilled water or refrigeration, but limited demand for heat.

Finally, natural gas was the only fuel identified to realistically supply most CHP projects. Although other types of fuel such as woody biomass, biogas, and landfill gas are available in some locations, unless a potential CHP user is located at an adjacent site, guaranteeing supply and transportation of these fuels is likely to be risky and cost prohibitive, respectively.

The major and minor sectors of the Michigan CHP supply chain are summarized in **Figure 6**.

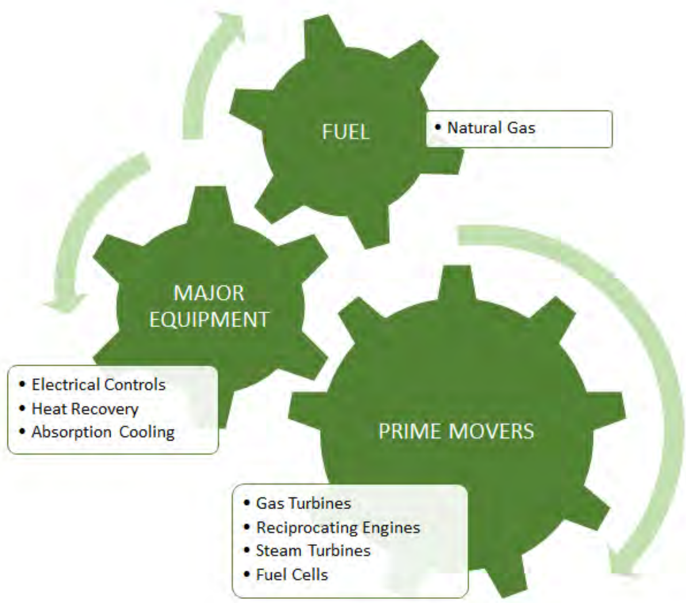


Figure 6: CHP Supply Chain (excluding end-users)

The majority of turbine and reciprocating engine prime movers – the highest value components in the supply chain – are designed and manufactured in a small geographic region in Germany and Austria. The firms operating in that region compete for the same engineering talent, which further encourages new CHP engineers to move there, much in the same manner as Silicon Valley has become the dominant location where computer engineers and their employees locate in the U.S.. Caterpillar is a notable exception as they manufacture reciprocating engines at a plant in Lafayette, Indiana and gas turbines at a plant in San Diego, California. Michigan prime mover manufacturers and distributors are identified in **Figure 7.**

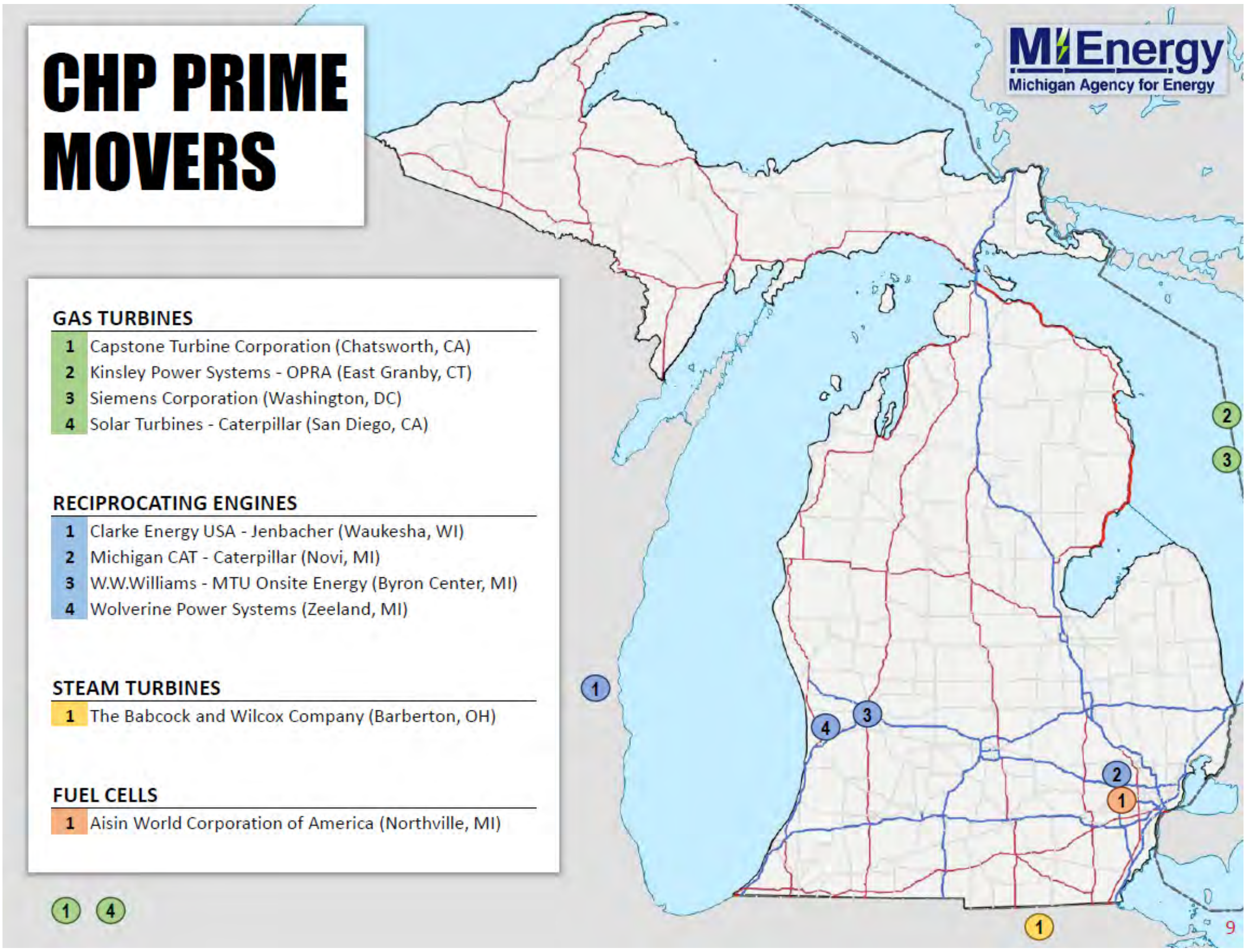


Figure 7: CHP Prime Movers

Project partners interviewed distributors from the companies MTU On-site Energy and Caterpillar serving the Michigan market. These distributors could not identify any companies in Michigan that currently manufacture any of the components found within the prime movers. These components are readily sourced from a well-developed domestic and international marketplace, with high economic, technical, and regulatory barriers to entry. Existing major equipment is sold based on decades of successful performance history which would be rendered invalid if any significant changes were made to the design of the equipment or sourcing of components. It is unlikely that Michigan manufacturers could someday tap into this market due to the unwillingness of prime mover and major component manufacturers to even entertain the possibility. From their perspective, sourcing components from Michigan manufacturers has insignificant upside potential and is fraught with considerable potential downside risks.

As identified in **Figure 8**, a handful of Michigan companies manufacture some of the major ancillary equipment that may be found in CHP projects but are not part of the prime mover systems. However, the vast majority of these firms' sales of these components are not to support CHP projects, but rather to support an array of traditional electric power and thermal energy processes. Broader deployment of

CHP would have a positive impact on the total economic activity generated by these firms, but the bulk of these firms' sales would still be expected to be for non-CHP purposes.

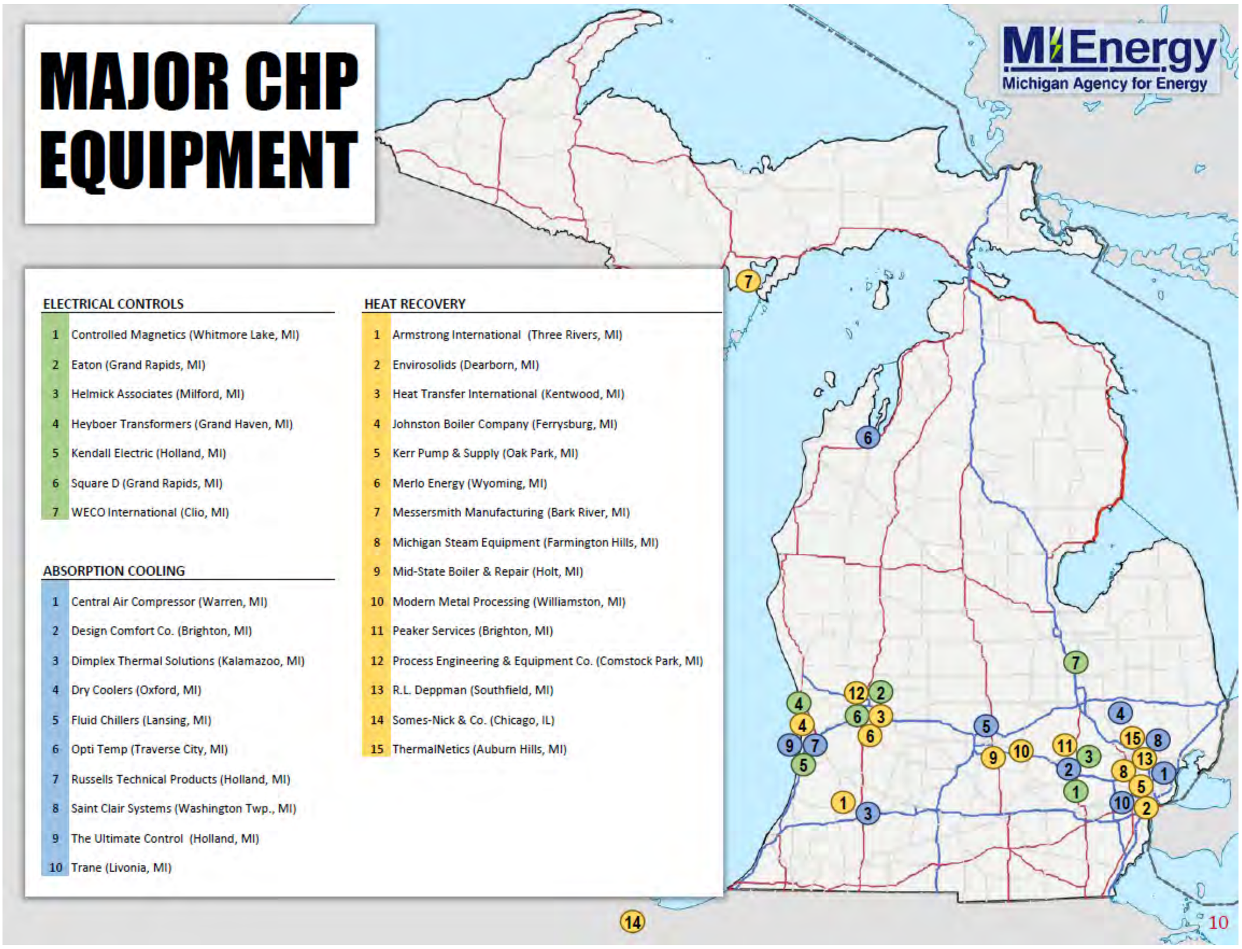


Figure 8: CHP Major Equipment

Fuel supply represents the largest ongoing expense for CHP projects. Natural gas, the most common fuel for CHP systems, is widely available in many parts of Michigan at cost near historical lows. Long-term contracts of 5 to 10 years are readily available through a large number of natural gas traders and brokers, allowing investors to control natural gas fuel supply and pricing during the project's payback period, significantly mitigating investment risk.

In some regions of the state, particularly rural areas and the Upper Peninsula, the infrastructure for transporting or receiving large volumes of natural gas is inadequate or nonexistent. Other fuel sources, such as woody biomass, biogas from anaerobic digesters, and landfill gas, may be utilized but are typically difficult to source, requiring significant additional effort on the part of the project developer to negotiate long-term project-specific supply agreements. Ultimately, this means that in the Upper Peninsula of Michigan, unless a potential CHP project is located in one of the few major cities or along the east-west gas pipeline corridor, fuel supply may be an impossible hurdle to overcome.

However, in general, and especially in the Lower Peninsula, instances where lack of access to appropriate fuel may prevent deployment of otherwise viable CHP projects will be rare. To be a candidate for CHP, one must have a significant existing thermal energy load, and in turn, existing access to a fuel source used to meet that load, which in most cases is natural gas which could be repurposed for a CHP application. Michigan natural gas suppliers and brokers are identified in **Figure 9**. A map of Michigan's natural gas transmission pipelines is available online.[76]

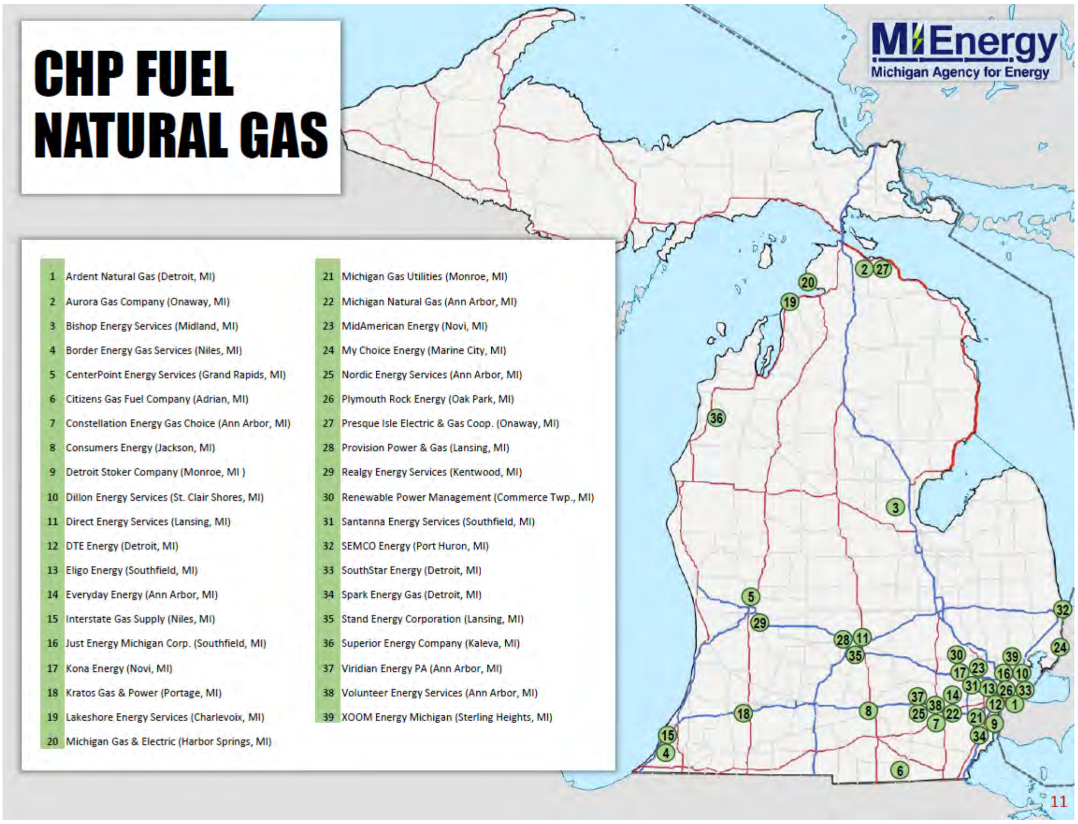


Figure 9: CHP Natural Gas Fuel Marketers

[76] Michigan Public Service Commission. 2002. *Natural Gas Transmission Pipeline and Storage Field Map*. http://www.michigan.gov/mpsc/0,4639,7-159-16385-413020--,00.html.

5.2 Value Chain Mapping

Limited opportunities for Michigan firms in the CHP supply chain are overcome by the robust ability of Michigan firms to participate throughout the value chain. As discussed in Section 3.4, project partners have defined the **CHP value chain** as the intellectual capital and skilled trades required to develop, design, engineer, finance, install, and integrate CHP systems. The major sectors of the value chain include public policy advocates and accelerators, project developers and technical advisors, design/engineering firms, and plant integration contractors.

CHP accelerators and public policy advocates play a critical role in developing the market for CHP applications through encouraging technological innovation, educating and lobbying policy-makers, and supporting end-users and industry organization. With the framework for CHP in place, project developers then identify and conceptually develop projects, assisted by valuable technical advisors and their specific expertise. Design/engineering firms bring the CHP projects from concept to a state of construction readiness. Finally, plant integration contractors, which may include construction management firms, electrical subcontractors, and mechanical subcontractors, install the CHP systems and ensure they operate as designed.

The major and minor sectors of the Michigan CHP value chain are summarized in **Figure 10.**

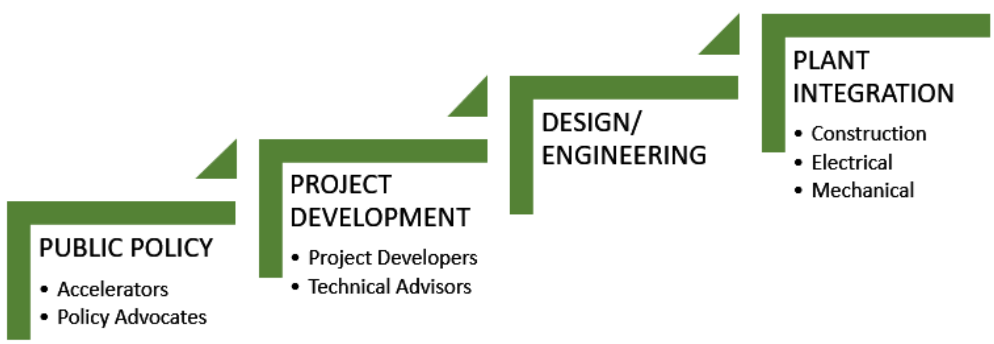


Figure 10: CHP Value Chain

The majority of the economic impact of CHP will be realized by using this pool of talent based in Michigan companies to design and implement projects. However, many value chain firms currently lack significant CHP experience due to the dearth of completed CHP projects in the state in recent years. This obstacle will be rapidly overcome as more projects are deployed throughout the state.

CHP accelerators and policy advocates in Michigan are identified in **Figure 11**. Not surprisingly, most of these firms are clustered around Lansing, Michigan and Washington, D.C., where regulatory policy and legislation are crafted at the statewide and national levels, respectively.

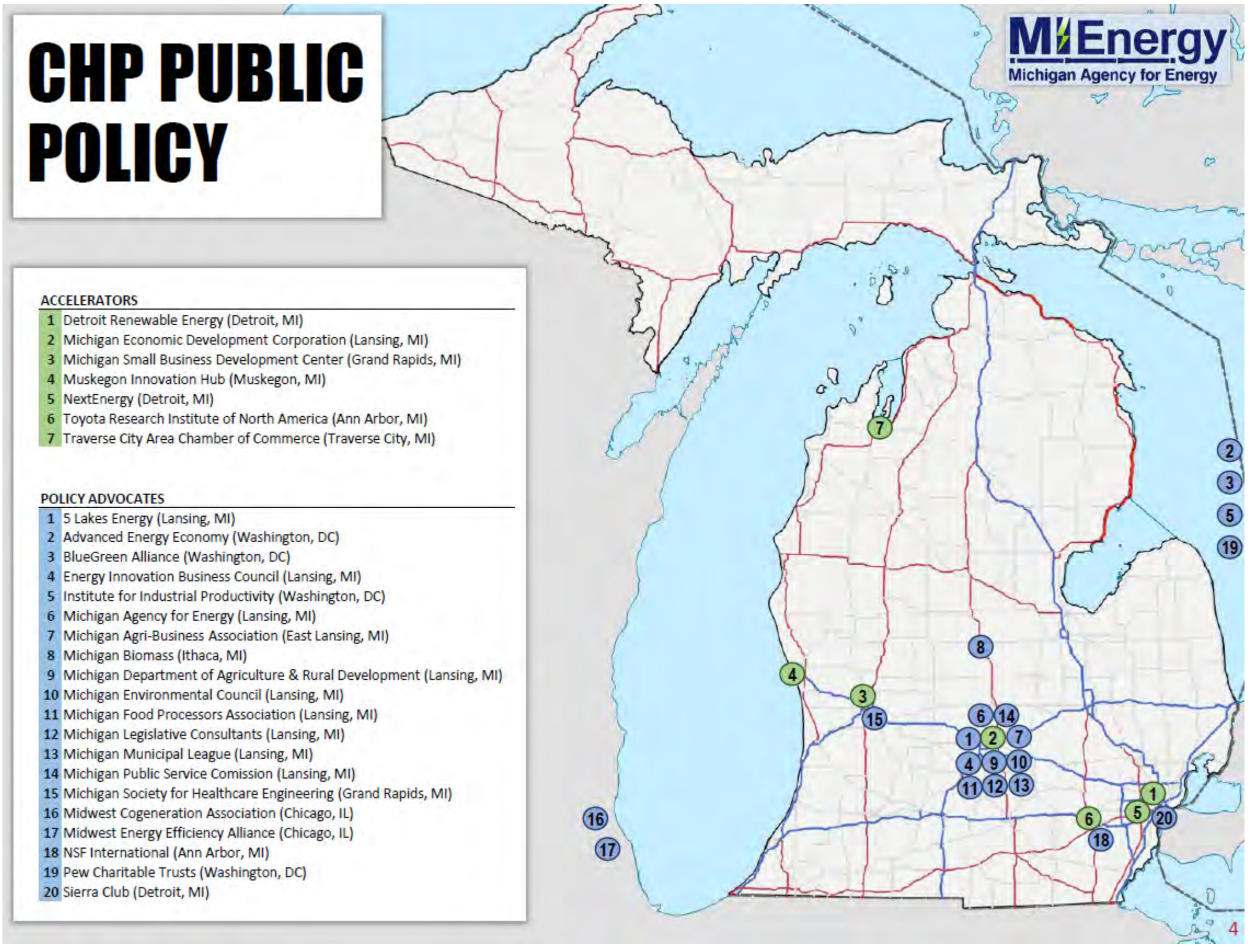


Figure 11: CHP Public Policy

CHP project developers and technical advisors are identified in **Figure 12**. In many cases, firms that principally develop projects also have some capabilities to provide technical expertise, and vice versa. One major difference may be in terms of the business model, where developers often take significant financial risk on developing and securing financing for projects, whereas technical advisors often have a clear fee structure and will only take minimal financial risk.

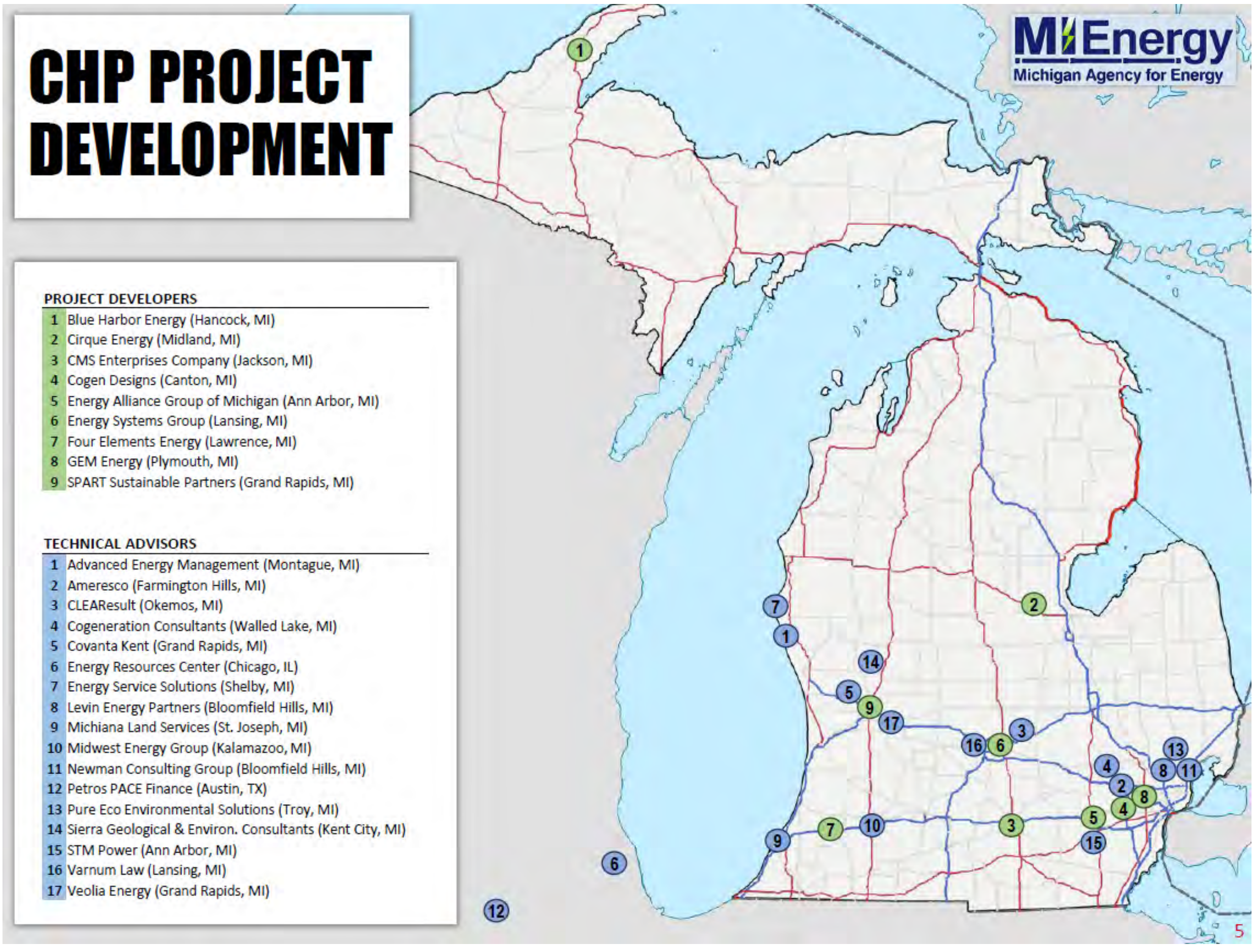


Figure 12: CHP Project Development

CHP design/engineering firms are identified in **Figure 13**. There are a great number of firms with the civil, electrical, and mechanical capabilities required to engineer CHP project in Michigan, and for simplicity many potential end-users may opt to work with the same firm that designed their existing electrical and thermal systems. Generally these firms are clustered around the state's major population centers.

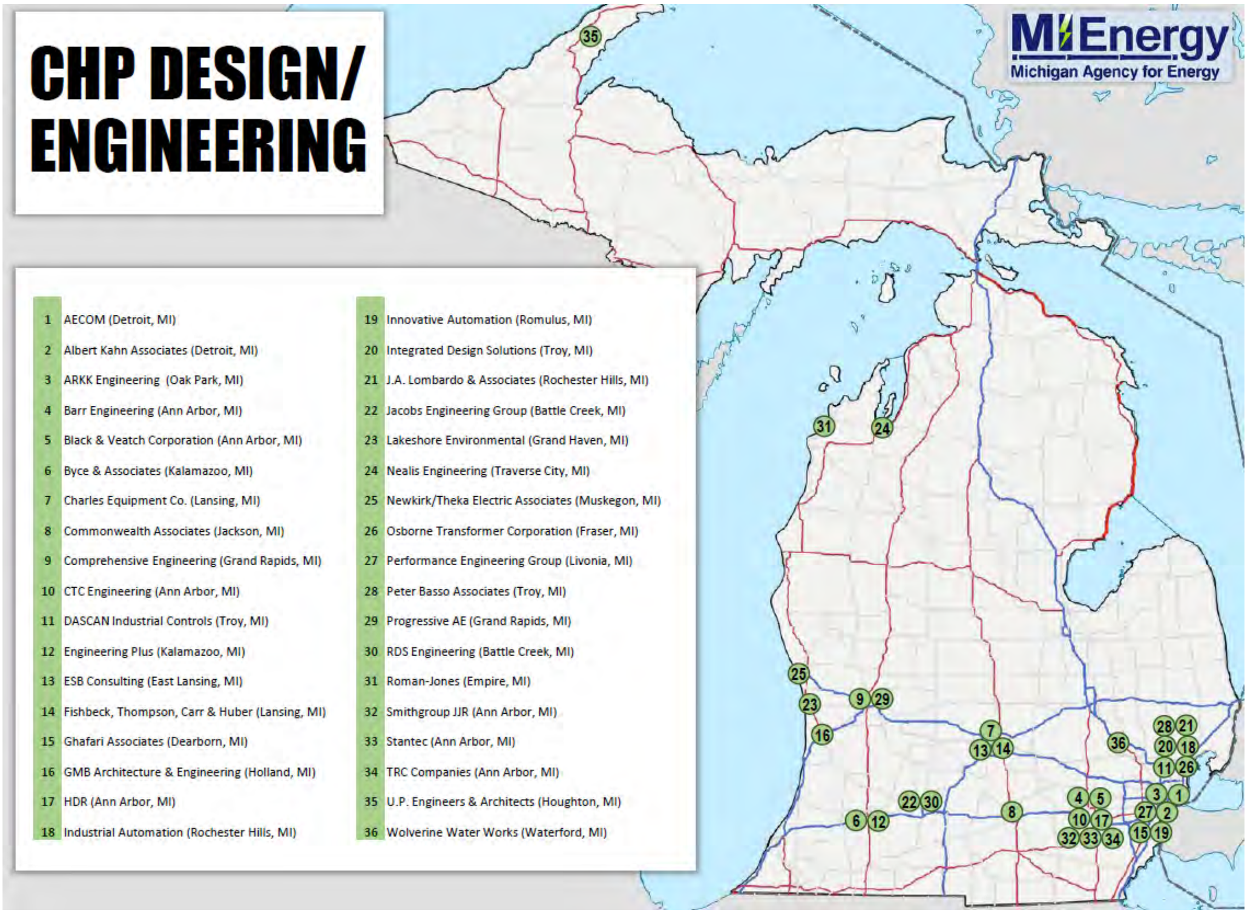


Figure 13: CHP Design/Engineering

CHP plant integration contractors are identified in **Figure 14**. These firms encompass the disciplines of construction management, electrical installation, and mechanical installation. Generally, these firms are clustered around the state's major population centers.

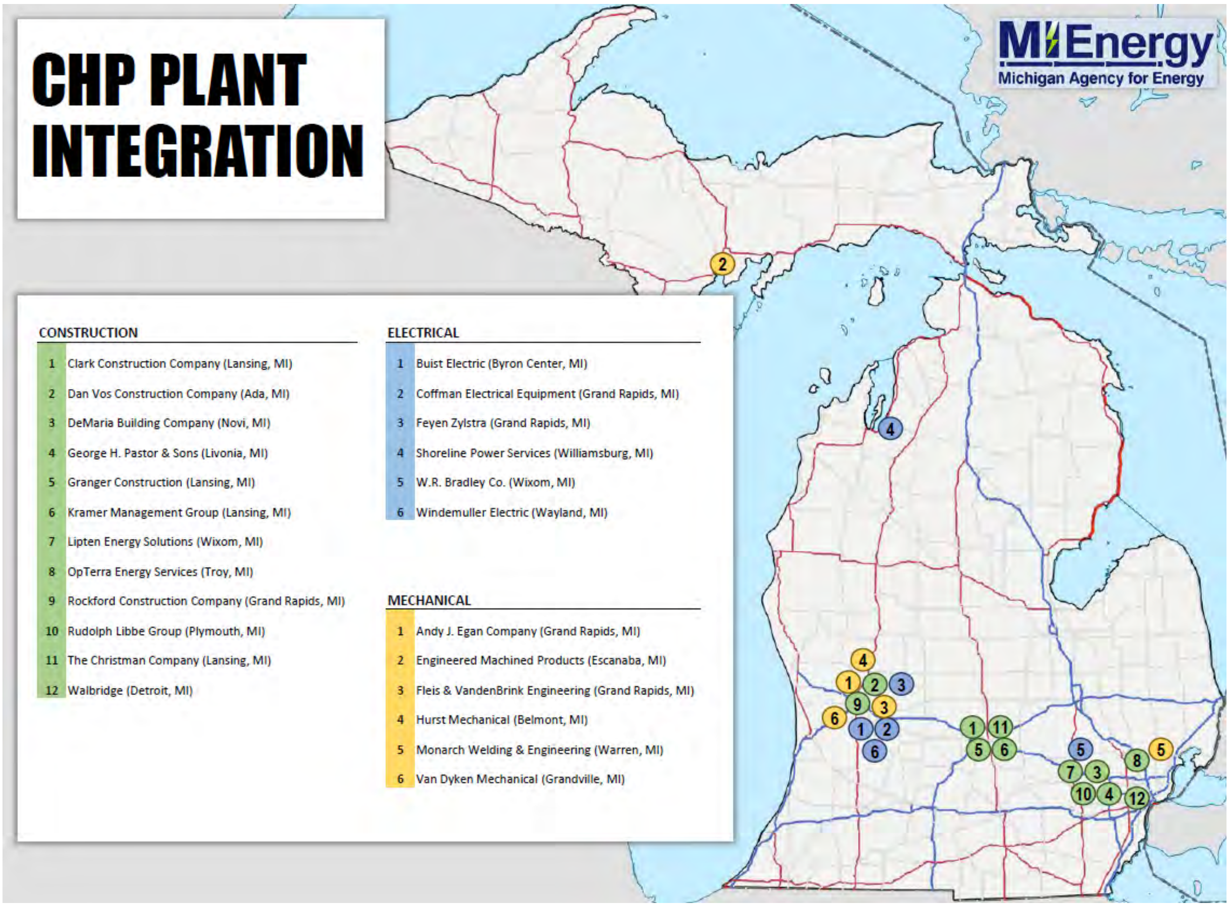


Figure 14: CHP Major Equipment

5.3 Michigan Economic Impact

Deployment of some portion of DOE's estimated 5 GW of Michigan CHP technical potential would generate significant economic activity throughout each project's lifecycle. However, the net economic impact on Michigan due to CHP deployment is quite difficult to discern. We can begin with the assumption that a business will spend less money on energy generation by implementing CHP than by maintaining the status quo, which must be true for a given project to be economically-viable. A business could use this saved money in many different ways. For example, if the business shifted this saved money, which it previously contributed to the Michigan economy, into dividends for company owners, there would be a negative impact on Michigan economic activity following CHP deployment. Alternatively, what is more likely is that widespread CHP deployment would actually be expected to significantly increase Michigan economic activity for a number of reasons:

- Businesses that save money on energy costs with CHP are likely to reinvest a significant portion or all of that savings into company growth;
- Electric utilities cannot simply scale back their generation and infrastructure investments proportionally to the loss of revenue due to CHP deployment. Incrementally, there will need to be more aggregate investments made in electric infrastructure in Michigan with CHP deployed than without, if there is the expectation to maintain an equivalent level of performance;
- Electric utilities will have additional capacity available, providing an opportunity to export to other power providers, or permitting a reduction in purchased power;
- Experience gained by Michigan-based participants in the CHP value chain could be deployed to other states, providing opportunities for many of these firms to bring new revenue streams into the Michigan economy.

Finally, there are factors that do not increase or reduce the economic impact on Michigan, but rather shift the economic impact from one market participant to another. For example, the public electric utilities will experience reduced revenues and likely spend less money on distribution system maintenance with widespread CHP deployment; but in turn, private sector developers, engineering firms, and project implementers will see increased revenues.

In Section 4.8, we determined through STEER modeling that optimal deployment of CHP in Michigan would require direct capital investment of about $865.7 million, annual non-fuel expenditures of about $67.6 million, and produce about $109.5 million per year in incremental profit. Optimal CHP deployment would also save Michigan's economy about $94.7 million per year in fuel costs.

Ultimately, the amount of direct and indirect economic activity in Michigan and the consequent employment (jobs) impact depends on the degree to which Michigan-based businesses are able to participate in the supply and value chains for CHP systems. A directory of Michigan CHP supply and value chain participants has been created and will be shared with potential end-users to foster the use of Michigan-based companies and resources when considering or implementing CHP projects. The database is ultimately envisioned as a tool that will continue to grow as the market for CHP in Michigan also expands. State policymakers could further encourage potential end-users to "Buy Michigan" and "Hire Michigan" through appropriate incentives.

6 Barriers to CHP in Michigan

CHP has the potential to be a significant, reliable, cost-effective, and environmentally protective contributor to Michigan's energy mix. Further, the Michigan CHP supply and value chain is well-positioned to deploy sustainable and cost-effective CHP projects for Michigan's largest energy users. However, those interested in installing CHP projects face a number of obstacles. In order to fulfill the promise of EWR in Michigan through optimal deployment of CHP, these barriers should be examined and understood in general, and in light of the unique circumstances facing Michigan energy users.

While CHP can save a system owner money in the long run, there are a few economic barriers that could prevent a CHP project from moving forward in the first place. The relatively high upfront cost of installing a CHP system can be a barrier in and of itself. Additionally, a lack of sufficient access to financing options can prevent otherwise cost-effective installations. According to the DOE's Advanced Manufacturing Office, "CHP developers must navigate a complex landscape of project financing alternatives and provide detailed project information in order to attract investors. Inadequate information can cause project delays, leading investors to offer less favorable financial terms, or even decline a CHP investment opportunity all together."[77]

Regulatory barriers can dramatically affect a CHP project's bottom line and projected payback period. An overarching barrier that affects the valuation of CHP throughout regulatory and policy discussions stems from the failure to account for the full value of CHP, including qualities such as resilience. Ignoring grid-wide and societal benefits affects how CHP is portrayed in standby rates, avoided cost rates, energy waste reduction standards and integrated resource planning.

Standby rates, or charges a utility customer pays for the utility to provide backup service in case of a scheduled or unscheduled CHP system outage, can be so high as to completely undermine the economic viability of a proposed CHP system. Beyond standby rates, avoided cost or buyback rates under the Public Utility Regulatory Policies Act of 1978 (PURPA) may be insufficient to make a CHP project worthwhile. Interconnection processes can be lengthy, cumbersome and costly. Whereas Michigan has embraced EWR goals through PA 341 and 342 of 2016, a failure to incorporate CHP, or to properly calculate energy savings from participating CHP systems, will lead to less than ideal deployment numbers. Finally, even as regulators and utilities embrace a longer-term resource planning approach, IRP models often fail to recognize the value of CHP as both a supply side and demand side resource, resulting in CHP being overlooked in utility long-range resource plans.

Each of these barriers – which are often dependent on geography, project size and technology, utility constraints, and the prevailing regulatory climate – adds to the risk and cost associated with a potential CHP project. Given the substantial capital investment involved in developing a CHP project, and in light of the benefits offered by more robust deployment of CHP, it is vitally important that these risks and costs be mitigated through thoughtful policies and incentives to avoid killing CHP projects that would otherwise make good sense for Michigan businesses, and good sense for the state's future energy mix.

[77] ICF. Prepared for the U.S. DOE, Advanced Manufacturing Office. 2017. Combined Heat and Power (CHP) Financing Primer. p. ii. https://energy.gov/sites/prod/files/2017/06/f35/CHP%20Financing%20Primer%206-16-17%20Final.pdf.

6.1 Overview of Economic Barriers

One of the most commonly-cited barriers to CHP development is the upfront capital cost associated with the acquisition and installation of equipment. A potential CHP system owner encounters this barrier early in the planning process, as cash or financing is required to purchase components such as turbine or engine parts needed to generate the needed heat and electricity. With an installed cost of between $700 and $3,000 per kW,[78] a potential CHP installation competes for scarce investment capital within a firm. Decision-making structures within a company can pose an additional hurdle, with many business leaders lacking familiarity with the business's typical patterns of energy use, or different energy options, including CHP.

If a business lacks the cash on-hand to invest in CHP equipment, financing can be an option, but a lack of access to low-cost financing can present a major barrier long before a CHP project ever breaks ground. According to the DOE's Advanced Manufacturing Office, "Lenders and investors typically decide to invest in a CHP project based on its perceived level of risk and expected financial performance. These groups focus solely on the expected monetary benefits, and typically do not consider environmental or other non-energy benefits from the project that may be important to the end-user."[79] The size of a typical CHP system can pose a challenge to obtaining financing, with a typical CHP project being too small to interest banks or private equity firms without giving away massive equity stakes.[80] Financing with debt, although generally cheaper than equity financing, can be intimidating due to the high cost of CHP equipment, even if a company has good credit and rates are favorable.[81]

For owners of larger CHP projects intending to sell the power generated, a power purchase agreement (PPA) can be critical to securing CHP project financing (equity and debt). The PPA or off-take agreement typically provides the CHP project's owner with stable and sufficient revenue to pay its project debt obligation, covers the project's operating expenses, and provides a reasonable risk-adjusted return to investor(s). Lenders will look to whether or not there is a guaranteed revenue stream from a creditworthy purchaser that is sufficient to support the project's economics. The terms of the PPA determine whether equity investors and debt lenders view the project as financeable, and lenders are concerned with the length of the PPA term, with a strong preference for longer-term contracts of at least 10-15 years.[82]

Uncertainty about energy costs can pose an additional barrier to CHP development. Fluctuations in natural gas prices introduce a substantial level of risk and uncertainty into the economics of a potential CHP project. Even with natural gas prices perceived as relatively low, natural gas prices can vary widely if "(i) there are significant variations in weather-related factors, (ii) crude oil prices change significantly,

---

[78] Chittum, A., and Kaufman, N. American Council for an Energy-Efficient Economy. 2011. *Challenges Facing Combined Heat and Power Today: A State-by-State Assessment*. p. 6. http://aceee.org/sites/default/files/publications/researchreports/ie111.pdf.

[79] ICF. Prepared for the U.S. DOE, Advanced Manufacturing Office. 2017. Combined Heat and Power (CHP) Financing Primer. p. iii. https://energy.gov/sites/prod/files/2017/06/f35/CHP%20Financing%20Primer%206-16-17%20Final.pdf.

[80] Ibid., p. 10.

[81] Ibid., p. 10.

[82] ICF. Prepared for the U.S. DOE, Advanced Manufacturing Office. 2017. Combined Heat and Power (CHP) Financing Primer. https://energy.gov/sites/prod/files/2017/06/f35/CHP%20Financing%20Primer%206-16-17%20Final.pdf.

(iii) other substantial disruptions to the energy market occur, or (iv) certain cost-related assumptions are significantly different."[83]

In addition to natural gas prices, a potential CHP system owner must have a thorough understanding of projected local electricity prices. Any firm must compare the cost of installing and operating a CHP system to the cost of conducting business as usual, and the cost of purchasing power must be higher than the levelized costs of self-generation. Because the price of purchased power is utility-specific, the economic feasibility of CHP varies geographically; higher costs of purchased power make CHP more attractive than in places where electricity is comparatively cheap.[84] According to EIA, Michigan has the 12th highest electricity prices in the U.S.,[85] making it a relatively good candidate for locating CHP based on the cost of power alone.

6.2 Michigan Economic Barriers

Capital Cost, Financing, and Payback Period

Analysis of survey and interview responses showed that the most commonly-cited barrier was "Cost/payback period/value" of CHP. Of the 83 survey respondents that cited potential barriers to CHP in Michigan, 55 (66%) of these respondents identified "Cost/payback period/value" as a major barrier, and 23 (42%) of these respondents cited it as the largest barrier to CHP implementation. 32 respondents (58%) cited it as the first or second largest barrier overall, and 40 out of 55 (73%) put it in the top three.

In one interview response, an attorney with experience representing clients interested in CHP explained: "Companies are reluctant to make a 20-year bet that they will be in business. The horizon where these projects make economic sense, because of the uncertainty in the world economically, can be the 'Achilles heel' of CHP. Just staying in business long enough to really see the economic benefits." Ensuring a reasonable payback period is crucial to the success of CHP development.[86]

According to National Regulatory Research Institute (NRRI), "The simple payback of a CHP system is the number of years that it will take for the annual operating cost savings from CHP to pay back the upfront costs of installing the CHP system… Economic feasibility has no single definition. Some analysts refer to it in terms of the payback period, with one definition specifying the payback period of five years or less."[87] End-user expectations for investment payback are generally less than 10 years in the public and

[83] Fujihara, R. U.S. EIA. Office of Technical and Regulatory Analysis. 2017. *Wholesale Natural Gas Market Assessment: Wholesale Natural Gas Futures Prices as of October 5, 2017*. https://www.dcpsc.org/PSCDC/media/PDFFiles/NaturalGas/NGAssessmenandinfo_current.pdf.

[84] Chittum, A., and Kaufman, N. American Council for an Energy-Efficient Economy. 2011. *Challenges Facing Combined Heat and Power Today: A State-by-State Assessment*. p. 8. http://aceee.org/sites/default/files/publications/researchreports/ie111.pdf.

[85] U.S. EIA. 2017. *Michigan State Profile and Energy Estimates.* https://www.eia.gov/state/?sid=MI.

[86] ICF International. Prepared for the American Gas Association (AGA). 2013. *The Opportunity for CHP in the United States*. p. ES-3. https://www.aga.org/research/reports/the-opportunity-for-chp-in-the-us---may-2013/.

[87] Costello, K. National Regulatory Research Institute (NRRI). 2014. *Gas-Fired Combined Heat and Power Going Forward: What Can State Utility Commissions Do?*. pp. vii, 18. http://energy.ky.gov/Programs/Documents/NRRI%20Report-What%20Can%20Commissions%20Do.pdf

institutional sectors, and less than 5 years in the private sector. Some end-users expect even shorter payback periods – 1 to 2 years – but this will never be realistic for CHP systems, which like utility power generation should be considered as a long-term investment. Ultimately when a CHP system's payback period or return on investment does not meet the end-users' internal requirements, the decision will often be to not implement the CHP project.[88]

Related to the payback period is a lack of low-cost financing to pay for the upfront cost of CHP equipment. As previously stated, the installed cost of CHP is between $700 and $3,000 per kW.[89] This means a relatively small CHP system of 2 MW in capacity could cost up to $6 million to install. Financing is critical for a project to move forward. Of those survey respondents citing potential barriers to CHP, a "lack [of] access to low cost capital" was listed by roughly a third of respondents as a major barrier to the development of CHP, with 20% of these individuals ranking it as the number one barrier to CHP in Michigan. In order to meet minimum equity investor expectations and investment requirements, projects must typically be financed such that the equity investor can achieve a leveraged, after-tax, payback on investment in less than 5 years, or the project will not move forward. To achieve this leveraged return on equity, a debt financing term of at least 7 to 10 years (best case), and often up to 15 or 20 years, typically must be negotiated with a long-term lender.[90]

Uncertain Energy Costs

"Spark spread" – the difference between the price of electricity and the cost of fuel to produce electricity – is widely understood to be one of the most critical factors in the economic viability of CHP projects. The price of natural gas can have a significant effect on spark spread. 31 survey respondents identified "natural gas price risk" as a top five barrier to the development of CHP in Michigan, with 17 respondents (55%) considering it to be either the fourth or fifth largest barrier, and 26 (84%) putting it in the bottom three of the five largest barriers.

Michigan residents and businesses enjoy natural gas choice, meaning they can transparently view competing offers from natural gas suppliers and "shop around." The Department of Licensing and Regulatory Affairs (LARA) provides a helpful website for consumers to easily "shop for gas for your home or business from a diverse market of natural gas suppliers."[91] This system provides flexibility for consumers to "choose an alternative gas supplier (AGS or supplier) that will invest in renewable products on their behalf while others are looking for other pricing options or value added services."[92] Despite the transparency and flexibility of being able to choose a natural gas supplier, Michigan businesses interested in exploring CHP will still be subject to risk from variations in natural gas prices overall. According to EIA, Michigan is currently ranked 40th in the U.S. for its natural gas prices, putting it on the relatively low side in the short term.[93]

---

[88] ICF International. Prepared for the American Gas Association (AGA). 2013. *The Opportunity for CHP in the United States*. p. ES-3. https://www.aga.org/research/reports/the-opportunity-for-chp-in-the-us---may-2013/.

[89] Chittum, A., and Kaufman, N. American Council for an Energy-Efficient Economy. 2011. *Challenges Facing Combined Heat and Power Today: A State-by-State Assessment*. p. 6. http://aceee.org/sites/default/files/publications/researchreports/ie111.pdf.

[90] Feldman, D. National Renewable Energy Laboratory. 2016. *Put a Fence around It: Project Finance Explained*. https://financere.nrel.gov/finance/content/put-fence-around-it-project-finance-explained.

[91] State of Michigan. 2018. *Compare MI Gas*. https://w2.lara.state.mi.us/gaschoice/.

[92] Ibid.

[93] U.S. EIA. 2017. *Rankings: Natural Gas Residential Prices.* https://www.eia.gov/state/rankings/#/series/28.

According to the DOE's Midwest CHP TAP, "The risk of CHP projects can be reduced by utilizing available commodity price risk management tools."[94] Concerning uncertain natural gas prices, types of hedging include physical hedging and financial hedging. Physical hedging includes storing and withdrawing excess natural gas. Financial hedging includes:[95]

- Index Purchasing, in which natural gas is purchased month-by-month at a 'first of the month' index price;
- Fixed Price Purchase, in which all or a portion of natural gas needs are purchased at one time, with the vendor providing an average fixed price for the term of the contract;
- Cap, in which a fixed price for gas is set, but 'put' contracts are purchased to guarantee that when future market prices for gas settle below the fixed cost, the monthly price is adjusted downward;
- Collar, in which a series of 'put' and 'call' contracts are purchased to guarantee that monthly prices for natural gas will be contained within a defined price range regardless of market conditions;
- Hybrid Approach, in which a percentage of each month's natural gas needs are purchased at a fixed price, and the remainder purchased at an index price; and
- Winter Strip, in which November through March gas is purchased at a fixed price and all other months are purchased at an Index price.

Overall, long-term energy contracts allocate price risk between parties: the buyer faces price uncertainty in the upward direction, and the seller faces price risk resulting from the risk of decline.[96] As a result, longer-term energy contracts "can serve as a 'hedge' on price movements for consumers. Like other forms of hedges and price management tools, there are implications for parties entering into such contracts in terms of future obligations and liabilities."[97]

---

[94] University of Illinois at Chicago. Energy Resources Center. 2004. *CHP – Managing Commodity Price Risk: An Introduction to Combined Heat and Power*. http://www.midwestchptap.org/Archive/presentations/050518-IL/050518_Pruitt.pdf.
[95] Ibid.
[96] Ibid.
[97] Ibid.

6.3 Overview of Regulatory Barriers

Regulatory barriers to CHP deal with the legal framework around utilities and self-generation which can sometimes put up unintended roadblocks to CHP development. Often, the impact of the regulatory barriers to CHP manifest as negative impacts on project economics, similarly to the economic barriers discussed above. Because a variety of economic and regulatory barriers often intermingle in affecting the prospects of a potential CHP project, there is a critical need to use a holistic approach to achieving optimized CHP adoption. The following section builds upon the fundamental understanding of CHP project economics discussed above with a discussion of regulatory barriers to the optimal deployment of CHP.

Standby Rates

Standby rates are a type of electric tariff paid to utilities by customers with on-site distributed energy resources, such as CHP systems. Standby charges are intended to help the utility recover costs related to reserving such service and providing backup electricity during scheduled and unscheduled outages of the customer's CHP system. Although well-designed standby rates are clear and transparent to the customer, and based on cost of service principles, poorly designed standby rates are often based on erroneous assumptions about CHP reliability, and are frequently unclear and difficult to navigate. (As examples of existing standby tariffs, copies of Consumers Energy Rate GSG-2 and DTE Energy's Rider 3 are attached as **Attachment L.**)

As a result, standby rates can be a significant barrier to the development of otherwise economically viable CHP projects. When rates are too high, inflexible, unpredictable, or simply too difficult for customers to navigate, the economics of a CHP system will fail to provide the needed return on investment, and a potential project will not pencil out.

PURPA Buyback Rates

Owners of CHP projects intending to sell excess generation back to the grid rely on the Public Utility Regulatory Policies Act of 1978 (PURPA). This law, originally designed to encourage energy waste reduction and promote the use of distributed energy resources, such as CHP, requires utilities to purchase or "buy back" power at a rate equal to the utility's "avoided cost." The Federal Energy Regulatory Commission (FERC) has oversight over PURPA, and state utility commissions are in charge of regulating the particular avoided-cost calculation methodology applied by rate-regulated utilities in their state. If avoided cost or buyback rates are set too low, this can have a negative impact on the economics of a proposed CHP installation.

Failure to Recognize Value of Distributed Energy Resources

Until recently, whether in formulating standby rates, PURPA avoided cost/buyback rates, or utility distribution system plans, electric utilities have rarely accounted for the benefits of distributed generation. Many states, including Michigan, have similarly failed to embrace the full value of CHP as a DER in their energy policy development. This means that grid benefits, such as increased reliability and avoided built central-station generating capacity, are not compensated, even with regard to CHP, which can help to stabilize grids while decreasing transmission losses in times of increased electricity demand.[98] Resilience, in particular, is a major potential value of CHP that is often overlooked. When properly configured to operate independently from the grid, CHP systems can provide critical power reliability for businesses and critical infrastructure facilities while providing electric and thermal energy to the sites on a continuous basis, resulting in daily operating cost savings. There are a number of ways in which CHP systems can be configured to meet the specific reliability needs and risk profiles of various customers, and to offset the capital cost investment for traditional backup power measures such as diesel generators. By supporting critical infrastructure in Michigan, CHP can save lives. From reliability to avoided built central-station generating capacity, overlooking CHP's full value represents a missed opportunity, and can be a significant barrier to CHP development.

RE/EWR Standards and Integrated Resource Planning (IRP)

A lack of emphasis on CHP in state portfolio standards relating to renewable energy and EWR can be a major barrier to the deployment of CHP. While some states explicitly include CHP in the language of their RPS, other states' standards bundle CHP in with other energy efficiency measures, making other energy efficiency investments more cost effective in the short term.[99] Other states (including Michigan, discussed below) have tended to overlook CHP almost entirely when it comes to these standards, thus missing out on CHP's full potential for energy waste reduction.

Many states, including Michigan, require utilities to provide regular IRPs. The Regulatory Assistance Project (RAP) defines an IRP as "a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period."[100] A lack of emphasis on the consideration of CHP as a resource in a utility IRP could have a chilling effect on how CHP is viewed long-term. Alternatively, if a utility is required to consider CHP as a potential resource, CHP has a chance to compete on the merits. According to the National Association of State Energy Officials (NASEO), "By altering or broadening the scope of utility resource planning, state policymakers and regulators place CHP on a more equal playing field with traditional energy resources."[101]

Beyond the need to include CHP within an RPS or EWR standard, or within a utility IRP's scope, it is also important to view CHP as both a supply-side and demand-side resource. Current utility analyses of CHP often examine the costs and benefits of CHP from too narrow a perspective, treating CHP as either a supply-side option or a demand-side option. This ignores a major benefit of CHP – that it can supply cost-effective electricity and save energy. By analyzing CHP merely as an efficiency measure, it is not possible to account for its full benefits, which could include reductions in grid congestion, reduced transmission and distribution costs, and other supply benefits. In contrast, supply-side modeling of CHP

---

[98] Ibid.

[99] Chittum, A., and Kaufman, N. American Council for an Energy-Efficient Economy. 2011. *Challenges Facing Combined Heat and Power Today: A State-by-State Assessment*. p. 15. http://aceee.org/sites/default/files/publications/researchreports/ie111.pdf.

[100] Wilson, R. and Biewald, B. Regulatory Assistance Project (RAP). 2013. *Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans*. p. 2. www.raponline.org/document/download/id/6608/.

[101] Friedman, J. and Otto, G. National Association of State Energy Officials (NASEO). 2013. *Combined Heat and Power: A Resource Guide for State Energy Officials*. p. 10. https://www.naseo.org/data/sites/1/documents/publications/CHP-for-State-Energy-Officials.pdf.

often only considers the capital cost of the CHP generation and does not take into account the benefits of the thermal energy. If a utility simultaneously considers CHP as a supply option and a demand/energy waste reduction option, it is much more likely to encourage development of the best CHP projects – projects that capture the full benefits for the utility, the site/host, and all utility ratepayers.

Interconnection Standards

Potential CHP system owners encounter the need to interconnect to the electric grid when they: 1) sign up for standby service from the utility to provide power in case of a CHP system outage; 2) desire to sell excess generation back to the utility; and/or 3) serve a utility customer behind the meter. The process of interconnecting a CHP system to the grid can be onerous and complex, posing a potential barrier to CHP deployment. According to ACEEE, "The lack of a consistent interconnection standard establishing parameters and procedures for connecting to the grid drives up both monetary and transaction costs for technology manufacturers and owners, discouraging CHP deployment."[102] Without standardized and streamlined interconnection processes and fees, potential CHP system owners face a confusing, costly task, which could stand in the way of a potentially beneficial CHP project.

6.4 Michigan Regulatory Barriers

Standby Rates

Among survey respondents, the third most commonly-cited barrier was "high cost standby rates," with 39 respondents naming this as a barrier to CHP development in Michigan. 20 of the 39 respondents (51%) named it as either the first or second largest barrier. The vast majority of the respondents (82%) identified standby rates in the top three. As described previously, in the context of growing stakeholder interest in distributed generation, and concern over standby rates as a potential barrier, the MPSC staff held workgroup discussions aimed at examining standby rates in Michigan.[103] As part of the working group process, Michigan utility standby rates for CHP sites were analyzed and compared to the standby rates of other utilities in the Midwest. The analysis found that standby charges experienced in Michigan are relatively high, potentially posing a barrier to CHP deployment. Further, the analysis found that standby tariffs in Michigan can be confusing and difficult for customers to navigate. While no formal requirements came out of the working group process, the MPSC staff issued several recommendations related to standby rate best practices.[104]

---

[102] American Council for an Energy-Efficient Economy (ACEEE). *Interconnection Standards*. https://aceee.org/topics/interconnection-standards.

[103] Michigan Public Service Commission Staff. 2017. *Standby Rate Working Group Supplemental Report June 2017*. http://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-376753--,00.html.

[104] 5 Lakes Energy. Prepared for the Michigan Public Service Commission. 2017. *"Apples to Apples" Standby Rate Analyses*.
http://www.michigan.gov/documents/mpsc/Copy_of_UPPCO_UMERC_jws_rev_03172017_rev2_568778_7.xlsx;
http://www.michigan.gov/documents/mpsc/UPPCO_UMERC_5Lakes_Analyses_03202017_568776_7.docx;
http://www.michigan.gov/documents/mpsc/mca_5_lakes_scenarios_545589_7.xlsx;
http://www.michigan.gov/documents/mpsc/5LE_Standby_Rate_Scenarios_10202016_538737_7.pdf

Coming out of the MPSC staff standby rate working group, engagement in the overall discussion of standby rates continued, and some interested parties went on to pursue formal intervention in utility general rate cases as a means of continuing to raise concerns about the effect of standby rates on CHP installations. Outside of formal intervention, businesses and associations have expressed their support for standby rate reform through comments and sign-on letters submitted to the MPSC.[105, 106]

PURPA Avoided Cost/Buyback Rates

Among survey respondents, the fourth most commonly-cited barrier was "lack of an adequate mechanism to sell excess generation to the grid." As discussed above, implementation of PURPA in Michigan is the legal mechanism by which utilities are required to buy back power generated by qualifying facilities. 38 respondents identified this as a top five barrier, with 19 of the 38 (50%) respondents naming this barrier as the first or second most significant barrier to CHP development in Michigan.

Similarly to standby rates, PURPA avoided cost/buyback rates have recently been a topic of interest at the MPSC. In October 2015, the Commission directed staff to form a technical advisory committee for the purpose of reviewing and considering its implementation of PURPA. "PURPA Technical Advisory Committee (PURPA TAC) participants provided a wide range of backgrounds and perspectives. Participation was welcomed from all who volunteered and included utilities, environmental groups, current and potential future qualifying facilities (QF), industry PURPA experts and MPSC Staff."[107] The PURPA TAC held a series of meetings and a report was issued by MPSC staff on April 8, 2016.[108] Afterwards, the Commission directed utilities to make avoided cost calculation filings in June 2016. While the results of some of these cases are still pending, the concern over an inadequate buyback rate remains, and continues to be a potential barrier to the development of CHP in Michigan. The MPSC has issued one order with new PURPA rates for Consumers Energy.[109]

In addition to its jurisdiction over the avoided cost methodology used in setting buyback rates, the Commission potentially also affects CHP deployment through approving other terms of power purchase agreements under PURPA, including the duration of and project size limitations included in utilities' proposed standard offer contracts. As discussed above, longer-term PPAs are more helpful to CHP

---

[105] Michigan Public Service Commission Staff. 2017. Public comments. http://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-376753--,00.html.

[106] Alliance for Industrial Efficiency. 2017. *Signed Coalition Letters.* https://alliance4industrialefficiency.org/resources/type/signed-coalition-letters/.

[107] Michigan Public Service Commission staff. PURPA Technical Advisory Committee. 2016. *Report on the Continued Appropriateness of the Commission's Implementation of PURPA.* p. 2. https://www.eenews.net/assets/2017/06/12/document_ew_05.pdf.

[108] Ibid.

[109] Michigan Public Service Commission. November 21, 2017. *Order in Case No. U-18090.* https://mi-psc.force.com/s/filing/a00t0000005ppUqAAI/u180900273.

projects seeking financing. Allowing larger-sized projects to benefit from the ease of the standard offer contract can also reduce transaction costs related to proposed CHP projects.[110, 111]

Lack of Government and Utility Support for CHP

Survey respondents perceived a lack of support for CHP in Michigan in the form of government or utility incentives. The second most commonly-cited barrier was a “lack of government grants or incentives” for CHP. 22 respondents (51%) ranked this barrier in their top two, and 27 respondents (63%) placed it among the top three. Similarly, the fifth most commonly-cited barrier was “lack of utility incentives.” 37 respondents named this in their top five, with 10 of 37 (27%) naming it in the top two most significant barriers to the deployment of CHP. The following discussion of EWR programs, integrated resource planning, and interconnection standards are all captured under the broad umbrella of government and utility incentives for CHP.

Energy Waste Reduction

Among the most important and impactful energy incentive programs in Michigan are the EWR programs run through the utilities.[112] PA 342 of 2016 requires utilities to achieve a specified amount of EWR savings. Electric and gas savings targets are based on prior years sales and are set at 1% per year for electric and 0.75% per year for gas utilities.[113] In order to achieve these savings, utilities conduct outreach and provide incentives to their customers to install energy waste reduction measures. The MPSC may authorize rate-regulated utilities to receive a financial incentive when they successfully meet the required savings reductions.

The law requires a “cost and benefit analysis and other justification for specific programs and measures included in a proposed energy waste reduction plan.”[114] Michigan utilities rely on the utility system resource cost test, otherwise known as the Program Administrator Cost Test (PACT) approach, when assessing the cost/benefit ratio of each EWR measure. This approach compares the cost of program administration including incentive costs to supply-side resources. Unfortunately, the supply-side resources in question only refer to the avoided transmission, distribution and fuel costs, and not to the long-term avoided capacity costs as would be modelled under an IRP process. Further, the PACT method does not incorporate additional resource savings, such as natural gas savings, or any societal non-monetized benefits such as cleaner water or air.

---

[110] Feldman, D. National Renewable Energy Laboratory. 2016. *Put a Fence around It: Project Finance Explained*. https://financere.nrel.gov/finance/content/put-fence-around-it-project-finance-explained.

[111] Parsons, J. E. Massachusetts Institute of Technology, Center for Energy and Environmental Policy Research, 2008. *The Value of Long Term Contracts for Investments in New Generation*, www.mit.edu/~jparsons/Presentations/Contract%20Value%20w%20Berger.pdf.

[112] Michigan’s energy waste reduction standards in PA 342 maintain the energy efficiency goals established with the energy optimization standards developed in PA 295.

[113] Michigan Public Service Commission. 2018. *Energy Waste Reduction.* http://www.michigan.gov/mpsc/0,4639,7-159-52495---,00.html.

[114] Michigan Legislature. 2016. PA 342, Sec.201. http://www.legislature.mi.gov/(S(orha3tn1ppom5z5a11udqezd))/mileg.aspx?page=getObject&objectName=2015-SB-0438.

While CHP provides both electric and thermal energy at efficiency levels far above conventional methods, it is not currently included in the EWR plans of Michigan utilities, in part because it does not survive the PACT cost-benefit analysis. Part of what drives this barrier is the complex nature of CHP as a technology application. Unlike more traditional efficiency measures such as lighting improvements, CHP projects often result in greater energy usage on-site. In order to include CHP as an eligible resource in EWR plans, the proper methodology with which to calculate CHP energy savings must be assigned. Because CHP projects provide both thermal and electric supply at increased efficiencies, it is necessary to compare the fuel required under separate generation in order to assess total energy savings. Michigan utilities' reliance on the PACT method as required by law, and resulting failure to properly value the energy savings from CHP, pose an additional barrier to CHP development.

In addition to the reliance on the PACT method, concerns about fuel-switching and competition for customers among utilities pose an additional obstacle to fully encouraging CHP in EWR programs. These concerns will need to be addressed in order to obtain the full benefits of CHP as an energy waste reduction resource.

Integrated Resource Planning

Because CHP functions as both a supply and demand side technology, it is often overlooked in traditional load forecasts. Through an IRP, a utility is required to analyze the least-cost resource mix from both supply and demand-side options. Since EWR measures and CHP applications are often lower-cost resources compared to constructing new generation facilities, proper utilization of IRP can result in the incorporation of these measures as utility system resources, which may reduce the need for additional supply resources. For example, under the STEER model, which was designed to function similarly to IRP models, ideal levels of CHP in Michigan, as a least-cost resource option, range between 722 MW to 1,014 MW of new CHP built.

PA 341 of 2016 requires Michigan's electric utilities to file periodic IRPs with the Commission. While PA 341 requires a utility IRP to include the projected energy and capacity purchased or produced by the utility from a cogeneration resource, there is no requirement that the utility consider customer-sited CHP on the supply-side, or EWR from CHP on the demand-side. In order to realize the full benefit of CHP, IRP analyses should be updated to incorporate CHP as both a supply-side and demand-side measure. Formally requiring utilities to assess CHP on both the supply and demand-side in an IRP would help ensure that these complicated projects are allotted equivalent analysis as other resources. Further, including customer-sited CHP projects with other supply-side resources would signal an acceptance that these projects exist in the grey area between demand reduction and power generation.

Distributed Generation Program

Historically, CHP has not been included in Michigan's net metering program law. Additionally, the full value of CHP as a distributed energy resource has not been fully captured in utility rates or other energy policies and programs. This overarching barrier continues in the revised 2016 PA 342 net metering/distributed generation program currently in the implementation process. Pursuant to 2016 PA 342, the MPSC is in the process of establishing a new distributed generation program to reflect "equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program under the clean and renewable energy and energy waste reduction act."[115] Under the law, the distributed generation program is limited to customers who install certain on-site grid-connected, renewable generation. The size limitations of the program likely prevent participation from even renewably-fueled CHP systems (qualifying generation projects must be no larger than 150 kW).[116]

Interconnection Standards

In 2005, the Federal Energy Regulatory Commission (FERC) issued Order No. 2006 requiring all public utilities to adopt standard rules for interconnecting new sources of electricity less than or equal to 20 MW in size. The goal of this order was to decrease interconnection time, increase energy supply, lower wholesale electricity prices, and facilitate development of renewable resources. FERC Order No. 2006 established a "fast track" process based on technical screening criteria for generators under 2 MW.

In response FERC Order No. 2006, the MPSC began a process to revise the rules governing interconnection standards for small electrical generators (under 150 kW). The revised rules were approved by the Commission in March 2009. According to the MPSC, "Technical requirements (data, equipment, relaying, telemetry, metering) are defined according to type of generation, location of the interconnection, and mode of operation (Flow-back or Non-Flow-back). The process is designed to provide an expeditious interconnection to the Utility electric system that is both safe and reliable."[117] The MPSC interconnection standards are general interconnection procedures approved by the MPSC and are intended to be used for reference only. Each utility will has its own set of documents updated with the utility-specific interconnection requirements and all system owners, including CHP system owners excluded by the MPSC general standards due to system size, must work with each utility individually to navigate the complex interconnection process.

In 2013 and 2014, FERC issued Order Nos. 792 and 792-A, which expanded and revised the technical screening process adopted in Order No. 2006, and changed the fast track process to include differentiation by voltage and interconnection location and increased the maximum project size for the fast track process to 4 MW, which can now include many small to medium CHP projects. This technical screening process creates an efficient, expedited, and yet technically sound method to process applications without subjecting projects that do not significantly impact the grid to unnecessary review. Especially with increased demand for interconnection, it is critical to institute policies that avoid costly, time consuming reviews for projects that do not require such reviews. These Orders also established a process to allow developers/customers to request pre-application reports, enabling potential interconnection customers to identify issues that may delay or halt the interconnection process prior to investing significant time and capitol. Finally, Order Nos. 792 and 792-A created the opportunity for a "supplemental study" prior to conducting a full study if a project fails the initial fast track technical screens.

---

[115] Michigan Public Service Commission. 2018. *Distributed Generation Program.* http://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406256--,00.html.
[116] Methane digester generation projects as large as 550 kW may also participate.
[117] Michigan Public Service Commission. 2018. *What is Interconnection?* http://www.michigan.gov/mpsc/0,4639,7-159-16393_48212_58223---,00.html.

The MPSC has not revisited these interconnection standards since FERC issued Order Nos. 792 and 792-A. Michigan's new energy law gives the MPSC authority to revisit and update the interconnection technical standards. As the MPSC considers revisions to the rules governing interconnection standards for electrical generators, it will be important to acknowledge the need for streamlining and expediting CHP system interconnection, where possible.

6.5 Lack of Expertise and Information

CHP is a well-established technology application and itis not new – it has been around for over a century. According to DOE, "CHP has been used in the United States for more than 100 years since Thomas Edison used it to power the world's first commercial power plant. Decentralized CHP systems located at industrial and municipal sites became the foundation of the U.S.'s early electric power industry."[118] Despite this long history, many businesses lack familiarity with CHP. This lack of awareness and need for further CHP education can be a barrier to optimal levels of CHP installations.

One reason for this lack of familiarity is that, according to a 2012 report from DOE and EPA, "CHP is not regarded as part of most end-users' core business focus and, as such, is sometimes subject to higher investment hurdle rates than competing internal options. In addition, many potential industrial project hosts are not fully aware of the full array of benefits provided by CHP, or are overly sensitive to perceived CHP investment risks."[119] As business leaders default to more familiar options, they miss out on the potential benefits of CHP.

For business leaders who are familiar with CHP, some may have longstanding negative expectations regarding the ease of CHP operations. This was confirmed directly via interviews with potential end-users, as many candidates for CHP either have direct negative past experience with CHP, or more commonly, have heard stories about the negative experiences of others with CHP systems. In many cases, these negative stories or rumors lead to CHP never being considered as a legitimate option.

Michigan businesses interested in CHP have access to the DOE Midwest CHP TAP, managed by the Energy Resources Center and based in Chicago, Illinois. The Midwest CHP TAP is one of seven regional CHP TAPs formed in 2003 "to promote greater adoption of clean and efficient energy generation and use through recycled energy. Recycled energy includes CHP, district energy, and WHP."[120] The Midwest CHP TAP educates prospective adopters of CHP and fosters CHP technologies as viable technical and economic options, providing businesses with free or reduced-cost CHP feasibility studies, among other resources. A number of private firms provide similar no-cost or low-cost services.

Despite Michigan's strong relationship with the Midwest CHP TAP, there is a lack of awareness and familiarity with CHP among end-users that is preventing businesses from reaching out for information. This lack of awareness of the potential benefits of CHP is preventing optimal levels of CHP development. In interviews with stakeholders, the need for increased education of end-users was mentioned as a barrier to CHP development in the state. According to a representative from an engineering firm

[118] Department of Energy. 2013. *Top 10 Things You Didn't Know About Combined Heat and Power.* https://www.energy.gov/articles/top-10-things-you-didn-t-know-about-combined-heat-and-power.
[119] U.S. DOE and U.S. EPA. 2012. *Combined Heat and Power: A Clean Energy Solution.* p. 18. https://energy.gov/eere/amo/downloads/chp-clean-energy-solution-august-2012.
[120] U.S. DOE Midwest CHP Technical Assistance Partnerships. http://www.midwestchptap.org/about/.

specializing in CHP systems, "Michigan's CHP market is at the point of asking: how does CHP benefit my facility? How is it done? Michigan's potential CHP users need education on the technology and financial resources." A Michigan-based component distributor agrees. "The biggest challenge is getting people to understand CHP. Companies don't realize these opportunities are out there." Successful CHP projects in Michigan typically have a strong champion within the end-user organization providing leadership to build consensus for the project across engineering, sustainability, energy, and finance disciplines.

7 Roadmap for CHP Deployment

There is strong interest and capability on the part of participants in the Michigan CHP supply and value chain for Michigan to move closer to optimal levels of CHP deployment. Currently, Michigan is home to over 3,300 MW of installed CHP capacity.[121] STEER model results indicate that ideal levels of CHP in Michigan, as a least-cost resource option, range between 722 MW to 1,014 MW built, in addition to the 3,300 MW in CHP capacity already installed. In order to pursue a greater role for CHP in Michigan's future energy mix, the following roadmap is offered in an effort to outline concrete policy actions for consideration. The following recommendations reflect lessons learned from stakeholder surveys, interviews, Midwest CHP TAP experience and expertise, and best practices from other states. A case study on the impact of incentives on CHP economics is provided in Section 9.1.

7.1 Reduce the Payback Period

In light of the importance of the payback period to the development of a CHP project, efforts to reduce the payback period of CHP by either defraying some of the initial upfront cost through a grant or offering a production incentive would be beneficial in addressing this barrier. For example, AEP Ohio's Combined Heat and Power and Waste Energy Recovery Program (CHP/WER) "supports the installation of high efficiency, sustainable and cost effective projects in AEP Ohio's service territory as allowed by SB 315."[122] CHP projects are eligible for the incentive if they meet minimum efficiency requirements of 60% overall efficiency and 20% useful thermal energy. CHP incentive payments are based on production of kWh recovered by the project, and incentive rates for projects approved in 2017 are $0.035 per kWh recovered for systems >1000 kW. There is a yearly cap of $500,000.[123] This incentive is a critical aspect of AEP Ohio's EWR program. The company estimates that it will generate 600,000 MWh in incremental annual energy savings through its CHP/WER Program between 2015 and 2019.[124]

[121] U.S. DOE. 2016. *Combined Heat and Power Installation Database*. https://doe.icfwebservices.com/chpdb/.
[122] AEP Ohio. *Combined Heat and Power and Waste Energy Recovery Program.* https://www.aepohio.com/save/business/programs/CombinedHeatandPower.aspx.
[123] Ibid.
[124] AEP Ohio. 2014. *Energy Efficiency/ Peak Demand Reduction Action Plan*. p. 118. https://aceee.org/files/pdf/aep-ohio-2015-2017-ee-pdr-plan.pdf.

7.2 Promote PACE and Other Financing Tools

For those citing a lack of low-cost financing as a barrier to CHP development in Michigan, PACE financing could be a solution. PACE financing is a long term financing tool for commercial property owners to pay for energy efficiency, water efficiency, and renewable energy upgrades, including CHP systems. According to Kyle Peczynski of Petros PACE Finance, "PACE financing eliminates the high upfront cost and spreads the repayment over a long enough term that the annual savings generated from the CHP project exceed the PACE payments starting in the very first year. In other words, PACE is a no-money-down, cash-flow-positive way to fund large CHP projects." Michigan's "Property Assessed Clean Energy" Act, or PA 270 of 2010, authorizes local governments to adopt PACE financing programs. This means PACE must first be adopted at the local level in order for PACE to be active in a particular county or city. PACE financing is currently available in 23 Michigan counties and 11 of the larger cities in non-participating counties. The adoption of local PACE authorization ordinances should be encouraged, and Michigan residents and businesses should be educated about this innovative financing tool.

On-Bill Financing (OBF) could also be helpful in facilitating CHP development. In OBF, the customer's costs of energy waste reduction retrofits or equipment are amortized and added to savings from the measures on the customer's utility bill. In Michigan's new energy legislation, PA 342, Part 7, Sec. 201-209 describes a framework for creating a residential OBF program. The new law invites utilities to file a residential OBF plan proposal for Commission approval. On April 24, 2017, the MPSC and MAE initiated a stakeholder meeting for the purposes of receiving feedback for OBF program goals. Currently, the OBF program is limited to residential energy installations, which would exclude industrial and commercial CHP installations. However, in the future, OBF programs could be revised to allow for commercial and industrial applications such as CHP projects.

7.3 Reform Standby Rates

Standby rates have a significant impact on whether a CHP project is developed. Both in terms of how difficult they are to interpret and navigate, and in terms of the negative impact on a project's bottom line, the need for a revised approach to standby rates in Michigan stands as a prime example of a barrier to CHP that can be readily reduced or eliminated. The MPSC Staff Standby Rate Working Group began a constructive conversation with stakeholders, with several important recommendations issued in the June 2017 Supplemental Report.[125] These include recommendations dealing with transparency and clarity of the published standby tariffs, the desire to encourage efficient use of the grid by incenting scheduled maintenance of CHP systems, and the overarching principle that standby rates should be based on cost of service principles.[126] A case study on the impact of standby rate mitigation is presented in Section 9.2.

The MPSC should continue to look to best practices in standby rate design as Michigan utilities further develop their approach to working with customers with CHP systems.

The RAP outlines best practices for standby rates,[127] including:

---

[125] Michigan Public Service Commission Staff. 2017. *Standby Rate Working Group Supplemental Report June 2017*. http://www.michigan.gov/mpsc/0,4639,7-159-16377_47107-376753--,00.html.
[126] Ibid.
[127] Selecky, J., Iverson, K., and Al-Jabir, A. Regulatory Assistance Project (RAP). 2014. *Standby Rates for Combined Heat and Power Systems*. p. 5. http://www.raponline.org/knowledge-center/standby-rates-for-combined-heat-and-power-systems/?sf_data=results&_sf_s=standby+rates+for+combined+heat+and+power+systems.

- Reservation fees should be based on the utility's cost and the forced outage rate of the CHP system;
- Standby rate design should not assume that all forced outages of CHP systems occur simultaneously, or at the time of the utility system peak;
- Demand charges should be designed to recognize the scheduling of maintenance service during periods when the utility generation requirements are low.

With regard to clarity and transparency of standby rates, utilities should provide educational materials to help customers navigate complex standby rate structures. For example, AEP Ohio helpfully provides bill calculation spreadsheets on its website.[128]

Ameren Missouri, another example, provides a standby rate billing model to any inquiring customer. The purpose of the model is to simulate the annual bill for a customer on the new standby rate given standby contract capacity and generation output and to calculate the standby avoided rate. The model includes a customer's annual 15-minute interval consumption data. The customer, or a third party entity, would only need to enter anticipated generation, supplemental capacity, and standby capacity. Once entered, the model calculates the annual bill and the avoided rate percentage create by the standby tariff. This model provides important information on the financial impact that Ameren's standby rate has on CHP customers. Further, this model allows customers to assess the financial effect of different operating schedules, standby contract capacities, and outages durations.[129]

The transparency provided by AEP Ohio and Ameren Missouri should be emulated by Michigan's utilities, including Consumers Energy and DTE Energy.

7.4 Improve Distributed Generation Program

PA 341 of 2016 requires the MPSC to determine "an appropriate tariff reflecting equitable cost of service for utility revenue requirements for customers who participate in a net metering program or distributed generation program." While Michigan's current distributed generation program is targeted at small installations and does not include CHP, future consideration of the cost and benefits of distributed energy resources should include CHP and attempt to capture its full value, including the value of resilience. This analysis would build on the findings regarding the distributed generation program.

According to the National Association of Regulatory Utility Commissioners (NARUC), "...a growing number of parties involved in the [distributed energy resource] debate acknowledge DER can provide material benefits beyond just those enjoyed by the customer behind whose meter the DER is sited... Some jurisdictions, utilities, researchers, and advocates have also concluded or posited that responsible encouragement of other types of DER adoption leads to positive cost benefit results. In this respect, when using the traditional model for rate design, which does not compensate (or charge) particular customers for producing particular benefits (or costs) for the grid... a regulator would be missing that

[128] AEP Ohio. https://www.aepohio.com/account/bills/rates/AEPOhioRatesTariffsOH.aspx.
[129] Standby Service Rider - Ameren, March 8, 2017, *available at* https://www.ameren.com/-/media/rates/files/missouri/uecesheetno92riderssrstandbyservicerider.ashx.

portion of the cost benefit analysis for DER... At the very least, neglecting DER benefits could represent a lost opportunity to meet customer needs on a more cost-effective basis."[130]

For example, in New York, under the Reforming the Energy Vision (REV) process, New York Public Service Commission issued its Value of Distributed Energy Generation Phase One Decision[131] in March of 2017, and the Phase One Implementation Order was released September 14, 2017. The New York methodology moves beyond Net Energy Metering (NEM) "to a more accurate valuation and compensation of Distributed Energy Resources. [The new method's] factors include the price of the energy, the avoided carbon emissions, the cost savings to customers and utilities, and other savings from avoiding expensive capital investments."[132] New York is wrestling with the issue of how to consider non-metered technologies, such as CHP projects, in its valuation of distributed energy resources. "A number of existing tariffs and programs govern the treatment and compensation of projects that are not eligible for NEM. Inclusion of those projects in VDER tariffs will require a thorough analysis of how a transition from those tariffs and programs can best be achieved."[133]

Michigan will be required to undergo a similar transition and accompanying analysis of larger distributed energy resources, such as CHP, as it pursues its grid modernization objectives. As the full benefits of CHP are increasingly taken into account, this barrier to CHP development should be diminished.

7.5 Update Interconnection Standards

As previously discussed, the MPSC has not yet revisited the interconnection standards since FERC issued Orders 792 and 792-A. Michigan's new energy law (passed in December 2016, PA 341 and PA 342) gives the MPSC authority to revisit and update the interconnection technical standards. Other states in the Midwest have recently revised their interconnection standards for small electrical generations to follow best practices and reflect the proposed standards in FERC 792 and 792-A. Michigan should follow their lead and adopt the following revisions to the state's interconnection standards:

1. Require utilities to facilitate pre-application reports to enable early assessment of proposed interconnections, decrease utility interconnection queues, and streamline applications.
2. Develop and implement a technical screening process for projects based on size, voltage, and location to allow those projects with limited expected impact on the grid to avoid undergoing full distribution and engineering studies.
3. Develop and implement a supplemental review process for projects that do not meet the criteria for expedited approval based on the original technical screening process, but that are not likely to significantly impact the grid or require grid upgrades.

---

[130] National Association of Regulatory Utility Commissioners (NARUC) Staff Subcommittee on Rate Design. 2016. *NARUC Manual on Distributed Energy Resources Rate Design and Compensation*. http://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0.

[131] New York Public Service Commission. 2017. *Order in Cases 15-E-0751 and 15-E-0082.* http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7b5B69628E-2928-44A9-B83E-65CEA7326428%7d.

[132] New York State Energy Research and Development Authority (NYSERDA). 2017. *Value of Distributed Energy Resources (VDER).* https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Project-Developers/Value-of-Distributed-Energy-Resources.

[133] New York Department of Public Service. 2016. *Staff Report and Recommendations in the Value of Distributed Energy Resources Proceeding*. p. 47. https://www.nyserda.ny.gov/All-Programs/Programs/NY-Sun/Project-Developers/Value-of-Distributed-Energy-Resources.

4. Address energy storage as an "electrical generator."
5. Require utilities to create and utilize dynamic electronic submittal and tracking portals.
6. Require utilities to create maps of the grid system to facilitate siting of proposed interconnections (including hosting capacity analysis, interconnection points).

With updated and streamlined interconnection processes in place, distributed energy resources such as CHP will have an easier path to connecting to, and providing benefits to, Michigan's electric grid.

7.6 Incorporate CHP as a Resource in Michigan Utility EWR Plans

The STEER model results indicate that ideal levels of CHP in Michigan, as a least-cost resource option, range between 722 MW to 1,014 MW built – in addition to the 3,300 MW in CHP capacity already installed. A key way to achieve this increase in CHP deployment is for Michigan utilities to embrace CHP as an EWR resource.

Michigan utilities have so far been extremely successful in setting and meeting their EWR goals, even without relying on CHP. "For the seven year period of 2009 through 2015, Energy Optimization program savings achieved for electric utility providers were 129 percent of the target… EO program savings achieved for natural gas utility providers were 127 percent of the required target."[134] There have been job creation benefits, as well. "The EO programs have led to the creation of new jobs in Michigan, by process contractors and by installation contractors. EO programs have also prompted the increasing availability of higher efficiency equipment such as LED lighting for homes and businesses."[135]

However, as more traditional energy efficiency measures become increasingly common in the market, utilities in other states are beginning to struggle to meet efficiency savings targets. When allowed as an eligible measure, CHP can improve a utility's ability to meet energy reduction goals and further increase CHP deployment. For example, in 2016, CHP was only responsible for 10% of AEP Ohio's efficiency portfolio savings; however, AEP Ohio's business plan aims to increase CHP contribution to efficiency savings targets to over 30% by 2020.[136] This proposed increase stems in part to the large energy savings that CHP applications can create, as well as the increased familiarity of their CHP incentives.

By failing to embrace the potential contribution of CHP as an EWR resource, Michigan is missing out on an opportunity to reap the full benefits of its EWR strategy. EWR program savings could be even higher with CHP and by deploying participants in the Michigan CHP supply and value chains, Michigan could experience increased job creation from CHP development, as well. According to ACEEE, which ranks states on progress towards energy efficiency metrics, "All of the highest-scoring states define CHP as an eligible resource in an energy efficiency resource standard, have implemented a standard for connecting CHP systems to the grid, and have a state-approved CHP production goal."

---

[134] Michigan Public Service Commission. 2016. *2016 Report on the Implementation of P.A. 295 Utility Energy Optimization Programs*. p. 2.
http://www.michigan.gov/documents/mpsc/2016_Energy_Optimization_Report_to_the_Legislature_with_Appendix_Nov_30_543919_7.pdf.
[135] Ibid., p. 10.
[136] AEP Ohio, Energy Efficiency, *available at*
https://www.aep.com/about/IssuesAndPositions/Distribution/EnergyEfficiency/GeneralPolicy.aspx

There are two main approaches to creating utility CHP incentive programs: passive and active. The passive approach, employed in states like Illinois and Ohio, is to define EWR broadly enough as too include savings from CHP. Utilities in those states are thereby incented to create CHP incentive programs themselves once the technology is deemed eligible. In 2013, Illinois passed Public Act 98-0090, which redefined "Energy Efficiency Project" as a measure that reduces the total Btus of electricity and natural gas needed to meet the end use or uses.[137] This new definition removed any concerns over fuel switching for CHP projects and allowed for future CHP incentive programs such as the Illinois public sector CHP pilot program, the Commonwealth Edison CHP incentive program and the Nicor Gas CHP incentive program. The downside of such an approach is that there is no requirement to include CHP as eligible. Indeed utilities such as Ameren Illinois, North Shore Gas, Duke Energy and First Energy do not yet have CHP incentives, though they are allowed under state law.[138] However, this approach may be more feasible to accomplish in the short term, as it does not require a CHP-specific carve-out, but instead only a broad redefinition of efficiency as total energy savings.

The active approach, on the other hand, involves creating a mechanism with which to require utilities to achieve specific savings targets from CHP installations. This is the approach used in Massachusetts through the Green Communities Act (S.B. 2768) passed in 2008, which created the state's Alternative Energy Portfolio and Energy Efficiency First Fuel Requirement.[139] The efficiency requirement requires utilities to prioritize cost-effective energy efficiency and demand reduction over supply resource and specifically mentions CHP as an eligible technology. The Alternative Energy Portfolio Standard (AEPS) is similar to Michigan's EWR program, but instead of requiring a certain level of load from efficiency, the AEPS requires utilities to achieve a specific amount of load from "alternative energy generating sources," including CHP projects, flywheel energy storage, energy efficient steam technology and renewable technologies that generate useful thermal energy. From 2009 to 2014, roughly 99% of compliance was met using CHP technologies.[140]

Under either approach, the proper methodology with which to calculate CHP energy savings must be carefully chosen. As discussed above, Michigan utilities' reliance on PACT fails to accurately capture the full energy savings of a CHP system. As an alternative, the Illinois Technical Reference Manual (TRM) provides a potential methodology for calculating energy savings from CHP.[141] Strengths of the Illinois TRM include the fact that it accurately reflects the energy required from the grid and on-site boilers/furnaces to produce an equivalent amount of electricity and thermal energy. On the electricity side, the Illinois TRM divides CHP into two categories, those operating above 6,500 hours a year and those operating below 6,500 hours a year. For systems operating fewer than 6,500 hours per year, the

---

[137] Illinois General Assembly. Illinois Compiled Statutes 3501/825-65 (a)(iii)(b). http://www.ilga.gov/legislation/ilcs/fulltext.asp?DocName=002035010K825-65.
[138] U.S. DOE. 2015. *Energy Incentive Programs, Illinois*. https://energy.gov/eere/femp/energy-incentive-programs-illinois.
[139] Massachusetts Legislature. 2008. Chapter 169. https://malegislature.gov/Laws/SessionLaws/Acts/2008/Chapter169.
[140] Ballam, J. Massachusetts Department of Energy Resources. 2013. *Massachusetts Alternative Portfolio Standard for Combined Heat & Power (CHP): An Effective Program for Clean, Efficient Energy*. https://www.maeep.org/sites/default/files/CHP2013/MAEEP%20CHP%20061913%20(Ballam).pdf.
[141] *Illinois Statewide Technical Reference Manual for Energy Efficiency Version 6.0*. 2017. http://ilsagfiles.org/SAG_files/Technical_Reference_Manual/Version_6/Final/IL-TRM_Version_6.0_dated_February_8_2017_Final_Volumes_1-4_Compiled.pdf.

avoided grid energy calculations use the non-baseload heat rate provided by EPA eGRID for utility specific regions (RFC West region for ComEd territory and SERC Midwest region for Ameren territory) and includes any line losses.[142] For systems operating more than 6,500 hour per year, the avoided grid energy calculations use the All Fossil Average heat rate provided by EPA eGRID for utility specific regions.[143] The utilities then monetize the energy savings from CHP using utility-specific avoided cost data to calculate the cost and value of incentives as outlined in a resource cost test (and requiring some sort of evaluation measurement and verification protocol). These cost tests determine what costs and benefits may be incorporated when assessing energy savings and their respective implementation costs.

An efficiency threshold for CHP projects should be a required feature of incorporating CHP in the EWR program. A reasonable eligibility threshold for CHP systems is one that is set high enough that so that it is clear that the CHP is achieving energy savings compared to separate heat and power, but not so high as to prevent CHP systems considered to be "high efficiency" from eligibility.[144]

The New York State Energy Research and Development Authority (NYSERDA) CHP incentive program is commonly thought of as the gold standard for state supported CHP policies.[145, 146] Incentives levels are divided between geographies, system sizes, and technology types and are capped at $2.5 million per project. The NYSERDA CHP Program provides incentives through a catalog approach and a custom approach. According to NYSERDA, under the catalog approach, approved CHP vendors act as a single point of responsibility for the entire project and provide a minimum 5-year maintenance/warranty agreement on the CHP system.[147] Under the custom approach, NYSERDA accepts applications from the site owner, the CHP System owner, or any member of the project team takes responsibility for the proper design, integration, installation, commissioning and maintenance of the CHP System.[148] NYSERDA will contract only with the applicant. The Custom Approach is available for projects 1 MW and larger in size.[149]

---

[142] Ibid.
[143] Ibid.
[144] U.S. EPA. 2017. *Methods for Calculating CHP Efficiency*. https://www.epa.gov/chp/methods-calculating-chp-efficiency.
[145] CleanEnergy States Alliance. 2015. *Clean Energy Champions: The Importance of State Programs and Policies*. p. 112. https://www.cesa.org/assets/2015-Files/Clean-Energy-Champions-LR.pdf.
[146] New York State Energy Research and Development Authority (NYSERDA). 2017. *Combined Heat and Power Program.* https://www.nyserda.ny.gov/All-Programs/Programs/Combined-Heat-and-Power-Program.
[147] Ibid.
[148] Ibid.
[149] The deadline for applications to the program is December 31, 2018 and projects are to be commissioned within 30 months of approval of application. Therefore, comprehensive program evaluation is expected to commence by June 2021. https://portal.nyserda.ny.gov/CORE_Solicitation_Document_Page?documentId=a0lt0000000kzvQAAQ.

7.7 Consider CHP Supply and Demand in IRP

Building upon Michigan's 2016 energy law's requirement that CHP must be considered in a utility's IRP, utilities should also be required to consider:

- the demand-side savings from CHP;
- on-site CHP as both a supply-side and demand-side resource.

IRP analysis should incorporate CHP as both a supply and demand-side measure. On the supply side analysis, CHP would be included as another generation resource similar to combined cycle generation. Unlike combined cycle plants, CHP requires a host facility capable of using the thermal output. Relatedly, the value of this thermal load would need to be accounted for either through a credit or another mechanism to account for the total cost of CHP to the utility. Formally requiring Michigan utilities to assess CHP on both the supply-side and demand-side in an IRP would help ensure that these complicated projects are allotted equivalent analyses as other resources. While the final proposed course of action might not include CHP, its required inclusion as a supply-side and demand-side resource would ensure a level playing field between all potential resources.

As one example of utility that has successfully included CHP in its IRP, Alabama Power includes more than 500 MW of company-owned and 1,500 MW of customer-owned CHP generation in its IRP. The plan states that the company aims to identify "CHP projects that are expected to bring benefits to all customers" and attributes its success in developing CHP resources to "a good working arrangement between all parties" and "an adaptive regulatory process."[150]

7.8 Promote Outreach and Technical Assistance

The DOE Midwest CHP TAP is an enormously helpful resource for those interested in developing CHP projects. Businesses in Michigan that are interested in CHP should work closely with the Midwest CHP TAP to utilize all available services and resources needed to better understand if CHP is right for them. Government leaders, along with trade associations and advocacy groups like the Midwest Cogeneration Association and the Michigan EIBC, should work in close collaboration with the Midwest CHP TAP to ensure their constituents and members are aware of the potential benefits of CHP and the resources provided by the Midwest CHP TAP. This can include assistance with navigating the complex array of financing options available for the development of CHP projects. Proactive engagement with technical assistance resources can also help to overcome structural organizational challenges necessitating education for energy and financial decision-makers within a company.

Targeted outreach to emergency management professionals are an additional key group that must be engaged in the effort, because they provide a gateway to their stakeholders who play an important role, at the local level, in developing emergency response plans and taking action when needed. Those involved with emergency planning and critical infrastructure are likely to be most interested in the resilience benefits of CHP. As discussed above, when properly configured to operate independently from the grid, CHP systems can provide critical power reliability for businesses and critical infrastructure facilities while providing electric and thermal energy to the sites on a continuous basis, resulting in daily

[150] Alabama Power. 2016. *2016 Integrated Resource Plan*. p. 34. https://www.alabamapower.com/our-company/how-we-operate/regulation/integrated-resource-plan.html.

operating cost savings. There are a number of ways in which CHP systems can be configured to meet the specific reliability needs and risk profiles of various customers, and to offset the capital cost investment for traditional backup power measures. In order to optimally deploy CHP for Michigan's critical facilities, outreach and education will need to be a high priority. "Successful application of CHP in critical infrastructure sectors will depend on overcoming institutional barriers, and engaging the support of decision-makers who build, manage, and operate these facilities. An element of 'out-of-the-box' thinking is also required as the needs of our infrastructure evolve to contend with growing and changing risks."[151]

8 Moving Michigan Forward

Michigan is poised to move forward toward optimal levels of CHP development. According to the DOE, Michigan has nearly 5 GW of CHP technical potential across more than 10,000 sites across 17 industrial and 24 commercial sectors. This potential, on a capacity basis, is roughly evenly split between 17 industrial sectors and 24 commercial sectors.[152] As discussed above, STEER model results indicate that ideal levels of CHP in Michigan, as a least-cost resource option, range between 722 MW and 1,014 MW built, in addition to the 3,300 MW in CHP capacity already installed.

This increase in CHP deployment will enhance Michigan's efforts to lead on EWR among other states. Currently, Michigan ranks 7th in the nation for potential annual CO_2 reductions from industrial energy efficiency and CHP/WHP.[153] In the 2017 ACEEE Energy Efficiency Scorecard, Michigan scored 14th (tied with Arizona, Delaware, Iowa, New Jersey, New Mexico, Ohio, Texas, and Wisconsin) in the CHP category, slightly lower than its overall energy efficiency rank of 11th.[154]

Demonstrating leadership in CHP development will serve to both reinforce and grow Michigan's demonstrated commitment to serious levels of energy waste reduction. According to the MPSC, regarding EWR overall, "For 2015, Michigan utility providers successfully complied with the energy savings targets laid out in PA 295. Providers met a combined average of 121 percent of their electric energy savings targets and 117 percent of their natural gas energy savings targets – one percent of retail sales for electric providers, and 0.75 percent of retail sales for gas providers. EO programs across the state accounted for electric savings totaling over 1.1 million MWh (megawatt hours) and natural gas savings totaling over 4.58 million Mcf (thousand cubic feet) for program year 2015."[155] CHP could be key

---

[151] State and Local Energy Efficiency Action Network. U.S. DOE. 2013. *Guide to the Successful Implementation of State Combined Heat and Power Policies*. p. 4. https://www4.eere.energy.gov/seeaction/system/files/documents/see_action_chp_policies_guide.pdf.

[152] U.S. DOE. 2016. *Combined Heat and Power (CHP) Technical Potential in the United States*. https://www.energy.gov/eere/amo/downloads/new-release-us-doe-analysis-combined-heat-and-power-chp-technical-potential.

[153] Alliance for Industrial Efficiency. 2016. *State Ranking of Potential Carbon Dioxide Emission Reductions through Industrial Energy Efficiency*. https://alliance4industrialefficiency.org/wp-content/uploads/2016/09/FINAL-AIE-State-Industrial-Efficiency-Ranking-Report_9_15_16.pdf.

[154] Berg, W., et al. American Council for an Energy-Efficient Economy. 2017. *The 2017 State Energy Efficiency Scorecard*. http://aceee.org/research-report/u1710.

[155] Michigan Public Service Commission. 2016. *2016 Report on the Implementation of P.A. 295 Utility Energy Optimization Programs*. p. 1.

to continuing to meet strong energy savings targets in the future. According to the ACEEE, "In states with energy efficiency goals, CHP can offer a more cost-effective way to reach efficiency targets and earn performance incentives. A single CHP system can offer the efficiency savings of many smaller efficiency projects. In times when some utilities are reporting less low hanging efficiency fruit in the commercial and industrial sector, CHP can offer deep savings at a very low cost, enhancing the overall cost-effectiveness of energy efficiency portfolios."[156]

Execution of the Michigan CHP Roadmap will likely have significant impacts on the levels of CHP deployed in Michigan. For example, by addressing the CHP barrier of standby rates, STEER Model results using the EIA 2016 Annual Energy Outlook Reference Case indicate that Michigan could see an increase of 345 MW of CHP capacity built. In Missouri, this pattern has already been demonstrated. In 2016, the Missouri Energy Office and Ameren Missouri reached a settlement agreement on standby rate reform. The new standby rate was a significant improvement to the previous rate, which was modelled to have detrimental financial effects on CHP development. As a result, there has been a noticeable uptick in CHP qualification screenings requested and provided by the Midwest CHP TAP. In 2016, before the standby model was created, the Midwest TAP provided technical assistance to only 10 sites in Missouri. In 2017, this number jumped to 46 sites, including Mercy Hospital in St. Louis. The renewed interest in CHP by Mercy Hospital was due in large part to the new standby rate in conjunction with the Missouri Energy Office's outreach.

Additionally, CHP incentive programs in other states have seen dramatic results in additional CHP capacity coming online. The NYSERDA CHP incentive program has had an enormous market impact in New York. Between 2013 and 2016, the NYSERDA program has provided incentives to over 150 sites with a cumulative total capacity of over 70 MW. In New York City alone, the program is directly responsible for over 100 MW of new CHP capacity since 2003. Similarly, in Illinois, the impact of the public sector CHP incentive was immediately felt. When released in 2013, the public sector incentive program received 17 applications providing 31 MW of capacity. Of these applicants, seven were selected as finalists to receive incentives. Through implementing the Michigan CHP Roadmap, well-crafted CHP incentive programs could have similar positive effects on CHP development in Michigan.

Building on its strong commitment to EWR, Michigan is well-positioned to take advantage of the opportunities offered by increased CHP development in the state. By implementing the Michigan CHP Roadmap, the state can expand its energy waste reduction vision to include the many benefits of CHP, helping businesses to achieve their cost-savings and energy reliability goals. With key revisions to programs and policy, CHP has the potential to be a significant, reliable, cost-effective, and environmentally protective contributor to Michigan's energy mix.

---

http://www.michigan.gov/documents/mpsc/2016_Energy_Optimization_Report_to_the_Legislature_with_Appendix_Nov_30_543919_7.pdf.

[156] Chittum, A. American Council for an Energy Efficient Economy (ACEEE). 2013. *How Electric Utilities Can Find Value in CHP*. p. 5. http://aceee.org/files/pdf/white-paper/chp-and-electric-utilities.pdf.

9 Case Studies

9.1 Impact of Incentives

Incentive programs help to improve the economics of proposed projects and can be an important consideration in the decision to move forward. Several models from other states exist for how such a CHP incentive program may be structured:

- Commonwealth Edison's (ComEd) Smart Ideas program provides CHP incentives for business customers in northern Illinois;
- Nicor Gas's (Nicor's) Energy Smart program provides natural gas incentives for CHP projects pursued by business customers in its in northern Illinois territories;
- The Illinois Energy Office, under its Illinois Energy Now program, provides incentives to public entities for CHP projects;
- Dayton Power and Light (DP&L) provides CHP incentives to public and private customers in its Ohio service territory;
- Baltimore Gas and Electric (BG&E) provides CHP incentives to public and private customers in its Maryland service territory.

Each of the five incentive programs has unique features, although they have some commonalities. All of the programs set a minimum efficiency level for eligibility – 60% for the Illinois-based programs and DP&L and 65% for BG&E.[157] The ComEd, Nicor, and DP&L programs provide incentives for feasibility assessments and the ComEd program further provides cost sharing for interconnection expenses. The Illinois Energy Now and BG&E programs offer a design incentive and these two programs along with DP&L provide incentive payments at the time of project commissioning. The design and commissioning incentives effectively act as up front capital cost buy downs.

All of the programs provide production incentives after a period of operation based on the electric generation and, in the case of Nicor, on the gas displaced from the existing on-site boilers. The production incentives are frequently structured to encourage higher efficiencies in the CHP systems. For example, DP&L's incentive ranges from 80% to 100% of $0.08/kWh depending on the system efficiency. For basic systems with a CHP efficiency of 60%, Illinois-based programs allow only 65% of generation to be eligible for incentives, but this percentage increases as the efficiency of the system increases. Some of the gas savings are also counted when CHP efficiencies exceed 65%. The BG&E program is not structured to incentivize higher efficiencies, but it sets the highest efficiency threshold for eligibility.

Table 10 summarizes the incentive structure for each of the five programs. Note that each of the programs has additional requirements that can be examined through the sources cited.[158] In northern

[157] The Illinois and BG&E programs calculate the CHP efficiency based on higher heating value (HHV), whereas the DP&L program uses Lower Heating Value (LHV). HHV and LHV are a measure of the range of expected energy content for a volume of fuel, typically natural gas for CHP applications. Therefore, the DP&L eligibility is a lower threshold.

[158] CHP Incentive Program Details:

Illinois, when a customer is shared by both ComEd and Nicor, the incentive programs operate in concert under rules for counting savings in the Illinois Technical Reference Manual.[159]

Table 10: Comparison of Five CHP Incentive Programs

Category	ComEd[1]/Nicor[2]	ComEd Only[1]	Illinois Energy Now[3]	DP&L[4]	BG&E[5]
Minimum CHP Efficiency	60% HHV	60% HHV	60% HHV	60% LHV	65% HHV
Feasibility Assessment	up to $25,000 or 50% of study cost	up to $25,000 or 50% of study cost		up to $10,000 for study cost	
	up to $12,500 or 25% of study cost				
Design incentive			up to $75/kW, max. 50% of design cost or $195,000		$75/kW
Installation/Commissioning Incentive			$175/kW, max. $650,000 including design incentive	$100/kW	$275/kW for <250 kW, $175 kW for ≥250 kW
Interconnection Incentive	up to $25,000 or 50% of interconnection cost				
Production incentive rate	$0.07/kWh @ 12 months	$0.07/kWh @ 12 months	$0.08/kWh @ 12 mos. if CHP eff ≥70% HHV	$0.08/kWh @ 12 months	$0.07/kWh @ 6, 12, & 18 months
	$1/therm @ 12 months		$0.06/kWh @ 12 mos. if CHP eff ≤60%<70% HHV		
Savings eligible for incentives	65% of kWh + 1% x each % CHP eff ≤60%<65% HHV	65% of kWh + 1% x each % CHP eff ≥60%	65% of kWh + 1% x each % CHP eff ≤60%<65% HHV	100% of kWh CHP eff ≥80% LHV	100% of kWh
	70% of kWh CHP eff ≥65% HHV		70% of kWh CHP eff ≥65% HHV	90% of kWh CHP eff ≤70%<80% LHV	
	2.5% of therms x each % CHP eff>65% HHV		2.5% of therms x each % CHP eff>65% HHV	80% of kWh CHP eff ≤60%<70% LHV	
Incentive Caps	$2,500,000 or 50% of project $2,000,000 elec, $500,000 gas	$2,000,000 or 50% of total project costs	$2,000,000 or 50% of total project costs	$500,000 or 50% of total project costs	$1.25 million design & installation $1.25 million production

To assess the impact of these incentives on a potential CHP project, we begin with the operating and financial data for a sample university as defined in Table 11.

Table 11: University Base Energy Load and Costs

Annual Operating Hours	8,760
Average Electric Demand (kW)	7585
Annual Electric Demand (kWh)	66,444,600
Average Thermal Demand (MMBtu/hr)	25
Annual Thermal Demand (MMBtu)	219,000
Annual Natural Gas Demand (therms)	2,737,500

(1) ComEd. 2017. https://www.comed.com/SiteCollectionDocuments/WaysToSave/Business/PY9_CHP_flyer_v03.pdf.
(2) Nicor Gas. 2018. https://www.nicorgasrebates.com/your-business/custom-incentive/Combined-Heat-and-Power.
(3) Illinois Department of Commerce & Economic Opportunity. 2017. https://www.illinois.gov/dceo/whyillinois/TargetIndustries/Energy/Pages/CHPprogram.aspx.
(4) Dayton Power & Light. 2018. https://www.dpandl.com/save-money/business-government/custom-rebates/chp-rebates.
(5) Baltimore Gas and Electric. 2015. http://www.bgesmartenergy.com/business/chp.

[159] *Illinois Statewide Technical Reference Manual for Energy Efficiency Version 6.0*. 2017. http://ilsagfiles.org/SAG_files/Technical_Reference_Manual/Version_6/Final/IL-TRM_Version_6.0_dated_February_8_2017_Final_Volumes_1-4_Compiled.pdf.

Average electricity price ($/kWh)	$0.072
Average natural gas price ($/MMBtu)	$3.56

A feasibility evaluation had specified a gas turbine system with a net capacity of 4,324 kW and 25.2 MMBtu/hour of useful thermal output, as the optimal technical solution for this end-user. The specifications for this CHP project are sourced from a DOE factsheet[160] and summarized in Table 12.

Table 12: CHP Specifications

Nominal Electric Power (kW)	4,600
Net Electric Power (kW)	4,324
Fuel Input (MMBtu/hr)	59.1
Useful Thermal (MMBtu/hr)	25.2
Electric Efficiency	25%
CHP System Efficiency (HHV)	67.6%
CHP System Efficiency (LHV)	74.7%
Total Installed Cost ($/kW)	2,817
CHP O&M costs ($/kWh)	$0.013

[160] U.S. DOE. *Combined Heat and Power Basics.* http://energy.gov/eere/amo/combined-heat-and-power-basics#factsheet.

Using the specified gas turbine, and in the absence of incentives, the sample university would expect an implemented CHP project to achieve the metrics outlined in Table 13.

Table 13: Energy Savings and Payback

Energy Savings	
Net electric generation (kWh)	$35,984,328
Natural Gas Boiler Savings (therms)	$2,621,430
Energy in Btus	
Fuel total CHP (mmBtu) HHV	$491,830
Net CHP generation (mmBtu)	$122,779
Useful thermal (mmBtu)	$209,714
Costs and Payback	
Annual Operating Savings	$1,046,302
Total Installed Costs	$12,180,708
Incentives	$0
Simple Payback, Years, w/o incentives	11.6
Assumptions	
CHP up-time	95%
Thermal utilization	100%
Parasitic load	6%
Existing boiler efficiency	80%
% of electricity costs saved by CHP	90%

Table 14 summarizes what kind of incentives the hypothetical University project would be eligible for under these five utility programs. Note that 70-100% of the generation would be eligible for production incentives across the various programs, based on CHP system efficiency. In addition, 6.5% of the boiler natural gas displaced by the system would be eligible for incentives under the Nicor program.

Table 14: Electricity Generation and Natural Gas Savings Eligible for Incentives

Category	ComEd/Nicor	ComEd Only	Ilinois Energy Now	DP&L	BG&E
Electric (%)	70.0%	72.6%	70.0%	90.0%	100.0%
Natural gas %)	6.5%	0.0%	0.0%	0.0%	0.0%
Electricity (kWh)	25,189,030	26,125,771	25,189,030	32,385,895	35,984,328
Natural gas (therms)	170,602	-	-	-	-

Before applying any program caps on total incentives, the project would be eligible for incentives of $1.9 to $4.9 million under the various programs, as depicted in Table 15. However, given the size of the potential university CHP system, the program caps would apply under some of the programs. The Illinois Energy Now program would cap the incentives at $2 million, while the BG&E program would cap the production incentive portion of the incentive, resulting in a total incentive of about $2.3 million. The

DP&L program has the lowest cap – $500,000 – but DP&L encourages customers considering larger projects (over 500 kW) to contact the utility to discuss potential incentive levels that could be higher than this cap.

Table 15: Potential Incentives under the Various CHP Programs

Category	**ComEd/Nicor**	**ComEd Only**	**Illinois Energy Now**	**DP&L**	**BG&E**
Feasibility study	$37,500	$25,000		$10,000	
Design incentive			$195,000*		$324,300
Installation/Commissioning incentive			$455,000*	$432,400	$756,700
Interconnection Incentive	$25,000	$25,000	$0	$0	
Electric production incentive	$1,763,232	$1,828,804	$1,350,000*	$67,600*	$1,250,000*
Natural gas incentive	$170,602	$0	$0	$0	$0
Incentive (calculated w/o cap)	$1,996,334	$1,878,804	$2,592,342	$3,033,272	$4,859,354
TOTAL Incentive (with caps)	$1,996,334	$1,878,804	$2,000,000	$510,000	$2,331,000

**Cap applied to this portion of the incentive.*

The impact on total project costs and simple paybacks are summarized in Table 16. The combined incentives from ComEd and Nicor and the Illinois Energy Now incentive would reduce the payback period by nearly two years, whereas if the DP&L caps were applied the incentive would only reduce the payback by about one-half year. The BG&E program would provide the greatest benefit, offsetting nearly 20% of installation costs and reducing the payback period by over two years. Again, other rules and requirements may apply and utilities (as DP&L suggests) may negotiate different incentive levels in individual situations.

Table 16: Cost Reductions from Incentives

Category	**ComEd/Nicor**	**ComEd Only**	**Illinois Energy Now**	**DP&L**	**BG&E**
Installed Cost with incentive	$10,184,374	$10,301,904	$10,180,708	$11,670,708	$9,849,708
% of Project Offset	16.40%	15.40%	16.40%	4.20%	19.10%
Simple Payback (in years) w/o incentive	11.6	11.6	11.6	11.6	11.6
Simple Payback (in years) w/incentive	9.7	9.8	9.7	11.2	9.4
Reduction in Payback (in years)	1.9	1.8	1.9	0.5	2.2

9.2 Impact of Standby Rates

Using data from nine Michigan CHP project evaluations, completed by the Energy Resources Center from 2014 to 2017 to support potential new projects, project partners were able to model the effects of standby rate changes on system payback for each of the projects, as identified in Table 17 by their corresponding utility, market sector, estimated capacity, and estimated system payback. While two of these sites are viewed as economically viable under existing conditions (Consumers Casino and Consumers University), none of these nine sites are currently proceeding with a CHP installation. We consider economic viability to include a payback period of less than 10 years for the public and institutional sectors and less than 4 years for the private sector.

Table 17: Michigan Site Screening Results for CHP

Site	Utility	Capacity	Base Case Payback (years)
Office Building	DTE	613 kW	21.1
Waste Water Plant	Consumers	1,000 kW	14.4
Casino	DTE	600 kW	12.5
Waste Water Plant	DTE	9,800 kW	11.3
Auto Mfg.	DTE	9,400 kW	6.9
Metals Mfg.	DTE	9,000 kW	6.5
Food Mfg.	DTE	7,000 kW	6.2
University	Consumers	3,000 kW	5.3
Casino	Consumers	600 kW	3.5

Current standby rates are unfavorable to the financial viability of CHP applications in Michigan. Project partners used an avoided rate model to analyze the financial effects that standby rates have on CHP system payback. The concept of avoided rate evaluates the financial impacts of standby rates on distributed generation systems by comparing the per kilowatt-hour (kWh) cost of full-requirements customers to that of standby customers. Ideally, a decrease in electricity purchased from the utility would be commensurate with a decrease in monthly electric costs. However, many standby rates are created such that they increase capacity demand charges when a customer decreases energy consumption, thus negating much of the expected savings.

The avoided rate is a percentage that reflects the relationship between the aggregate cost of a kWh before and after CHP implementation. An avoided rate of 70% means that the savings for each kWh generated on-site will only equal 70% of the utility's aggregate kWh price. According to the EPA, avoided rates above 90% are not considered a significant barrier to CHP implementation. [161] With an avoided rate of 100%, standby rates are not considered a barrier at all.

Project partners have calculated that the standby rates of DTE Energy create avoided rates that range from 70% to 77%, while the avoided rates of Consumers Energy range from 81%-86%. These are both

[161] Regulatory Assistance Project. Prepared for the U.S. EPA. Office of Atmospheric Programs, Climate Protection Partnerships Division. 2009. *Standby Rates for Customer-Sited Resources: Issues, Considerations, and the Elements of Model Tariffs*. https://www.epa.gov/sites/production/files/2015-10/documents/standby_rates.pdf.

considered major barriers to CHP implementation and significantly increase project payback periods as illustrated in **Figure 15**.

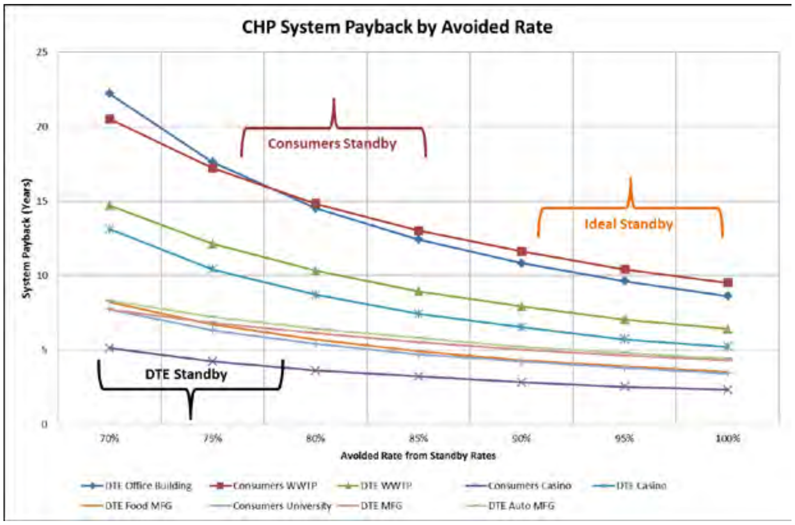


Figure 15: CHP System Payback by Avoided Rate

Project partners modeled the effects of standby rate improvement on system payback for each site, as depicted in **Figure 16**. Under ideal standby rates all sites would experience paybacks under ten years with a majority having paybacks less than five years. Compared to status quo, this change causes an additional two sites to become economically viable (Consumers Waste Water Plant and DTE WWP) while three sites are on the cusp of viability (DTE Food MFG, DTE MFG, DTE Auto MFG).

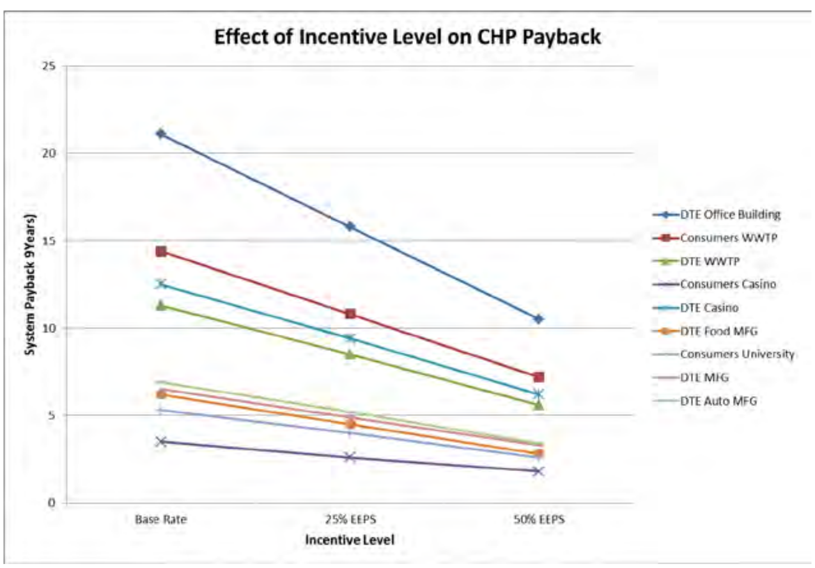


Figure 16: CHP System Payback by Incentive Level

Project partners also modeled the effects of EWR incentives (offered in the form of rebates) on system payback. Two levels were analyzed, 25% of installed costs and 50% of installed costs. Under a 25%

incentive level, one additional site becomes economically viable (DTE WWP), bringing the total to three viable projects. Under a 50% incentive an additional four sites become economically viable (Consumers WWP, DTE Food MFG, DTE MFG, DTE Auto MFG), bringing the total to six.

When both measures are implemented, eight of the nine sites become economically viable. Table 18 shows the revised system paybacks under each scenario. It is important to note that the one site not achieving economic viability was an office building located within DTE Energy's territory. Though the "Commercial Buildings" category contains 718 MW of CHP potential according to DOE estimates, most of this potential is very unlikely to be realized as these facilities do not operate enough hours per year or do not have large enough total energy requirements for CHP to be a reasonable economic fit.

Table 18: CHP Payback by Avoided Rate and Incentive Levels

Site	Utility	Capacity	Base Case Payback (years)	Ideal Standby Payback (Years)	Ideal Standby + 25% Incentive	Ideal Standby + 50% Incentive
Office Building	DTE	613 kW	21.1	8.6	6.5	4.3
Waste Water Plant	Consumers	1,000 kW	14.4	9.5	7.1	4.7
Casino	DTE	600 kW	12.5	5.2	3.9	2.6
Waste Water Plant	DTE	9,800 kW	11.3	6.4	4.8	3.2
Auto Mfg.	DTE	9,400 kW	6.9	4.4	3.3	2.2
Metals Mfg.	DTE	9,000 kW	6.5	4.3	3.2	2.1
Food Mfg.	DTE	7,000 kW	6.2	3.8	2.9	1.9
University	Consumers	3,000 kW	5.3	3.4	2.6	1.7
Casino	Consumers	600 kW	3.5	2.3	1.7	1.1

Attachments

List of Attachments

A. Property Assessed Clean Energy (PACE) Overview
B. Michigan CHP Directory of Supply/Value Chain Participants
C. CHP Survey and Interview Responses
D. STEER Results - EIA 2016 Annual Energy Outlook Reference Case w/ renewables
E. STEER Results - EIA 2016 Annual Energy Outlook Reference Case w/o renewables
F. STEER Results - EIA 2016 Annual Energy Outlook High Resource Case w/ renewables
G. STEER Results - EIA 2016 Annual Energy Outlook High Resource Case w/o renewables
H. STEER Results - EIA 2016 Annual Energy Outlook Low Resource Case w/ renewables
I. STEER Results - EIA 2016 Annual Energy Outlook Low Resource Case w/o renewables
J. STEER Results – Resilience Values and EIA 2016 Annual Energy Outlook Reference Case w/ renewables
K. STEER Results – Standby Rates and EIA 2016 Annual Energy Outlook Reference Case w/ renewables
L. Sample Standby Tariffs – Consumers Energy Rate GSG-2 and DTE Energy Rider 3

Consumers Energy
Count on Us

A CMS Energy Company

General Offices:
One Energy Plaza Tel: (517) 788-0550
Jackson, MI 49201 Fax: (517) 768-3644

*Washington Office:
1730 Rhode Island Ave. N.W. Tel: (202) 778-3340
Suite 1007
Washington, DC 20036 Fax: (202) 778-3355

Writer's Direct Dial Number: (517) 788-1846
Writer's E-mail Address: robert.beach@cmsenergy.com

October 8, 2018

<u>Via Electronic Mail</u>

Toni L. Newell, Esq.
Varnum, LLP
The Victor Center, Suite 910
201 North Washington Square
Lansing, MI 48933

RE: Case No. U-20165 – 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.

Dear Ms. Newell:

Attached to this letter are copies of the following documents:

- Consumers Energy Company's response to discovery question 20165-MEI-CE-328; and
- Proof of service.

Please contact me if you have any questions regarding this matter.

Sincerely,

RWB
Digitally signed by
Robert W. Beach
Date: 2018.10.08
13:18:20 -04'00'

Robert W. Beach

CC: Hon. Sharon L. Feldman, ALJ (letter and proof of service only via e-mail)
Kavita Kale, Executive Secretary (letter & proof of service via e-file)
Sebastian Coppola (letter & responses via e-mail), sebcoppola@corplytics.com (<u>& Hard C. of AG Reqs</u>) +Excels/Disks
Parties of Record

20165-MEI-CE-328
Page 1 of 2

Question:

1. Based on the values for the Financial Compensation Mechanism included in the testimony filed by Consumers in U-20165 and actual values for competitive bids received by Consumers after Consumers' Request for Proposals filed in June 2018, please provide data and analyses to describe the following scenarios. If it is not possible to use the actual values for competitive bids, please use average values that reflect the recently received competitive bids by Consumers. Specifically, please provide an example of a side-by-side comparison for each scenario, showing inclusion of the Financial Compensation Mechanism, Consumers' ROE, and all other applicable factors anticipated to affect the analysis and evaluation of the bids that respond to the competitive solicitation.

   a. Proposed IPP built project that Consumers contracts using a PPA.
   b. Proposed utility –built project that Consumers owns.
   c. Proposed IPP built project that IPP sells to Consumers.

Response:

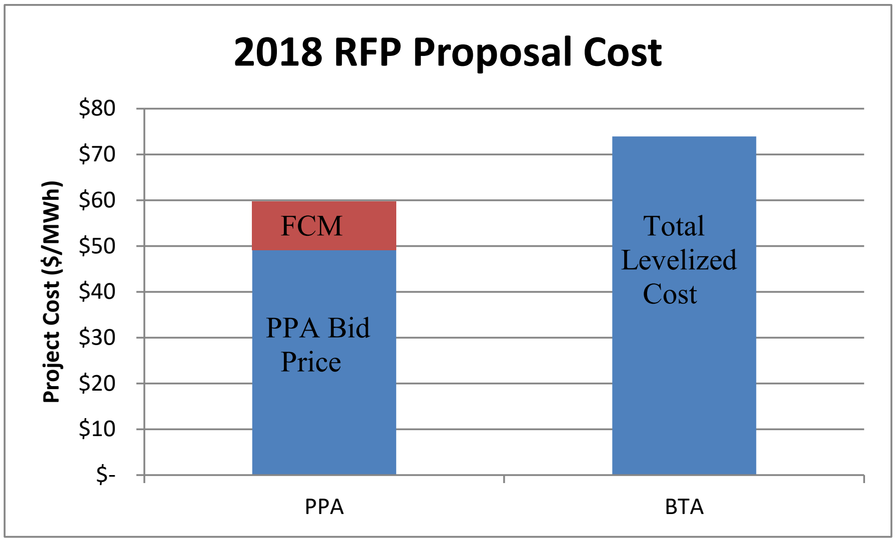
The Company has completed its preliminary analysis of the solar proposals received in response to its June 2018 Request For Proposals. The following information is provided for the eligible proposals that are expected to be economic when the cost of the facility is compared to a market forecast of energy and capacity values.

a. The Company solicited PPA proposals up to 100 MW in size for a contract length up to 20 years. The weighted average levelized PPA cost of the economic solar PPAs was $49.10/MWh. The FCM for a 20 year PPA at this cost would be $10.57/MWh, resulting in a total cost of $59.67/MWh.

b. The Company solicited Development Asset Acquisition proposals for the purchase of a solar development up to 100 MW in size. None of the proposals received were forecast to be economic. The FCM does not apply to Company-owned resources.

c. The Company solicited Build-Transfer Agreement ("BTA") proposals up to 100 MW in size for the acquisition of a solar asset constructed by an Independent Power Producer. The weighted average levelized cost of the economic solar BTAs was $73.92/MWh. The FCM does not apply to Company-owned resources.

The following graph shows a comparison of the total forecast cost of an average PPA with the FCM from part a) of this response to an average BTA proposal from part c) of this response. The total cost of the PPA to customers includes both the PPA price paid to the supplier and the FCM. BTA proposals result in the Company owning the facility, therefore the total cost to customers is shown in the BTA pricing, including the Company's return, capital cost, and ongoing project expenses through the life of the facility. The Company would not apply an FCM to any BTA or DAA proposal.



Keith Troyer
October 8, 2018

Transactions and Wholesale Settlements

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of)
UPPER PENINSULA POWER COMPANY)
for approval of its integrated resource plan) Case No. U-20350
pursuant to MCL 460.6t and for other relief.)

DIRECT TESTIMONY AND EXHIBITS OF

GRADON R. HAEHNEL

FOR

UPPER PENINSULA POWER COMPANY

February 12, 2019

A. The IRP base modeling assumes both the energy and capacity from these units, as these facilities were submitted for inclusion in Case No. U-20276. As such, they are not included in the PCA but rather in the base model, pending the outcome of Case U-20276.

IV. Request for Proposals and Results

Q. Please describe the process UPPCO utilized for its pre-filing RFP.

A. For a description of the overall RFP process, please see Company witness David R. Tripp's testimony.

Q. How many RFP processes has UPPCO commenced prior to its IRP filing? Please explain.

A. Two. UPPCO has initiated an RFP process to obtain bids for energy and capacity sources from (i) solar generation facilities, and (ii) RICE generation facilities.

Q. Please describe the solar generation RFP.

A. UPPCO sought to acquire up to 20 MW of AC solar photovoltaic ("PV") generating capacity with a Commercial Operation Date ("COD") commencing on or before June 1, 2022, all located in the Upper Peninsula of Michigan. As such, the capacity could be met by a single 20 MW facility or multiple facilities of lower capacity. For purposes of this RFP, AC capacity referred to the net generating capacity at the facility's point of interconnection ("POI"), as controlled by the plant supervisory control and data acquisition ("SCADA") system. Respondents could propose solutions with an aggregate inverter capacity exceeding the 20 MW AC limit at the point of interconnection, if advantageous.

Q. Please describe the options scoped within the solar generation RFP.

A. Solar generation options:

- Build Transfer/EPC or Build-Own-Operate-Transfer PPA with a purchase option. In this option, the Developer is responsible for development, turn key EPC construction and commissioning of Solar PV facilities up to the POI with UPPCO's Generation Step-up ("GSU") transformer. UPPCO is responsible for design and construction of related interconnection facilities. UPPCO to provide the project land through lease or purchase and the interconnection substation. Option for Respondent to own and operate the facilities and sell energy and capacity under a PPA to UPPCO with an option for UPPCO to purchase any time after 5 years plus one day. Option for Respondent to provide long term O&M of the facility.
    a. Interconnected on UPPCO's established distribution system with capacity options consisting of 20MW constructed in two (2) - 10 MW installations. Increments of 10 MW AC.
- Build Transfer/EPC or Build-Own-Operate-Transfer PPA with a purchase option. Developer is responsible for development, turn key EPC construction and commissioning of Solar PV and related interconnection facilities. UPPCO to provide the project land for 20MW capacity option through lease or purchase. Alternatively, Respondent may opt to provide land. Option for Respondent to own and operate the facilities for specified term and sell energy and capacity under a PPA to UPPCO, with an option for UPPCO to purchase any time after 5 years plus one day. Option for Respondent to provide long term O&M of the facility.
    a. Interconnected at transmission voltage anywhere in Load Resource Zone 2 of MISO with capacity options of 20 MW in increments of 5, 10 or 20 MW AC.

- Equity Ownership. In this option, UPPCO enters a 25-year PPA (for energy and capacity) with an equity investment made in year 6 from COD. The Developer and its partners will be responsible for fully executing development, construction, commissioning and performing O&M of the facility.
    a. Interconnection at transmission voltage anywhere in the Upper Peninsula of Michigan with a capacity of up to 20 MW AC.

Q. Please describe the RICE generation RFP.

A. UPPCO is seeking to acquire 18 to 20 MW of natural gas-fired RICE generating facility with a COD commencing on or before June 1, 2022, located in UPPCO's established service territory within MISO Load Resource Zone 2 in Michigan. As such, this capacity can be met by simple cycle single or two engine generation in an enclosed facility. For purposes of the RFP, capacity refers to the net generating capacity at the facility's POI, as controlled by the plant SCADA system. The Respondents shall define the incoming gas, water, chemical (if necessary, for exhaust treatment) requirements and the outgoing electrical generating capacity for the facility. Through the RFP process, UPPCO intends to provide more detailed Minimum Functional Specifications to the Respondents during the RFP process. UPPCO intends to structure the minimum requirements such that Respondents will have flexibility to propose technical solutions which maximize overall financial benefit of the project.

Q. Are these RFP processes still ongoing?

A. Yes. The RFP process will be completed when a resulting contract is signed by both parties, which will become effective pursuant to a subsequent Commission order. Regarding UPPCO's Solar RFP, UPPCO has received all bids and has identified its preferred bids. Further, the Company has notified one or more of the respondents of the Company's intent to initiate discussions that will lead into substantive contract negotiations. Regarding UPPCO's RICE RFP, UPPCO has initiated the RFP process with potential respondents and will update associated costs and terms pursuant to MCL 460.6t (7), prior to the 150-day mark in the case schedule.

Q. Please describe the Solar RFP bid results.

A. UPPCO received 30 bids from 6 different bidders. As evidenced in Company Witness David R. Tripp's Exhibit A-20 (DRT-3) Solar RFP Evaluation Summary, the PPAs, including those with purchase options, were more economic than EPC alternatives for UPPCO's customers at this time.

Q. Who is UPPCO's preferred bidder on the Solar RFP?

A. _______________, which was bid for 20 MW of a 125 MW facility.

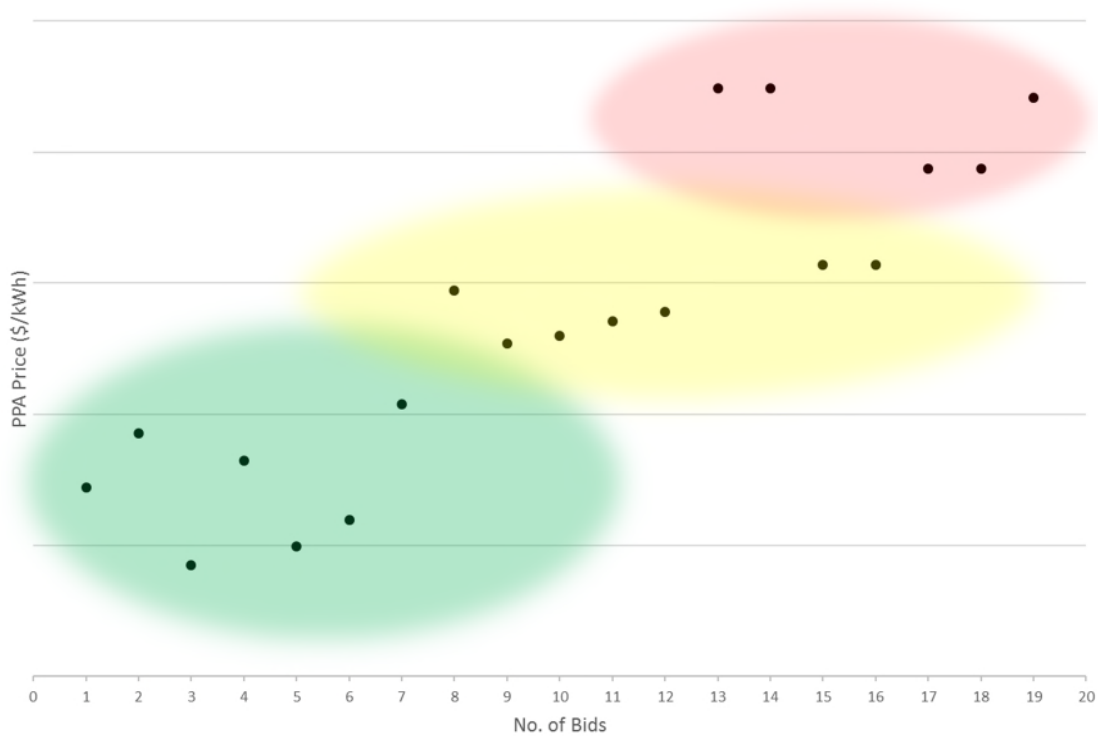
Q. Does Mr. Tripp's Exhibit A-20 (DRT-3) support this bid preference?

A. Yes, UPPCO's preferred bid and bidder represent the lowest Levelized Cost of Entry ("LCOE").

Q. Please provide a graphical representation of most relevant PPA bid prices.

A. See below, Figure 2.

Solar RFP Bid Prices (including assumed Interconnection Costs) Figure 2



Q. Please summarize your observations from the sample of PPA bid prices provide in Figure 2.

A. First, the Solar RFP was extremely competitive with several PPA bids that resulted in, assumedly, three natural groupings of bid prices, as identified above in the three separate color bands. For purposes of confidentiality, UPPCO has removed the scale, pricing, and bidder names. That being said, UPPCO's preferred bid and bidder resides in the green, lower priced band. Also, UPPCO's bid, as represented in the chart above, includes the levelized FCM charge, which is expressed in $/MWh.

Q. Do other bids reflected in Figure 2 include the levelized FCM charge? Please explain.

A. No. UPPCO has included the levelized FCM charge in its preferred bid to augment the competitiveness of the fixed price PPA with an FCM in relation to the other bid prices that do not include it. Said alternatively, UPPCO's preferred bid price with an FCM is still one of the most competitive bids being evaluated.

Q. How has the Solar RFP process informed UPPCO's PCA?

A. While the bids came back in alignment with the scope of the RFP document, the pricing and information was such that UPPCO evaluated increasing the size of its energy and capacity purchases to 125 MW from the original 20 MW target. This is further discussed in Company witness Eric W. Stocking's testimony.

Q. Why is the increase in size from 125 MW from 20 MW justified in this case?

A. UPPCO has a high degree of confidence in the RFP process which was undertaken, and which has resulted in over 30 evaluated bids from various respondents. With its preferred bid price identified, UPPCO ran an additional IRP modeling scenario to include a Business-As-Usual modeling run with 125 MW of a fixed price Solar PPA. As evidenced in Black & Veatch's Report in Section 10, the 125 MW Solar PPA came back with the least cost Cumulative Present Worth Calculation ("CPWC").

Q. What happens if UPPCO is not able to come to agreement with its preferred bidder and bid price through the Solar RFP process?

A. UPPCO will continue an objective pursuit of the best project and will contemporaneously evaluate the other smaller, yet still reasonably priced competitive bids and bidders.

Q. Will UPPCO's approach through the RICE RFP process be similar to that of the Solar RFP process?

A. Yes.

Additional Sensitivity Analyses
Base Capacity and LMP Sensitivities

Case No. U-20350
Witness: Gradon R. Haehnel
Exhibit A-34 (GRH-16)
July 8, 2019
Page 1 of 1

Column / Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		BASE CAPACITY & LMP SENSITIVITIES						RICE Capital Cost	
1	**LMP SCENARIOS**	**LOWEST (-25%)**	**LOWER (-10%)**	**LOW**	**BASE**	**HIGH**	**HIGHER (+10%)**	**+25% RICE**	**-10% RICE**
2		**SOLAR**	**SOLAR**	**SOLAR**	**SOLAR**	**SOLAR**	**SOLAR**	**SOLAR**	**SOLAR**
3	**Levelized Revenue Requirement (RR)**	$8,023,308	$8,023,308	$8,023,308	$8,023,308	$8,023,308	$8,023,308	$8,023,308	$8,023,308
4	**Levelized PSCR Savings**	($10,334,411)	($11,571,188)	($12,130,082)	($12,395,706)	($12,807,965)	($13,220,224)	($12,395,706)	($12,395,706)
5	**Net Levelized RR**	($2,311,103)	($3,547,880)	($4,106,774)	($4,372,398)	($4,784,657)	($5,196,916)	($4,372,398)	($4,372,398)
6	**Levelized RR ($/MWh)**	$42.63	$42.63	$42.63	$42.63	$42.63	$42.63	$42.63	$42.63
7	**Levelized PSCR Savings ($/MWh)**	($58.22)	($65.29)	($68.43)	($70.01)	($72.37)	($74.73)	($70.01)	($70.01)
8	**Net Levelized RR**	($15.59)	($22.67)	($25.80)	($27.38)	($29.74)	($32.10)	($27.38)	($27.38)
9									
10		**RICE**	**RICE**	**RICE**	**RICE**	**RICE**	**RICE**	**RICE**	**RICE**
11	**Levelized Revenue Requirement (RR)**	$4,635,886	$4,635,886	$4,635,886	$4,635,886	$4,635,886	$4,635,886	$5,288,300	$4,374,921
12	**Levelized PSCR Savings**	($1,669,623)	($1,828,992)	($1,901,734)	($1,935,237)	($1,988,360)	($2,041,483)	($1,935,237)	($1,935,237)
13	**Net Levelized RR**	$2,966,263	$2,806,895	$2,734,152	$2,700,649	$2,647,527	$2,594,404	$3,353,062	$2,439,684
14	**Levelized RR ($/MWh)**	$147.00	$147.00	$147.00	$147.00	$147.00	$147.00	$167.69	$138.73
15	**Levelized PSCR Savings ($/MWh)**	($52.94)	($58.00)	($60.30)	($61.37)	($63.05)	($64.73)	($61.37)	($61.37)
16	**Net Levelized RR**	$94.06	$89.01	$86.70	$85.64	$83.95	$82.27	$106.32	$77.36
17									
18		**TOTAL**	**TOTAL**	**TOTAL**	**TOTAL**	**TOTAL**	**TOTAL**	**TOTAL**	**TOTAL**
19	**Levelized Revenue Requirement (RR)**	$12,659,194	$12,659,194	$12,659,194	$12,659,194	$12,659,194	$12,659,194	$13,311,608	$12,398,229
20	**Levelized PSCR Savings**	($12,459,074)	($13,855,220)	($14,486,857)	($14,785,983)	($15,251,365)	($15,716,747)	($14,785,983)	($14,785,983)
21	**Net Levelized RR**	$200,120	($1,196,025)	($1,827,662)	($2,126,789)	($2,592,171)	($3,057,552)	($1,474,376)	($2,387,754)
22	**Delta**				$0			$652,413	($260,965)

MPSC Case No.:	U-20471
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-8.32
Respondent:	L. K. Mikulan/Legal
Page:	1 of 3

Question: It appears that the SOLAR-All Transaction Hourly Profile was used to represent the solar output from all existing solar, planned solar, and potential resource additions. Since most existing solar is fixed-tilt, and Ms. Mikulan represents that fixed-tilt solar was screened out and single-axis solar was used for future resources, please explain how this profile was used to represent both types of solar systems.

Answer: DTE Electric objects to the request as it seeks information that is either the confidential and proprietary commercial information of DTE Electric or of others acquired by DTE Electric via a license that does not allow dissemination to non-licensed parties. In further answer and without waiving the objection the Company states as follows:

A capacity factor of 22.9% was used for single axis tracking systems, and a lower capacity factor of 18.5% was used for fixed tilt systems in the LCOE screening. The desired capacity factor was applied to the same hourly solar shape and the resulting annual solar energy scaled to be consistent with the desired capacity factor. Upon completion of the modeling, it was identified that the shape used was that of fixed tilt, as opposed to single-axis tracking solar. A delta analysis was performed at that time on a few select runs and the difference in shape was considered immaterial. Those modeling runs were not retained.

To support this discovery response, another delta analysis was completed for seven select Strategist runs. All solar was changed; both the Strategist alternatives and the solar that was forced in as transactions, if applicable. The difference in the NPVRR of the select runs was 0.02% on average and the build plans generated by the Strategist optimization did not change. As a result, the impact of using the fixed tilt shape remained immaterial. This result can be explained by the firm capacity and modeled solar energy remaining constant for each solar resource regardless of shape indicating that the shape itself has minimal effect on the PVRR and least cost build plan. The results of the IRP, the Strategist and PROMOD modeling, and the resulting PCA choices were not affected by the solar shape used.

MPSC Case No.: U-20471
Requestor: MECNRDCSC
Question No.: MECNRDCSCDE-8.32
Respondent: L. K. Mikulan/Legal
Page: 2 of 3

In the table below are the results of the modeling of seven selected runs with both the fixed tilt shape and the single axis tracking shape. The first six runs were from the STDE2.3b supplemental modeling. The STDE 2.3b modeling was used because there was resource selection in 2030 and 2040 in those runs whereas the original scenario optimizations only had resource optimization in 2029-2030. The last run shows the BAU all solar run with the single axis tracking shape. This run has the most solar of any build plan in the IRP and shows that the solar shape used is immaterial.

Comparison of solar shapes used in modeling

Run	FIXED TILT, NPVRR $M	SINGLE AXIS TRACKING, NPVRR $M	Delta NPVRR, $M	% of original
BAU LCP	13,563	13,558	-4.8	0.035%
BAU 2030 OPT	13,506	13,505	-0.3	0.002%
BAU 2040 OPT	13,506	13,505	-0.5	0.004%
ET LCP	12,805	12,800	-4.9	0.039%
ET 2030 OPT	12,887	12,887	0.0	0.000%
ET 2040 OPT	12,849	12,849	-0.2	0.002%
BAU All Solar	12,496	12,488	-8.1	0.065%

Attachments: The documents listed below are available for download at the following hyperlink:
https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U204712019IRPPublic/default.aspx

MPSC Case No.:	U-20471
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-8.32
Respondent:	L. K. Mikulan/Legal
Page:	3 of 3

U-20471 MECNRDCSCDE 8.32 (STDE 2.3b) BAU LCP-Single tracking.TXT
U-20471 MECNRDCSCDE 8.32 (STDE 2.3B) BAU OPTIMIZATION 2030-Single tracking.TXT
U-20471 MECNRDCSCDE 8.32 (STDE 2.3B) BAU OPTIMIZATION 2040 RERUN-Single tracking.TXT
U-20471 MECNRDCSCDE 8.32 (STDE 2.3B) ET LCP-Single tracking.TXT
U-20471 MECNRDCSCDE 8.32 (STDE 2.3B) ET OPTIMIZATION 2030-Single tracking.TXT
U-20471 MECNRDCSCDE 8.32 (STDE 2.3B) ET OPTIMIZATION 2040-Single tracking.TXT
U-20471 MEC8.32 WP LKM -804 BAU -2.0 EWR-Single tracking (Plan 7).TXT
U-20471 MECNRDCSCDE 8.32 1-axis tracking_load profile.xlsx
U-20471 MECNRDCSCDE 8.32 Seasonal_Transaction_Capacity.xlsx
U-20471 MECNRDCSCDE 8.32 Solar Shape - Delta Analysis.xlsx

The following Confidential Strategist Modeling files are available for download from the Company's Discovery Portal to those who have properly executed a Non-disclosure agreement subject to the protective order in this case and who hold a Strategist® License, using the hyperlink below.
https://dteenergy.sharepoint.com/sites/DiscoveryPortal/Elec/U-204712019IRPLicenseHolders/default.aspxx
U-20471 MEC 8.32 (STDE 2.3b) BAU LCP-Single tracking.SAV
U-20471 MEC 8.32 (STDE 2.3B) BAU OPTIMIZATION 2030-Single tracking.SAV
U-20471 MEC 8.32 (STDE 2.3B) BAU OPTIMIZATION 2040_RERUN-Single tracking.SAV
U-20471 MEC 8.32 (STDE 2.3B) ET LCP-Single tracking.SAV
U-20471 MEC 8.32 (STDE 2.3B) ET OPTIMIZATION 2030-Single tracking.SAV
U-20471 MEC 8.32 (STDE 2.3B) ET OPTIMIZATION 2040-Single tracking.SAV
U-20471 MEC 8.32 WP LKM -804 BAU - 2.0 EWR-Single tracking.SAV

DTE Electric Company
U-20471 Jester WP LKM-81 Support for Exhibit A-6 CONFIDENTIAL
Jester Starting Point

Case No.: U-20471
Witness: L.K. Mikulan

Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC)

Line	(a)	(b) PY 2018-2019	(c) PY 2019-2020	(d) PY 2020-2021	(e) PY 2021-2022	(f) PY 2022-2023	(g) PY 2023-2024	(h) PY 2024-2025	(i) PY 2025-2026	(j) PY 2026-2027	(k) PY 2027-2028	(l) PY 2028-2029
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW	10,448	10,384	10,343	10,298	10,212	10,161	10,114	10,064	10,020	10,002	9,979
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	9	17	17	17	17	7	-	-	-	-	-
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	10,439	10,367	10,326	10,281	10,195	10,154	10,114	10,064	10,020	10,002	9,979
4	Load Diversity Factor coincident to MISO, %.	96.07%	96.14%	96.14%	96.14%	96.14%	96.14%	96.14%	96.14%	96.14%	96.14%	96.14%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	10,029	9,967	9,927	9,884	9,801	9,762	9,724	9,675	9,633	9,616	9,594
6	Transmission Losses, %	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%
7	Planning Reserve Margin % UCAP Basis	8.40%	8.40%	8.30%	8.30%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 7))	10,871	10,805	10,751	10,705	10,625	10,582	10,541	10,488	10,442	10,423	10,400
9	Company Owned, In-State, Non-Intermittent, ZRC	9,646	9,755	9,603	9,697	10,085	9,351	9,347	9,345	9,343	9,341	9,340
12	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-	-	-	-	-	-	-	-
13	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	7	7	7	7	7	7	7	7	7	7	7
14	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-	-	-	-
15	Company Owned, In-State, Intermittent, ZRC	53	72	92	128	154	171	187	208	238	276	269
16	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-	-	-	-	-	-	-	-
17	Company Owned, In-State, Intermittent (BTMG), ZRC	33	33	38	38	38	38	38	38	38	38	38
18	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-	-	-	-
19	Total Company Owned Generation, ZRC (sum of lines 9-18)	9,739	9,867	9,739	9,869	10,283	9,566	9,579	9,597	9,626	9,662	9,654
20	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 4)	674	731	747	775	821	857	863	863	863	863	863
25	PPA, In-State, Non-Intermittent, ZRC	-	-	-	-	-	-	-	-	-	-	-
26	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-	-	-	-	-	-	-	-
27	PPA, In-State, Non-Intermittent (BTMG), ZRC	105	104	105	105	105	105	105	105	105	105	105
28	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-	-	-	-
29	PPA, In-State, Intermittent, ZRC	53	53	53	53	53	53	53	53	53	53	53
30	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-	-	-	-	-	-	-	-
31	PPA, In-State, Intermittent (BTMG), ZRC	1	1	1	1	1	1	1	1	1	1	1
32	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-	-	-	-
33	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-	-	-	-	-	-	-	-
34	Other Forward Capacity Contract, ZRC - Out-of-State	300	100	200	-	-	-	-	-	-	-	-
35	Total PPA, ZRC (sum of lines 25-34)	459	258	359	159	159	159	159	159	159	159	159
36	Total Planning Resources, ZRC (line 19 + line 20 + line 35)	10,872	10,856	10,845	10,803	11,263	10,583	10,600	10,619	10,648	10,684	10,676
37	UCAP Surplus/(Shortfall), MW (line 36 - line 8)	1	51	94	98	639	0	60	131	206	260	276
38	Remove Unexplained New Peaker Resources from Line 9			-7			-16					
39	Wind ZRCs included in Line 15	53	72	92	128	153	171	187	188	188	188	188
40	Wind ELCC	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%
41	Wind Nominal Capacity Included in Line 15	454	615	784	1094	1309	1459	1598	1609	1609	1609	1609
42	Wind Nominal Incremental Capacity Included in Line 15	454	161	169	310	215	150	139	11	0	0	0
43	Commission Approved Wind Nominal Incremental Capacity	454	161	455	0	0	0	0	0	0	0	0
44	Commission Approved Wind Nominal Cumulative Capacity	454	615	1070	1070	1070	1070	1070	1070	1070	1070	1070
45	Commission Approved Wind ZRCs in Line 15	53	72	125	125	125	125	125	125	125	125	125
46	Wind ZRCs in Line 15 Not Approved by the Commission	0	0	-33	3	28	46	62	63	63	63	63
47	Solar ZRCs included in Line 15	0	0	0	0	0	0	0	21	52	89	83
48	Solar ZRCs Included in Line 15 Not Approved by the Commission	0	0	0	0	0	0	0	21	52	89	83
49	Line 37 Less Lines 38, 46, and 48	1	51	134	95	611	(29)	(2)	47	91	108	130
50	Wind ZRCs Not Approved by the Commission Prior to July 18, 2019	0	0	53	53	53	53	53	53	53	53	53
51	DTE Starting Point Capacity Position Before July 18, 2019	1	51	81	42	557	(82)	(55)	(6)	38	55	77
52	Line 49 Less 35 MW ZRCs for Wind Dedicated to VGP programs in PY 2020-21 and thereafter	1	51	99	60	576	(64)	(37)	12	56	73	95

Line	(a)	(m) PY 2029-2030	(n) PY 2030-2031	(o) PY 2031-2032	(p) PY 2032-2033	(q) PY 2033-2034	(r) PY 2034-2035	(s) PY 2035-2036	(t) PY 2036-2037	(u) PY 2037-2038	(v) PY 2038-2039	(w) PY 2039-2040	PY 2040-2041
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW	9,958	9,951	9,919	9,898	9,876	9,850	9,829	9,807	9,784	9,756	9,762	9,769
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	-	-	-	-	-	-	-	-	-	-	-	-
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	9,958	9,951	9,919	9,898	9,876	9,850	9,829	9,807	9,784	9,756	9,762	9,769
4	Load Diversity Factor coincident to MISO, %.	96.14%	96.14%	96.14%	96.14%	96.14%	96.14%	96.14%	96.14%	96.14%	96.14%	96.14%	96.14%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	9,573	9,567	9,536	9,516	9,494	9,470	9,449	9,428	9,406	9,379	9,385	9,392
6	Transmission Losses, %	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%
7	Planning Reserve Margin % UCAP Basis	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%	8.40%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 7))	10,378	10,370	10,337	10,315	10,292	10,265	10,243	10,220	10,196	10,167	10,173	10,181
9	Company Owned, In-State, Non-Intermittent, ZRC	8,851	8,355	8,354	8,353	8,340	8,356	8,351	8,347	8,344	8,341	8,339	5,605
12	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-	-	-	-	-	-	-	-	-
13	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	7	7	7	7	7	7	7	7	7	7	7	7
14	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-	-	-	-	-
15	Company Owned, In-State, Intermittent, ZRC	301	364	431	478	517	587	645	702	772	829	885	942
16	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-	-	-	-	-	-	-	-	-
17	Company Owned, In-State, Intermittent (BTMG), ZRC	38	38	38	38	38	38	38	38	38	38	38	38
18	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-	-	-	-	-
19	Total Company Owned Generation, ZRC (sum of lines 9-18)	9,197	8,764	8,829	8,875	8,901	8,987	9,040	9,094	9,160	9,214	9,269	6,591
20	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 4)	863	863	863	863	863	863	863	863	863	863	863	863
25	PPA, In-State, Non-Intermittent, ZRC	-	-	-	-	-	-	-	-	-	-	-	-
26	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-	-	-	-	-	-	-	-	-
27	PPA, In-State, Non-Intermittent (BTMG), ZRC	105	105	105	105	105	105	105	105	105	105	105	105
28	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-	-	-	-	-
29	PPA, In-State, Intermittent, ZRC	53	53	53	53	53	53	53	53	53	53	53	53
30	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-	-	-	-	-	-	-	-	-
31	PPA, In-State, Intermittent (BTMG), ZRC	1	1	1	1	1	1	1	1	1	1	1	1
32	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-	-	-	-	-	-	-	-
33	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-	-	-	-	-	-	-	-	-
34	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-	-	-	-	-	-	-	-	-
35	Total PPA, ZRC (sum of lines 25-34)	159	159	159	159	159	159	159	159	159	159	159	159
36	Total Planning Resources, ZRC (line 19 + line 20 + line 35)	10,219	9,785	9,851	9,897	9,923	10,009	10,062	10,116	10,182	10,236	10,291	7,613
37	UCAP Surplus/(Shortfall), MW (line 36 - line 8)	(159)	(585)	(486)	(418)	(369)	(256)	(181)	(105)	(15)	69	117	(2,568)
38	Remove Unexplained New Peaker Resources from Line 9												
39	Wind ZRCs included in Line 15	188	188	200	200	200	212	212	212	223	223	223	223
40	Wind ELCC	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%	11.7%
41	Wind Nominal Capacity Included in Line 15	1609	1609	1709	1709	1709	1809	1809	1809	1909	1909	1909	1909
42	Wind Nominal Incremental Capacity Included in Line 15	0	0	100	0	0	100	0	0	100	0	0	0
43	Commission Approved Wind Nominal Incremental Capacity	0	0	0	0	0	0	0	0	0	0	0	0
44	Commission Approved Wind Nominal Cumulative Capacity	1070	1070	1070	1070	1070	1070	1070	1070	1070	1070	1070	1070
45	Commission Approved Wind ZRCs in Line 15	125	125	125	125	125	125	125	125	125	125	125	125
46	Wind ZRCs in Line 15 Not Approved by the Commission	63	63	75	75	75	86	86	86	98	98	98	98
47	Solar ZRCs included in Line 15	114	177	233	280	318	377	435	492	550	607	663	720
48	Solar ZRCs Included in Line 15 Not Approved by the Commission	114	177	233	280	318	377	435	492	550	607	663	720
49	Line 37 Less Lines 38, 46, and 48	(336)	(825)	(793)	(772)	(762)	(719)	(702)	(683)	(662)	(636)	(644)	(3,386)
50	Wind ZRCs Not Approved by the Commission Prior to July 18, 2019	53	53	53	53	53	53	53	53	53	53	53	53
51	DTE Starting Point Capacity Position Before July 18, 2019	(389)	(879)	(846)	(826)	(815)	(772)	(755)	(736)	(715)	(689)	(697)	(3,440)
52	Line 49 Less 35 MW ZRCs for Wind Dedicated to VGP programs in PY 2020-21 and thereafter	(371)	(860)	(828)	(807)	(797)	(754)	(737)	(718)	(697)	(671)	(679)	(3,421)

Section 4. Supply-Side Resources

4.1 Fuel Procurement Strategy

4.1.1 Coal Procurement and Inventory Management Practices

4.1.1.1 Coal Supply Strategy

NIPSCO employs a multifaceted strategy to guide coal procurement activities associated with the fuel supply requirements for its coal-fired units. The goal of this strategy is to maximize reliability while maintaining customer affordability. Key elements include: (1) procuring coal supply from sources that minimize the total cost of fuel, O&M costs, environmental costs, inventory costs and other cost impacts ("total cost of ownership"); (2) hedging customers' price exposure with forward purchases to protect against price volatility; (3) supporting environmental compliance; (4) maintaining reliable inventory levels; (5) ensuring reliability of coal supply and delivery; and (6) maximizing operational flexibility and reliability by procuring coal types that can be used in more than one unit whenever possible.

4.1.1.2 Coal Procurement

NIPSCO maintains a five-year baseline coal forecast that is used to create a strategy that drives its fuel procurement plan. It estimates coal and related coal transportation procurement requirements needed to maintain reliable and economic coal inventory levels. The strategy and fuel procurement plan are highly dynamic and are updated on a periodic basis in response to energy market conditions. Over the past several years, environmental regulations, a significant influx of highly variable renewable generation (e.g. wind and solar), low natural gas prices, and energy efficiency and other demand side initiatives have made coal-fired generation the marginal supply source. Consequently, this has created an environment with highly variable and nearly unpredictable coal purchase requirements. Therefore, NIPSCO's fuel procurement plans must remain as flexible as possible while still maintaining reliable supply. Obtaining volume flexibility can be challenging since coal suppliers and transportation providers typically require firm volume commitments.

4.1.1.3 Coal Pricing Outlook

Coal competes for a share of the energy market against other fuels (natural gas, nuclear, and oil), renewable energy sources (biomass, hydro, wind, and solar) and energy efficiency programs. Specifically, energy market supply and demand generally set the market price of these competing sources. Also, coal prices are influenced by the supply and demand balance of coal in domestic, international, and metallurgical coal markets, coal production costs, transport costs, and environmental compliance considerations. Energy market dynamics have been heavily influenced by the increased exploration and production of North American shale oil and gas resources and have fundamentally altered the price spread between coal and natural gas. Lower production costs and highly efficient natural gas extraction processes (horizontal drilling and fracking) have kept natural gas a competitive fuel when used in high efficiency, CCGT units. In addition, increases in wet gas production to gather petroleum liquids further increase natural gas supply when oil prices rise. Oil prices have risen steadily over the last year helping to spur wet gas production. These dynamics are expected to keep natural gas pricing low in the near term. Longer term natural gas prices are expected to recover somewhat with the addition of new CCGTs and increased natural gas export capacity. These market dynamics continue to displace a significant amount of coal-fired electric generation and are keeping coal prices relatively low. Decreased coal demand and higher mining costs driven by government regulations have adversely impacted coal producers' margins and profits causing a number of producer bankruptcies over the last few years. The restructuring of coal companies' debt and other costs through the bankruptcy process should allow them to produce coal in this competitive environment. Supply has been rationalized and any significant increase in demand could result in coal price volatility. However, several factors may limit the upside for coal prices. The first factor is the cost to produce electricity from coal has increased significantly due to stringent environmental regulations placed on coal-fired electric generation. A second factor is utilities continue to retire older, higher cost coal-fired generation and this has reduced demand. Lastly, low energy prices driven by natural gas pricing and renewables will also limit demand for coal if coal prices spike.

The competitive energy market has also driven a shift in coal supply regions. Specifically, the cost to produce coal in the Appalachian regions and low coal prices have resulted in declining coal production and this has increased market share of the lower cost Illinois Basin ("ILB") region. Even with its higher sulfur content, ILB coal has become an export resource, and its use has increased domestically as utilities have installed flue gas desulfurization systems ("FGDs") to meet tighter sulfur dioxide limits and other emission standards. Southeast utilities have started using ILB coal to replace higher cost Columbian and Central Appalachia coal.

The use of Powder River Basin ("PRB") coal from Wyoming and Montana has increased significantly over the last decade. Although PRB coal has a lower heat content than coals mined in other regions, utilities typically blend PRB coal with Central Appalachian, ILB, or Northern Appalachian ("NAPP") coals to reduce their overall fuel costs. Asian demand for PRB coal has also grown as Japan and China have built new, high efficiency coal units and new coal plants are being built in Korea and Taiwan as well as they prepare to meet their future electricity demand. Historically, Central Appalachian and NAPP coal have been exported into metallurgical coal and some steam coal markets abroad. Since the end of 2016, demand for seaborne coal has increased. It appears that exports will remain resilient with export volumes over the last year at or near the top of the five year range. Coal suppliers need this to continue in order to offset losses in domestic markets.

Overall, these fundamentals are bearish for coal demand. Notwithstanding, NIPSCO will continue to monitor market dynamics and coal prices and incorporate in its procurement strategies.

4.1.1.4 NIPSCO Coal Pricing Outlook

NIPSCO currently procures coal from three geographic regions in the United States: the PRB, the ILB, and the NAPP region. Domestic demand for coal has continued to trend lower over the last two years; therefore, prices have remained relatively low and stable. NAPP coal, used by NIPSCO as a blend fuel in one of its cyclone units, and ILB coal have had relatively strong price increases off of 2016 lows as export demand and prices have trended higher over the last two years.

Pricing for PRB coal has remained low over the last two years and is close to the marginal cost of production.

The export dynamic will likely keep upward pressure on the market in the near term and this would likely lower domestic demand for coal unless domestic energy prices rise. All domestic coal pricing is expected to remain soft as long as energy prices stay low, and will likely keep coal prices flat for the balance of 2018 into 2019.

4.1.1.5 Coal and Issues of Environmental Compliance

Depending on the manner and extent of current and future environmental regulations, NIPSCO's coal purchasing strategy will continue to evolve in a manner that meets current and future environmental requirements.

4.1.1.6 Maintenance of Coal Inventory Levels

NIPSCO has an ongoing strategy to maintain stable coal inventories and reviews inventory target levels annually and may make adjustments in anticipation of changes in supply availability relative to demand, transportation constraints and unit consumption. NIPSCO may modify target inventory levels on a unit-by-unit basis depending on the unit consumption, delivery rates, reliability of coal supply and station coal handling operations. Adequate inventories are essential to maintaining generation reliability. Uncertainty in consumption rates and variability in delivery performance generally require higher levels of inventory to insure reasonably adequate reliability.

4.1.1.7 Forecast of Coal Delivery and Transportation Pricing

To ensure the delivery of fuel in a timely and cost-effective manner, NIPSCO negotiates and executes transportation contracts that consider current and future coal supply commitments. All fuel procurement options are compared on a delivered cost basis, which includes a complete evaluation of all potential logistical issues.

Coal deliveries, excluding exceptional weather conditions, have been somewhat stable from the various supply regions, particularly shipments originating in the PRB region due to infrastructure improvements. Railroads typically make investment in infrastructure and equipment to support anticipated shipment rates. The cyclical nature of the railroad business can create short term transportation constraints and can impact NIPSCO's coal deliveries. These cycles have been shorter in duration and more volatile over the past several years.

Transportation rates have declined somewhat given the competition in the energy markets. Railroads have been willing to rationalize rail rates, as shown in the market assessment plots below, to keep market share.

Figure 4-1: PRB Customer Rates

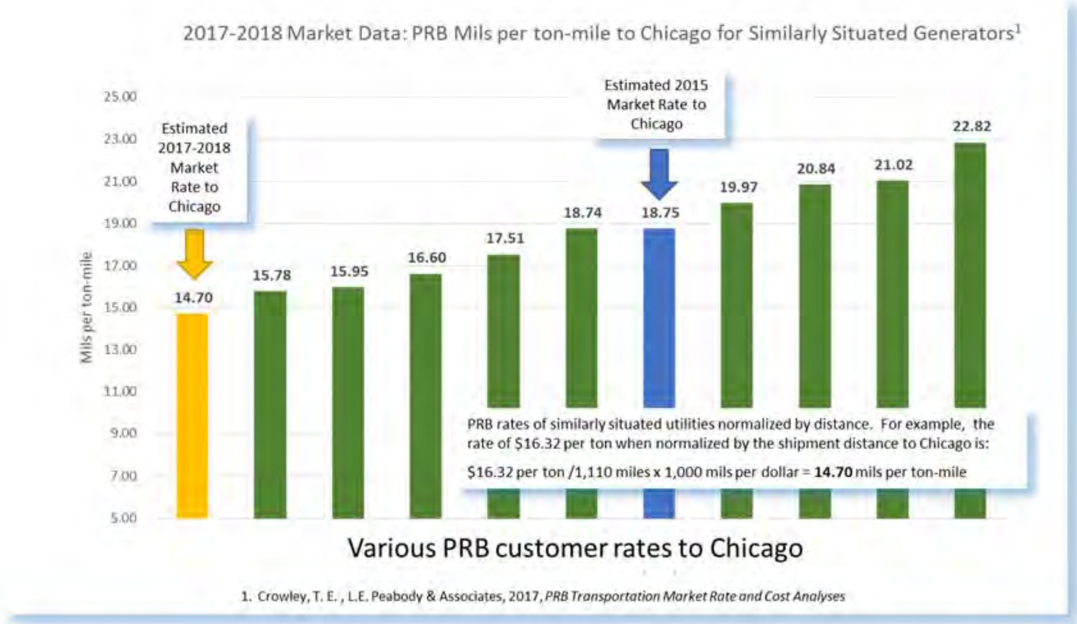
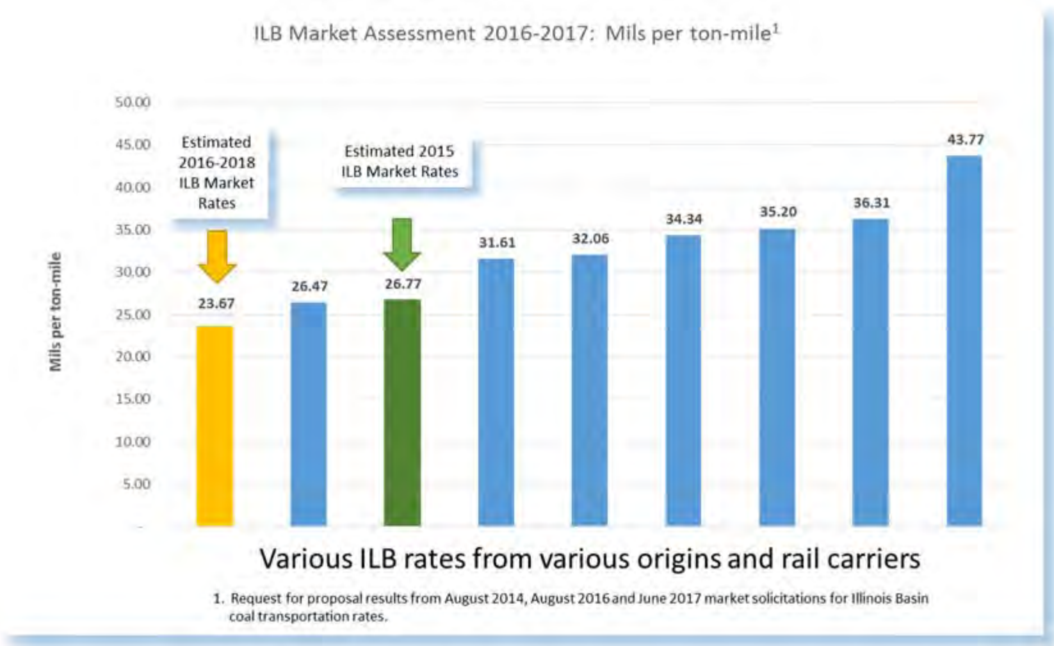


Figure 4-2: ILB Customer Rates



This pricing trend has improved the competitiveness of NIPSCO's coal-fired generation to a certain extent.

4.1.1.8 NIPSCO Transportation Pricing Outlook

NIPSCO has limited rail options from various supply regions and destination for most of its coal transportation moves, and is further disadvantaged due to its geographical location. Not only are rail transportation options limited, other transport modes (trucking, barging and lake vessels) are not economically or logistically feasible alternatives. NIPSCO's largest generating station, Schahfer, is served by only one railroad. All coal deliveries by this railroad to Schahfer have been transported under agreements that historically escalated transportation rates that also included fuel surcharges indexed to oil prices. However, under this structure, lower power prices lead to a reduction in coal demand. Therefore, NIPSCO and this railroad worked to develop an agreement that lowered rates to improve the station's competitiveness in the market. As stated above, energy markets have forced a rationalization of coal pricing and associated transportation costs. NIPSCO expects this dynamic to continue for the foreseeable future.

As a result, PRB and ILB coal transportation rates have been reduced by nearly 50%. Fuel surcharges continue to fluctuate with the changes in oil prices. The expectation for transportation pricing is also expected to remain soft as long as energy prices stay low, and expect rates to be flat for the balance of 2018 into 2019. Increases in fuel charges could lead to modest transportation cost increases as oil prices trend higher.

4.1.1.9 Coal Contractual Flexibility, Deliverability and Procurement

Contract terms for coal and coal transportation agreements are typically one to five years in duration. Spot purchases are made on an as-needed basis to manage inventory fluctuations. In an effort to minimize variations in inventory levels and accommodate unit maintenance outages, most coal types under contract can be used in more than one unit. The fuel blending strategy can also be adjusted to conserve a particular type of coal if supply problems are experienced. In addition, coal suppliers have been more amenable to providing some volume flexibility. This has supported NIPSCO's inventory management efforts.

4.1.2 Natural Gas Procurement and Management

NIPSCO currently procures natural gas for its CCGT generating station using a natural gas supply contract with an energy manager that delivers to the interstate pipeline interconnect at the station, or other locations along the interstate pipeline upon request of NIPSCO for balancing purposes. NIPSCO currently holds firm capacity on the interstate pipeline, Midwestern Gas Transmission Company, and releases the capacity to the energy manager. The contract has provisions to purchase next day and intraday firm gas supplies to serve the daily needs of the facility. NIPSCO nominates and balances the gas supply needs of the CCGT generating station. A portion of the gas supply for the Sugar Creek Generating Station ("Sugar Creek") is financially hedged with the intention of smoothing out market price swings over a specific time period. The volatility mitigation plan consists of purchasing monthly NYMEX Henry Hub natural gas contracts that settle at expiration.

The coal units and combustion turbines ("CTs") at NIPSCO are located within the NIPSCO natural gas local distribution company service territory. NIPSCO maintains a separate contract for firm delivered natural gas supply and energy management for these units. The contract has provisions to nominate next-day usage based on the expected usage of each generating station. The actual usage is balanced daily and balancing is the responsibility of the energy manager.

4.2 Electric Generation Gas Supply Request for Proposal Process

NIPSCO conducts two separate RFPs for the electric generation firm natural gas supply, one for the Sugar Creek facility and a separate one for the coal units and CTs. The RFP process may be done on a seasonal or annual basis depending on the current contract length and supplier agreement. The process includes qualifying potential suppliers, customizing the RFP based on near-term system needs, and gas supply trends. Suppliers are chosen based on the overall value of the package and ability to serve the needs of the facility. To date, NIPSCO has entered into electric generation gas supply agreements that extend no longer than one year, but is always evaluating the value and benefits of longer term agreements.

4.3 Existing Resources

NIPSCO has a variety of generation resources to meet its customers' forecast capacity and energy needs. Not only do these resources need to meet the principles set out in Section 1, they must operate within MISO, the Regional Transmission Organization, and subject to NERC standards. NIPSCO has registered with NERC as a Distribution Provider, Generator Owner, Generator Operator, Load Serving Entity, Purchasing-Selling Entity, Resource Planner and Transmission Planner. NIPSCO is registered as a Balancing Authority, Transmission Operator and Transmission Owner in MISO. Each Registered Entity is subject to compliance with applicable NERC and Regional Reliability Organization, ReliabilityFirst, standards approved by the Federal Energy Regulatory Commission ("FERC").

4.4 Supply Resources

NIPSCO owned generating resources consist of coal, natural gas and hydro units. Additionally NIPSCO meets it customer needs with 2 wind purchase power agreements and has an extensive demand response ("DR") program via its large industrial customers. The total Net Demonstrated Capacity ("NDC") of the existing resources is 2,925 MW across multiple generation sites, including the Schahfer (Units 14, 15, 16A, 16B, 17 and 18), Michigan City (Unit 12), Bailly (Units 10), Sugar Creek and two hydroelectric generating sites near Monticello, Indiana (Norway Hydro and Oakdale Hydro). Of the total capacity, 61% is from coal-fired units, 21% is from natural gas-fired units and 18% is from industrial interruptible DR program. Consistent with the 2016 IRP preferred plan NIPSCO retired 2 coal fired units (Units 7 and 8) at the Bailly in May 2018.

Table 4-1 provides a summary of the current generating facilities operated by NIPSCO.

Table 4-1: Net Demonstrated Capacity

Resource	Unit	Fuel	Capacity NDC (MW)
Michigan City	12	Coal	469
Schahfer	14	Coal	431
	15	Coal	472
	16A	NG	78
	16B	NG	77
	17	Coal	361
	18	Coal	361
		Subtotal	1,780
Sugar Creek		NG	535
Bailly	10	NG	31
Hydro	Norway	Water	4
	Oakdale	Water	6
		Subtotal	10
Wind		Wind	100
NIPSCO			2,925

NG=Natural Gas

4.4.1 Michigan City Generating Station

Michigan City is located on a 134-acre site on the shore of Lake Michigan in Michigan City, Indiana. It has one base-load unit, Unit 12 and is equipped with selective catalytic reduction (“SCR”) and over-fire air (“OFA”) systems to reduce nitrogen oxide (“NO_x”) emissions. A new FGD (“”) system was placed in service in 2015. The individual unit characteristics of Michigan City are provided in Table 4-2.

Table 4-2: Michigan City Generating Station

	Unit 12
NET Output	
Min (MW)	315
Max (MW)	469
Boiler	Babcock & Wilcox
Burners	10 Cyclone
Main Fuel	Coal
Turbine	General Electric
Frame	G2
In-Service	1974
Environmental Controls	FGD, SCR, OFA

4.4.2 R.M. Schahfer Generating Station

Schahfer is located on approximately a 3,150-acre site two miles south of the Kankakee River in Jasper County, near Wheatfield, Indiana. It is the largest of NIPSCO's generating stations. There are four coal-fired base-load units and two gas-fired simple cycle peaking units that came on-line over an 11-year period ending in 1986. The Schahfer units are equipped with significant environmental control technologies, including FGD to reduce sulfur dioxide ("SO_2") emissions and SCR, SNCR, low NO_x burners ("LNB"), and OFA systems to reduce NO_x emissions. Unit 14 burns low and medium sulfur coal blends and Unit 15 burns low-sulfur coals to minimize SO_2 emissions. As part of the Company's Clean Air Interstate Rule (CAIR) Compliance Phase I Strategy, FGD system upgrades to improve SO_2 removal efficiency were completed for Units 17 and 18 in 2010 and 2009, respectively. Installation of a new LNB with OFA system was completed on Unit 15 in 2009. A new FGD plant on Unit 14 was placed in service in 2013. FGD installation on Unit 15 was completed in 2014. The individual unit characteristics of Schahfer are provided in Table 4-3.

Table 4-3: R.M. Schahfer Generating Station

	Unit 14	Unit 15	Unit 17	Unit 18	Unit 16A	Unit 16B
NET Output						
Min (MW)	290	250	125	125	----	----
Max (MW)	431	472	361	361	78	77
Boiler	Babcock & Wilcox	Foster Wheeler	Combustion Engineering	Combustion Engineering	----	----
Burners	10 Cyclone	6 Pulverizers	6 Pulverizers	6 Pulverizers	----	----
Main Fuel	Coal	Coal	Coal	Coal	Gas	Gas
Turbine	Westinghouse	General Electric	Westinghouse	Westinghouse	Westinghouse	Westinghouse
Frame	BB44R	G2	BB243	BB243	D501	D501
In-Service	1976	1979	1983	1986	1979	1979
Environmental Controls	FGD, SCR, OFA	FGD, SNCR, LNB, OFA	FGD, LNB, OFA	FGD, LNB, OFA	----	----

4.4.3 Sugar Creek Generating Station

Sugar Creek is located on a 281-acre rural site near the west bank of the Wabash River in Vigo County, Indiana. The gas-fired CTs and CCGTs were available for commercial operation in 2002 and 2003, respectively. Sugar Creek was purchased by NIPSCO in July 2008, and is its newest electric generating facility. Sugar Creek has been registered as a MISO resource since December 1, 2008. Two generators and one steam turbine generator are operated in the CCGT mode and environmental control technologies include SCR to reduce NO_x, and dry low NO_x ("DLN") combustion systems. The individual unit characteristics of Sugar Creek are provided in Table 4-4.

Table 4-4: Sugar Creek Generating Station

	CT 1A	CT 1B	SCST
NET Output			
Min (MW)	120	120	120
Max (MW)	156	157	222
Heat Recovery Steam Generator	Vogt Power	Vogt Power	---
Main Fuel	Gas	Gas	Steam
Turbine	GE	GE	GE
Frame	7FA	7FA	D11
In-Service	2002	2002	2003
Environmental Controls	SCR, DLN	SCR, DLN	---

4.4.4 Norway Hydro and Oakdale Hydro (NIPSCO-Owned Supply Resources)

Norway Hydro is located near Monticello, Indiana on the Tippecanoe River. The dam creates Lake Shafer, a body of water approximately 10 miles long with a maximum depth of 30 feet, which functions as its reservoir. Norway Hydro has four generating units capable of producing up to 7.2 MW. However, its output is dependent on river flow and the typical maximum plant output is 4 MW. The individual unit characteristics of the Norway Hydro are provided in Table 4-5.

Table 4-5: Norway Hydro

	Unit 1	Unit 2	Unit 3	Unit 4
NET Output				
Min (MW)	---	---	---	---
Max (MW)	2	2	2	1.2
In-Service	1923	1923	1923	1923
Main Fuel	Water	Water	Water	Water

Oakdale Hydro is located near Monticello, Indiana along the Tippecanoe River. The dam creates Lake Freeman, a body of water approximately 12 miles long with a maximum depth of 45 feet, which functions as its reservoir. Oakdale Hydro has three generating units capable of producing up to 9.2 MW. However, its output is dependent on river flow and the typical maximum plant output is 6 MW. The individual unit characteristics of the Oakdale Hydro are provided in Table 4-6.

Table 4-6: Oakdale Hydro

	Unit 1	Unit 2	Unit 3
NET Output			
Min (MW)	---	---	---
Max (MW)	4.4	3.4	1.4
In-Service	1925	1925	1925
Main Fuel	Water	Water	Water

4.4.5 Barton and Buffalo Ridge Wind (NIPSCO Purchase Power Agreements)

NIPSCO is currently engaged in a 20-year PPA with Iberdrola, in which NIPSCO will purchase generation from Barton. Barton, located in Worth County, Iowa, went into commercial operation on April 10, 2009. The individual unit characteristics of Barton are provided in Table 4-7.

Table 4-7: Barton Wind PPA

	Barton PPA
NET Output	
Per Unit (MW)	2
Number of Units	25
Total Output (MW)	50
In-Service	2009
Main Fuel	Wind

NIPSCO is also engaged in a 15-year PPA with Iberdrola, in which NIPSCO will purchase generation from Buffalo Ridge. Buffalo Ridge, located in Brookings County, South Dakota, went into commercial operation on April 15, 2009. The individual unit characteristics of Buffalo Ridge are provided in Table 4-8.

Table 4-8: Buffalo Ridge Wind PPA

	Buffalo Ridge PPA
NET Output	
Per Unit (MW)	2
Number of Units	24
Total Output (MW)	50
In-Service	2009
Main Fuel	Wind

4.5 Total Resource Summary

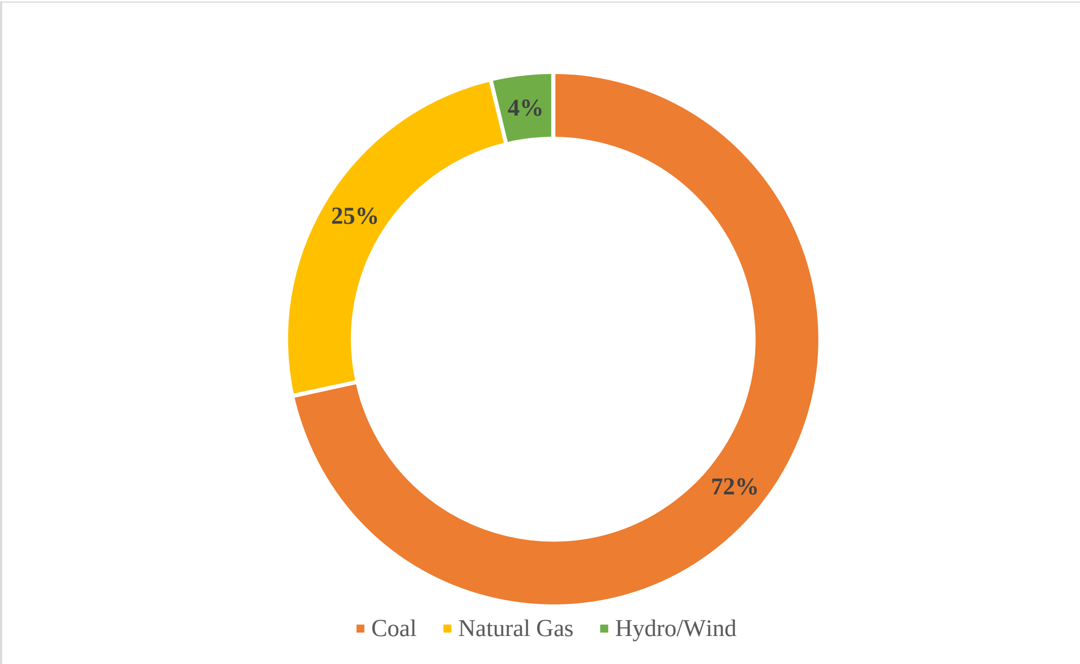
Table 4-9 illustrates various characteristics of NIPSCO's owned and contracted generating units. Figure 4-3 illustrates NIPSCO's existing resources by fuel type.

Table 4-9: Existing Generating Units

Resource	Unit	Fuel	Capacity NDC (MW)	Year in Service
Michigan City	12	Coal	469	1974
Schahfer	14	Coal	431	1976
	15	Coal	472	1979
	16A	NG	78	1979
	16B	NG	77	1979
	17	Coal	361	1983
	18	Coal	361	1986
		Subtotal	1,780	
Sugar Creek		NG	535	2002
Bailly	10	NG	31	1968
Hydro	Norway	Water	4	1923
	Oakdale	Water	6	1925
		Subtotal	10	
Wind		Wind	100	2009
NIPSCO			2,925	

NG=Natural Gas

Figure 4-3: Existing Resources Net Demonstrated Capacity



4.6 Operations Management and Dispatch Implications

The future dispatch of NIPSCO's electric generation fleet will be a function of the cost to market price (or locational marginal price). Many factors will contribute to the dispatch of local units within NIPSCO's service territory. The delivered cost of coal and natural gas, transmission congestion, environmental considerations and the overall generation mix within MISO may affect the level of future dispatch.

4.7 MISO Wholesale Electricity Market

MISO supplies an important element to NIPSCO's long term plans – ongoing liquidity. MISO provides an enduring, relatively efficient market for marginal purchases and sales of electricity. In 2018, MISO has members from 15 states and one Canadian province with a generation capacity of 200,000 MW and 65,800 miles of high-voltage transmission. MISO manages one of the world's largest energy and operating markets that includes a Day-Ahead Market, Real-Time Market and Financial Transmission Rights Market.

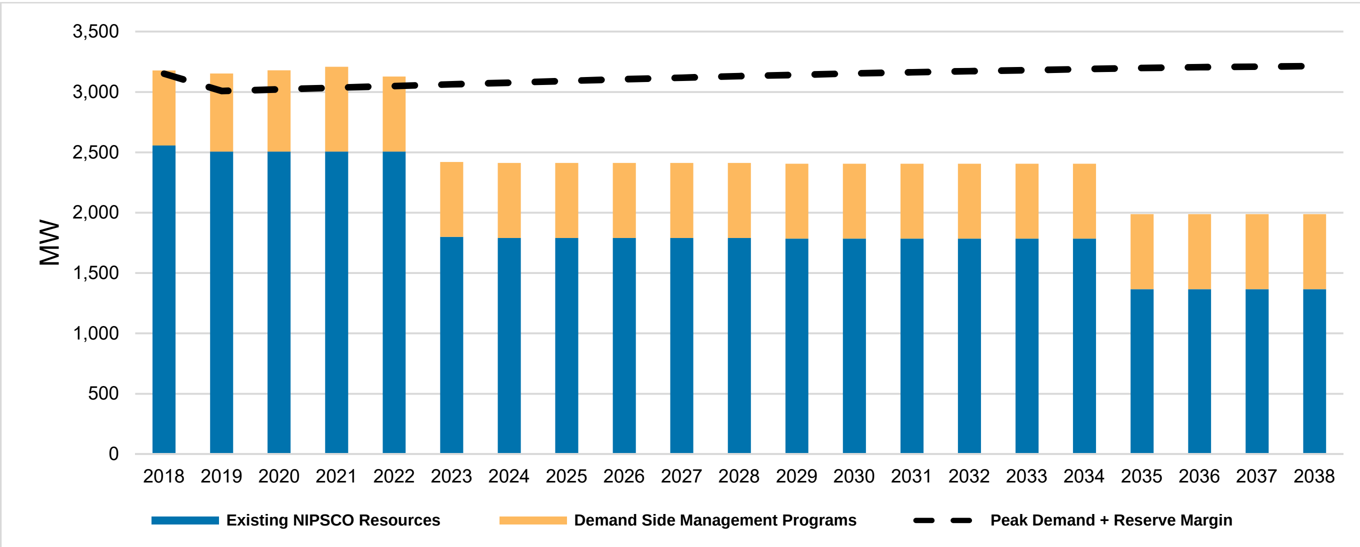
4.8 Resource Adequacy

Consistent with the principles set out in Section 1, NIPSCO is committed to meet the energy needs of its customers with reliable, compliant, flexible, diverse and affordable supply. As part of the Resource Adequacy planning process, NIPSCO is now utilizing the peak demand forecast coincident with the MISO peak demand to determine its capacity requirements. The MISO coincident peak is where NIPSCO demand is projected to be at the time the entire MISO system peaks, which is typically in the summer. The methodology for calculating the coincident peak demand is described in detail in Section 3. NIPSCO's assessment of its existing resources against the future needs of its customers is shown in Table 4-10.

Table 4-10: Assessment of Existing Resources v. Demand Forecast (Base)

	(a)	(b)	(c)	(d)	(e)
Year	**MISO Coincident Peak Demand**	**Peak Demand + Reserve Margin**	**Demand Side Management Programs**	**Existing NIPSCO Resources**	**Capacity Position/Long Short (c+d-b)**
2018	2,907	3,152	621	2,557	26
2019	2,776	3,009	646	2,507	144
2020	2,788	3,022	673	2,507	158
2021	2,801	3,036	702	2,507	173
2022	2,813	3,050	621	2,507	78
2023	2,827	3,064	621	1,799	(644)
2024	2,839	3,078	621	1,791	(666)
2025	2,853	3,092	621	1,791	(680)
2026	2,866	3,106	621	1,791	(694)
2027	2,877	3,119	621	1,791	(707)
2028	2,890	3,132	621	1,791	(721)
2029	2,899	3,143	621	1,785	(737)
2030	2,910	3,154	621	1,785	(748)
2031	2,919	3,164	621	1,785	(758)
2032	2,927	3,173	621	1,785	(767)
2033	2,934	3,181	621	1,785	(775)
2034	2,943	3,190	621	1,785	(784)
2035	2,951	3,199	621	1,367	(1,212)
2036	2,957	3,206	621	1,367	(1,218)
2037	2,961	3,210	621	1,367	(1,222)
2038	2,966	3,215	621	1,367	(1,227)
Notes:					
Reserve Margin Assumption = 8.4%					
Existing Resource Capacity based on NIPSCO UCAP calculation and reflects retirements in 2023 and 2035 *Demand Side Management Programs include Demand Response and Energy Efficiency Programs*					

Figure 4-4: Resource Adequacy Assessment (MW)



Based on the 2016 IRP preferred plan, NIPSCO would need additional capacity resources to meets its customer demand starting in 2023 after the retirements of Schahfer Units 17 and 18. NIPSCO has evaluated a range of resource options to meet that need.

4.9 Future Resource Options

New resources may be needed to meet the future electricity requirements of NIPSCO's customers over time, so it is critical that valid cost and operational estimates are developed for such future resource options in the IRP modeling. In the 2018 IRP, NIPSCO developed a two-step process to improve the new resource evaluation process and to respond to feedback received in the 2016 IRP.[2] This process entailed:

- A review of multiple third-party data sources to assess current and future estimates of resource technology cost, as well as plausible cost ranges, and performance characteristics
- Development of final inputs for IRP modeling based on real bid data that was received from the All-Source RFP.

4.9.1 Third-Party Data Source Review

NIPSCO worked with CRA to perform a screen of third-party sources for new resource cost and operational parameter estimates. The screen included the study NIPSCO commissioned for its 2016 IRP, public sources that develop estimates, such as government forecasts and other

2 Note that a discussion of future demand-side resource options is included in Section 5.

utility IRPs, and subscription services which provide data and capital cost estimates over time. Figure 4-5 provides a list of the sources that were relied upon for the third-party screen.

Based on the source review, NIPSCO identified a list of feasible technology options to be assessed in the initial round of review. These included:

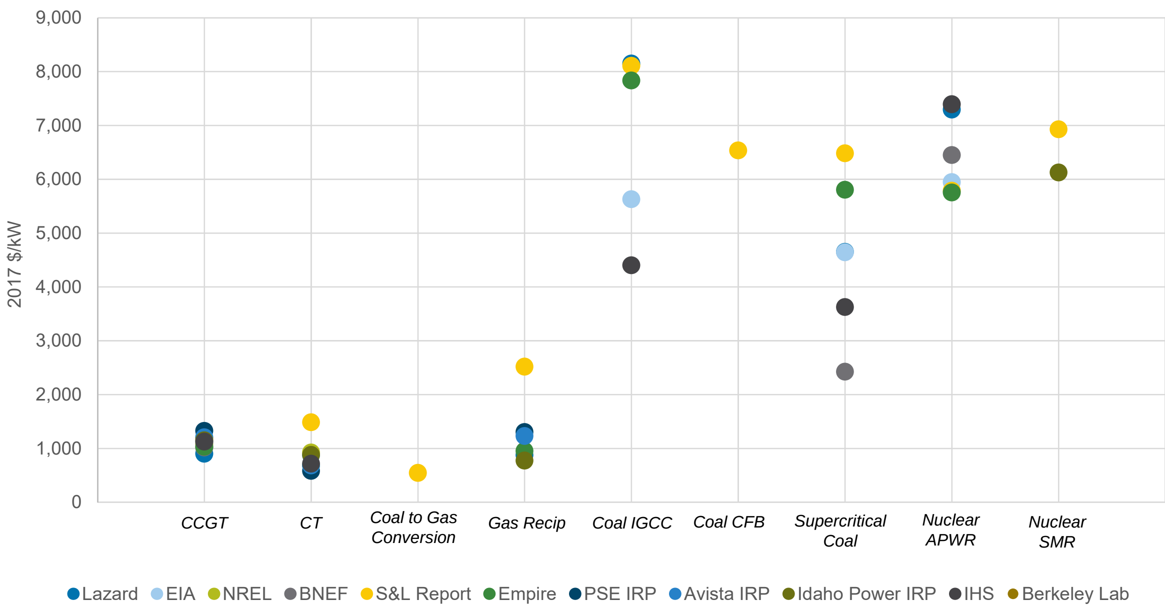
- Coal technologies – integrated gasification combined cycle, circulating fluidized bed, and supercritical pulverized coal
- Natural gas technologies – CTs, CCGTs, reciprocating engines, and coal-to-gas conversion
- Nuclear technologies – small module reactors and advanced pressurized water reactions
- Renewable technologies – onshore wind, offshore wind, distributed wind, utility-scale photovoltaic ("PV") solar, and distributed PV solar
- Other technologies – combined heat and power, battery storage, microturbines, and biomass

Figure 4-5: Data Sources for Third-Party Resource Review

Data Source	Description
Sargent & Lundy	NIPSCO Integrated Resource Plan Engineering Study Technical Assessment (2015)
Energy Information Administration (EIA)	Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants (2018 Annual Energy Outlook)
Utility Integrated Resource Plans	Empire District Electric Company, Puget Sound Energy, Avista Utilities and Idaho Power (screened for filings with transparent data within the last 6 months to year)
Lazard	Levelized Cost of Energy Analysis Version 11.0 (2017)
	Lazard Levelized Cost of Storage Version 3.0 (2017)
IHSMarkit	US Solar PV Capital Cost and Required Price Outlook
	US Wind Capital Cost and Required Price Outlook
	US Battery Storage: Costs, Drivers, and Market Outlook (2017)
	North American Power Market Fundamentals: Rivalry, October 2017 – New Capacity Characteristics & Costs
Bloomberg New Energy Finance	Historical and forecast U.S. PV Capex Stack by Segment and Region
	Key cost input in LCOE Scenarios, 1H 2017
	Benchmark Capital Costs for a Fully-Installed Energy Storage System (2017)
National Renewable Energy Technology Laboratory (NREL)	Annual Technology Baseline 2017

NIPSCO then aggregated the cost estimates from all sources by technology type to evaluate current costs on a $/kilowatt ("kW") basis. As part of this assessment, average, median, minimum, and maximum costs were recorded. A summary of the results of the survey is presented in Figure 4-6 and Figure 4-7.

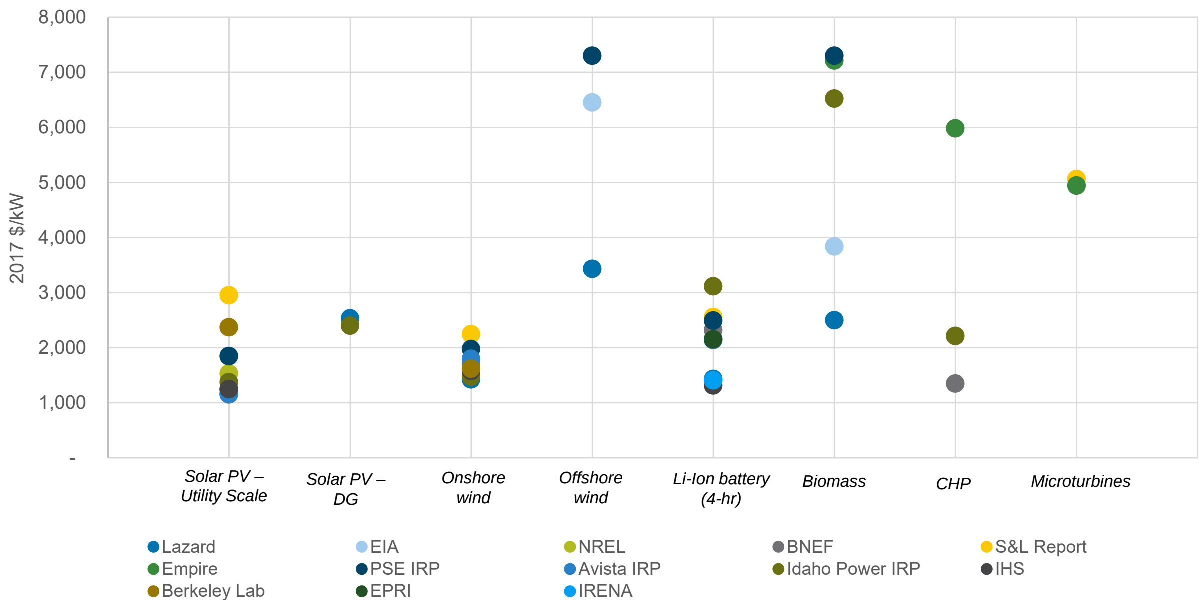
Figure 4-6: Current Capital Cost Summary for Coal, Gas, and Nuclear Technologies (2017$/kW)



2017 $/kW	CCGT	CT	Coal to Gas Conversion	Gas Recip	Coal IGCC	Coal CFB	Supercritical Coal	Nuclear APWR	Nuclear SMR
Average	1,113	834	543	1,276	6,824	6,536	4,605	6,437	6,527
Median	1,116	715	543	1,092	7,835	6,536	4,646	6,198	6,527
Min	900	583	543	775	4,401	6,536	2,425	5,752	6,126
Max	1,326	1,485	543	2,519	8,150	6,536	6,482	7,392	6,927

Gas Recip – Gas Reciprocating Engine
IGCC – Integrated Gasification Combined Cycle
CFB – Circulating Fluidized Bed
APWR – Advanced Pressurized Water Reactor
SMR – Small Modular Reactor

Figure 4-7: Current Capital Cost Summary for Renewable, Storage, and Other Technologies (2017$/kW)[3]



2017 $/kW	Solar PV – Utility Scale	Solar PV – DG	Onshore Wind	Offshore wind	Li-Ion battery (4-hr)	Biomass	CHP	Microturbines
Average	1,673	2,466	1,719	5,728	2,110	5,475	3,182	5,001
Median	1,453	2,466	1,677	6,454	2,160	6,522	2,213	5,001
Min	1,155	2,400	1,425	3,430	1,317	2,500	1,350	4,943
Max	2,370	2,532	1,977	7,300	3,114	7,300	5,984	5,059

Given relatively large uncertainty ranges for certain technologies and given even larger uncertainty regarding future cost trends, NIPSCO determined that it was necessary to conduct an RFP process to collapse the uncertainty and identify transactable projects that could be available for future capacity needs, especially by 2023. In the 2016 IRP, NIPSCO identified several screening criteria to confirm project viability, including technical feasibility, commercial availability, economic attractiveness, and environmental compatibility. In the 2018 IRP, each of these criteria could be tested with actionable data from the RFP process as opposed to solely relying on engineering advice.

4.9.2 All Source Request for Proposals

NIPSCO worked with CRA's Auctions and Competitive Bidding practice to conduct an All-Source RFP during the spring and early summer of 2018. During NIPSCO's first Public Advisory meeting, an overview of the All-Source RFP design was provided to stakeholders and comments were solicited and accepted through April 2018. After incorporating stakeholder feedback, NIPSCO and CRA formally launched the All-Source RFP on May 14, 2018 and closed the window for proposals on June 29, 2018.

[3] Note that renewable cost data from the S&L summary was excluded in the summaries due to vintage concerns. Old solar PV – Utility Scale data was also excluded from the Berkeley Lab source.

The All-Source RFP provided several guidelines to bidders, which are summarized below:

- Technology: The All-Source RFP requested all solutions regardless of technology, including demand-side options and storage

- Size: The All-Source RFP defined a minimum total need of 600 MW for the portfolio, but placed no size restrictions on the potential bidders. The All-Source RFP explicitly allowed for resources below 600 MW to offer their solution as a piece of a potential total need. The All-Source RFP also encouraged larger resources offer their solution for consideration.

- Ownership Arrangements: The All-Source RFP was open to asset purchases (new or existing) and PPAs. However, it required that resources qualify as MISO internal generation (not pseudo-tied) or load in the form of DR.

- Duration: The All-Source RFP requested delivery beginning June 1, 2023, but indicated that it would evaluate deliveries as early as June 1, 2020. The minimum contractual term and/or estimated useful life was requested to be five years, except for DR, which was allowed to offer for a one-year term.

- Deliverability: The All-Source RFP required that bidders have firm transmission delivery to MISO Local Resource Zone 6 ("LRZ6").

- Participants & Pre-Qualification: The All-Source RFP required counterparties be credit-worthy to ensure an ability to fulfill future resource obligations.

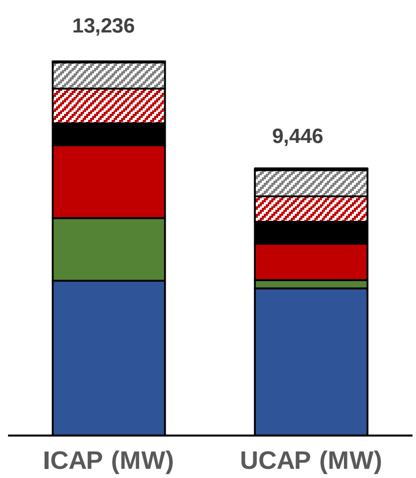
Overall, the All-Source RFP generated a large amount of bidder interest, with 90 total proposals received across a range of deal structures. NIPSCO received bids for 59 individual projects across five states with over 13 GW of installed capacity ("ICAP") represented. Many of the proposals offered variations on pricing structure and term length, and the majority of the projects were in various stages of development. A summary of the total number of proposals received by technology type is shown in Figure 4-8.

Figure 4-8: Summary of Number of Proposals Received by Technology Type

Technology	CCGT	CT	Coal	Wind	Wind + Solar + Storage	Solar	Solar + Storage	Storage	Demand Resp.	Total Bids
Asset Sale	4	-	-	1	-	1	-	-	-	6
PPA	8	-	3	6	-	26	7	8	1	59
Option	3	1	-	7	1	8	4	1	-	25
Total	15	1	3	14	1	35	11	9	1	90
Locations	IN, IL	IN	IN, KY	IA, IN, IL, MN	IN	IL, IN, IA	IN	IN	IN	

On a total MW basis, the 13 GW of ICAP offered represented just under 10 GW of UCAP, providing a sufficiently large set of candidate options for NIPSCO to evaluate for any capacity need during the All-Source RFP delivery window. Over half of the offered UCAP was in the form of natural gas-fired projects, primarily CCGTs. However, a significant amount of renewable, coal-based, and storage resources were also offered. Figure 4-9 shows a summary of total MW offered in response to the All-Source RFP by type.

Figure 4-9: Summary of Total MW of Proposals Received by Type

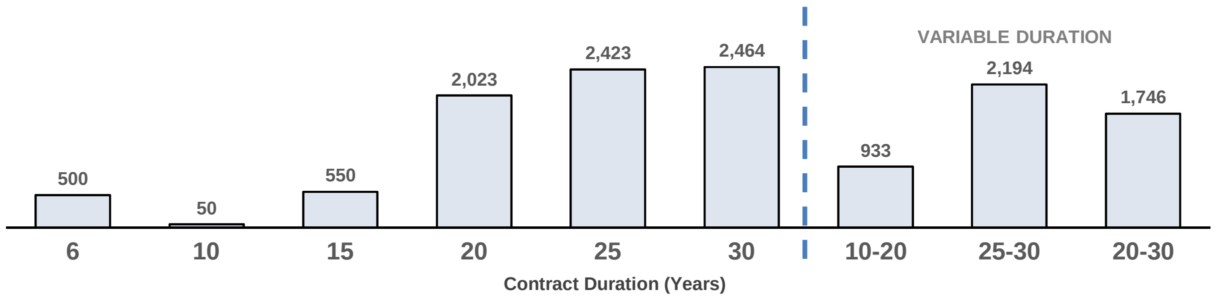


	ICAP (MW)	UCAP (est. MW)
Demand Response	70	70
Storage	925	925
Solar + Storage	1,220	902
Wind + Solar + Storage	0	0
Coal	772	772
Solar	2,580	1,291
Wind	2,209	287
Natural Gas (CT)	0	0
Natural Gas (CCGT)	5,470	5,199
	13,236	9,446

*Note that totals are on a project basis, which eliminates double counting of multiple proposals for the same facility.

Most PPA offers were relatively long in duration, with the majority of proposals offering contracts for 20 year terms or longer. Several bidders offered shorter-term options, including a number that provided NIPSCO with options to select from multiple duration possibilities. Figure 4-10 provides a summary of the total UCAP MW offered by duration.

Figure 4-10: Summary of Proposals Received by Duration (UCAP MW)



Most importantly, the All-Source RFP responses provided transactable cost and price information to be incorporated in the IRP analysis. Overall, much of the cost information was relatively consistent with the third-party data review, but renewable offers were at the low end of the estimates observed in the public literature. This indicated that technology change and developer activity in a competitive process are dynamic forces that influence the costs of resource options for NIPSCO in the future. A summary of the various proposals by type and by price is provided in Figure 4-11. Note that due to confidentiality considerations, individual project prices cannot be disclosed.

Figure 4-11: Summary of Proposals by Price

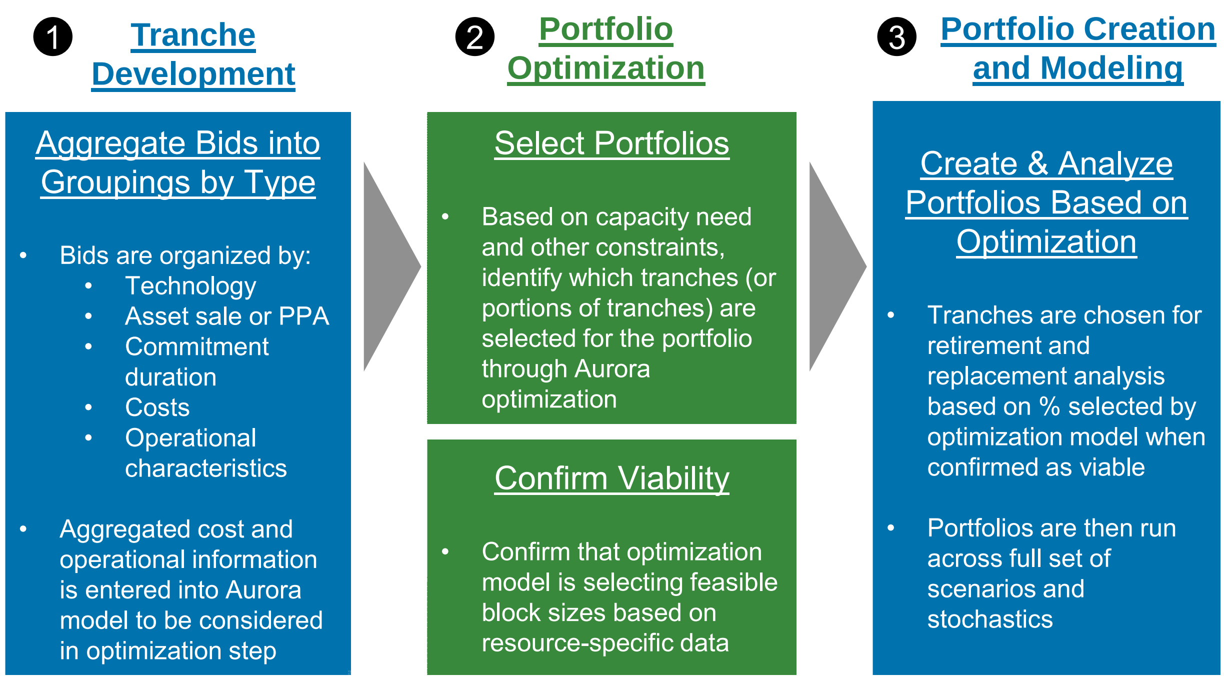
	Technology	# of Bids	Bid MW (ICAP)	# of Projects	Project MW	Average Bid Price	Pricing Units	Comments
Asset Sale or Option	Combine Cycle Gas (CCGT)	7	4,846	4	3,055	$959.61	$/kW	
	Combustion Turbine (CT)	1						
	Solar	9	1,374	5	669	$1,151.01	$/kW	
	Wind	8	1,807	7	1,607	$1,457.07	$/kW	
	Solar + Storage	4	705	3	465	$1,182.79	$/kW	
	Wind + Solar + Storage	1						
	Storage	1						
Purchase Power Agreement	Combine Cycle Gas (CCGT)	8	2,715	6	2,415	$7.86	$/kW-Mo	+ fuel and variable O&M
	Solar + Storage	7	1,055	5	755	$5.90	$/kW-Mo	+ $35/MWh (Average)
	Storage	8	1,055	5	925	$11.24	$/kW-Mo	
	Solar	26	3,591	16	1,911	$35.67	$/MWh	
	Wind	6	788	4	603	$26.97	$/MWh	
	Fossil	3	1,494	2	772	N/A		Structure not amenable to price comparison
	Demand Response	1						
	Total	**90**	**20,585**	**59**	**13,247**			

4.10 Incorporation of the All-Source RFP Results into the IRP

After gathering the All-Source RFP bidder data, the next step in the process was to organize the information and incorporate the results into the IRP analysis. NIPSCO and CRA developed a three-step process for All-Source RFP-IRP integration, which is outlined in Figure 4-12:

1. Organize the various bids into groupings or tranches according to technology, whether the bid offered a PPA or an asset acquisition, the bid's commitment duration, and the bid's costs and operational characteristics.
2. Perform portfolio optimization analysis based on NIPSCO's potential capacity need and other portfolio design constraints, confirming option viability based on feasible block sizes of All-Source RFP tranche data.
3. Develop comprehensive portfolios with selected tranches from the portfolio optimization step and analyze them across the full set of scenarios and stochastics.

Figure 4-12: Summary of Proposals by Price



4.10.1 Tranche Development

It was determined that a tranche approach would be most effective in aggregating the numerous data points from the All-Source RFP into useable IRP information for three main reasons:

- The IRP is intended to select the best resource mix and future portfolio concept rather than select specific assets or projects. While the IRP analysis can now be highly informed by actionable All-Source RFP data, it is only meant to develop a planning-level recommended resource strategy. NIPSCO determined that asset-specific selection would require an additional level of diligence, including assessment of development risk, evaluation of locational advantages or disadvantages for specific projects, and review of transmission system impacts, to be conducted outside of the standard IRP process.

- The IRP is a highly transparent and public process that requires sharing of major inputs with stakeholders and the public. There would be confidentiality concerns with showing and analyzing asset-level options, which would contain specific cost bids and detailed technology data.

- The IRP modeling is complex, and resource grouping improves the efficiency of the process. Resource evaluation requires organizing large amounts of operational and cost data into IRP models, so a smaller data set would improve the efficiency of setup and run time.

When developing tranches, the CRA All-Source RFP team first organized resources by technology and then sorted them into categories according to whether they were offered as asset sales or PPAs. Projects were screened by the All-Source RFP team to determine conformity with bid requirements, and any non-conforming bids were eliminated. Duplicate projects that were offered multiple times under different structures were consolidated into the lowest-cost option to avoid double-counting. Beyond the initial organization and screening, the bids were then arranged by commitment duration and finally costs and operational characteristics.

For example, the All-Source RFP received multiple CCGT bids, with some being based on the same project. In developing the tranches, the team first separated the PPAs from the asset sales and then sub-divided PPA bids into short and long duration options for evaluation. The sale bids were all long duration, but had meaningfully different costs, so they were organized into two separate tranches for evaluation. This illustrative example is shown in Figure 4-13.

Figure 4-13: CCGT Tranche Development Example

PPA

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)*	Online Year	PPA Term (years)
PPA Bid 1	CCGT	250	250	2023	6
PPA Bid 2	CCGT	625	575	2023	30
PPA Bid 3	CCGT	625	625	2023	30
PPA Bid 4	CCGT	725	700	2023	20
PPA Bid 5	CCGT	600	600	2023	30

Tranche Name	# Of Resources	ICAP (MW)	UCAP (MW)	Online Year	PPA Term (years)	Cost range** ($/kW-mo)
PPA CCGT #1	1	250	250	2023	6	
PPA CCGT #2	4	2,575	2,500	2023	27	

Sale

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)*	Online Year
Sale Bid 1	CCGT	625	625	2023
Sale Bid 2	CCGT	625	625	2023
Sale Bid 3	CCGT	1,025	925	2023
Sale Bid 4	CCGT	725	700	2023

Tranche Name	# Of Resources	ICAP (MW)	UCAP (MW)	Online Year	Price Range** ($/kW)
Sale CCGT #1	2	1,250	1,250	2023	
Sale CCGT #2	2	1,750	1,750	2023	

*Capacity is rounded to the nearest 25 MW.
**Given the small number of projects within each CCGT tranche, PPA costs and asset sale prices are not being shown to preserve confidentiality. Note that PPAs were structured as tolling arrangements with fixed cost capacity payments (in $/kW-mo) plus certain variable charges (in $/MWh).

As another example, the All-Source RFP received 26 solar PPA bids. These bids generally all had similar contract structures, duration commitments, and capacity factors. Therefore, PPA price was the major factor that drove development of the tranches. In this instance, five solar PPA tranches were developed, organizing individual bids into groupings with similar pricing. Figure 4-14 provides an illustrative example of how these bids could be grouped together for evaluation.

Figure 4-14: Solar PPA Tranche Development Example

Bid Name	Bid Type	ICAP (MW)*	UCAP (MW)	Online Year	PPA Term (years)	Price*	Capacity Factor
Bid 1	Solar	-	-	2023	20	$27.xx	-
Bid 9	Solar	275	138	2023	20	$32.00	24%
Bid 10	Solar	100	50	2023	20	$34.00	24%
Bid 11	Solar	75	38	2023	20	$34.00	23%
Bid 12	Solar	25	13	2023	20	$35.00	24%
Bid 13	Solar	500	250	2023	25	$35.00	25%
Bid 26	Solar	-	-	2023	20	$73.xx	-

Tranche Name	Tranche Type	# of Resources	ICAP (MW)	UCAP (MW)	Online Year	PPA Term (weighted average years)	Price (weighted average)	Capacity Factor (weighted average)
Indiana Solar #3	Solar	5	975	488	2023	23	$33.93	24.2%

Ultimately, the tranche development process resulted in the production of 17 PPA tranches and 11 asset sale tranches. These are summarized by resource type, size, term, and costs in Figure 4-15 and Figure 4-16 for PPAs and asset sales, respectively.

Figure 4-15: Summary of PPA Tranches Used in Modeling

Tranche	Resource Type	Nameplate Capacity (MW)	UCAP (MW)	Storage Capacity (MW)	PPA Start	PPA Term (yrs)	Pricing ($/MWh)	Pricing ($/kW-mo)	Pricing ($/MW-d)
1	CCGT	250	250	-	2023	6		8.71	
2	CCGT	2,570	2,487	-	2023	27		8.58	
3	CT	685	678	-	2023	30		5.17	
4	Demand Response	70	70	-	2023	1			115.00
5	Solar	500	250	-	2023	20	28.45		
6	Solar	975	488	-	2023	23	33.93		
7	Solar	1,352	676	-	2023	26	37.62		
8	Solar	308	154	-	2022	21	62.87		
9	Solar + Storage	175	92	5	2023	20	24.80		
10	Solar + Storage	295	200	52	2023	20	28.24		
11	Solar + Storage	1,525	1,158	395	2023	22	34.54	2.27	
12	Solar + Storage	25	23	10	2024	20	61.41		
13	Storage	510	510	510	2023	16	12.58	4.31	
14	Storage	400	400	400	2023	20			323.14
15	Wind	945	128	-	2021	19	25.54		
16	Wind	479	72	-	2022	22	38.11		
17	Wind + Solar + Storage	300	95	30	2021	20	28.68		

Figure 4-16: Summary of Asset Sale Tranches Used in Modeling

Tranche	Resource Type	Nameplate	UCAP	Transfer Date	Pricing ($/kW)
1	CCGT	1,255	1,242	2023	962
2	CCGT	1,750	1,633	2023	1,084
3	CT	685	678	2023	615
4	Solar	265	133	2023	951
5	Solar	639	320	2023	1,125
6	Solar	400	200	2023	1,287
7	Solar + Storage	265	183	2023	1,067
8	Solar + Storage	440	330	2023	1,253
9	Storage	100	100	2023	932
10	Wind	1,099	165	2020	1,486
11	Wind + Solar + Storage	300	95	2021	1,406

4.10.2 Renewable Resource Tax Incentives and Tax Equity Partnership

Federal tax incentives are currently in place for renewable and paired renewable/storage resources. Resources are eligible for a production tax credit ("PTC") or an investment tax credit

("ITC"). The PTC provides a credit of \$24/megawatt hour ("MWh")[4] for all generation produced by the facility, and the ITC provides a credit as a portion of the total cost of the facility. It is generally advantageous for wind resources to take the PTC, due to their high capacity factors, and solar resources to take the ITC.

The tax incentives are currently in the midst of a phase-out, as summarized in Figure 4-17. In order to qualify for the credits, projects need to begin construction by a certain date and be put into service by a certain date. The start of construction deadline can be met as long as certain equipment purchases and development costs have been "safe harbored" by federal tax authorities. The safe harbor for beginning of construction is investment of at least 5% of the total project cost on or before the specified date.

Figure 4-17: PTC (Wind) and ITC (Solar) Phase-Out Schedule

Wind

Year During Which Equipment is Safe Harbored	Last Year Project Can Be Placed in Service to Qualify for Continuity Safe Harbor	Credit Percentage
2016	2020	100
2017	2021	80
2018	2022	60
2019	2023	40
2020	n/a	

Solar

Year During Which Equipment is Safe Harbored	Last Year Project Can Be Placed in Service to Maximize ITC	ITC Rate
2016	2020	30
2017	2021	30
2018	2022	30
2019	2023	30
2020	2023	26
2021	2023	22
2022	n/a	n/a

Given the importance of these tax incentives, NIPSCO preformed a review of their impact on All-Source RFP bids prior to developing final costs for the portfolio modeling. The impact of the tax incentives needed to be treated differently for the different types of All-Source RFP bids:

- For PPAs, no adjustments were needed, since tax incentives flow to the developer and are theoretically reflected in PPA pricing; and

[4] This value is indexed to inflation.

- For asset ownership, tax benefits flow to the utility and ultimately to the customer in rates, so adjustments needed to be made.

Without proper structuring, the Internal Revenue Code normalization rules stretch the flow of tax benefits to the customers over the regulatory life of the asset, but an alternative tax equity ownership structure can adjust the flow of benefits. In this arrangement, NIPSCO and a tax equity investor would form a partnership to develop a renewable energy project. The tax equity investor would invest to obtain a specified internal rate of return through the receipt of tax benefits in the form of depreciation, tax credits, and cash for a specified timeframe. NIPSCO would place its portion of the investment, which would be a fraction of the total cost, in rate base.

In order to properly account for the rate base reduction impact of partnering with a tax equity investor, CRA worked with NIPSCO's tax team to develop relevant financial models to estimate the breakdown of capital expenditures. For solar and solar-storage paired projects, the tax equity contribution is estimated to be around 35% of total capital costs, meaning NIPSCO would cover the remaining 65%. For wind assets, the range of tax equity contributions would be between 33 and 60%, depending on the asset's online date and expected capacity factor. Wind assets are assumed to utilize the PTC, while solar assets are assumed to take advantage of the ITC. The expected range of tax equity partner contributions for renewable resources is summarized in Figure 4-18.

Figure 4-18: Capital Cost Adjustments due to Tax Equity Partnership

Resource Type	Tax Equity Capital Cost Contribution
Solar	35%
Wind	33-60%
Solar + Storage	35%
Wind + Solar + Storage	35%

4.10.3 Self-build

As part of the process of evaluating its resource alternatives, NIPSCO investigated the feasibility of building a CCGT facility to meet its resource needs. The study considered an 800MW combine cycle F class 2x1 configuration and a 635MW advance class 1x1 consideration to be located on land at Schahfer.

For the study, NIPSCO developed conceptual site plans, conducted geotechnical studies, established the design criteria, developed single line studies and cost estimates for the two technologies. The study also considered the electric, natural gas and water interconnection requirements.

From the feasibility study results, NIPSCO determined that a self-build option was a more expensive alternative as compared to the All-Source RFP bid results for similar technology. Consequently, NIPSCO believes that a self-build CCGT is not the best resource alternative to meet customers need at this time.

4.10.4 CCGT Breakeven Analysis

NIPSCO's replacement analysis, as discussed in Section 9.2, found that replacement portfolios with renewable resources from the all source RFP are more cost effective than portfolios without. Furthermore, portfolios with CCGT are higher cost and carry increased risk due to exposure to natural gas prices and dispatch cost volatility. Selection of resource portfolios with new-build CCGT would require criteria other than economics and cost risk to justify.

NIPSCO explored the conditions that could support the inclusion of an additional CCGT into its supply portfolio. A CCGT could be part of a transmission/reliability solution to support renewables but analysis using new-build CCGT costs concludes that other reliability solutions are more cost effective. NIPSCO performed an analysis to identify the purchase price at which CCGT would be economically competitive with renewable resources. NIPSCO's analysis shows that, to be economically competitive with its preferred resource portfolio, CCGT costs would need to be approximately \$284/kW or lower in the Base Scenario. This breakeven price does not appear to be likely for new-builds, but may be a possibility for re-sale of existing CCGT. A breakeven price was not achievable in the Aggressive Environmental Regulation Scenario, was \$589/kW or lower in the Challenged Economy Scenario, \$637/kW or lower in the Booming Economy / Abundant Natural Gas Scenario. Additional details are in Confidential Appendix D.

4.10.5 Coal to Gas Conversion

NIPSCO evaluated the potential to convert one or two units at Schahfer from coal-fired units to natural gas-fired units. As part of this analysis, NIPSCO developed operational assumptions for the potentially converted units as well as cost estimates associated with the conversion. In evaluating the operational parameters for a converted unit, NIPSCO relied on the Sargent & Lundy ("S&L") study conducted as part of the 2016 IRP process. The study concluded that a conversion would result in a 15% capacity de-rate for either Schahfer 17 or 18 when fired by gas instead of coal, as well as a slight efficiency penalty for the plant's heat rate. The key operational parameters for the conversion option are shown on a per-unit basis in Figure 4-19.

Figure 4-19: Coal-to-Gas Conversion Operational Parameters

	Category	NIPSCO Assumption
Operating Parameters	Conversion Capacity(MW) per unit	309.2
	Heat Rate (Btu/kWh)	11,106
	Forced Outage Rate	10%

Separately, NIPSCO developed capital and ongoing maintenance cost assumptions associated with a potential conversion. These costs were developed from the S&L study from 2016, as well as NIPSCO's internal experts in generation, plant operations, and major projects. The key assumptions included:

- The capital cost for conversion, which includes materials, construction labor, contingency, and owners and indirect costs were estimated by S&L .

- Gas interconnection costs were reviewed by S&L and NIPSCO's operational teams. Based on the data from the S&L study and a preliminary review with NIPSCO Gas Systems Engineering, it would be possible to convert Unit 17 or Unit 18 to natural gas without installing an additional pipeline as long as both Units 14 and 15 are retired. Leaving Units 14 and 15 in operation would likely create operational limitations related to when the units would be available to start up. Conversion of Units 17 and 18 to run simultaneously would require an additional pipeline. The size of the additional line could be smaller than the 30" used in the engineering study, but further detailed engineering analysis would be required to determine the appropriate size. Therefore, to be conservative and to evaluate whether conversion would be economic in the event that gas interconnection costs were minimal, NIPSCO assumed zero cost in its analysis.

- Environmental compliance costs were assumed to be zero.

- Maintenance capital needs were assumed to be 25% lower than current coal operations. This assumption was based on a review of NIPSCO's last three years of capital expenditures for Schahfer Units 17/18 that showed 25% of maintenance capital expenditures were for coal-specific components.

- Fixed O&M costs were estimated by S&L in the engineering study.

A summary of the assumptions for each of these cost categories is shown in Figure 4-20.

Figure 4-20: Coal-to-Gas Conversion Capital and Maintenance Cost Estimates

	Category	Estimated Cost
Conversion Investment Costs	Conversion (2015$)	$43M for 17 $87M for 17/18
	Gas Interconnection	$0M
	Environmental Compliance	$0M
Maintenance Capital	Maintenance Capital (Total 2024-2038) Nominal $	$122M for U17 $298M for 17/18
Ongoing Costs	Fixed O&M Costs (2015$/KW-yr)	$39

Ultimately, the analysis showed that converting one unit would cost at least $230 million more than retirement and replacement with economically optimized selections from the All-Source RFP results and replacing both units would cost customers at least $540 million more. Based on this, it is not economically feasible to complete the conversion of either unit. This is discussed more in depth in Section 9.1.7.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commissions own motion,	)	
establishing the method and avoided cost calculation	)	
for **DTE ELECTRIC COMPANY** to fully	)	Case No. U-18091
comply with the Public Utilities Regulatory	)	
Policy Act of 1978, 16 USC 2601 et seq.	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

ON REMAND

OF

DON M. STANCZAK

Line
No.

Q. Until a final order is issued in its upcoming IRP proceeding how should the Company's need for capacity be evaluated?

A. In the recent past, the Company has reported to the Commission regarding its capacity position. Specifically, the Company filed documents pertaining to its capacity position in December 2018 in Case No. U-20154, relative to the administration of the State Reliability Mechanism ("SRM"), the Company filed a report documenting its capacity position. In that proceeding, the Company indicated that it did not expect to make any MISO PRA purchases during the MISO plan years 2020-21 through 2029-30. In addition, the Company is including an updated view of its capacity position in this case, which is the same data that will be included in the Company's IRP filing which will be submitted to the Commission on March 29th, 2019. This capacity assessment is supported by Company Witness Niscoromni, and is reflected on Exhibit DE-6. As reflected in the Company's December 2018 submission in Case No. U-20154 and reflected on Exhibit DE-6, the Company does not have a persistent need for incremental capacity over the next 10 years.

Q. Why is a persistent capacity need key to informing a utility's PURPA obligations?

A. If a persistent capacity need does not exist, then there is no new plant construction or long-term purchase contract to defer, and therefore no avoided cost associated with such deferral; I address short-term or intermittent needs later in my testimony. DTE Electric would not build a physical generation asset to meet a short-term or intermittent capacity need, nor would DTE Electric sign a long-term capacity contract to meet such a need. More cost-efficient ways exist to meet short-term, insignificant capacity shortfalls, these include market purchases and demand response. Assuming that the Company would invest in assets or enter into Purchase Power Agreements ("PPA") in order to meet non-existent or minimal intermittent capacity shortfalls is therefore not appropriate in the context of setting PURPA avoided cost pricing. Again, this would violate the requirement that the Company, and therefore its customers, not pay more in avoided cost to the QF than it would have paid if the Company would have self-generated or purchased the power, absent the QF.

Q. What are the proper criteria to determine whether a utility has a persistent capacity need?

A. A persistent capacity need identified in an IRP must 1) be a significant projected shortfall in the utility's ability to demonstrate resource adequacy to MISO, and 2) represent an avoidable investment in generation capacity with the primary objective of addressing said shortfall. Any short duration or sporadic capacity need within the relevant planning horizon should not be viewed as persistent.

Q. In its December 20, 2018 Order on rehearing in this proceeding, did the Commission address the capacity planning horizon issue?

A. Yes. The Commission specifically requested that the parties address the following three potential planning horizon options: 1) a five-year planning horizon given current emerging planning and resource acquisition and development practices, 2) a 10-year planning horizon in which full avoided costs are paid to QFs in the year that the capacity need is projected and thereafter, and 3) a 10-year planning horizon in which the capacity payment varies depending on the amount of capacity needed and when it occurs in the planning horizon. In a footnote, the Commission provided some additional detail relative to options two and three.

Line
No.

Q. What PURPA planning horizon is DTE Electric supporting in this proceeding?

A. A five-year outlook is the most appropriate timeframe for determining a capacity need under PURPA. A five-year outlook is consistent with the IRP cycle in Michigan as well as with the requirement relative to the Commission reviewing PURPA avoided costs. Moreover, investments for new generation that are expected to occur within the five-year PURPA capacity outlook period that will come on-line after the five-year PURPA capacity outlook period, will still count as a persistent need, leveraging the IRP's longer term outlook. For example, if an IRP calls for new physical generation in the last year of the five-year planning horizon, and that new capacity would also be needed in years subsequent to the year five IRP planning horizon, such new capacity could constitute the basis for the avoided cost of capacity if the QF purchase allows the Company to defer construction of the new capacity. Investments that begin beyond the next five years should not be considered when determining capacity need under PURPA. Forecasts more than five years out are subject to significant uncertainty including; technology cost, efficiency and availability, and changes in peak demand and usage. Thus, expanding the time horizon for quantifying an explicit capacity need beyond five years increases risk for DTE Electric's retail electric customers. Potential capacity needs that may occur further than five years out can be addressed in subsequent IRP proceedings or additional filings to update critical assumptions.

Q. Should renewable generation build to meet renewable energy goals be considered a persistent capacity need?

A. No. Adding resources to meet renewable energy goals, either state-mandated or customer-imposed, does not inherently constitute a capacity need. These investments

Michigan Public Service Commission
DTE Electric Company
2016 PA 342 Renewable Energy 2018 Amended Plan
DTE Electric Owned Renewable Energy Facilities Generation

Case No.: U-18232
Exhibit: A-3
Witness: T. L. Schroeder
Page: 1 of 2

Line No.	(a)	(b)	(c)	(d) As Filed 2016	(e) 2017	(f) 2018	(g) 2019	(h) 2020	(i) 2021	(j) 2022
1	**DTE Electric Owned**									
2	Gratiot County Wind	Installed Capacity	**MW**	102.4	102.4	102.4	102.4	102.4	102.4	102.4
3		Generation	**1,000 MWh**	254	261	261	261	262	261	261
4	Thumb Wind Parks	Installed Capacity	**MW**	110.4	110.4	110.4	110.4	110.4	110.4	110.4
5		Generation	**1,000 MWh**	406	402	402	402	403	402	402
6	Echo Wind Park	Installed Capacity	**MW**	112.0	112.0	112.0	112.0	112.0	112.0	112.0
7		Generation	**1,000 MWh**	387	391	391	391	392	391	391
8	Brookfield Wind Park	Installed Capacity	**MW**	74.8	74.8	74.8	74.8	74.8	74.8	74.8
9		Generation	**1,000 MWh**	261	263	263	263	264	263	263
10	Pinnebog Wind Park	Installed Capacity	**MW**	51.0	51.0	51.0	51.0	51.0	51.0	51.0
11		Generation	**1,000 MWh**	13	170	170	170	170	170	170
12	Pine River Wind Park	Installed Capacity	**MW**	-	-	161.3	161.3	161.3	161.3	161.3
13		Generation	**1,000 MWh**	-	-	71	424	425	424	424
14	2019 Future Wind Build	Installed Capacity	**MW**	-	-	-	-	168.8	168.8	168.8
15		Generation	**1,000 MWh**	-	-	-	-	504	503	503
16	2020 Future Wind Build	Installed Capacity	**MW**	-	-	-	-	300.0	300.0	300.0
17		Generation	**1,000 MWh**	-	-	-	-	75	894	894
18	2021 Future Wind Build	Installed Capacity	**MW**	-	-	-	-	-	225.0	225.0
19		Generation	**1,000 MWh**	-	-	-	-	-	57	680
20	2022 Future Wind Build	Installed Capacity	**MW**	-	-	-	-	-	-	150.0
21		Generation	**1,000 MWh**	-	-	-	-	-	-	38
22	MIGreenPower Subscribed Wind	Subscribed Capacity	**MW**	-	(0.7)	(6.8)	(15.8)	(15.8)	(15.8)	(15.8)
23		Subscribed Generation	**1,000 MWh**	-	(2)	(23)	(53)	(53)	(53)	(53)
24	VGP Subscribed Wind	Subscribed Capacity	**MW**	-	-	-	-	(300.0)	(300.0)	(300.0)
25		Subscribed Generation	**1,000 MWh**	-	-	-	-	(75)	(894)	(894)
26	DTE Solar Currents (~13.75MW)	Installed Capacity	**MW**	12.8	13.3	13.3	13.3	13.3	13.3	13.3
27		Generation	**1,000 MWh**	16	16	16	16	16	16	16
28	DTE Solar Currents (~1.25MW)	Installed Capacity	**MW**	1.2	1.2	1.2	1.2	1.2	1.2	1.2
29		Generation	**1,000 MWh**	1	1	1	1	1	1	1
30	Demille/Turrill/O'Shea Utility-Scale Solar	Installed Capacity	**MW**	-	50.0	50.0	50.0	50.0	50.0	50.0
31		Generation	**1,000 MWh**	-	42	83	82	82	82	81
32	2019 Future Solar Pilot	Installed Capacity	**MW**	-	-	-	10.0	10.0	10.0	10.0
33		Generation	**1,000 MWh**	-	-	-	10	19	19	19
34	2020 Future Solar Pilot	Installed Capacity	**MW**	-	-	-	-	3.0	3.0	3.0
35		Generation	**1,000 MWh**	-	-	-	-	3	5	5
36	MIGreenPower Subscribed Solar	Subscribed Capacity	**MW**	-	(1.3)	(12.8)	(30.0)	(30.0)	(30.0)	(30.0)
37		Subscribed Generation	**1,000 MWh**	-	(2)	(21)	(49)	(49)	(49)	(49)
38	Total Wind Generation (excluding VGPs)		**1,000 MWh**	1,321	1,484	1,535	1,858	2,367	2,417	3,079
39	Total Solar Generation (excluding VGPs)		**1,000 MWh**	17	57	79	60	72	74	74
40	Total Generation (excluding VGPs)		**1,000 MWh**	1,338	1,542	1,614	1,918	2,439	2,492	3,153

Michigan Public Service Commission
DTE Electric Company
2016 PA 342 Renewable Energy 2018 Amended Plan
DTE Electric Owned Renewable Energy Facilities Generation

Case No.: U-18232
Exhibit: A-3
Witness: T. L. Schroeder
Page: 2 of 2

	(a)	(b)	(c)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
Line No.				2023	2024	2025	2026	2027	2028	2029
1	**DTE Electric Owned**									
2	Gratiot County Wind	Installed Capacity	**MW**	102.4	102.4	102.4	102.4	102.4	102.4	102.4
3		Generation	**1,000 MWh**	261	262	261	261	261	262	174
4	Thumb Wind Parks	Installed Capacity	**MW**	110.4	110.4	110.4	110.4	110.4	110.4	110.4
5		Generation	**1,000 MWh**	402	403	402	402	402	403	268
6	Echo Wind Park	Installed Capacity	**MW**	112.0	112.0	112.0	112.0	112.0	112.0	112.0
7		Generation	**1,000 MWh**	391	392	391	391	391	392	260
8	Brookfield Wind Park	Installed Capacity	**MW**	74.8	74.8	74.8	74.8	74.8	74.8	74.8
9		Generation	**1,000 MWh**	263	264	263	263	263	264	176
10	Pinnebog Wind Park	Installed Capacity	**MW**	51.0	51.0	51.0	51.0	51.0	51.0	51.0
11		Generation	**1,000 MWh**	170	170	170	170	170	170	113
12	Pine River Wind Park	Installed Capacity	**MW**	161.3	161.3	161.3	161.3	161.3	161.3	161.3
13		Generation	**1,000 MWh**	424	425	424	424	424	425	283
14	2019 Future Wind Build	Installed Capacity	**MW**	168.8	168.8	168.8	168.8	168.8	168.8	168.8
15		Generation	**1,000 MWh**	503	504	503	503	503	504	335
16	2020 Future Wind Build	Installed Capacity	**MW**	300.0	300.0	300.0	300.0	300.0	300.0	300.0
17		Generation	**1,000 MWh**	894	896	894	894	894	896	596
18	2021 Future Wind Build	Installed Capacity	**MW**	225.0	225.0	225.0	225.0	225.0	225.0	225.0
19		Generation	**1,000 MWh**	680	682	680	680	680	682	453
20	2022 Future Wind Build	Installed Capacity	**MW**	150.0	150.0	150.0	150.0	150.0	150.0	150.0
21		Generation	**1,000 MWh**	460	461	460	460	460	461	307
22	MIGreenPower Subscribed Wind	Subscribed Capacity	**MW**	(15.8)	(15.8)	(15.8)	(15.8)	(15.8)	(15.8)	(15.8)
23		Subscribed Generation	**1,000 MWh**	(53)	(53)	(53)	(53)	(53)	(53)	(35)
24	VGP Subscribed Wind	Subscribed Capacity	**MW**	(300.0)	(300.0)	(300.0)	(300.0)	(300.0)	(300.0)	(300.0)
25		Subscribed Generation	**1,000 MWh**	(894)	(896)	(894)	(894)	(894)	(896)	(596)
26	DTE Solar Currents (~13.75MW)	Installed Capacity	**MW**	13.3	13.3	13.3	13.3	13.3	13.3	13.3
27		Generation	**1,000 MWh**	16	16	16	16	15	15	10
28	DTE Solar Currents (~1.25MW)	Installed Capacity	**MW**	1.2	1.2	1.2	1.2	1.2	1.2	1.2
29		Generation	**1,000 MWh**	1	1	1	1	1	1	1
30	Demille/Turrill/O'Shea Utility-Scale Solar	Installed Capacity	**MW**	50.0	50.0	50.0	50.0	50.0	50.0	50.0
31		Generation	**1,000 MWh**	81	81	80	80	79	79	52
32	2019 Future Solar Pilot	Installed Capacity	**MW**	10.0	10.0	10.0	10.0	10.0	10.0	10.0
33		Generation	**1,000 MWh**	19	19	19	19	19	18	12
34	2020 Future Solar Pilot	Installed Capacity	**MW**	3.0	3.0	3.0	3.0	3.0	3.0	3.0
35		Generation	**1,000 MWh**	5	5	5	5	5	5	3
36	MIGreenPower Subscribed Solar	Subscribed Capacity	**MW**	(30.0)	(30.0)	(30.0)	(30.0)	(30.0)	(30.0)	(30.0)
37		Subscribed Generation	**1,000 MWh**	(48)	(48)	(48)	(48)	(47)	(47)	(31)
38	Total Wind Generation (excluding VGPs)		**1,000 MWh**	3,501	3,510	3,501	3,501	3,501	3,510	2,334
39	Total Solar Generation (excluding VGPs)		**1,000 MWh**	74	73	73	72	72	72	48
40	Total Generation (excluding VGPs)		**1,000 MWh**	3,574	3,583	3,573	3,573	3,573	3,582	2,381

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE Electric Company** for approval of its Large Customer Voluntary Green Pricing Program, and determination it complies with Section 61 of 2016 PA 342	)))))	Case No. U-20343

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

TERRI L. SCHROEDER

Q. Please describe how the capacity credit will be calculated.

A. The capacity credit will be equal to the Auction Clearing Price in the annual Planning Resource Auction for Zone 7 within MISO or equivalent successor, specifically using the generation node(s) capacity. The capacity credit will be updated annually. For each kWh subscribed, customers will receive the per kWh value of the capacity from the associated Program asset based on the formula below:

$$\frac{(\text{Auction Clearing Price}) \times (365\ \text{Days}) \times (\text{MISO Zone 7 Capacity Credit (MW)})}{(\text{Project Size}) \times (\text{Resource NCF}) \times (8760\ \text{hours})}$$

Q. Does the Program include Marketing and Administrative fees?

A. There are no additional Marketing and Administrative fees for this Program. Given that this Program is targeted toward large customers, the existing marketing team that serves DTE’s Major Accounts will be utilized to market the Program, and existing renewable energy staff will administer the Program. Costs for marketing materials will be accounted for as normal operating expenses within the Company’s overall renewable program costs, and are expected to be minimal.

Q. What are the contract terms in the tariff?

A. Customers can choose 5, 10, or 20-year contract terms. If the customer elects to re-enroll in the Program after their agreement term ends, that customer will enroll at the subscription rate available at the time of renewal.

Q. Can a Customer terminate a contract?

A. The customer may elect to terminate their subscription after the initial year, subject to an early termination fee. The termination fee will be calculated based on the terms

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE Electric Company** for approval of its integrated resource plan pursuant to MCL 460.6t, and for other relief.	Case No. U-20471 ALJ Sally L. Wallace

PROOF OF SERVICE

On the date below, an electronic copy of **Direct Testimony of Douglas Jester on behalf of Michigan Environmental Council, Natural Resources Defense Council and Sierra Club along with Exhibits MEC-53 through MEC-63** was served on the following:

Name/Party	E-mail Address
Administrative Law Judge Hon. Sally Wallace	wallaces2@michigan.gov
Counsel for DTE Electric Co. Lauren DuVal Donofrio Martin Heiser	mpscfilings@dteenergy.com donofriol@dteenergy.com martin.heiser@dteenergy.com
Counsel for MPSC Staff Amit T. Singh Heather M.S. Durian Daniel E. Sonneveldt Benjamin J. Holwerda Sarah Mullkoff	singha9@michigan.gov durianh@michigan.gov sonneveldtd@michigan.gov holwerdab@michigan.gov MullkoffS1@michigan.gov
Counsel for Department of Attorney General Joel B. King	ag-enra-spec-lit@michigan.gov kingJ38@michigan.gov
Counsel for ABATE Bryan A. Bradenburg Michael J. Pattwell	bbradenburg@clarkhill.com mpattwell@clarkhill.com
Counsel for Great Lakes Renewable Energy Association Don L. Keskey Brian W. Coyer	donkesey@publiclawresourcecenter.com bwcoyer@publiclawresroucecenter.com
Counsel for Energy Michigan Inc. Justin K. Ooms Laura Chappelle Timothy Lundgren	jkooms@varnumlaw.com lachappelle@varnumlaw.com tjlundgren@varnumlaw.com
Counsel for Environmental Law & Policy Center, the Ecology Center, the Solar Energy Industries Association, the Union of Concerned Scientists and Vote Solar Margrethe Kearney Jean-Luc Kreitner	mkearney@elpc.org jkreitner@elpc.org
Counsel for International Transmission Company Richard J. Aaron Courtney Kissel	raaron@dykema.com ckissel@dykema.com
Counsel for Geronimo Energy Timothy Lundgren Justin K. Ooms	tjlundgren@varnumlaw.com jkooms@varnumlaw.com

Counsel for Cypress Creek Renewables, LLC Jennifer Utter Heston	jheston@fraserlawfirm.com
Counsel for Convergen Energy, LLC Timothy Lundgren	tjlundgren@varnumlaw.com
Counsel for Association of Businesses Advocating Tariff Equity Bryan A. Brandenburg	BBrandenburg@clarkhill.com
Counsel for City of Ann Arbor Timothy Lundgren Justin Ooms	tjlundgren@varnumlaw.com jkooms@varnumlaw.com
Counsel for Heelstone Development, LLC **Midland Cogeneration Venture LP** Jason Hanselman John A. Janiszewski	jhanselman@dykema.com jjaniszewski@dykema.com
Counsel for Soulardarity Christopher M. Bzdok Lydia Barbash-Riley	chris@envlaw.com lydia@envlaw.com
Counsel for Michigan Public Power Agency Nolan Moody Peter H. Ellsworth	nmoody@dickinsonwright.com pellsworth@dickinsonwright.com
Co-Counsel for Soulardarity Rebecca J. Boyd Mark H. Templeton Robert A. Weinstock	rebecca.j.boyd@gmail.com templeton@uchicago.edu rweinstock@uchicago.edu

The statements above are true to the best of my knowledge, information and belief.

OLSON, BZDOK & HOWARD, P.C.
Counsel for MEC-NRDC-SC

Date: August 21, 2019

By: Breanna Thomas

Digitally signed by Breanna Thomas
Date: 2019.08.21 19:33:06 -04'00'

Kimberly Flynn, Legal Assistant
Karla Gerds, Legal Assistant
Breanna Thomas, Legal Assistant
420 E. Front St.
Traverse City, MI 49686
Phone: 231/946-0044
Email: kimberly@envlaw.com
karla@envlaw.com and
breanna@envlaw.com