ENVIRONMENTAL LAW & POLICY CENTER
Protecting the Midwest's Environment and Natural Heritage

January 26, 2018

Ms. Kavita Kale
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-18419

Dear Ms. Kale:

The following is attached for paperless electronic filing:

Corrected Direct Testimony of R. Thomas Beach on behalf of the Environmental Law & Policy Center, the Ecology Center, the Solar Energy Industries Association, the Union of Concerned Scientists, and Vote Solar

Proof of Service

Sincerely,

Margrethe K. Kearney

Margrethe Kearney
Environmental Law & Policy Center
mkearney@elpc.org

cc: Service List, Case No. U-18419

1514 Wealthy Street SE, Suite 256 • Grand Rapids, MI 49506
(773) 726-8701 • www.ELPC.org
Harry Drucker, Chairperson • Howard A. Learner, Executive Director
Chicago, IL • Columbus, OH • Des Moines, IA • Duluth, MN • Grand Rapids, MI • Jamestown, ND
Madison, WI • Minneapolis/St. Paul, MN • Sioux Falls, SD • Washington, D.C.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.	))))))))	Case No. U-18419

CORRECTED DIRECT TESTIMONY OF

R. THOMAS BEACH

ON BEHALF OF

ENVIRONMENTAL LAW AND POLICY CENTER, THE ECOLOGY CENTER, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, VOTE SOLAR, AND THE UNION OF CONCERNED SCIENTISTS

January 26, 2018

EXECUTIVE SUMMARY

Q: Mr. Beach, what is the purpose of your testimony?

A: My testimony presents recommendations on behalf of Vote Solar concerning the request of DTE Electric Company (DTE) for a Certificate of Necessity (CON) to build and operate a new natural gas-fired combined-cycle generating plant with a nominal capacity of about 1,100 megawatts (MW). This testimony respectfully asks the Commission to deny DTE's request.

Q: Please summarize your concerns with DTE's Proposed Project.

A: The gas plant is too risky and too expensive for DTE's ratepayers.

Q: Why is it too risky?

A: The uncertainty and volatility in future prices for natural gas, which comprise more than one-half of the life-cycle costs of the proposed gas plant, create significant risks to DTE's ratepayers. Although natural gas prices are low today, experience has shown that they are subject to significant uncertainty and volatility. In contrast, wind, solar, and efficiency resources have zero fuel costs and zero fuel price risk.

In my testimony, I calculate the added costs that DTE would incur to eliminate its fuel price risk, by fixing the price of natural gas to fuel the gas plant for the next 20 years; eliminating this risk would raise the gas plant's costs by 25%. DTE also has used an assumption that local gas market prices in Michigan will remain below the benchmark

Henry Hub price for the next 20 years, even though this is contradicted by the long-term gas forecasts on which the utility relies. Finally, DTE has subscribed to expensive new pipeline capacity to the Marcellus and Utica producing basins to provide a portion of the fuel for the gas plant. An affiliate of DTE is one of the sponsors of this pipeline. This conflicted commitment exposes ratepayers to the real risk that this capacity will be worth less than its cost in the long-run, as a result of overbuilding pipeline capacity out of these growing basins. In my testimony, I quantify all of these risks, which together could increase the costs of the gas plant by as much as 47% above what DTE has presented in its application for a CON.

Q: Have you formed an opinion as to what portfolio of resources would be less risky and less expensive than the gas plant?

A: Yes. A portfolio of renewable and efficiency (R / E) resources would provide the same capacity as the gas plant, at a significantly lower cost. I demonstrate that DTE could meet its capacity needs in 2022-2023 with a portfolio of wind and solar generation, plus incremental energy efficiency (EE) and demand response (DR) resources. My testimony shows that the Renewables / Efficiency (R / E) portfolio presented in Table ES-1 below will supply the same capacity that the gas plant would provide.

Table ES-1: *Vote Solar's Proposed Renewables / Efficiency Portfolio*

New renewable generation	**Nameplate Capacity (MW)**	**MISO Accredited Capacity (MW)**
Solar – fixed array	500	242
Solar – tracking	600	372
Wind	1,100	139
Incremental load reductions	**Load reduction (MW)**	**Reduction w/4% Reserve Margin (MW)**
2% per year EE	90	94
Demand response	251	261
Portfolio Total (MW)		**1,107**
Gas plant (MW)		***1,113***

Procurement of the R / E portfolio should begin immediately, at a measured pace designed to meet DTE's capacity needs in 2022-2023, which are driven by planned coal plant retirements. Near-term procurement of renewables has significant benefits: (1) it reduces the cost of the R / E portfolio by leveraging the availability of significant federal tax benefits that will expire (for wind) in 2020 and (for solar) in 2023; (2) the renewable resource additions needed for DTE to meet its commendable carbon reduction goals will be acquired at a more consistent pace over the next 20 years, and (3) as a result of the near-term capacity additions, DTE may be able to advance by one or two years the retirement of its River Rouge, St. Clair, and Trenton Channel coal units.

Q: What is the basis for your opinion that this scenario, which DTE failed to consider in its IRP, would have lower costs than its Proposed Project?

A: My testimony presents a detailed comparison between, first, the costs of the R / E portfolio and, second, DTE's stated gas plant costs (without considering the additional risks of the gas plant that are quantified in the first section of the testimony). For the solar capacity, I consider data on utility-scale and distributed solar costs that is more recent, more detailed, and more authoritative than what DTE used. I include the likely impact of the pending Section 201 trade case that may impose tariffs on some imported solar panels. DTE's own analysis shows that implementing a goal of 2% annual load reductions through energy efficiency programs is cost-effective; other intervenors will show that even more could be accomplished with EE programs. My assumptions for incremental demand response programs are based on just 50% of the "low" potential for incremental, cost-effective demand response programs identified in the Commission's new report, released last fall, on Michigan's demand response potential. To the extent that my R / E portfolio does not produce the same amount of energy or capacity as the gas plant on an annual, monthly, or hourly basis, I have priced out the small differences using DTE's forecast for MISO market prices. I also consider the added costs for ancillary services to integrate higher levels of renewable resources on DTE's system. Based on these cost assumptions, my R / E portfolio is $339 million (13%) less expensive than the gas plant over the forecast period, as summarized in **Table ES-2** below.

Table ES-2: *Summary of R / E Portfolio Costs vs. Gas Plant (2018-2042)*

Resource	Capacity (MW)		Energy (GWh)		NPV Costs (2018-2042)		
	Nameplate	Accredited	Total GWh	Levelized GWh/year	$MM	$/MWh	$/kW-year
R/E Portfolio:							
Solar	1,100	623	39,630	1,353	$947	$67	
Wind	1,100	139	80,427	2,783	$1,468	$50	
EE @ 2%	94	94	6,436	424	$53	$12	
New DR	261	261			$115		$44
Net Market	(151)	(151)	(11,706)	(771)	($349)	($43)	
Integration			39,737	3,790	$79	$2	
Total	**2,555**	**1,107**	**114,787**	**3,790**	**$2,314**	**$58**	
Gas Plant:							
Total	**1,113**	**1,113**	**114,787**	**3,790**	**$2,653**	**$67**	
Difference: Savings from R/E Portfolio					**$339 MM or 13% NPV**		

Q: Did you do anything to verify this conclusion?

A: Yes. My conclusion that the R / E portfolio is less expensive than the gas plant is robust, as I show by examining sensitivities to important assumptions, including the gas price forecast and the capacity factor of the gas plant. The conclusion that the R / E portfolio is more economic is also substantiated by the results when the portfolio is analyzed in the Strategist model that DTE used.

Q: Are there other benefits to ratepayers from the R / E scenario you discuss in your testimony?

A: Yes. The portfolio of renewables and efficiency will provide more jobs for Michigan, as well as significant environmental and reliability benefits. The R / E portfolio generates significantly more new jobs in southeast Michigan than the proposed gas plant, by a margin of almost ten-to-one in construction jobs and four-to-one in long-term employment in ongoing operations.

The clean energy resources in the R / E portfolio also will provide significant, quantifiable benefits from reductions in the emissions of both criteria pollutants and carbon. A very conservative estimate of the benefits of the R / E portfolio from reduced costs to comply with air emission regulations is $13 million per year. The societal benefits from the R / E portfolio's lower emissions of greenhouse gases and criteria pollutants, compared to the gas plant, are much larger – $367 million per year over the 2018-2042 period from improved health and mitigating the damages of climate change. Further, large societal benefits can be realized from accelerating the retirement of the coal units, largely as a result of the substantial drop in SO_2 emissions.

Q: Is the scenario you propose more reliable than DTE's proposed gas plant?

A: Yes. A diversified portfolio of small, widely dispersed renewable generation projects is inherently more reliable than a single gas plant in one location, because the impact of an outage at an individual wind or solar unit will be far less consequential than an outage at a major central station power plant. Moreover, most electric system interruptions are the result of weather-related transmission and distribution system outages; new central station generation does not reduce this risk. However, distributed renewables, located at the point of end use and matched with on-site storage, can provide customers with an assured back-up supply of electricity for critical applications should the grid suffer any type of outage. Thus, a vibrant and growing market for distributed solar and wind resources is an important foundation piece for a more reliable and resilient grid.

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I. <u>INTRODUCTION</u>

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

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: My experience and qualifications are described in the attached *curriculum vitae* (CV), which is **Ex. ELP-58 (RTB-1)** to this testimony. As reflected in my CV, I have more than 35 years of experience on resource planning and ratemaking issues for natural gas and electric utilities. I began my career in 1981 on the staff at the California Public Utilities Commission (CPUC), working on the initial implementation of the Public Utilities Regulatory Policies Act of 1978 (PURPA). While at the CPUC, I also served as policy advisor to three commissioners, and played a central role in the restructuring of California's natural gas industry. Since leaving the Commission in 1989, I have had a private consulting practice on energy issues and have appeared, testified, or submitted testimony, studies, or reports before state regulatory commissions in more than twenty states. My CV includes a list of the formal testimony that I have sponsored in state regulatory proceedings concerning electric and gas utilities. Prior to this professional experience, I earned an undergraduate degree in English and physics from Dartmouth

College and a Master's degree in mechanical engineering from the University of California at Berkeley.

Q: Please describe more specifically your experience on resource planning and pricing issues concerning both natural gas-fired and renewable resources.

A: Throughout my career, I have represented qualifying facilities (QFs) under PURPA on a wide range of issues involving both gas-fired cogeneration projects and the full range of renewable QF technologies. This experience includes testimony on power purchase agreements and avoided cost pricing issues in state regulatory proceedings in California, Idaho, Montana, Nevada, North Carolina, Oregon, Utah, and Vermont. I also have extensive experience on natural gas transportation and pricing issues, particularly related to serving natural gas-fired power plants. I have worked extensively on public policy issues related to the development and deployment of wind and solar generation, including the issue of assessing the capacity value of these variable renewable resources. This work includes evaluating the costs and benefits of solar – both small, distributed solar systems and large, utility-scale units. In 2006-2007, I testified on cost-effectiveness and represented the solar industry in the development of the implementation details for the California Solar Initiative, California's successful ten-year incentive program for rooftop solar systems. With respect to cost-effectiveness issues concerning renewable distributed generation (DG), I have sponsored testimony on net energy metering (NEM) and solar economics in California and ten other states, and since 2013 I have co-authored benefit-cost studies of NEM or solar DG in California, Colorado, Arizona, Arkansas, New Hampshire, and North Carolina. I also co-authored the chapter on Distributed Generation Policy in *America's Power Plan*, a report on emerging energy issues, which was released in 2013 and is designed to provide policymakers with tools to address key questions concerning distributed generation resources.[1]

In the Upper Midwest, in 2014 I testified before the Minnesota commission on behalf of Geronimo Solar, LLC in support of Geronimo's winning bid to provide new solar generating capacity on Xcel Energy's Northern States Power system.[2] Geronimo won a portion of this solicitation in competition with gas-fired combined-cycle and simple-cycle generation.

Q: Have you previously testified or appeared as a witness before this Commission?

A: No, I have not.

Q: On whose behalf are you testifying in this proceeding?

A: I am appearing on behalf of Vote Solar, the Environmental Law & Policy Center, the Ecology Center, the Solar Energy Industries Association, and the Union of Concerned Scientists. Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence, and fight climate change by making solar a

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1 This report has been published in *The Electricity Journal*, Volume 26, Issue 8 (October 2013). It is also available at http://americaspowerplan.com/ .

2 See OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240. My testimony was filed September 27 and October 18, 2013.

mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local, and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. Vote Solar is not a trade group and does not have corporate members. Vote Solar has more than 70,000 members throughout the United States, including members and supporters in DTE's Michigan service territory.

Q: Are you sponsoring any exhibits?

A: Yes, I am sponsoring the following exhibits:

- Exhibit ELP-58 (RTB-1) CV of R. Thomas Beach
- Exhibit ELP-59 (RTB-2) DTE Responses to Selected Data Requests
- Exhibit ELP-60 (RTB-3) State of Michigan Demand Response Potential Study
- Exhibit ELP-61 (RTB-4) Annual Capacity Balance for the R/E Portfolio
- Exhibit ELP-62 (RTB-5) Methane Leaks from Natural Gas Infrastructure Serving Gas-fired Power Plants

II. <u>BACKGROUND</u>

A. DTE's Proposed Gas Plant

Q: Please describe briefly the new natural gas-fired combined-cycle unit that DTE has proposed.

A: DTE proposes to build a nominal 1,100 MW gas-fired combined cycle generating facility at its existing Belle River site. The capital cost for the gas plant would be $989 million, and it would enter service in June 2022.[3] The gas plant would use new, advanced, H-class gas turbines to reduce the plant's heat rate in combined-cycle operations, and would include duct burners downstream from the gas turbines to increase project output (albeit with reduced efficiency). Project costs also include $20.2 million for construction of a gas pipeline lateral to access nearby major gas pipelines plus commitments to upstream firm transportation and storage capacity, as well as $29.3 million for new electric interconnection facilities to tie into the existing electric transmission grid.[4]

B. Statutory Requirements for a Certificate of Necessity

Q: Please summarize the statutory requirements that a utility must satisfy for the Commission to grant a Certificate of Necessity (CON) for a major new generating facility.

A: Section 6(s) of 2016 PA 341 provides that an electric company that proposes to build a new generation facility that represents investment costs of more than $100 million may submit an application to this Commission seeking one or more certificates of necessity finding that the new plant is needed and its costs should be recovered through the utility's rate base. Generally, DTE bears the burden of proof to show the Commission that:

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[3] See DTE Testimony of I.M. Dimitry, at pp. IMD-21 and IMD-34, D. Swiech at p. DS-13 to DS-14, and D. O. Fahrer at pp. DOF-4 and DOF-7.

[4] See, generally, DTE Testimony of W.H. Damon, at pp. WHD-14 to WHD-16, and E.P. Weber, at pp. EPW-9 to EPW-10. The added gas lateral, transportation, and storage costs are included in the natural gas cost forecast. The electric transmission interconnection costs are not included in the gas plant's $989 million capital cost. See DTE Testimony of D. O. Fahrer at p. DOF-8.

a. [it] has **demonstrated a need** for the power that would be supplied by the proposed electric generation facility . . . through its approved integrated resource plan . . .;

b. the proposed electric generation facility will **comply with all applicable state and federal environmental standards, laws, and rules**;

c. **the estimated cost of power from the proposed electric generation facility is reasonable**;

d. the proposed electric generation facility represents **the most reasonable and prudent means of meeting the power need relative to other resource options for meeting power demand**, including energy efficiency programs, electric transmission efficiencies, and any alternative proposals submitted by existing suppliers of electric generation capacity or by other intervenors; and

e. to the extent practicable, the construction of a new facility in Michigan is completed using **a workforce composed of Michigan residents.**[5]

III. DTE'S NEED FOR NEW CAPACITY AND ASSOCIATED ENERGY

A. Coal Plant Retirements

Q: DTE's need for new capacity in the 2022-2023 time frame is driven principally by the planned retirements of aging coal units at the River Rouge (Unit 2), St. Clair (Units 1-4, 6, and 7), and Trenton Channel (Unit 9) power plants in the 2020-2023 time frame. Do you agree that these retirements are prudent?

A: Yes. Further, as I will show below, these retirements may be accelerated by one to two years, if DTE pursues the alternative resource portfolio that I present in this testimony.

[5] See MCL 460.6s(4); also, DTE Testimony of I.M. Dimitry, at pp. IMD-11 to IMD-12.

B. DTE's Long-term Commitment to Reduce Carbon Emissions

Q: In May 2017, DTE announced a long-term commitment to reduce its existing carbon emissions by 80% by 2050.[6] Do you support this goal?

A: Yes. To accomplish this goal, DTE must phase out its use of coal and add significant amounts of renewable resources that will both replace the retired coal capacity and, ultimately, also displace gas-fired generation. However, the resource plan that DTE has proposed to reach this goal heavily backloads the renewable generation additions (and the carbon reductions) into the years after 2030, with two large gas plants being built in 2023 and 2029 before most of the renewable capacity is added. The 2023 gas plant is the subject of this application. DTE's renewable additions under its proposal are shown in **Figure 1**. In comparison, the portfolio of renewable and efficiency additions that I have proposed would begin the renewable build-out in the near future, in order to take advantage of the lower-cost renewables available with the existing tax credits. The resulting build-out of renewables is shown in **Figure 2**, with the renewable build-out after 2025 reduced to reflect the renewables added from 2018-2025. In reaching DTE's carbon reduction goal, my portfolio adds new solar capacity at a more consistent pace over time, which should result in a more manageable and flexible trajectory of resource additions than what the utility has proposed.

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[6] See DTE Testimony of K.J. Chreston, at p. KJC-10 and B.J. Marietta, at p. BJM-15. DTE has modeled a 75% reduction by 2040 as an intermediate step to the 2050 goal. See pp. KJC-30, KJC-31, KJC-57, and BJM-15.

Figure 1: *DTE Renewables Additions*

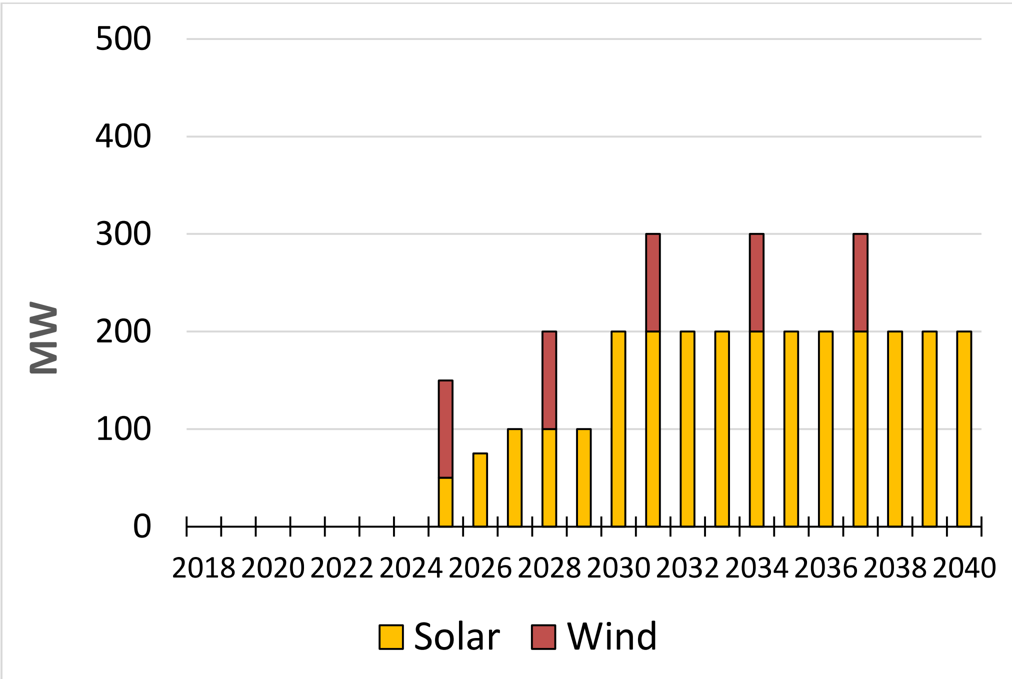
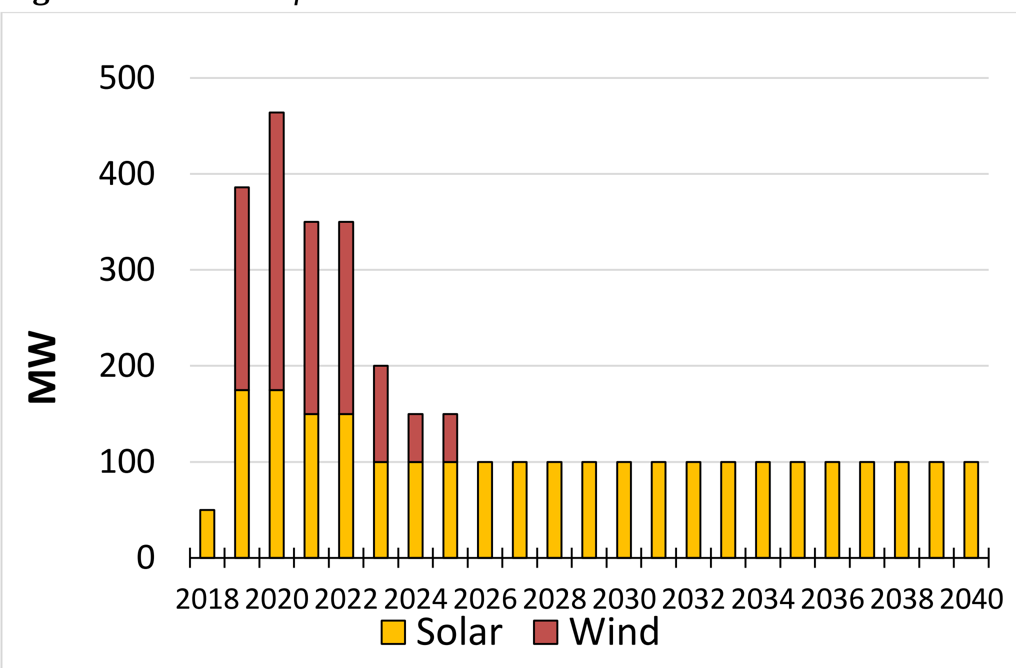


Figure 2: *R / E Portfolio – Renewables Additions*



IV. THE COMMISSION SHOULD REJECT A CON FOR DTE'S GAS PLANT

Q: Please summarize the reasons why the Commission should reject a CON for DTE's proposed gas plant.

A: There are three principal reasons for rejecting DTE's requested CON:

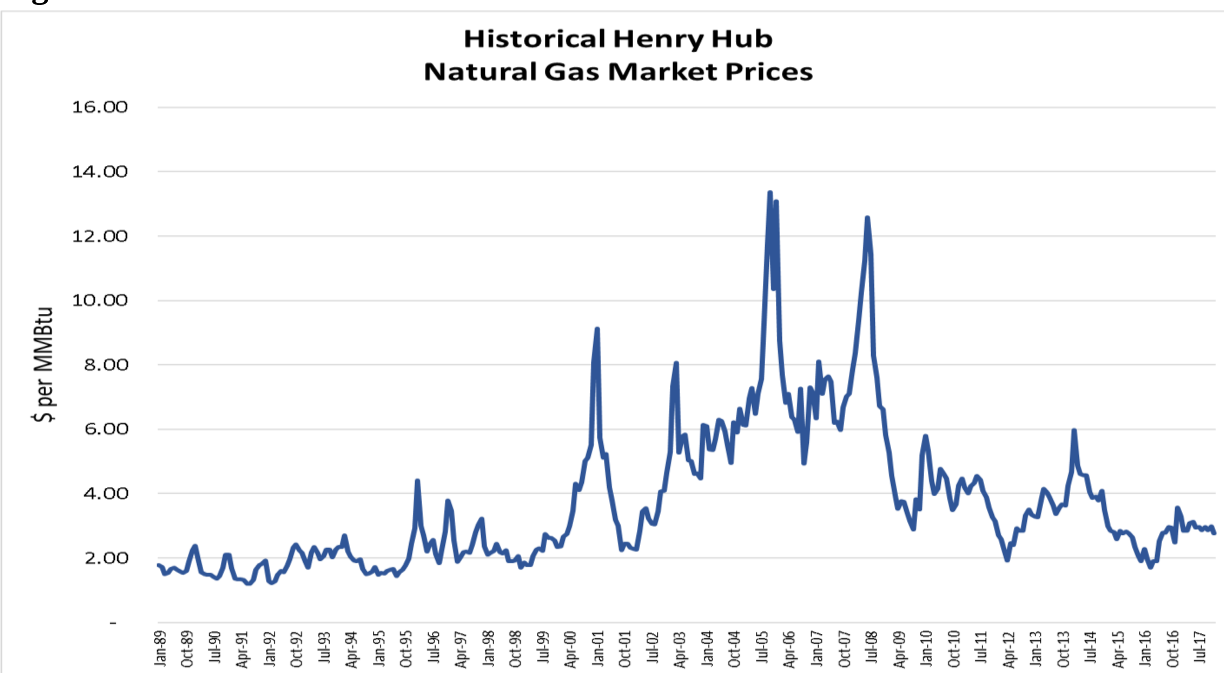
1. **The gas plant will be too expensive and too risky**. DTE has failed to explain how it will mitigate the price risks associated with a major new gas plant – in particular, the risk of significantly higher costs for ratepayers resulting from future uncertainty and volatility in the price for natural gas fuel. The costs to eliminate this uncertainty would add substantially to the gas plant's costs.
2. **A portfolio of wind, solar, and demand-side resources will be less expensive and less risky**, with costs that are lower, more certain, and less volatile than the gas plant.
3. The alternate portfolio of renewable and efficiency resources offers additional benefits compared to the gas plant:
   a. **More jobs** for Michigan,
   b. A more **reliable and resilient electric grid**, and
   c. Benefits from **reduced emissions of carbon and other criteria pollutants**.

A. The Gas Plant Will Be Too Expensive and Too Risky.

Q: What is the principal risk to ratepayers from the construction of a large gas plant?

A: The major risk is the price for the natural gas fuel, which comprises 57% of the expected levelized cost of the DTE gas plant, based on the utility's long-term gas cost forecast. However, natural gas prices are volatile and uncertain, as exemplified by the periodic spikes in natural gas prices. Such spikes have occurred regularly in the U.S. over the last several decades, as shown in the plot in **Figure 3** of historical benchmark Henry Hub gas prices.

Figure 3



Source: Natural Gas Intelligence monthly average Henry Hub prices.

The most recent major spike in natural gas prices occurred from January to March 2014 as a result of the "polar vortex" event of prolonged, very cold temperatures in the Midwestern and Eastern U.S.

Q: Is there significant uncertainty in the natural gas cost forecast that DTE has presented in this case?

A: Yes. DTE's long-term gas forecast is based on forward prices at the benchmark Henry Hub market for the next five years (2018-2022), then transitioning to a long-term forecast from Pace Global (Pace) of Henry Hub and producing basin prices. There are several issues with the forecast that DTE has used. First, DTE's reliance on more than one or two years of forward prices is questionable due to the thinly-traded forward markets after the initial two years. For example, **Table 1** shows the open interest in Henry Hub forward contracts on November 10, 2017. 99% of the open contracts are for the first two years plus one month, i.e. through calendar 2019.

Table 1*: Henry Hub Open Interest on November 13, 2017*

Period	Dec 17	2018	2019	2020	2021	2022	2023	2024	2025
Prior Day Open Interest	177,645	1,023,325	128,709	8,718	1,556	215	131	2	1
As %	13%	76%	10%	1%	0.1%	0.0%	0.0%	0.0%	0.0%

Second, other forecasts that are contemporaneous with the Pace projection are available, and are significantly higher. For example, the Energy Information Administration's *2017 Annual Energy Outlook* (*2017 AEO*) is the U.S. government's primary forecast of future natural gas prices. I have calculated the expected costs for the DTE gas plant under a sensitivity that uses current Henry Hub forward prices for 2018-2019, then transitions over four years to the *2017 AEO* forecast. I note that the Commission recently adopted the use of EIA's regional 2017 forecast of delivered natural gas prices for use in setting the long-term avoided costs for Consumers Energy.[7] This sensitivity increases the levelized cost of power from the gas plant by 15%, from $67 to $76 per MWh.

Q: You have noted that natural gas prices are uncertain and volatile. Can you quantify the additional cost to DTE's ratepayers that results from this uncertainty and volatility?

A: Yes, I can. The cost to ratepayers of the uncertainty and volatility in future natural gas prices is the additional cost that the utility would incur today to fix the price of natural gas for the gas plant over the planning horizon, thus eliminating all uncertainty and volatility in the new plant's cost of natural gas.

Q: How could you fix the price of the plant's future gas supplies?

A: One could contract today for future natural gas supplies at today's forward gas prices, and then set aside in risk-free investments (U.S. Treasury notes) the money needed to buy that gas in the future. This would eliminate from the outset the uncertainty in future gas costs. However, there is an additional cost of this approach, compared to purchasing gas on an "as you go" basis over time and using the money that did not have to be set aside for alternative investments that yield a higher return, which I assume to be the utility's

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[7] See Order dated November 21, 2017 in Case No. U-18090, at pp. 25-26. In that case, the utility recommended using a short-term forecast based on forward market prices, escalated using the year-to-year change in the 2017 EIA forecast; see p. 13.

weighted average cost of capital (WACC). This difference between returns at the utility's WACC and risk-free returns on U.S. Treasuries is the measure of the future market risks of purchasing natural gas on an as-you-go basis versus fixing the gas price upfront. The added cost of foregoing these higher returns is the cost to ratepayers of eliminating fuel price uncertainty, or, conversely, the benefit to ratepayers when they displace natural gas with renewables whose fuel is free and whose costs are more certain upfront. Avoiding the cost of fuel price uncertainty is a significant benefit provided by an alternative portfolio of renewables and efficiency which replaces the natural gas that would fuel the gas plant.

Q: Have you calculated the cost of fuel price uncertainty for the proposed gas plant?

A: Yes, I have, for the first twenty years of the plant's operations. The key inputs to this calculation are (1) the commodity portion of DTE's base gas cost forecast (i.e. the portion of DTE's gas costs that are subject to market uncertainty), (2) U.S. Treasuries at current yields (as the cost of risk-free investments), (3) DTE's WACC (as the return that could be realized if the money were not spent fixing the cost of gas), and (4) the gas plant's heat rate of 6,300 Btu per kWh (to express the results in dollars per MWh of generation). This calculation follows the methodology used in the *Maine Distributed Solar Valuation Study*, a 2015 study commissioned by the Maine Public Utilities Commission and authored by Clean Power Research that estimated the benefits to Maine of new renewable resources that displace gas-fired generation.[8] The benefits calculated in the Maine study included the reduction in the cost of fuel price uncertainty when renewable generation displaces natural gas.

For the proposed DTE gas plant, the result of this calculation is that the cost to DTE's ratepayers of eliminating the fuel price uncertainty in DTE's gas plant is an additional $17 per MWh, or $86 million per year, over the 2023-2042 period. Consideration of this factor increases the costs of the gas plant by 25%.

Q: Please comment on DTE's testimony that it intends to structure its gas supply contracts "to minimize price volatility."[9]

A: In discovery, we questioned DTE on how it planned to reduce volatility in its gas commodity costs. In response, DTE said that it will "consider long-term, fixed price gas supply contracts" to achieve this.[10] However, the utility has not executed any such contracts, and does not provide any details on the volume or term of such contracts or on whether such contracts would add costs.[11] DTE provided examples of its existing forward gas contracts, but these do not extend more than three years into the future and

[8] The Maine study is available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.
[9] DTE Testimony of D. Swiech, at p. DS-8.
[10] See DTE response to ELPCDE-1.41a, included in Exhibit RTB-2.
[11] See DTE response to ELPCDE-1.41b-d, included in Exhibit RTB-2.

do not have fixed prices.[12]

Q: Is there also uncertainty in other elements of DTE's natural gas cost forecast?

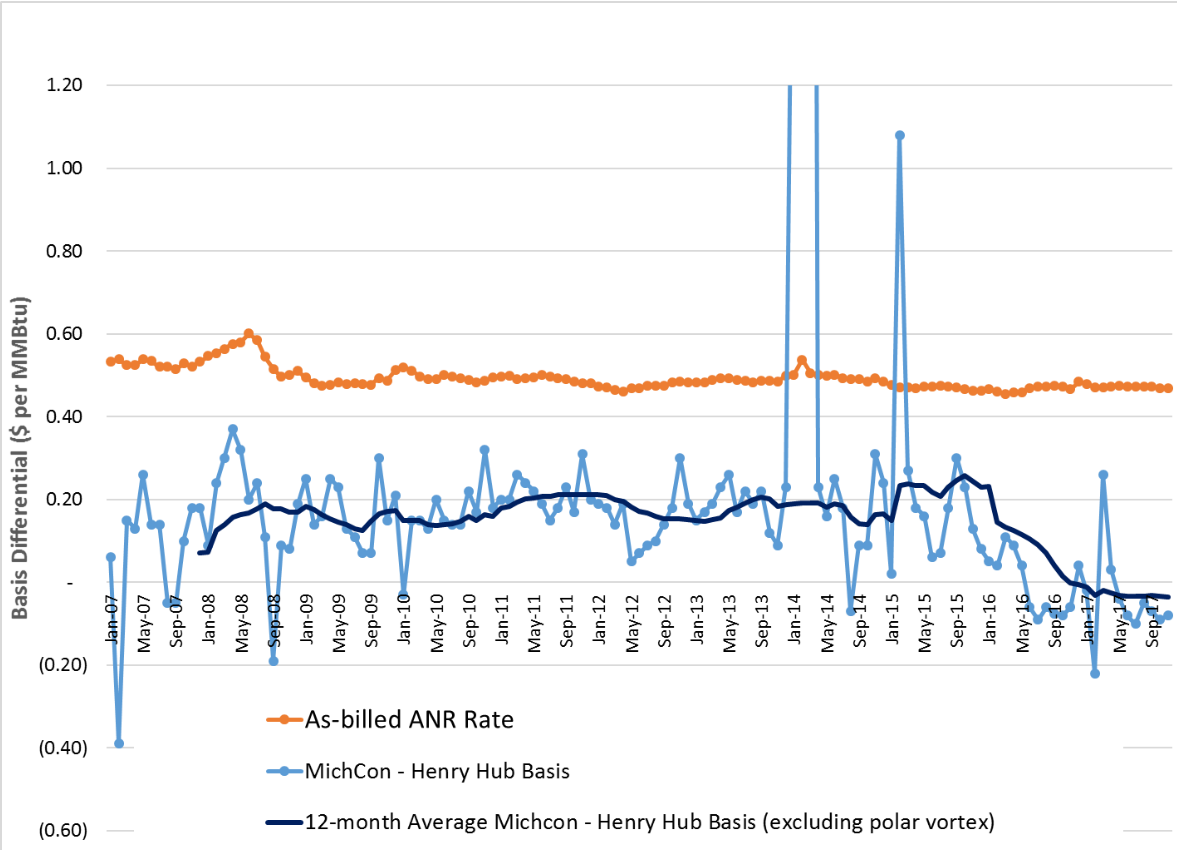
A: Yes. The utility projects that the price differential, or "basis," between the benchmark Henry Hub market and the nearest market hub, the Michcon City-gate, will be a negative -$0.13 per MMBtu (i.e. the Michcon City-gate will have a lower price) in 2023. This basis is taken from a sample of the gas forward markets on just one day – May 10, 2017.[13] DTE expects this basis to escalate over the long-term at the rate of inflation, i.e. to become more negative.

Q: How does the Henry Hub / Michcon City-gate basis that DTE has used compare with the historical record on this basis?

A: The -$0.13 per MMBtu basis that DTE assumes is significantly lower than the basis typically experienced in the market over the last 10 years, as shown in **Figure 5**.

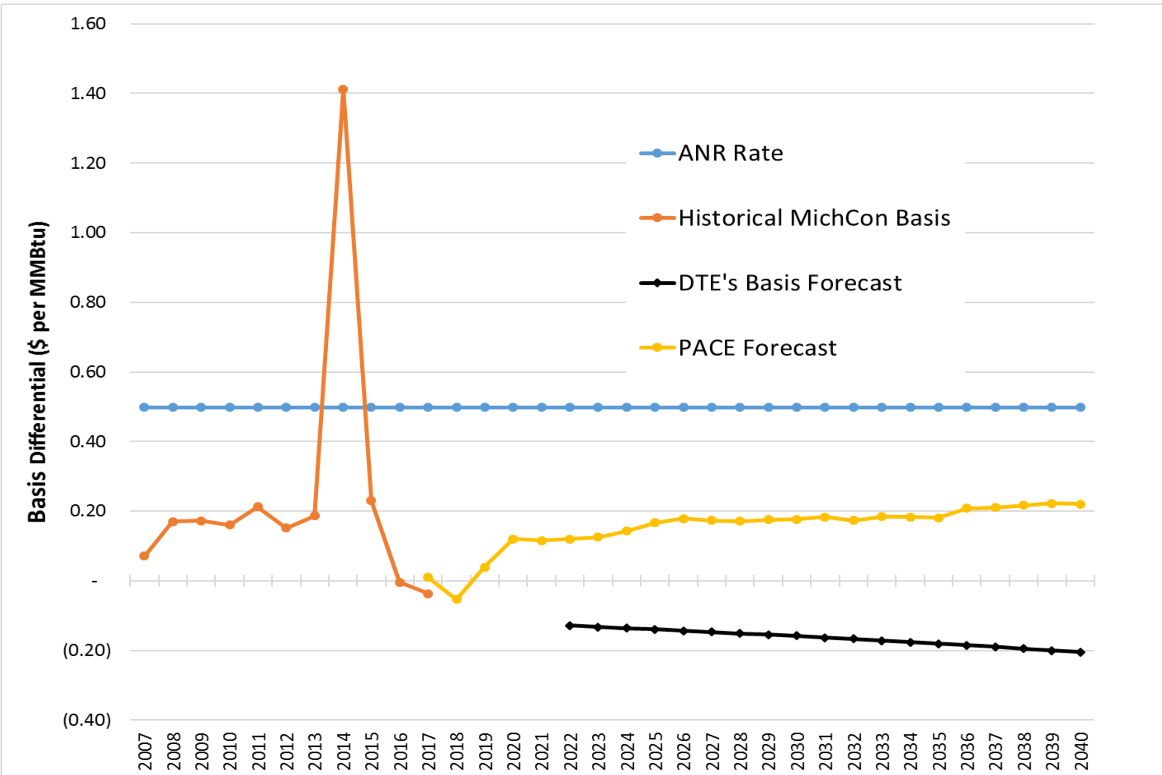
[12] See DTE response to ELPCDE-1.42a-b, included in Exhibit RTB-2.
[13] See DTE response to ELPCDE-2.4b, included in Exhibit RTB-2.

Figure 5: *Michcon City-gate to Henry Hub Basis Differential ($/MMBtu)*



DTE's gas cost forecast is thus too low if the increasing demand for natural gas in the Upper Midwest results in a return to the higher basis differentials seen in prior years. For example, over the last ten years not including 2014 (which featured the very high basis during the polar vortex event of January - March 2014), the Henry Hub / Michcon City-gate basis has averaged a positive +$0.13 per MMBtu. DTE's long-term gas fundamentals forecast from Pace Global projects a similar positive basis differential going forward to 2040, as shown in **Figure 6**. DTE ignored the PACE forecast in favor of the very low, one-time value from May 10, 2017.[14] The use of this higher basis would increase the cost of the gas plant by 3%.

Figure 6: *Michcon City-Gate to Henry Hub Past & Forward Basis ($ per MMBtu)*



Q: Are there new pipelines planned to serve southeast Michigan that might bring new gas supplies into the area?

A: Yes. DTE has entered into a precedent agreement for 30,000 to 75,000 Dth per day of pipeline capacity on the new NEXUS pipeline that would provide a new pipeline route connecting southeastern Michigan to the Marcellus and Utica Shale producing basins in

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[14] DTE admits that it did not use the Pace forecast for the Henry Hub – Michcon basis in its response to ELPCDE-2.4h, included as Exhibit RTB-2.

western Pennsylvania and Ohio. The higher amount of pipeline capacity (75,000 Dth per day) is contingent on DTE's operation of new gas-fired generating facilities, i.e. on the completion of the new gas plant.[15]

Q: How does DTE's commitment to NEXUS impact the risks of the gas plant for ratepayers?

A: As noted above, the new gas supplies from NEXUS may offset the upward pressure on the market basis that could result from the incremental demand from new gas-fired generation facilities such as the gas plant. However, the fact the DTE is likely to hold capacity on NEXUS increases the risks that the gas plant will result in above-market transportation costs for DTE's ratepayers, costs that are not included in DTE's gas forecast. Due to the NEXUS commitment, DTE's ratepayers are not just exposed to the risks of the volatility and uncertainty of the gas commodity market; they also are exposed to the risks of the markets for pipeline capacity in the region – specifically, the risk of whether new pipeline capacity from Michigan to western Pennsylvania and Ohio will be economic. NEXUS capacity is only economic if the basis differential between (1) southeast Michigan (at the Michcon City-gate or Dawn markets) and (2) the Marcellus/Utica basins is greater than the full cost of transportation on NEXUS, including the reservation charges that DTE will pay. This full cost is expected to be

[15] The higher amount of capacity would become effective upon the in-service date of a combined cycle plant with at least 680 MW of capacity and a 70% capacity factor, conditions which are satisfied by DTE's proposed gas plant. See DTE response to ELPCDE-1.36, included in Exhibit RTB-2.

$0.695 per Dth plus 1.32% fuel,[16] or a total of $0.75 per Dth assuming a $4 per MMBtu cost of fuel. If the Marcellus-to-Michcon City-gate basis is less than the full cost of NEXUS capacity, these new supplies will not be economic in DTE's service territory.

Q: In discovery, DTE provided a 3Q 2017 forecast from ICF which projects that the price of Marcellus gas in southwest Pennsylvania (presumably at the Dominion South hub) will be $0.90 to $1.45 per MMBtu less than the Henry Hub, throughout the period from 2018-2038.[17] Do you think that this forecast is realistic?

A: No. It is well-known and often-observed in the natural gas industry that the addition of new pipeline capacity to a growing producing basin tends to collapse the basis differential between the basin and the consuming markets at the downstream end of the new pipeline.[18] Once the cumulative pipeline capacity from a basin exceeds the production in the basin, competition will reduce the market value of pipeline capacity from the basin to a fraction of the full, "as-billed" rate for firm pipeline capacity to the basin.[19] Such a "basis collapse" has been observed repeatedly in North American producing basins that have grown rapidly for past boom periods, such as the San Juan basin in New Mexico, the Rocky Mountain region, and the Western Canadian

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[16] See DTE response to ELPCDE-1.37, included in Exhibit RTB-2.

[17] See DTE response to ELPCDE-1.40.

[18] DTE agrees that the addition of the Rover and NEXUS would reduce the basis differential between the Marcellus and the Michcon City-gate. See DTE response to ELPCDE-2.2.

[19] The fact that basis differentials tend to be much less than the full pipeline rate on unconstrained routes is shown in both Figures 5 and 6. Both figures compare the basis from the Michcon City-gate to the Henry Hub versus the full as-billed rate on the ANR pipeline that connects these two markets.

Sedimentary Basin. As just one example of many, the basis differential from the Rocky Mountain supply region to the Henry Hub declined from $2 to $3 per MMBtu in 2007-2008 to just $0.11 per MMBtu over the last six years (2012-2017), as a result of pipeline expansions completed out of the Rockies to both eastern and western markets.[20]

Q: What accounts for this propensity for pipeline expansions to exceed the production capacity of the producing basins which they access?

A: The regulatory structure and incentives for new interstate gas pipelines encourages pipeline developers to overbuild pipeline capacity to new and growing producing basins. These factors include:

- The FERC's longstanding **market-based policies for certificating new pipelines** do not require project proponents to demonstrate a need for the new capacity; instead, they can show significant market interest (for example, from executed precedent agreements) for the pipeline's capacity and must be willing to bear the risk of subscribing that capacity.
- In the gas industry, there are **no regional bodies responsible for planning** and rationalizing the amount of pipeline capacity built to a region with growing gas production. This differs from much of the nation's electric system, where there are regional transmission organizations (RTOs) with responsibility for planning and determining the need for new bulk electric transmission.

[20] Based on *Natural Gas Intelligence* monthly average gas prices from the Opal, Wyoming market center and the Henry Hub.

- Pipeline developers can **market capacity to both ends of the pipe** – on one hand to utilities and end use customers who may not have a full understanding of the economics of producing gas in the new, rapidly-growing basin, and on the other hand to producers who seek downstream market access but may lack firm customers or a firm knowledge of the likely future demand for gas in the consuming market. The result of this information asymmetry at both ends of the pipeline can be the oversubscription and overbuilding of pipeline capacity.
- The FERC has granted **attractive returns** in the neighborhood of 14% as the basis for the recourse rates of new interstate pipelines. Such returns significantly exceed those available to regulated utilities, which has attracted the unregulated affiliates of utilities to participate as partners in the new pipeline projects serving their utility affiliates. This equity involvement by the utility affiliate raises the concern that this financial interest in the success of the pipeline project may cause the utility to overcommit to the new capacity or not to adequately analyze the alternatives to their gas-fired generation resources that would be an "anchor" market for the new capacity.

This propensity to overbuild capacity to fast-growing basins is widely acknowledged in the natural gas industry. The CEO of Energy Transfer Partners, a major pipeline company, commented recently that "the pipeline business will overbuild until the end of time."[21]

Q: Are there more pipelines proposed to be built out of the Marcellus and Utica basins than the expected production capacity of these basins?

A: Yes. A number of studies, from sources as diverse as Moody's Investor Services (2014), Bloomberg New Energy Finance (2016), and Oil Change International (2016), have projected that pipeline takeaway capacity from the Marcellus and Utica basins will begin to significantly exceed the basins' production in 2018-2019.[22]

Q: Your final factor that contributes to pipeline overbuilding is the participation of utility affiliates as developers of new pipelines. Is this factor – the potential for a conflict of interest between DTE's affiliates and DTE's ratepayers – a particular concern in this case?

A: Yes, it is, because an unregulated affiliate of DTE is one of the sponsors of the NEXUS project.

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[21] Kelcy Warren, CEO of Energy Transfer Partners, in the second quarter 2015 earnings call, August 15, 2015.

[22] These results are reported in the Institute for Energy Economics and Financial Analysis's report *Risks Associated with Natural Gas Pipeline Expansion in Appalachia* (April 2016), at pp. 10-12. Available at http://ieefa.org/wp-content/uploads/2016/04/Risks-Associated-With-Natural-Gas-Pipeline-Expansion-in-Appalachia-_April-2016.pdf.

Q: If the long-term value of NEXUS capacity is 50% of the pipeline's full as-billed rate, how much would that increase the gas costs for the new gas plant?

A: The above-market pipeline costs of NEXUS would increase the gas plant's fuel costs by about $0.37 per MMBtu, resulting in a 5% increase in the gas plant's overall costs.

Q: Has this Commission approved DTE's cost recovery for its subscription to NEXUS capacity?

A: No, it has not. In its decision in DTE's 2016 and 2017 fuel cost recovery dockets, the Commission stated that its approval of fuel expenses in those cases specifically did not include recovery of any costs associated with the NEXUS project.[23]

Q: Does DTE specifically ask for approval of the NEXUS capacity subscription in its request in this case?

A: No. My understanding of the scope of DTE's request in this docket is that it is limited to a Certificate of Necessity for the gas plant, including the gas pipeline lateral that would interconnect the plant to existing nearby large-diameter gas transmission lines,[24] but not for any upstream interstate pipeline capacity such as the NEXUS commitment.

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[23] See the Commission's January 12, 2017 order in Case No. U-17920 and December 20, 2017 order in Case No. U-18143, at pp. 7-9. Also see DTE response to ELPCDE-7.14, included in Exhibit RTB-2, stating that in September 2017 DTE filed its 2018 PSCR Plan (Case No. U-18403), requesting Commission review and approval of the expenses associated with DTE Electric's agreements with NEXUS. See also DTE Testimony of D. Swiech, at pp. DS-7 to 8 and DS-13 to 14.

[24] DTE Testimony of D. Swiech, at p. DS-14.

Q: Please summarize the cumulative impact of all of the risks you have discussed and quantified on the overall costs for the DTE gas plant.

A: **Table 2** presents the quantifiable impacts of these risks, which together could increase the 20-year levelized costs of the gas plant from 2023-2042 by as much as 47%. Not all of these impacts may materialize; however, there is a significant potential for the gas plant's costs to be much higher than DTE has estimated.

Table 2: *Quantifiable Risks Impacting Gas Plant Costs*

Base Gas Plant Costs	**Cost (20-year levelized)** *$ per MWh*	
Capital revenue requirement	30.30	
Base fuel costs (DTE forecast)	36.40	
Total	**66.70**	
Risk Factors Impacting Gas Plant Fuel Costs	**Cost Change (20-year levelized)**	
	$ per MWh	*%*
Revised Henry Hub forecast	9	15%
Fuel price volatility	17	25%
Higher basis	2	3%
Above-market cost of NEXUS capacity	4	5%
Total	**32**	**47%**
Revised Gas Plant Costs	**$98 per MWh**	

Q: Table 2 shows that the gas plant's levelized costs from 2023-2042 are $67 per MWh. You have discussed above the issues associated with the plant' fuel costs. Do you accept DTE's estimates for the capital and O&M costs, and the modeled annual output, of the gas plant?

A: Yes, I do. However, I have several reservations about the utility's showing on the costs and expected output for the proposed gas plant. First, DTE's Strategist model does not isolate the revenue requirements for the proposed gas plant from additional gas units that the model selects in years after 2023, or from other capital additions from 2018-2022. In discovery, DTE declined to provide the revenue requirements for the gas plant alone.[25] In this application, DTE is requesting a CON only for the gas plant to come online in 2022, not for additional units further in the future. Thus, DTE should bear the burden to identify clearly the ratepayer costs for the plant for which they are requesting approval. I have attempted to calculate the revenue requirements for the 2022 gas plant alone using the same model that I used to calculate the levelized costs for the wind and solar resources; however, this model may understate the gas plant's costs because it does not include a full representation of ratepayer costs during the construction process.

Second, DTE is proposing to use a new class of advanced gas turbines, for which there is little operating experience to date. DTE is proposing a 1.1 GW plant, when only 8 GW of similar turbines have been developed.[26] DTE's witness Mr. Damon asserts that large frame combined cycle generating stations operating today have a typical availability of over 87% based on 2011-2015 data.[27] However, it is unclear whether this availability is based on the very limited operating history of this new class of turbines, because the 2011-2015 period that Mr. Damon cites appears to predate the first installations of this new class of turbines. Mr. Damon cites just one project in Oklahoma that became

[25] See DTE response to ELPCDE-3.8.
[26] See DTE Testimony of D.O. Fahrer, at p. DOF-9.
[27] DTE Testimony of W.H. Damon, at p. WHD-15.

operational in May 2017, as well as two projects in Texas that "recently completed commercial startup and commissioning operation."[28] In discovery, the utility, citing confidentiality, did not make available the operating data supporting the asserted 87% availability for this class of turbines.[29]

B. A Portfolio of Renewables and Efficiency Resources Provides the Same Capacity as the Gas Plant, and Will be Less Expensive and Less Risky.

1. The R / E Portfolio – capacity and output

Q: Please describe the alternative portfolio that you believe would be superior to the proposed gas plant, in terms of both costs and risks.

A: A superior alternative to the gas plant would be a portfolio of 2,200 MW of new renewable generation sited in Michigan, plus additional capacity and energy savings from cost-effective expansions of DTE's energy efficiency (EE) and demand response (DR) programs. This renewables / efficiency (R / E) portfolio has four major elements:

1. 1,100 MW (nameplate) of new solar generation, including:
   - 200 MW of distributed solar
   - 300 MW of utility-scale fixed-tilt systems
   - 600 MW of utility-scale tracking arrays
2. 1,100 MW (nameplate) of new wind projects
3. Increase DTE's EE target to 2.0% load reductions per year, from DTE's planned 1.5% per year.
4. Add 251 MW of incremental demand response capacity by 2023, based on 50% of the Realistic Low potential in the new *State of Michigan DR Potential Study*.

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28 *Ibid*., at p. WHD-20.
29 See DTE response to ELPCDE-3.11a and 3.11b, included in Exhibit RTB-2.

Q: Please explain how you have calculated the capacity which the R / E Portfolio would provide to DTE.

A: **Solar.** I have calculated the accredited capacity value of the 1,100 MW of new solar capacity. The capacity value of solar resources is less than its nameplate capacity, because solar will not be producing at full nameplate during the summer afternoon hours when demand peaks. I use the National Renewable Energy Laboratory's (NREL) PVWATTS tool to calculate the average hourly profiles of fixed and single-axis tracking arrays at several locations in southeast Michigan.[30] The accredited capacity for such these solar output profiles, as a percentage of nameplate capacity, is based on the methodology adopted by the Midcontinent Independent System Operator (MISO).[31] The MISO's rules for resource adequacy (RA) establish that the solar capacity value is the capacity factor of solar facilities from hour ending (HE) 3 p.m. to 5 p.m. Eastern Standard Time in June, July, and August, with a default of 50% of nameplate until actual output is available. Using this rule for the accreditation of solar capacity, I calculate that

[30] See http://pvwatts.nrel.gov/. In running PVWATTS, I assume an inverter loading ratio (ILR) – used to convert the DC output capacity of the solar array to a nameplate AC capacity – of 1.2 for fixed arrays and 1.3 for tracking systems. The higher ILR for tracking arrays produces a "flatter" output profile across a broader set of daylight hours, thus increasing the capacity value of the array based on the MISO accreditation criteria. There is a trend in utility-scale solar facilities toward the use of tracking systems with higher ILRs to achieve higher capacity values. See Lawrence Berkeley National Laboratory (LBNL), *Utility-scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (September 2017), at pp. 12-13, available at https://emp.lbl.gov/publications/utility-scale-solar-2016-empirical (hereafter, "*Utility-scale Solar 2016*"). Also see Footnote 25 below on the Aurora project in Minnesota.

[31] See MISO Business Practice Manual BPM-011-r16, Section 4.2.3.4.1.

the capacity value of solar facilities in southeastern Michigan will be 49% of nameplate for fixed arrays and 63% of nameplate for single-axis trackers.[32]

Wind. The hourly output profile of these resources is from NREL's System Advisor Model for wind resources.[33] I then used MISO's rules to determine the accredited capacity value of the 1,100 MW of wind resources in my R / E portfolio. As a base case, I use a capacity value of 12.6% of nameplate for MISO Zone 7, from MISO's most recent study of wind capacity value across its footprint. As an alternative to this value, the MISO system-wide average capacity value for wind resources is 15.6% of nameplate.[34]

Energy Efficiency. My portfolio assumes that cost-effective EE programs will achieve a 2% per year reduction in energy use, which is 0.5% per year more than DTE now plans. These incremental EE resources primarily reduce energy use, but DTE's modeling of this assumption from its *2016 Integrated Resource Plan* (*2016 IRP)* also shows that this incremental EE results in a 90 MW lower need for coincident peak capacity.[35]

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[32] Geronimo Solar's Aurora project in Minnesota is an example of the prior application of the MISO capacity accreditation method to a solar project in the Upper Midwest that was designed primarily as a capacity resource. The Aurora project uses an ILR of 1.3 and tracking arrays at multiple distributed sites across the Northern States Power system to achieve a capacity value of 71% of nameplate.

[33] See https://sam.nrel.gov/. I used SAM to model a wind farm in eastern Michigan with 2 MW turbines.

[34] See MISO, *Planning Year 2017-2018 Wind Capacity Credit* (December 2016), at pp. 4 and 14.

[35] See DTE Testimony of K. L. Bilyeu, workpapers for his Tables 7 and 8.

Demand response. 2016 legislation required the Commission to conduct an assessment of the potential use of demand response (DR) in Michigan for use as an input into integrated resource plan modeling scenarios.[36] The Commission recently released this new study of the demand response potential in Michigan.[37] The Commission's report shows that significant additional cost-effective capacity reductions from DR are achievable in Lower Michigan, particularly from various types of time- and demand-sensitive rates. This "realistic achievable" DR potential for Lower Michigan is summarized in Table 5-2 of the study, reproduced below:

Table 5-2 Overall Potential Results – Nominal and as a Percent of Baseline

Potential Case	2018	2019	2020	2023	2037
Potential Forecasts (MW)					
Realistic Achievable - High	849	1,179	1,706	2,017	2,214
Realistic Achievable - Low	265	520	991	1,255	1,339
Potential Savings (% of baseline)					
Realistic Achievable - High	3.8%	5.3%	7.7%	9.0%	9.7%
Realistic Achievable - Low	1.2%	2.3%	4.4%	5.6%	5.8%

In contrast, DTE's application includes about 100 MW less DR capacity than included in the last *IRP*, based on declining participation in DR programs. DTE does not appear to have assessed whether these participation rates could be improved. Furthermore, the utility's DR projections do not include the incremental reductions in peak loads that are achievable through new rate and tariff structures such as Time-of-Use (TOU), Critical

36 2016 PA 341 Sec. 6t.

37 See *State of Michigan Demand Response Potential Study*, released September 29, 2017. Available at http://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406250--,00.html. Hereafter, "*Michigan DR Potential Study*." This report is included as Exhibit **RTB-3**.

Peak (CPP), and Real-Time (RT) rates. My portfolio assumes that DTE could expand its existing DR programs, with cost savings for its ratepayers, by just 50% of the "Realistic Low" potential identified in the *Michigan DR Potential Study*.[38] This modest addition to DTE's DR programs would add 251 MW of capacity by 2023.

Q: Please summarize the capacity that your R/E portfolio would add by 2023.

A: **Table 3** summarizes the capacity that my R / E portfolio would add to the DTE system, showing that it would add an amount of capacity comparable to the proposed gas plant.

Table 3: *Renewables / Efficiency Portfolio*

New renewable generation	**Nameplate (MW)**	**MISO RA Criteria (%)**	**RA Capacity (MW)**
Solar – fixed array	500	49%	242
Solar – tracking	600	63%	372
Wind	1,100	12.6%	139
Incremental load reductions	**Load reduction (MW)**	**Reserve Margin @ 4% (MW)**	**RA Capacity (MW)**
2% per year EE	90	4	94
Demand response	251	10	261
Portfolio Total (MW)			**1,107**
Gas plant			***1,113***

Q: What would be the timing of the capacity additions from the R/E portfolio?

A: The R / E portfolio would begin to add significant new wind and solar capacity immediately, in 2019, in order to take advantage of the existing federal tax credits for wind and solar projects. This reduces the cost of the R / E portfolio. In addition, the

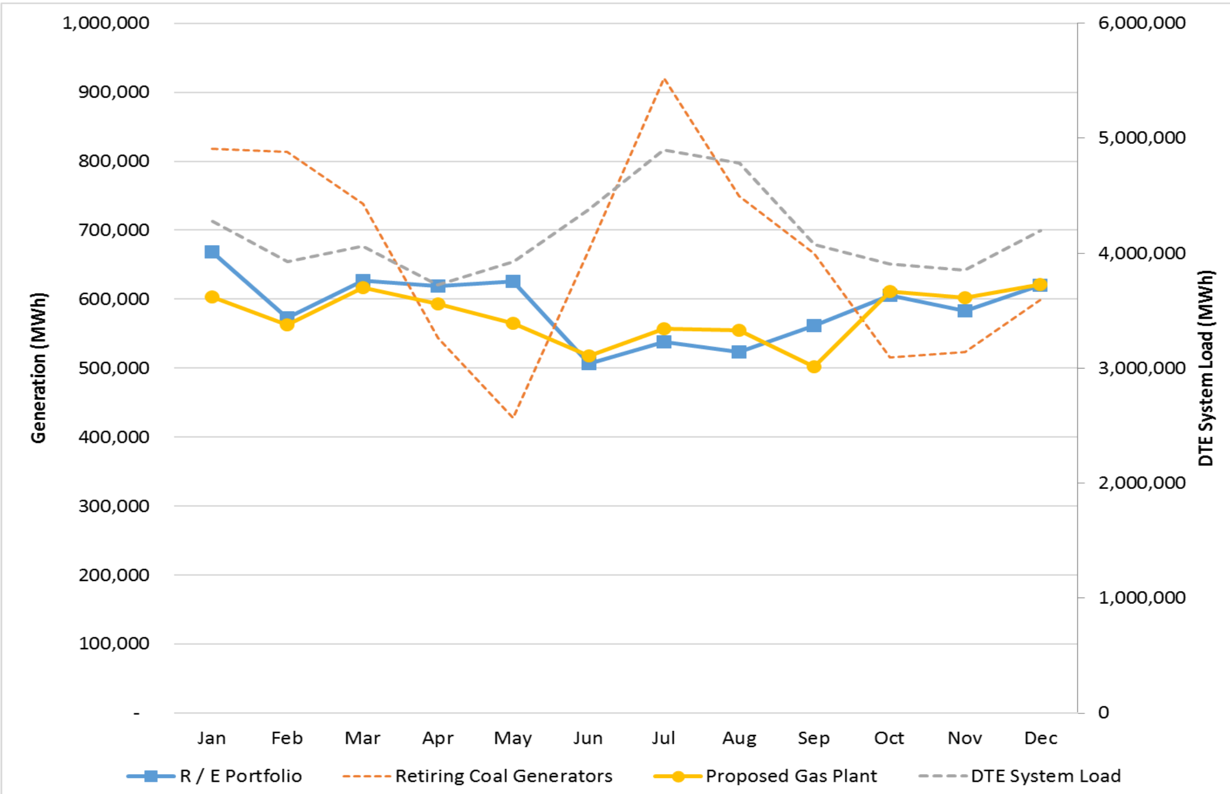
[38] Thus, I take 50% of the percentages shown in the last line of Table 5-2, and apply these percentages to DTE's expected peak demands in these years.

near-term procurement of renewable generation spreads out over more than 20 years the acquisition of new renewables – particularly the solar capacity – needed to meet DTE's long-term carbon reduction goal, rather than backloading the acquisition of most renewable capacity into the 2030-2040 decade. This more measured and consistent procurement of renewables will provide DTE with more flexibility to meet its long-term goal. The near-term acquisition of renewables also will supply DTE with new capacity before 2022-2023 that could allow DTE to accelerate the retirement of its coal plants before the schedule DTE proposes in its application. Finally, as discussed in the next section, this early procurement of new renewable capacity results in lower costs and reduced risks for DTE ratepayers. I include as **Ex. ELP-61 (RTB-4)** a chart of the annual capacity balance for the R/E portfolio that can be compared to the capacity balances that DTE provides for its 2016 and 2017 reference scenarios.

Q: DTE has proposed a gas plant that would operate initially at a capacity factor of approximately 71% to replace coal plants that historically have operated at capacity factors of 38% to 52%. Solar and wind capacity factors are lower – about 40% for wind and 20% for solar – and vary seasonally. Would the R / E portfolio you have proposed have a similar generation profile as the gas plant?

A: Yes, it would. In terms of monthly and seasonal output, **Figure 7** shows the expected outputs of the gas plant (solid yellow line) in the first year of operation and the R / E portfolio (solid blue line) when its capacity is fully in place. The R / E portfolio includes the expected monthly energy savings from the incremental EE programs that I propose. The figure also shows the profiles of DTE's system load (gray dashes) and the coal plants that will be retiring by 2023 (orange dots). The R / E portfolio provides the same capacity as the gas plant, with a monthly profile of energy production that is very similar to the expected output of the gas plant. Small amounts of sales into or purchases from the MISO energy market can be used to match the gas plant's output exactly, and I have included such sales or purchases in the costs of the R/ E portfolio. I have also compared the expected hourly output profiles for the gas plant and the R / E portfolio over an annual period, and have adjusted the costs of the market sales or purchases used to balance the two portfolios based on the market value of the small differences in the expected hourly profiles for the two portfolios.

Figure 7: *Monthly Profiles of the Gas Plant and the R / E Portfolio*



2. Costs of the R / E Portfolio

Q: Please discuss the basic strategy that you employ to develop an R / E portfolio that is less expensive than the proposed gas plant.

A: My approach to designing the R / E portfolio is, first, to leverage the existing (and expiring) wind and solar tax credits with an early build-out of renewables that takes advantage of these credits. Second, I develop incremental energy efficiency and demand response resources in a measured way that is both feasible and more cost-effective than the gas plant. As noted above, the R / E portfolio provides the same capacity as the gas plant and comparable amounts of energy. The early procurement of additional capacity also provides the flexibility to accelerate the retirement of the coal plants that DTE proposes to close by 2023, should that be desirable.

Q: What are the key assumptions that you used to calculate the costs of new solar generation in southeast Michigan?

A: I used reported capital costs through 2016 from Lawrence Berkeley National Laboratory's (LBNL) 2017 reports on actual utility-scale and distributed commercial solar costs in the U.S.[39] I extended this actual cost data to 2017-2022 using the changes in solar costs over this period from a recent forecast prepared by Wood Mackenzie's Greentech Media in conjunction with the Solar Energy Industries Association (GTM/SEIA).[40] These capital cost assumptions are shown in **Table 5** below.

[39] See LBNL, *Utility-scale Solar 2016*, at p. 20, and LBNL, *Tracking the Sun X* (August 2017), at p. 41, available at https://emp.lbl.gov/publications/tracking-sun-10-installed-price.

[40] See GTM Research, *PV System Pricing H1 2017: Breakdowns and Forecasts* (June 2017), at 7, 34, 41, and 43, available at https://www.greentechmedia.com/research/report/pv-system-pricing-h1-2017#gs.tHjJR6c. As discussed in LBNL, *Utility-scale Solar 2016*, at p. 20, LBNL uses a "top down" cost reporting methodology that is more comprehensive than GTM's "bottom up" approach to costing and forecasting. To compensate for the possible costs that are not captured in GTM's forecasts, we have increased GTM's forecasts in all years by the observed ratios of LBNL's 2016 reported costs to GTM's 2016 reported costs.

Q: Why did you not use the same forecast of solar costs that DTE employed?

A: DTE's testimony states that it used a forecast of utility-scale solar costs from Navigant Consulting's confidential report *U.S. Distributed Renewables Deployment Forecast*.[41] This forecast should not be given any weight, for the following reasons:

- The forecast was published in the second quarter of 2016, and thus is far older than the more recent data from LBNL and GTM/SEIA that I used.

[redacted]

[41] I obtained this report in response to data request ELPCDE-1.28.

[redacted]

The testimony of Mr. Kevin Lucas for the Solar Energy Industries Association, Environmental Law & Policy Center, the Ecology Center, Vote Solar, and the Union of Concerned Scientists provides a more detailed discussion of the problems with the Navigant forecast and the other projections of renewable costs that DTE has used for various modeling exercises relevant to this case.

[redacted]

Q: On Friday, September 22, 2017, the U.S. International Trade Commission (ITC) voted to approve a finding that imports of cheap solar panels have caused injury to domestic solar manufacturers. Did you adjust your forecast to incorporate the possible impact of the trade case on the cost of solar panels and cells?

A: Yes. The four members of the ITC have proposed a range of remedies, in terms of tariffs that would apply for up to the next four years (assumed to be 2018-2021). I have assumed that the remedy that the Administration ultimately adopts will be the remedy suggested by two of the four commissioners – a new tariff on solar imports starting at 30% of module costs in 2018, and declining by 5% in each of the next three years. The Administration has until January 2018 to decide on a final policy. I have applied the expected tariff to increase the assumed cost of modules in my forecast of solar costs from 2018-2021, even though there are reports that solar companies have been stockpiling modules and some imports may be exempt from the tariff. Further, the history of similar tariffs on imports suggests that any adopted tariff may be in place for less than four years, due to retaliation from foreign countries that manufacture panels or as a result of legal action before the World Trade Organization, both of which could lead to reductions or removal of any tariffs that the U.S. adopts. For this reason, I believe that my forecast of the impacts of the trade case on solar costs is reasonable, and even conservative in over-estimating the potential impacts. I also modeled a sensitivity case in which there are no tariffs on imported modules, and solar costs are lower as a result.

Q: What are the other assumptions that you have used to calculate the costs of solar generation?

A: These assumptions are summarized in **Table 4**. The capacity factor assumptions are based on PVWATTS output profiles for solar facilities located at several locations in southeast Michigan, as discussed above.

Table 4: *Solar Cost Assumptions*

Cost Parameter	Value	*Source*
Capacity factor: fixed arrays	18.5%	*PVWATTS for SE Michigan sites*
Capacity factor: tracking arrays	22.0%	*PVWATTS for SE Michigan sites*
Performance degradation	0.5%/year	*Industry standard assumption*
Annual O&M	$18/kW-yr	*2018 value; escalates at 2.5%/yr*
Property taxes	0.75%	*Workpaper KJC-479; DTE response to ELPCDE-3.6a*
Insurance	0.5%	
Federal Solar Investment Tax Credit	30% to 2020, 26% in 2021, 22% in 2022, 10% from 2023	*Current law*
Debt/Equity	50/50	*Workpaper KJC-479; also see LBNL Utility-scale Solar 2016, at p.41 for similar values.*
Debt Cost	4.6%	
Equity Cost	10.2%	
WACC (after tax)	6.5%	

Q: Based on the above assumptions, how did you calculate the cost of generation from new utility-scale solar facilities?

A: I used a pro forma model of the levelized cost of energy from utility-scale renewable generation projects owned by third-party independent power producers (IPPs) to calculate expected PPA prices for new utility-scale solar projects, based on the assumptions in Tables 4 and 5. This model was developed by the consulting firm Energy &

Environmental Economics (E3) for the utilities in the Western Electricity Coordinating Council (WECC), and has been used widely to project renewable PPA prices.[43] The results are shown in bold in **Table 5** below.

Table 5: *Solar PPA Costs*

DG System Type	Cost Metric	2017	2018	2019	2020	2021	2022
Fixed Utility-scale	*PV Cost $/Watt-dc*	*1.26*	*1.09*	*1.04*	*0.99*	*0.95*	*0.93*
	PPA Price $/MWh	**64.44**	**58.04**	**56.42**	**59.10**	**61.86**	**73.40**
Fixed Utility-scale (trade sensitivity)	*PV Cost $/Watt-dc*	*1.26*	*1.18*	*1.11*	*1.05*	*0.99*	*0.93*
	PPA Price $/MWh	**64.44**	**61.62**	**59.20**	**61.75**	**63.79**	**73.40**
Fixed DG Commercial	*PV Cost $/Watt-dc*	*1.50*	*1.29*	*1.20*	*1.13*	*1.06*	*1.03*
	PPA Price $/MWh	**100.21**	**88.64**	**84.24**	**87.32**	**89.95**	**107.21**
Fixed DG Commercial (trade sensitivity)	*PV Cost $/Watt-dc*	*1.50*	*1.95*	*1.81*	*1.68*	*1.57*	*1.48*
	PPA Price $/MWh	**100.21**	**92.22**	**87.02**	**89.53**	**91.89**	**107.21**
Tracking System	*PV Cost $/Watt-dc*	*1.42*	*1.24*	*1.17*	*1.12*	*1.07*	*1.05*
	PPA Price $/MWh	**63.49**	**57.27**	**55.05**	**57.98**	**60.54**	**72.45**
Tracking System (trade sensitivity)	*PV Cost $/Watt-dc*	*1.42*	*1.33*	*1.24*	*1.17*	*1.11*	*1.05*
	PPA Price $/MWh	**63.49**	**60.53**	**57.58**	**59.99**	**62.30**	**72.45**

I made two further adjustment to the costs of solar DG serving commercial customers: I assume that these facilities will be located on the DTE distribution system, will deliver their output to on-site or nearby loads, and thus will allow the utility to avoid (1)

[43] This *WECC Generation Costing Tool* model is available on the E3 website at https://ethree.com/public_projects/renewable_energy_costing_tool.php.

additional line losses at the transmission level and (2) upstream costs for high-voltage transmission service, in an amount equal to the accredited capacity of these solar DG units. As a measure of these avoided transmission costs, I used the MISO Network Integration Transmission Service tariff rate for ITC, which owns the transmission system serving DTE. These avoided losses and transmission costs reduce the cost of commercial DG solar by about $20 per MWh.

Q: What are the key assumptions that you used to calculate the costs of new wind facilities in Michigan that could supply DTE?

A: For new wind generation, I generally accept DTE's assumed trajectory of the future capital costs of new wind farms. Other important assumptions used to develop my projections for wind PPA prices are summarized below in **Table 6**.

Table 6: *Wind Cost Assumptions*

Cost Parameter	Value	*Source*
Capacity factor	38%	*Lower than DTE's 41%*
Annual O&M	$32/kW-yr	*2016 value; escalates at 2.5%/yr*
Property taxes	0.75%	*Workpaper KJC-479; DTE response to ELPCDE-3.6a*
Insurance	0.06%	
Wind PTC	$23.0/MWh in 2017, $18.4/MWh in 2018, $13.8/MWh in 2019, $9.2/MWh in 2020	*Current law*
Debt/Equity	50/50	*Workpaper KJC-479; also see LBNL Utility-scale Solar 2016, at p.41 for similar values.*
Debt Cost	4.6%	
Equity Cost	10.2%	
WACC (after tax)	6.5%	

The wind capacity factor assumption of 38% is lower than DTE's assumed 41%, and considers that a portion of future wind projects may not be located in the state's best wind resource areas. The best wind resources areas in the state, such as Huron County, already have seen significant wind development and have experienced some local opposition to further wind projects. Based on the assumptions in Table 6, I used the E3 WECC model to calculate for the cost of incremental wind PPAs. These results are shown in **Table 7** below.

Table 7: *Wind PPA Costs*

	2017	2018	2019	2020	2021	2022-25
Capital Cost ($/watt)	*1.641*	*1.533*	*1.526*	*1.519*	*1.416*	*1.409*
PPA Price ($/MWh)	**37.97**	**35.03**	**41.12**	**47.21**	**56.46**	**56.56**

Q: Please discuss the costs for the additional energy efficiency resources included in the R / E Portfolio.

A: DTE's IRP included a scenario with 2.0% annual energy savings, instead of the 1.5% annual savings which DTE used in its preferred IRP scenario and in this application. However, the DTE *IRP* shows that 2.0% EE savings per year is also cost-effective, and provides additional conserved energy and capacity in the near-term (2018-2027). The cost of this incremental conserved energy is low, about $12 per MWh, and these additional EE programs also provide an associated 94 MW of capacity. The testimony of other intervenors, such as the Natural Resources Defense Council (NRDC), will show that the potential for cost-effective energy efficiency savings is even greater than DTE's 2.0% annual savings. Thus, this is a conservative assumption for EE savings.

Q: You have also included additional capacity from demand response programs. Please discuss the costs and reasonableness of including these additional DR resources.

A: The Commission's new study of the demand response potential in Michigan – the *Michigan DR Study* – projects that there is significant additional potential for DR programs to reduce peak demand in Lower Michigan. Assuming just one-half of the DR capacity in the study's Realistic Achievable – Low scenario would result in an incremental 251 MW of demand response capacity in DTE's territory. Based on the program costs summarized in the Commission's study, the cost of these new DR programs is $44 per kW-year.

Q: The R / E portfolio uses market sales or purchases to ensure that the portfolio provides the same amount of capacity and energy as the gas plant, measured as the same levelized GWh as the gas plant over the forecast period. Please discuss the timing, magnitude, and cost of these assumed market sales or purchases.

A: Due to the early procurement of renewables to leverage tax credits, there are market sales of energy and excess capacity from the R / E portfolio in 2018-2022, before the gas plant would begin operations. These market sales would be reduced if there is an acceleration of the retirement of the coal units that DTE would shut down before 2023. After 2022, whether market purchases or sales are needed for the R / E portfolio to match the output of the gas plant depends on the gas plant's assumed capacity factor. In my base case, which uses the gas plant's capacity factor from the Strategist run of the 2016 reference case, there are generally market purchases from 2023-2028 and market sales from 2029 on. All of these differences in the timing of energy and capacity additions, compared to the gas plant, are priced out using the energy and capacity market prices assumed in the DTE application for the 2017 reference case. In the base case, these market sales contribute to reducing R / E Portfolio costs by 13%.

As a sensitivity, I also looked at an assumption that the gas plant operates at a constant capacity factor of 71% throughout the forecast period, based on the first-year output from DTE's Strategist modeling.[44] In this sensitivity case, a small amount of market purchases, with a modest (+8%) impact on R / E portfolio costs, are needed in order to produce the same levelized GWh as the gas plant over the forecast period.

Q: Do the market purchases in the R / E portfolio also expose DTE's ratepayers to some risk of volatile electric market prices linked to volatile natural gas prices?

A: The only exposure occurs if the R / E portfolio does not supply as much energy as the gas plant, such that the R / E portfolio must be supplemented with net purchases of energy

[44] From DTE's Strategist output file for the 2016 reference scenario.

from the MISO market. My analysis shows that the R / E portfolio requires supplemental market purchases of energy only if one assumes that the gas plant operates at a 70% or higher capacity factor for the entire forecast period. DTE's own Strategist modeling shows that the capacity factor of the gas plant will decline over time to well below this level, which is what is expected in the long run as utilities in the MISO footprint add more renewable generation with zero variable costs. Even if the R / E portfolio requires a small amount of market purchases to equal the output of the gas plant, this small share of market purchases, plus the fact that natural gas is the marginal fuel in MISO in only about 20% of hours,[45] results in a much more limited exposure to fuel price volatility than the gas plant.

Q: What are the total costs of the R / E portfolio over the 25-year forecast period of 2018-2042?

A: The net present value of the total costs of the R / E portfolio from 2018-2042 is $2.314 billion, with an average cost of $58 per MWh. These costs are summarized in **Table 8**. The table also shows the comparable total costs of the gas plant, which are $2.653 billion, with an average cost of $67 per MWh. Thus, the costs of the proposed R / E portfolio are $339 million (13%) lower than the costs of the gas plant.

[45] Based on an analysis of the data in the MISO Real-Time Fuel on the Margin Report for calendar year 2015.

Table 8: *Summary of R / E Portfolio Costs vs. Gas Plant (2018-2042)*

Resource	Capacity (MW)		Energy (GWh)		NPV Costs (2018-2042)		
	Nameplate	Accredited	Total GWh	Levelized GWh/year	$MM	$/MWh	$/kW-year
R/E Portfolio:							
Solar	1,100	623	39,630	1,353	$947	$67	
Wind	1,100	139	80,427	2,783	$1,468	$50	
EE @ 2%	94	94	6,436	424	$53	$12	
New DR	261	261			$115		$44
Net Market	(151)	(151)	(11,706)	(771)	($349)	($43)	
Integration			39,737	3,790	$79	$2	
Total	**2,555**	**1,107**	**114,787**	**3,790**	**$2,314**	**$58**	
Gas Plant:							
Total	**1,113**	**1,113**	**114,787**	**3,790**	**$2,653**	**$67**	
Difference: Savings from R/E Portfolio					**$339 MM or 13% NPV**		

Q: Has your R / E portfolio been analyzed using the Strategist model?

A: Yes, it has. Mr. George Evans provides testimony that discusses the results of running Strategist with the key elements of this R / E portfolio, including 2,200 MW of new wind and solar projects and the 2% annual EE savings described above. To be able to make the best comparison possible to DTE's proposed plan, the Strategist model was run using the other input assumptions in DTE's 2016 reference scenario.

Q: What were the results from Strategist when you analyzed your R / E portfolio compared with DTE's 2016 reference case?

A: The results of this run are that a new gas plant is delayed until 2027 and the R / E portfolio generates $1.2 billion (PV) in total cost savings compared to the 2016 DTE reference case with the proposed gas plant operational in mid-2022. The savings from the R / E portfolio in the Strategist model are higher than my more focused analysis, apparently due to (1) the higher gas and market prices in the 2016 reference case, (2) more market sales in the comprehensive Strategist modeling, and (3) a higher revenue requirement for the gas plants used in the Strategist model.

Q: Where does the $1.2 billion in savings come from when comparing the R / E scenario to DTE's 2016 reference case?

A: The savings reflected in the Strategist run come primarily from reduced capital costs and reduced fuel costs. Both are results of avoiding the construction of DTE's proposed combined cycle plant in 2022. Regarding capital costs, because the additional renewable energy and energy efficiency are represented as PPA purchases in Strategist, the model avoids, on average, more than 95% of the annual capital costs between 2018 and 2026. In addition, the Strategist results show an average decline in total fuel costs of 19% and an average decline of 18% in variable O&M costs between 2022 and 2026. Total emissions costs are also reduced by an average of 8% during this period.

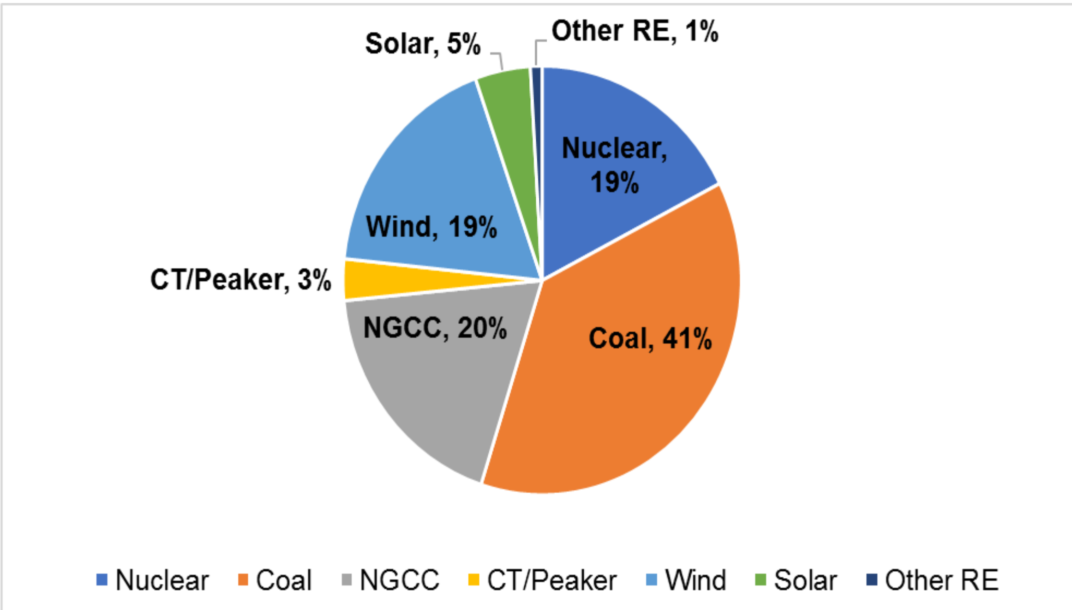
Q: In the R / E scenario, does Strategist choose to build a natural gas-fired combined cycle (NGCC) plant at any point?

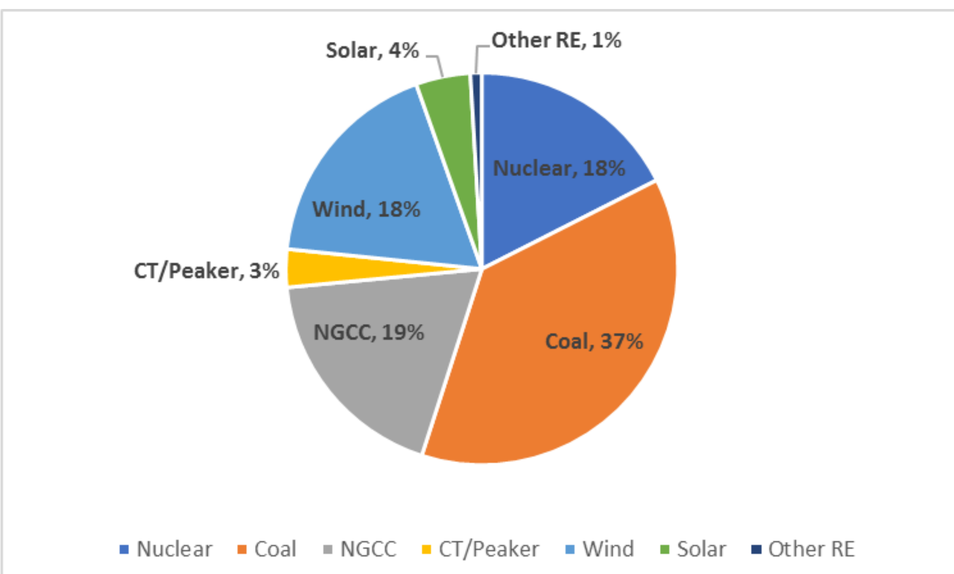
A: Yes. Under the R / E scenario, a new NGCC power plant is delayed until 2027. At that point, Strategist chooses to build a 1,531 MW NGCC plant with an additional 150 MW duct burner for a total of 1,681 MW. This new build replaces both NGCC plants in DTE's 2016 reference case – the one proposed in 2022 and the subject of this CON, and the additional one that DTE has stated it intends to build in 2029 as part of its long-term resource plan. This leads to a significant reduction in capital costs throughout the planning period, and, ultimately, significant reductions in the calculated NPV of the R / E scenario compared to DTE's 2016 reference case.

Q: Please describe how DTE's generation portfolio changes under the R / E scenario compared with DTE's 2016 reference case.

A: Under the R / E portfolio, DTE's generation portfolio is a more diverse, lower risk portfolio than DTE's preferred plan. Under the R / E scenario, renewable energy would be supplying about 23~~5~~% of DTE's energy by 2030, nuclear would make up about 18~~9~~%, the NGCC plant added in 2027 would supply approximately 19~~20~~%, and coal would make up most of the remainder. Even under this scenario, DTE would be~~ more than~~ 60~~4~~% reliant on fossil fuels for its energy needs. This 2030 resource mix is shown below in **Figure 8**.

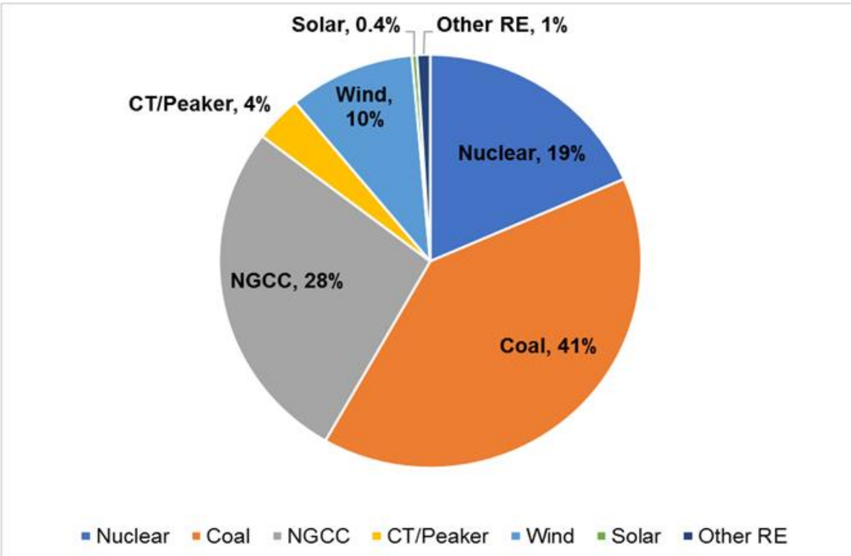
Figure 8: 2030 Resource Mix for the R / E Portfolio

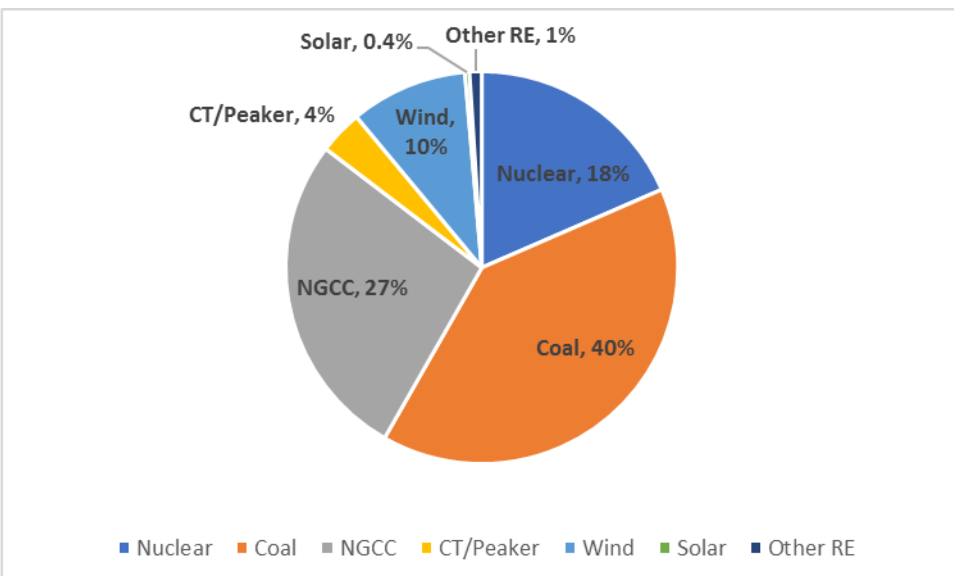




However, under DTE's preferred plan, the utility would be even more reliant on fossil fuels, further exacerbating the risks I discuss in my testimony. Under DTE's preferred plan, renewables would make up just over 11% of DTE's energy needs and fossil fuels would be more than 70~~2~~% of DTE's energy mix. See **Figure 9**. This higher level of reliance on fossil fuels exposes the Company and its ratepayers to even greater risk of fuel price volatility, regulatory costs, and other risks that I detail in my testimony.

Figure 9: 2030 Resource Mix for DTE's Preferred Plan





Q: Please describe how DTE's capacity portfolio changes under the R / E scenario compared with DTE's 2016 reference case.

A: Similar to the increased diversification of DTE's energy portfolio under the R / E scenario compared to the Company's 2016 reference case, the R / E scenario also improves the diversity of capacity resources for the Company. In 2030 under the R / E scenario, DTE's reliance on fossil fuel resources, including coal, the planned NGCC, and DTE's combustion turbine and other peaking plants is almost~~just over~~ 68~~4~~% – 29~~8~~%, 14%, and 25~~3~~%, respectively. The bulk of DTE's remaining capacity needs are split relatively evenly amongst nuclear, pumped hydro facilities, and renewables – about 11~~0~~% each.

By comparison, under DTE's preferred plan, more than~~nearly~~ 73~~0~~% of the Company's capacity needs will be me~~e~~t with fossil fuels including coal, the planned NGCC units, and DTE's combustion turbine/peaking plants – 29~~8~~%, 19~~8~~%, and 25~~4~~% respectively – in 2030. Renewables would contribute just 3% to DTE's capacity needs, with market purchases filling the remaining gap after nuclear and pumped hydro contribute their respective 11~~0~~% each.

Q: Why does a more diverse portfolio of energy and capacity resources matter?

A: As discussed above and throughout my testimony, DTE's ongoing overreliance on fossil fuels for its energy and capacity needs injects unnecessary risk into the Company's operations, and ultimately onto its ratepayers. While diversifying the fossil fuel mix with additional natural gas can help to reduce some risk, it inherently injects other types of risks into the mix, such as the risk posed by natural gas price volatility. Incorporating more renewable energy into the Company's mix of energy and capacity resources will reduce these risks.

Q: Did you consider Strategist results for your R / E portfolio using the revised assumptions in the 2017 reference case?

A: No, I did not. My review of the Strategist outputs for DTE's own run of the 2017 reference case revealed several unrealistic and apparently erroneous assumptions in the 2017 reference case. Most important, the advanced combined cycles selected in 2022-2023 and 2029 in DTE's own run using the 2017 reference case have average heat rates of just 5,300 Btu per kWh and 5,600 Btu per kWh, respectively, which clearly are not realistic. In comparison, the gas plant selected in 2022-2023 in DTE's 2016 reference case run has an average heat rate of about 6,500 Btu per kWh, which is appropriate for the advanced combined cycle unit that DTE proposes to build. In addition, the 2017 reference case shows the existing Belle River peaker (BLRPKR) with a heat rate of just 5,800 – 5,900 Btu per kWh, when that unit's actual heat rate is 12,000 Btu per kWh. Given these apparent significant errors in the assumptions for the Strategist modeling using the 2017 reference case, I have not considered results using that case. My analysis comparing the R / E portfolio and the gas plant does use certain important elements of the 2017 reference scenario, including the forecasts of natural gas and MISO market prices.

3. Cost Sensitivities

Q: Have you examined sensitivity cases that change key drivers of the costs of the R / E portfolio?

A: Yes. **Table 9** lists the key base case assumptions as well as the sensitivities for these assumptions that I examined. The sensitivity cases labeled "low" <u>reduce</u> the cost difference between the gas plant and the R / E portfolio; the cases labeled "high" <u>increase</u> the savings from the R / E portfolio compared to the gas plant.

Table 9: *Base Case Assumptions and Sensitivity Cases*

Assumption	Base Case	Sensitivity Cases	
		Low	**High**
Natural gas price	DTE Forecast	6 years of forwards & PACE escalation	2 years of forwards & PACE escalation
Solar trade case	Tariff imposed		No tariff
Wind capacity value	Zone 7 (12.6%)		MISO-wide (15.6%)
Early coal retirements?	No	1 year early	
EE assumptions	DTE 2.0%/yr	DTE 1.5%/yr	
Gas plant capacity factor	Strategist output	Fixed at 71%	

Q: How do these sensitivities impact the cost difference between the gas plant and your R / E portfolio?

A: **Table 10** shows the cost difference between the gas plant and the R / E portfolio for each of the Low and High sensitivities listed in Table 9. The differences are expressed in terms of both (1) the difference in the net present value of the revenue requirement

(NPVRR) in millions of dollars and (2) the difference as a percentage of the gas plant's costs.

Table 10: *Results of Sensitivity Cases – R / E Portfolio Savings vs. DTE Gas Plant*

Assumption	Low		High	
	NPVRR (*MM $*)	%	NPVRR (*MM $*)	%
Natural gas price	$25	1%	$408	15%
Solar trade case			$359	14%
Wind capacity value			$350	13%
Retire coal 1-year early	$308	12%		
Retire coal 2-years early	$274	10%		
EE assumptions - 1.5%/yr	$182	7%		
Constant gas plant output	$87	3%		

4. Procuring the R / E portfolio

Q: The R / E portfolio that you have proposed includes the procurement of 2,200 MW of new wind and solar resources. How would DTE procure this significant amount of new renewables?

A: There are multiple ways in which these new renewable resources can be procured, as discussed below.

PURPA Contracts. Michigan utilities may see significant renewable development in the state under the new PURPA avoided cost pricing methodology that the Commission has adopted, as exemplified in the Commission's recent order for Consumers Energy.[46] The

[46] On May 31, 2017, the Commission issued an order in Case No. U-18090 finding that the most appropriate method for determining Consumers' avoided capacity and energy costs is the Staff's hybrid-proxy method, which is based on the avoided capacity cost of a gas-fired combustion turbine (NGCT) and the avoided energy cost of a combined-cycle unit, plus assigning a portion of combined-cycle investment costs to the energy rate.

new pricing is based on the assumption that avoided energy and capacity costs should be based on the energy- and capacity-related costs of a new combined-cycle unit. Thus, if this approach is implemented accurately, and if wind and solar resources are less expensive than a new combined-cycle unit (as my analysis of the R / E portfolio suggests is likely), then DTE's service territory may see significant development of new renewable resources under long-term PURPA contracts. States such as Idaho, North Carolina, and Utah have seen substantial development of solar QFs when they have made long-term PURPA contracts available under avoided cost contracts that are based largely on marginal generation costs from natural gas-fired resources.

Long-term contracts from Renewable RFPs. DTE also could procure new renewable resources through a Commission-authorized procurement process based on competitive requests for proposals (RFPs). Utilities in many states have used competitive RFPs to meet requirements to procure new renewable resources to comply with the Renewable Portfolio Standards (RPS).

Utility-owned generation. DTE owns a portion of its wind resources and both of its existing utility-scale solar facilities. DTE could develop and own a portion of the new renewable resources in the proposed R / E portfolio, assuming that it can show that utility ownership is less expensive than contracting with third party developers for these new resources.

Customer-sited DG. New renewable generation, particularly distributed solar, can be installed at a wide range of scales on customers' premises under Michigan's net metering program. The higher costs of smaller-scale solar DG installations can be offset by the added benefits of savings in the utility's "wires" costs for line losses and for transmission and distribution upgrades. The widespread adoption of solar DG also could require increases in or the removal of Michigan's existing cap on the capacity of net-metered, customer-sited facilities.

Community solar and **green pricing** programs are used in a number of states to increase access to incremental solar and wind generation by utility customers of all sizes.

V. <u>THE R / E PORTFOLIO PROVIDES SIGNIFICANT ADDITIONAL NET BENEFITS</u>

A. Employment Benefits

Q: Will the R / E portfolio generate more new jobs in southeast Michigan than the proposed gas plant?

A: Yes. The testimony of Mr. Philip Jordan of BW Research Partnership (BW Research) discusses the added jobs and general economic impacts of the capacity and energy that would result from the R / E portfolio proposed in this testimony. This includes the short-term construction jobs associated with the wind and solar capacity additions, the longer-term employment operating and maintaining this capacity over time, and the industry jobs associated with the incremental energy efficiency programs. BW Research found that the portfolio of wind, solar, and energy efficiency would create 5,779 direct jobs, of which 5,642 are construction/installation jobs and 137 are ongoing operating and maintenance jobs. In addition, the economic activity created by the R / E portfolio would create another 2,582 indirect jobs in the supply chain, and 7,998 induced jobs in the broader economy. Mr. Jordan's testimony discusses in detail the methodology that BW Research used to perform this analysis.

In comparison, DTE's testimony asserts that the gas plant will add, at the peak of construction, 580 full-time-equivalent jobs.[47] The ongoing, long-term jobs required to operate the plant will be 35 employees.[48]

B. Reduced Air Emissions of Carbon and Criteria Pollutants

Q: Will the R / E portfolio have reduced air emissions of criteria air pollutants (NO_x, SO_2, and particulates) and carbon dioxide (CO_2), compared to the gas plant?

A: Yes. DTE's testimony provides the gas plant's expected air emissions.[49] The only emissions associated with the R / E portfolio are those that would result if net purchases from the MISO market are needed to balance the R / E portfolio's output to equal the production of the gas plant. My base case modeling of the gas plant suggests that the R / E Portfolio will result in about 771 GWh/year of additional energy production compared

[47] DTE Testimony of I.M. Dimitry, at pp. IMD-31 and D. O. Fahrer at pp. DOF-13.
[48] DTE Testimony of I.M. Dimitry, at pp. IMD-31 to IMD-32.
[49] DTE Testimony of B.J. Marietta, at p. BJM-13 and Exhibit A-36.

to the gas plant. This renewable energy can be sold into the MISO market, reducing emissions. To calculate these incremental emission reductions, I used MISO's reported hourly data on the marginal fuel in its markets. There also may be significant incremental emission reductions achievable if the retirement dates of coal units scheduled to close before 2023 are moved forward in time. **Table 11** shows the assumed marginal air emissions from the gas plant, the MISO market, and the retiring coal plants. Note that the marginal emissions from the market are higher than from the gas plant.

Table 11: *Marginal Air Emissions*

Resource	**CO_2** *(tons/Mwh)*	**SO_2** *(lbs/MWh)*	**NOx** *(lbs/MWh)*	**$PM_{2.5}$** *(lbs/MWh)*
Proposed Gas Plant	0.381	0.004	0.024	0.013
MISO Market	0.589	4.701	1.222	0.037
Retiring Coal Plants	1.284	11.721	3.036	0.092

Q: What are the benefits of reducing criteria air pollutants?

A: Reductions in criteria pollutant emissions improve human health. Exposure to particulate matter (PM) causes asthma and other respiratory illnesses, cancer, and premature death.[50] Nitrous oxides (NO_X) react with volatile organic compounds in the atmosphere to form ozone, which causes similar health problems.[51] For quantifying the health benefits, I use the health co-benefits from reductions in criteria pollutants that the EPA has developed,

[50] EPA, *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014), p. 4-14 and Table 4-6 ("*CPP Impact Analysis*"). Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

[51] *Ibid.*

discussed below.[52] My analysis assumes a real societal discount rate of 3%, which is a typical societal discount rate often used in long-term benefit/cost analyses.

SO_2. The EPA has calculated the health-related costs of SO_2 emissions for 2020, 2025, and 2030.[53] Values for intermediate years are interpolated between the five-year values. I assume that generators must purchase SO_2 emission allowances at market prices; thus, the societal value of reduced air emissions should be net of the market cost of required allowances. The market value of SO_2 can be taken from the EPA's 2017 SO_2 allowance auctions. However, the final clearing price of the latest spot auction was just $0.04 per ton.[54] This is low enough compared to the social cost that it is negligible for my calculations.

NOx. Heath damages from exposure to nitrous oxides come from the compound's role in creating secondary pollutants: nitrous oxides react with volatile organic compounds to form ozone, and are also precursors to the formation of particulate matter.[55] EPA has calculated the health benefits of reductions in NOx emissions in 2020,

[52] For example, in 2014 EPA summarized its work on the health benefits of reductions in criteria pollutant emissions as part of the technical analysis for the Clean Power Plan. Additional reductions in emissions of criteria pollutants would have been an accompanying benefit of the Clean Power Plan.

[53] The total social cost of SO_2 is taken from *CPP Impact Analysis*, at Tables 4-7, 4-8, and 4-9.

[54] EPA 2017 SO2 Allowance Auction. Found at: https://www.epa.gov/airmarkets/2017-so2-allowance-auction-0.

[55] *CPP Impact Analysis*, p. 4-14 and Table 4-6.

2025, and 2030.[56] The compliance market for NO_x in Michigan is governed by the EPA's Cross State Pollution Rule. I assume a recent value of $750 per ton for NOx compliance costs, and subtract this cost from the health benefits to determine the net benefits.[57]

Fine Particulates ($PM_{2.5}$). I use the damage costs for $PM_{2.5}$, because $PM_{2.5}$ are the small particulates with the most adverse impacts on health. The EPA health co-benefit figures distinguish between types of particulate matter, and calculate two separate benefit-per-ton estimates for PM: for PM emitted as elemental and organic carbon, and for PM emitted as crustal particulate matter.[58] The EPA estimates that approximately 85% of primary $PM_{2.5}$ emitted in Michigan is crustal material, with the bulk of the remainder being elemental or organic carbon.[59] The emissions factors for total primary $PM_{2.5}$ do not differentiate among particle types.[60] As a result, I weigh the mid-point of each of the two benefit-per-ton estimates according to EPA's assumptions for Michigan emissions.

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[56] *Ibid.*, at Tables 4-7, 4-8, and 4-9.
[57] See the EPA Cross State Air Pollution Rule. Found at: https://www.epa.gov/csapr. Recent NOx emission allowance prices can be found at http://www.evomarkets.com/content/news/reports_23_report_file.pdf.
[58] *CPP Impact Analysis*, p. 4-26, Tables 4-7, 4-8, and 4-9.
[59] *Ibid.*, p. 4A-8, Figure 4A-5.
[60] AP 42, Table 1.4-2, Footnote (c).

Q: How have you valued the benefit of reducing carbon dioxide emissions?

A: Yes. I first calculated the direct ratepayer benefits from the potential reduced costs of compliance with future carbon regulations, based on the carbon prices that DTE projected in several of its IRP scenarios. Then I estimated the societal benefits of lower carbon emissions, based on mitigating the damages from climate change. For this calculation I used the **social cost of carbon** (SCC) net of the assumed carbon compliance costs.

The SCC is "a measure of the seriousness of climate change."[61] It is a way of quantifying the value of actions to reduce greenhouse gas emissions, by estimating the potential damages if carbon emissions are not reduced. The anticipated costs to comply with future regulation of carbon emissions may well be lower than the true costs that carbon pollution imposes on society, which are the damages estimated by the SCC. As a result, the additional costs in the SCC, above the compliance costs of mitigating carbon emissions, represent the societal benefits of avoided carbon emissions.

The most prominent and well-developed source for estimates of the social cost of carbon is the federal government's Interagency Working Group on the Social Cost of Carbon.[62] These values have been vetted by numerous government agencies, research institutes, and

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[61] Anthoff, D. and Toll, R.S.J. 2013. The uncertainty about the social cost of carbon: a decomposition analysis using FUND. *Climactic Change* 117: 515-530.

[62] Interagency Working Group on Social Cost of Carbon, *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (May 2013, Revised July 2015). Available at: https://www3.epa.gov/climatechange/Downloads/EPAactivities/social-cost-carbon.pdf.

other stakeholders. The cost values were derived by combining results from the three most prominent integrated assessment models, each run under five different reference scenarios.[63] The group gave equal weight to each model and averaged the results across each scenario to obtain a range of values depending on the discount rate, given in the table below.

Table 12: *Social Cost of Carbon*[64] *(2007 $ per metric tonne of CO_2)*

	Discount Rate		
	5%	**3%**	**2.5%**
Social Cost of Carbon	11	36	56

I have assumed a value for the SCC using the mid-range value of $36 per metric tonne based on a 3% real discount rate. I escalate these benefits by 5% per year, recognizing that "future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climate change."[65]

While estimating the social cost of carbon contains many inherent uncertainties, I believe these values are appropriate. As noted above, the mid-range real discount rate of 3% is often used in long-term benefit/cost analyses. It is also a conservative assumption, when

[63] *Id.* The three models are the Dynamic Integrated Climate-Economy (DICE) model, the Climate Framework for Uncertainty, Negotiation and Distribution (FUND) model, and the Policy Analysis of the Greenhouse Effect (PAGE) model.

[64] *Id.*, p. 13.

[65] *Id*, pp. 13-14. 5% annual escalation in carbon costs has been used in both California and Arizona. See the CPUC Final Public Tool referenced in Footnote 2, at tab "Key Driver Inputs," at Cell D33. 5% is also midway between the two escalation rates (2.5% and 7.5% per year) used in the carbon cost scenarios in Arizona Public Service's *2014 Integrated Resource Plan*.

considering the diminished prosperity future generations will face in a world heavily impacted by climate disruption. Because "the choices we make today greatly influence the climate our children and grandchildren inherit," future benefits should not be significantly discounted relative to current costs.[66] As Pope Francis wrote in his encyclical calling for "all people of goodwill" to take action on climate change: "The climate is a common good, belonging to all and meant for all."[67]

Reduced methane leakage. Methane leakage in the natural gas infrastructure that serves the gas plant also will be a significant source of carbon emissions. I attach to this report as **Ex. ELP-62 (RTB-5)** a recent white paper calculating the additional greenhouse gas emissions associated with methane leaked in providing the fuel to gas-fired power plants. This issue has received significant attention recently as a result of the major methane leak from the Aliso Canyon gas storage field in southern California. The bottom line is that the CO_2 emission factors of gas-fired power plants should be increased by 50% to account for these directly-related methane emissions from the production and pipeline infrastructure that serves gas-fired electric generation. I do not quantify this additional benefit of the R / E portfolio, but it is a reason why the benefits from reduced carbon emissions that I do quantify should be viewed as conservative.

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[66] California Climate Change Center, Our Changing Climate: Assessing the Risks to California (2006) at p. 2. http://www.energy.ca.gov/2006publications/CEC-500-2006-077/CEC-500-2006-077.pdf.

[67] Encyclical Letter *Laudato Si'* of the Holy Father Francis on Care for Our Common Home. June 18, 2015.

Q: What are the air emission benefits from the R / E portfolio, compared to the gas plant?

A: The first set of benefits from the R/E portfolio compared to the gas plant are the reduction in direct ratepayer costs for complying with emissions regulations for NOx and carbon. These are $13 million per year. The annual societal air emission benefits, net of the compliance benefits, are $367 million per year over the 2018-2042 period, as shown in the first three rows of **Table 13** below.

Q: Would there also be air emission benefits from the early retirement of River Rouge, St. Clair, and Trenton Channel coal units?

A: Yes. The air emission benefits of a one-year acceleration of the retirement of these three coal units are very large, as shown in the bottom line of **Table 13** below, as a result of the high value of reducing SO_2 emissions.[68]

Table 13: *Annual Societal Benefits / (Costs) from Air Emission Reductions / (Increases) (NPV 2018-2042, millions of $ per year)*

Resource	CO_2	SO_2	NOx	$PM_{2.5}$	Total
Proposed Gas Plant	(174)	(1)	(1)	(2)	(177)
R / E Portfolio	32	150	7	1	190
Net Benefit of R / E					367
Retiring Coal Plants *(one year advance in retirement)*	501	3,409	150	25	4,084

[68] Air emissions from the retiring coal plants and from the gas plant are from DTE Testimony of B.J. Marietta, at p. BJM-13.

C. Reliability and Resiliency

Q: Does the proposed R / E portfolio offer greater reliability and resiliency benefits that a single central station gas plant?

A: Yes. Utility-scale wind and solar projects typically are installed in greater numbers and with smaller average project capacities than central-station fossil units. Renewable DG obviously consists of hundreds or thousands of small, widely distributed systems. As a result of their smaller size, wide geographic dispersion, and different prime movers, renewable resources are highly unlikely to experience outages at the same time. As a simple example, a single 1,000 MW gas plant with a 5% forced outage rate will have a 5% chance that the entire 1,000 MW of capacity will be unavailable during a peak demand hour. A portfolio of 2,000 MW of solar capacity that provides 1,000 MW of firm capacity equivalent to the gas plant might consist of forty 50 MW units that are widely dispersed. If each solar unit also has a 5% forced outage rate, the chance that the entire 2,000 MW of solar capacity will be unavailable in a peak demand hour is much less than 5%, and indeed is vanishingly small. Thus, the impact of any individual outage at a solar unit will be far less consequential than an outage at a major central station power plant.[69] In addition, if the renewable resource is owned by a third-party developer

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[69] One study of the benefits of solar DG has estimated the reliability benefits of DG from a national perspective. The study assumed that a solar DG penetration of 15% would reduce loadings on the grid during peak periods, mitigating the 5% of outages that result from such high-stress conditions. Based on a study which calculated that power outages cost the U.S. economy about $100 billion per year in lost economic output, the levelized, long-term benefits of this risk reduction were calculated to be $20 per MWh ($0.02 per kWh) of DG output. This calculation does not necessarily assume that the DG is located behind the customer's meter, so this reliability benefit also might result from widely distributed DG at the

or by a customer, it is the developer or DG customer, and not ratepayers, who will bear this operating risk and will pay for the repairs.

However, most electric system interruptions do not result from generation outages or high demand on the system, but from weather-related transmission and distribution system outages. Renewable DG is located at or near the point of end use, and thus also reduces the risk of outages due to transmission or distribution system failures. In these more frequent events, renewable DG paired with on-site storage can provide customers with an assured back-up supply of electricity for critical applications should the grid suffer an outage of any kind. This benefit of enhanced reliability and resiliency has broad societal benefits as a result of the increased ability to maintain government, institutional, and economic functions related to safety and human welfare during grid outages.

Both DG and storage are essential in order to provide the reliability enhancements that are needed to eliminate or substantially reduce weather-related interruptions in electric service. The DG unit ensures that the storage is full or can be re-filled promptly in the absence of grid power, and the storage provides the alternative source of power when the grid goes down. DG also can supply some or all of the on-site generation necessary to develop a micro-grid that can operate independently of the broader electric system. It is challenging to quantify this benefit, which will be realized over time as storage

wholesale level. Hoff, Norris and Perez, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania* (November 2012), at Table ES-2 and pages 18-19.

technology is added to renewable DG systems.[70] Nonetheless, solar DG is a foundational element necessary to realize this benefit – in much the same way that smart meters are necessary infrastructure to realize the benefits of time-of-use rates, dynamic pricing, and demand response programs that will be developed in the future – and thus the reliability and resiliency benefits of wider renewable deployment should be recognized as a broad societal benefit in comparison to central station generation.

D. Integration Costs Will Be Nominal

Q: The R / E portfolio will result in a higher penetration of solar and wind resources in Michigan. Please comment on whether this increasing penetration of renewables is likely to result in additional costs to integrate these new resources.

A: The addition of significant intermittent wind and solar resources may increase the variability of the "net load" – defined as the end use load less wind and solar resources – that the utility must serve with dispatchable generation. This increased variability that intermittent wind and solar output adds to the utility system can require additional ancillary services, such as regulation. A number of utilities have performed detailed studies of such integration costs, including studies that cover a wide range of renewable penetrations. Xcel Energy in Colorado calculated solar integration costs as $1.80 per

[70] It is also important to recognize that adding storage may be cost-effective even without considering its reliability benefits when paired with DG. Distributed storage can reduce demand charges, allow TOU rate arbitrage, and provide power quality and capacity-related benefits to the utility or grid operator. Indeed, distributed storage may be economic as a result of the benefits in these other use cases, without considering the reliability benefits for the customer.

MWh on a 20-year levelized basis.[71] A March 2014 study by Duke Energy estimated solar integration costs on its system in North Carolina ranging from $1.43 to $9.82 per MWh, depending on the level of PV penetration.[72] Based on the solar penetration level in Michigan, the lower end of the range in the Duke study would apply. Arizona Public Service did a 2012 integration study that estimated integration costs on its system of $2 per MWh in 2020.[73] Based on this body of work, $2 per MWh represents a reasonable assumption for a 25-year levelized solar integration cost in DTE's service territory, and this cost has been included as a cost of the R / E portfolio, as shown in Table 8 above. In its application, DTE did not assume any incremental integration costs in its scenarios with higher amounts of renewables.[74]

VI. CONCLUSION

Q: Can you please summarize your conclusions?

A: DTE's IRP process was incomplete and flawed. As a result, the Proposed Project is not the most reasonable and prudent means for DTE to meet its customers' needs. DTE's

[71] Xcel Energy Services for Public Service Company of Colorado, "Cost and Benefit Study of Distributed Solar Generation on the Public Service Company of Colorado System" (May 23, 2013), at Table 1, pages v and 41-42. Available at http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Costs%20and%20Benefits%20of%20Distributed%20Solar%20Generation%20on%20the%20Public%20Service%20Company%20of%20Colorado%20System%20Xcel%20Energy.pdf

[72] See http://www.pnucc.org/sites/default/files/Duke%20Energy%20PV%20Integration%20Study%20201404.pdf

[73] See Arizona Public Service, *2014 Integrated Resource Plan*, at p. 43, citing Black & Veatch, "Solar Photovoltaic (PV) Integration Cost Study" (B&V Project No. 174880, November 2012).

[74] DTE response to ELPCDE 3.1f and 3.3a/b, included in Exhibit RTB-2.

failing is exemplified by my evaluation of a portfolio of renewables and efficiency resources that could provide the same capacity and energy as the gas plant, with appreciably lower costs and risks to DTE's ratepayers. There are no negative impacts from this alternative scenario, and this clean course of action will provide much greater employment benefits to southeast Michigan than the gas plant, will reduce harmful air emissions, and will enhance the reliability of the electric system.

Q: Does this conclude your direct testimony in this case?

A: Yes, it does.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.	))))))))	Case No. U-18419

PROOF OF SERVICE

I hereby certify that a true copy of the foregoing *Corrected Direct Testimony of R. Thomas Beach* was served by electronic mail upon the following Parties of Record, this 26th of January, 2018.

Name/Party	E-mail Address
MPSC Staff Heather M.S. Durian Bryan A. Brandenburg Amit T. Singh	durianh@michigan.gov brandenburgb@michigan.gov singha9@michgan.gov
DTE Electric Company Michael J. Solo, Jr. Jon P. Christinidis David S. Maquera Richard P. Middleton Andrea E. Hayden	Mpscfilings@dteenergy.com Michael.solo@dteenergy.com Jon.christinidis@dteenergy.com david.maquera@dteenergy.com middletonr@dteenergy.com haydena@dteenergy.com
MEC/Sierra Club/NRDC Christopher M. Bozdok Tracy Jane Andrews Lydia Barbash-Riley Kimberly Flynn Marcia Randazzo	Chris@envlaw.com tjandrews@envlaw.com Lydia@envlaw.com Kimberly@envlaw.com marcia@envlaw.com
Counsel for Attorney General Celeste R. Gill John A. Janiszewski	Gillc1@michigan.gov Janiszewskij2@michigan.gov ag-enra-spec-lit@michigan.gov

Energy Michigan, Inc. Timothy J. Lundgren Toni L. Newell Laura Chappelle	tjlundgren@varnumlaw.com tlnewell@varnumlaw.com lachappelle@varnumlaw.com
International Transmission Company Amy C. Monopoli Stephen J. Videto	amonopoli@itctransco.com svideto@itctransco.com
Association of Business Advocating Tariff Robert A.W. Strong Michael J. Pattwell Sean P. Gallagher Stephen A. Campbell	rstrong@clarkhill.com mpattwell@clarkhill.com sgallagher@clarkhill.com scampbell@clarkhill.com
Midland Cogeneration Venture Richard Aaron Kyle M. Asher Jason Hanselman	raaron@dykema.com kasher@dykema.com jhanselman@dykema.com
Administrative Law Judge Hon. Suzanne D. Sonneborn	sonneborns@michigan.gov
Consultant for ABATE Nicholas L. Phillips James R. Dauphinais Maria Decker	nlphillips@consultbai.com jdauphinais@consultbai.com mdecker@consultbai.com
Natural Resources Defense Council Shannon Fisk	sfisk@nrdc.org

Margrethe K. Kearney

Margrethe Kearney
Environmental Law & Policy Center
MKearney@elpc.org