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

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter of the application	)	
of DTE ELECTRIC COMPANY	)	Case No. U-20471
for approval of its Integrated	)	
Resource Plan pursuant to	)	
MCL 460.6t and for other relief.	)	

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on December 23, 2019.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before January 9, 2020, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before January 21, 2020.

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Sally L. Wallace
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Sally L. Wallace
Administrative Law Judge

December 23, 2019
Lansing, Michigan

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MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

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PROPOSAL FOR DECISION

I.

HISTORY OF PROCEEDINGS

On March 29, 2019, DTE Electric Company (DTE) filed an application, with supporting testimony and exhibits, requesting approval of an integrated resource plan (IRP) pursuant MCL 460.6t. In its application, DTE avers that its IRP supports a proposed course of action (PCA) "that identifies the most reasonable and prudent means of meeting the Company's energy and capacity needs through 2035."[1] Specifically, for 2020-2024, DTE proposes a "fixed" PCA comprised of:

a. Additional 11 MW of solar plus storage pilot projects;

b. Additional 693 MW of wind energy;

c. Additional Voluntary Green Pricing (VGP) program renewables (MIGreenPower) between 465 MW and 715 MW depending upon subscription levels;

[1] Application, p. 2.

d. Acceleration of previously announced retirement of the Trenton Channel Power Plant to 2022;

e. Acceleration of previously announced retirement of St. Clair Power Plant Unit 7 to 2022;

f. Accelerated retirement of St. Clair Unit 1 to 2019;

g. River Rouge Unit 3 will end the use of coal in 2020, and will continue to operate until 2022 on recycled industrial gases and natural gas;

h. Increase Energy Waste Reduction ("EWR") programs to achieve annual energy savings to 1.65% in 2020 and 1.75% in 2021;

i. Increase Demand Response ("DR") programs to 859 MW by 2024; and

j. Conduct a Conservation Voltage Reduction and Volt-Var Optimization ("CVR/VVO") pilot program by 2020.[2]

For the 2025-2035 period, DTE proposed a "flexible" PCA, comprised of four hypothetical pathways (A, B, C, and D), which include renewable energy goals, but which also leave certain other issues to be decided in the company's next IRP. DTE explains that for 2025-2035:

a. The Company will continue to build renewables to support our clean energy and carbon reduction goals, and expects to add 525 MW of solar between 2025 - 2030, with another 2000 MW of solar by 2040;

b. The EWR program levels will be analyzed in subsequent IRPs, but it is expected that the 1.75% annual reduction level of EWR that begins in 2021 would at least be continued through 2040;

c. DR program levels will be analyzed in subsequent IRPs, but it is expected that the 859 MW that is expected to be achieved by 2024 will at least be maintained at that level through 2040;

d. Building on the momentum of our current VGP programs, we have included up to 675 MW of voluntary renewable energy between 2025 and 2030;

[2] Id. at 2-3.

e. Belle River Units 1 and 2 are currently expected to retire in 2029 and 2030 respectively, but that retirement timing will be reevaluated in the next IRP;

f. Monroe Power Plant is planned for retirement by 2040, but that retirement timing will be reevaluated in the next IRP;

g. CVR/VVO will be analyzed in subsequent IRPs (50 MW by 2030 included in two of the four potential pathways in the flexible years of the PCA);

h. Additional generation resources will be analyzed in the next IRP. There is a combined cycle gas addition in two of the four potential pathways in the flexible years of the PCA. The size of the potential gas addition would be a 414 MW 1x1 combined cycle. In the two plans that do not have combined cycle additions, there are other resources selected to fill the capacity need in 2030.[3]

DTE states that "[its] defined PCA for years 2020-2024 is fully integrated and requires approval in its entirely [sic]; the flexible PCA for years 2025-2035 is by its nature undefined and may be separately approved."[4]

A prehearing conference was held on April 26, 2019, at which DTE and Commission Staff (Staff) appeared. At the prehearing conference, petitions to intervene filed by Attorney General Dana Nessel (Attorney General);[5] the Association of Businesses Advocating Tariff Equity (ABATE); Energy Michigan; Environmental Law and Policy Center/Ecology Center/Solar Energy Industries Association/Union of Concerned Scientists/Vote Solar (collectively, ELPC et al.); Great Lakes Renewable Energy Association (GLREA); Michigan Energy Innovation Business Council/Institute for Energy Innovation (together, EIBC/IEI); Michigan Environmental Council (MEC); Natural Resources Defense Council (NRDC); Sierra Club (SC) (collectively, MEC/NRDC/SC); Convergen Energy; City of Ann Arbor (Ann Arbor); Geronimo Energy (Geronimo);

[3] Id. pp. 3-4.
[4] Id. p. 4.
[5] The Attorney General filed a notice of intervention.

Soulardarity; ITC Transmission Company (ITC); Cypress Creek Renewables; Midland Cogeneration Venture Limited Partnership; Heelstone Development; and Michigan Public Power Agency (MPPA) were granted. On April 29, 2019, the ALJ entered a protective order as stipulated to by all parties.

On June 20, 2019, the Commission held a public hearing at Wayne County Community College in Detroit. On June 28, 2019, DTE Electric filed the revised direct testimony and exhibits of Laura K. Mikulan. On July 8, 2019, DTE Electric filed a stipulation and agreement by all parties to extend the schedule for the proceedings by approximately 30 days. Consistent with the parties' stipulation, a revised schedule was entered on July 9, 2019. On July 17, 2019, DTE Electric filed revised Exhibit A-19.

On August 28, 2019, the Department of Environment, Great Lakes, and Energy (EGLE) filed an advisory opinion concerning potential decreases in emissions of sulfur dioxide (SO_2) oxides of nitrogen (NO_X), mercury, and particulate matter (PM) resulting from the IRP, in accordance with MCL 460.6t(7).

Per the revised schedule, the Staff and several intervenors filed testimony on August 21, 2019, and the company, Geronimo, EIBC/IEI, and GLREA filed rebuttal testimony on September 19, 2019. Evidentiary hearings were held on October 2-4 and 7-9, 2019. The parties filed briefs and reply briefs on October 29 and November 15, 2019 respectively. The record in this case consists of 3385 pages of transcript and 438 exhibits admitted into evidence. Portions of the transcript and several exhibits are designated confidential.

Although the parties organized their briefs consistent with an agreed-upon outline, for purposes of simplifying the discussion, this PFD begins in Section II with an overview of the testimony and pre-filed exhibits. Positions of the parties are contained in Section III, and legal standards are addressed in Section IV. The IRP, which includes subsections addressing the PCAs, modeling background, sales forecast, starting point, supply-side resources, demand-side resources, and transmission, among other items, is contained in Section V. Section VI are findings and recommendations.

In order to ensure compliance with the statutorily imposed timeframe for deciding this case, only the evidence and arguments necessary for a reasoned analysis of the disputed issues are expressly addressed in this PFD.[6] However, all of the evidence presented in this case, and the arguments made by the parties based on that evidence, were considered.

II.

OVERVIEW OF THE RECORD

A. DTE Electric

DTE filed the testimony and exhibits of 15 witnesses as follows:

Sharon G. Pfeuffer, the Director of Environmental Engineering for DTE Energy, LLC,[7] provided an overview of the company's case, introduced DTE's other witnesses, and she discussed the statutory framework for IRPs under Section 6t, MCL 460.6t. Ms. Pfeuffer also described how the company met the IRP filing requirements set out in Section 6t and the Commission's orders in Case Nos. U-18418, U-18419, and U-18461.

[6] For issues where the ALJ finds that a decision on an issue is dispositive, this PFD provides only a limited summary of any additional evidence or arguments of the parties.

[7] Ms. Pfeuffer's revised direct testimony is transcribed at 2 Tr 33-74, and her rebuttal testimony is available at 2 Tr 76-101. Cross examination of Ms. Pfeuffer begins at 2 Tr 102 and continues through 2 Tr 250. She sponsored Exhibits A-1 (revised); A-2.1; and A-2.2.

Ms. Pfeuffer reviewed the stakeholder process the company used to engage customers and other interested parties, which included four technical workshops and three public open houses. She further identified DTE's goals to reduce carbon emissions over the life of the plan—including a 50% clean energy goal by 2030 and an 80% reduction in carbon emissions by 2040. Ms. Pfeuffer described the company's analysis of coal plant retirements, including Trenton Channel and the remaining St. Clair unit in 2022, as well as any capacity need, which is not expected to occur until 2029-2030 when Belle River is retired.

Ms. Pfeuffer testified that DTE will begin annual reporting on the implementation of the IRP in 2021, with reporting suspended when the company files its next IRP in 2025. She further testified that in compliance with MCL 460.6t(8)(b), and consistent with past practice, DTE will continue its preference for a Michigan workforce in any projects it undertakes as part of the IRP.

Ms. Pfeuffer explained that DTE's planning principles, as reflected in the IRP, consider reliability, affordability, clean, flexible and balanced, compliance, reasonable risk, and community impact of the company's proposals. Ms. Pfeuffer then described how the IRP team integrated its work with distribution planning in developing the CVR/VVO and storage pilots as well as DTE's collaboration with ITC on transmission planning and with the MidContinent Independent System Operator (MISO) on plant retirements.

Ms. Pfeuffer stated that the company is requesting that the Commission: (1) approve DTE's 2019 IRP for the years 2020 through 2035; (2) acknowledge that DTE does not have a persistent capacity need for the next 10 years; (3) preapprove costs for the company's proposed EWR investments and resources through 2022, which will be consistent with DTE's EWR Plan filing in 2019 for the period 2020 through 2021; (4) preapprove costs for the company's proposed DR investments and resources through 2022; and (5) preapprove costs for the company's proposed CVR/VVO pilot through 2022.

Ms. Pfeuffer filed rebuttal testimony to several Staff and intervenor witnesses addressing asset ownership issues, the need to issue a pre-IRP request for proposals (RFP), the company's near-term capacity need, approval of the flexible PCA, reporting issues, and stakeholder engagement.

Laura K. Mikulan, Business Planning and Development Manager – IRP for DTE Electric,[8] provided details on the inputs and modeling undertaken as part of the IRP process. Ms. Mikulan explained that, as part of its certificate of need (CON) filing in Case No. U-18419, DTE undertook an IRP process and that the major differences between the IRP conducted as part of the CON and this IRP filing include: (1) certain scenarios were modeled in this case, consistent with the latest IRP modeling requirements; (2) the modeling in this case uses more publicly available forecast information; (3) stakeholder collaboration and input were more extensive in this case; (4) the company incorporated transmission studies from ITC; and (5) fewer constraints, including smaller block sizes for renewables, were used in the analysis in this case.

Ms. Mikulan outlined the steps involved in creating this IRP, including: (1) a review of DTE's planning principles; (2) the development of assumptions for the various scenarios and sensitivity analyses as well as the determination of any capacity need; (3)

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[8] Ms. Mikulan's second revised direct testimony is transcribed at 3 Tr 331-475, and her revised rebuttal testimony is transcribed at 3 Tr 477- 587. Cross, redirect, and recross examination of Ms. Mikulan begins at 3 Tr 588 and continues through 4 Tr 781. She sponsored Exhibits A-3 (revised), A-4 (revised), and A-5 through A-9. She also sponsored rebuttal Exhibits A-66 through A-75.

development of alternatives and corresponding assumptions to meet any capacity need; (4) actual modeling; (5) analysis of results including risk assessment and other considerations (i.e., DTE's planning principles) ultimately arriving at a PCA.

Ms. Mikulan testified that the company ran four different modeling scenarios as required under Section 6t: (1) a reference case based on company assumptions; (2) a business-as-usual (BAU) case; (3) an emerging technologies (ET) scenario; and (4) an environmental policy (EP) case. To each of these scenarios, DTE applied sensitivity analyses required under the Michigan Integrated Resource Plan Parameters (MIRPP) as well as additional sensitivities requested by stakeholders. The sensitivities included changing load levels, EWR levels and costs, capital costs, renewable energy amounts, gas commodity prices, retirement dates, DR, discount rates, elimination of a gas unit in 2029, and CO_2 emission tax levels.

Ms. Mikulan explained that based on the company's starting point assumptions and planned retirements of Belle River units 1 and 2 in 2029 and 2030, the company identified a capacity shortfall of 585 MW beginning in 2030-2031.[9] Ms. Mikulan testified that because there is no near-term persistent capacity need, the company did not issue an RFP for additional capacity resources.

Ms. Mikulan testified that, at the outset of the modeling, DTE considered the following resource alternatives: (1) coal; (2) nuclear; (3) natural gas; (4) energy efficiency; (5) renewable energy; (6) DR, including CVR/VVO; (7) customer-owned distributed generation (DG); (8) storage; (9) market purchases; and (10) transmission alternatives

[9] See, Exhibit A-6. Exhibit A-7 updates the company's projected capacity position to reflect updated retirement dates, updated DR, updated planning reserve margin requirement and unforced capacity consistent with DTE's capacity demonstration filing, updated ELCC for solar and wind, updated Ludington upgrades implementation, and additional resources for the flexible PCA.

and distribution efficiency. These alternatives were screened by technical feasibility, commercial availability, cost, and environmental considerations.[10] Ms. Mikulan stated that operational and cost inputs for each of the resources were obtained from the most complete, publicly available, data sources.[11]

Certain technologies, including hydropower, geothermal, thermal storage, and specific battery technologies, were screened out due to technical infeasibility or cost. In addition, micro turbines, combined heat and power (CHP), solar fixed tilt, biogas, coal with carbon capture, advanced nuclear, and reciprocating internal combustion engines were screened out due to economics. An additional market valuation was performed to eliminate higher cost alternatives based on a benefit cost analysis. As a result, several specific DR alternatives were eliminated from the modeling. Ms. Mikulan testified that only utility-scale solar was modeled due to economics, and new PURPA contracts were not included because avoided cost has not yet been determined for DTE and because the company does not require capacity until 2029. Solar effective load carrying capacity (ELCC) was assumed to be 50% through 2023, declining 2% per year through 2033, reflecting higher solar penetration and the shift in peak load to later in the day.

Ms. Mikulan testified regarding how near- and long-term capacity purchases were modeled, noting that there is significant uncertainty about the amount, availability, and cost of capacity in 2029. She also reviewed DTE's collaboration with ITC on determining the projected capacity import limit (CIL) and transmission alternatives, observing that because of uncertainty about available resources outside of Zone 7, even if transmission capability were increased, imports from outside the zone were not modeled.

[10] See, Exhibit A-3, Section 14.
[11] See, Exhibit A-4, Appendix B.

Ms. Mikulan described the company's starting point for each scenario, which included: (1) DTE's existing generation fleet; (2) forecasted load; (3) the current 1.5% EWR level; (4) existing and planned DR; (5) an assumption that all current PURPA contracts are renewed; and (6) renewable energy amounts that meet the company's carbon reduction goals and 300 MW of wind to meet VGP program requirements. The starting point also included the same planned retirement dates for coal units (except for St. Clair unit 4) that were modeled in Case No. U-18419. She explained the data sources or assumptions used for technology capital costs, EWR costs, gas price, and carbon price, as well as the changes included in the various sensitivities. Ms. Mikulan testified that although the company did not run every sensitivity on every scenario, in the end, 77 sensitivities and scenarios were run over 138 modeling runs.

Ms. Mikulan reviewed the language in the Filing Requirements pertaining to unit retirement analysis and testified that the company undertook three analyses of alternative retirement dates for St. Clair, Trenton Channel, and Belle River. Although the economic analysis showed a slight benefit to maintaining the current retirement dates for St. Clair and Trenton Channel, considering economics along with DTE's planning principles, DTE determined that it was preferable to move the retirement of St. Clair and Trenton Channel to 2022 rather than 2023, assuming that the BWEC begins operation as planned in May 2022, and that the transmission reliability issue at Trenton Channel is resolved.

With respect to retirement of Monroe, Ms. Mikulan testified that because that plant comprises DTE's most efficient units in terms of heat rate and emissions, consistent with the Filing Requirements, DTE assumed the 2040 retirement date for Monroe and did not model an earlier date. For Belle River, Ms. Mikulan explained that at the request of a stakeholder, DTE modeled retirement dates of 2025 and 2026, rather than 2029/30 in both the reference and ET scenarios. In both cases, it was more beneficial to run the Belle River units until 2029/30.

Next, Ms. Mikulan provided a detailed explanation of the various modeling platforms the company used in developing the IRP including ABB Strategist (with Load Forecast Adjustment, Generation and Fuel, and PROVIEW application modules) ABB PROMOD, Epis Aurora, GPCM Natural Gas Forecasting System, and a revenue requirements model developed by DTE using an Excel worksheet.

Ms. Mikulan reviewed the least-cost plan results for each of the four scenarios. She noted that the output for each plan was quite different, demonstrating the way in which input assumptions for each of the scenarios drive the resulting output. According to her, this makes comparison of plans between or among scenarios difficult.[12] Ms. Mikulan continued, explaining why the model selected certain resources (wind over solar, for example) and a certain level of EWR. Ms. Mikulan summarized the results of the various sensitivities, both required and stakeholder requested, run on each of the scenarios. Ms. Mikulan also reviewed the results of the scenarios, with no gas plant added in 2029, as requested by the Commission.

Ms. Mikulan explained that there were four key drivers of the variation in the modeling results and least-cost plans: (1) future CO_2 regulation and price; (2) EWR incentive costs; (3) gas price forecast uncertainty; and (4) assumptions about cost and operating characteristics of wind and solar.

[12] See, 3 Tr 407, Table 9. 3 Tr 409, Table 11 shows nine least-cost plans over the four scenarios.

Next, Ms. Mikulan discussed the importance of risk analysis, the incorporation of DTE's planning principles in developing the risk analysis approaches, and the five different risk analyses the company conducted (stochastic risk analysis, change analysis, application of planning principles, evaluation of key inputs and scenario and global sensitivity analysis) along with the results of the various analyses.

Finally, Ms. Mikulan explained the revenue requirement analysis contained in Exhibits A-8 and A-9, noting that the revenue requirements for the VGP resources are excluded to eliminate costs paid only by VGP program participants.

Ms. Mikulan filed rebuttal testimony to Staff and several intervenors regarding DTE's calculation of capacity need, various modeling inputs for solar, wind, storage, DG, capacity price, retirement analyses, EWR, and requirements for future IRPs. She also responded to assumptions and results of modeling runs by intervenors.

Kevin L. Bilyeu, Principal Supervisor of Energy Waste Reduction Strategy in DTE's Business Planning and Development department,[13] provided an overview of DTE's current EWR programs, noting that EWR programs, initiated in 2009, have ramped up savings from 0.3% in 2009 to 1.5% in 2018.[14]

For the IRP, Mr. Bilyeu testified that DTE updated its energy efficiency potential study[15] and used "achievable potential" to model EWR savings by end use (i.e., the category of equipment or service that consumes energy). Mr. Bilyeu explained that the IRP modeling of EWR began with a foundational level of savings for each end use, with

[13] Mr. Bilyeu's direct testimony is transcribed at 6 Tr 1544-1571, and his revised rebuttal testimony is transcribed at 6 Tr 1573-1598. Cross-examination of Mr. Bilyeu begins at 6 Tr 1539 and concludes at 6 Tr 1654. He sponsored Exhibits A-20 and A-21 and rebuttal Exhibit A-54.
[14] See, Table 1, 6 Tr 1551.
[15] See, Exhibit A-20.

the foundation based on DTE's experience, market trends, savings potential limits, and energy efficiency targets. Gross EWR savings were adjusted for net-to-gross (NTG) or installation rate adjustment factors (IRAF). DTE also calculated a weighted average measure life for each end use in the 2018 potential study.[16]

Mr. Bilyeu testified that DTE worked with its third-party evaluator to define EWR load shapes, which were in turn used to develop hourly EWR savings that were used in the IRP modeling. In addition, DTE applied an average line loss of 6.8%, the amount that was approved in Case No. U-15244.

Mr. Bilyeu testified that DTE used several incentive cost sensitivities for the various EWR levels including: (1) flat incentive costs: high (assumes 50% incentive levels across all savings levels); (2) flat incentive costs: low (assumes a 35% reduction in EWR measure costs and a reduced incentive level across all savings levels); and (3) tiered incentive costs (assumes that as EWR savings levels increase, incentive amounts also increase). Mr. Bilyeu explained that tiered savings costs were recommended for the IRP EWR cost assumptions based on the 2018 Potential Study and a data analysis by GDS.[17]

For non-incentive EWR costs (i.e., program administration, data tracking, reporting), Mr. Bilyeu testified that starting costs were based on 2016/2017 costs per first year kWh saved and were escalated by inflation over the term of the IRP. In addition, DTE included costs of pilots (5% of annual program spending), education (3% of annual program spending), and a financial incentive (20% of annual program spending).

[16] See, Table 3 and Table 4, 6 Tr 1558.
[17] See, Exhibit A-20.

Mr. Bilyeu testified that five different EWR savings levels were evaluated in the IRP process: 1.50%, 1.75%, 2.00%, 2.25%, and 2.50% of total annual retail sales.[18] The company also determined the cost-effectiveness of the savings for each level using the utility system resource cost test (USRCT), as required under MCL 460.1073(2).[19] Mr. Bilyeu testified that the IRP starting point assumes a 1.50% EWR savings level and the various EWR sensitivities increased the savings to 2.50%. As a result of the modeling, Mr. Bilyeu stated that DTE found an EWR savings level of 1.50%, escalating to 1.625% in 2020 and 1.75% in 2021-2024 to be optimal. In the flexible PCA, three of the pathways continue the 1.75% EWR savings level and one increases it to 2.00%. Mr. Bilyeu indicated that the company believes that the 1.75% EWR level is achievable, based on the 2018 Potential Study, noting that only two utilities in the country have achieved energy efficiency savings of 1.75% or more according to the 2017 ACEEE 2017 Utility Energy Efficiency Scorecard. Mr. Bilyeu listed challenges to achieving higher levels of EWR including program saturation, uncertainty about federal efficiency standards, increased free-ridership, and increased non-incentive costs. Finally, Mr. Bilyeu testified that DTE is requesting preapproval of $103 million in projected capital costs for 2020-2022.

In rebuttal, Mr. Bilyeu responded to testimony by several intervenor witnesses regarding the reasonableness of DTE's EWR level for the IRP, EWR costs, line loss rates applied to EWR savings, and low-income programs recommendations.

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[18] See, Exhibit A-21.
[19] See, Table 5, 6 Tr 1565.

Judy Chang, a Principal at The Brattle Group,[20] discussed the potential implications associated with integrating a large amount of renewable generation into MISO Zone 7. Specifically, Ms. Chang discussed a Brattle Group Report (Brattle Report) on the potential impact of adding renewable resources in the Lower Peninsula on resource adequacy and wholesale market operations. Ms. Chang testified that the Brattle Report is a stochastic analysis of resource adequacy in Zone 7, assuming that 25% of load will be served by renewables in 2030 and 30% of load will be served by renewables in 2040. Looking at the year 2031, Ms. Chang testified that maintaining resource adequacy in Zone 7 will depend on increasing or at least maintaining CIL, maximizing flexibility at Ludington pumped storage, and increased DR available at any time of the year. Ms. Chang asserted that, by 2040 the situation could be more challenging, especially if CIL is not increased or if there are not capacity resources outside of Zone 7 available for import. Ms. Chang further explained that with future generation retirements and more renewable energy generation, ramping capability will be more necessary but may not be as available as it is presently. She noted that as the amount of renewable generation increases, negative market prices will become more frequent and curtailment of renewables will become more common.

In response to several intervenor witnesses, Ms. Chang provided rebuttal testimony clarifying the purposes of the Brattle Report.

[20] Ms. Chang's direct testimony is transcribed at 5 Tr 1207-1215, and her rebuttal testimony can be found at 5 Tr 1217-1231. Cross-examination of Ms. Chang begins at 5 Tr 1232 and ends at 5 Tr 1270. Ms. Chang sponsored Exhibits A-46, A-47.

Shawn D. Burgdorf, Manager of the Power Supply Strategy & Modeling team within DTE's Generation Optimization department,[21] provided an overview of the MISO and Michigan resource adequacy requirements and MISO's capacity market. In addition, Mr. Burgdorf describe the planning reserve margin requirement (PRMR) (including an overview of the MISO Zone 7 forecasted capacity positions for planning years (PY) 2019/20, 2020/21 and 2021/22) and the company's existing capacity resources including power purchase agreements (PPAs) that were modeled as part of the IRP. He also described the CIL and effective capacity import limit (ECIL), which impact the amount of capacity that can be imported into Zone 7.

Mr. Burgdorf explained the interplay among the North American Electric Reliability Corporation (NERC), MISO, and the Commission in establishing the company's resource adequacy requirements, including the PRMR. Mr. Burgdorf testified that the PRMR capacity requirement is established each year by MISO, based on weather-normalized coincident peak demand plus an additional amount—the planning reserve margin (PRM)[22]—to cover unforeseen events such as extreme weather or plant outages. Mr. Burgdorf testified that a utility can meet its PRMR through a combination of a fixed resource plan, capacity purchases from the MISO PRA, or by paying a capacity deficiency charge.

[21] Mr. Burgdorf's direct testimony is transcribed at 4 Tr 786-802, and his revised rebuttal testimony is transcribed at 4 Tr 804-812. Cross-examination, redirect, and recross of Mr. Burgdorf begins at 4 Tr 813 and ends at 4 Tr 911. (A portion of Mr. Burgdorf's cross-examination is confidential). He sponsored Exhibit A-44 and rebuttal Exhibits A-62 through A-65.

[22] "The PRM is established by performing a Loss of Load Expectation (LOLE) study, which considers factors including . . . : generator forced outage rates, generator planned outages, expected performance of load modifying resources, load forecasting uncertainty, and transmission system import and export capabilities." 4 Tr 791.

With respect to the local resource requirement (LRR),[23] Mr. Burgdorf explained that MISO determines the CIL and capacity export limit (CEL) for each MISO Zone, along with the local clearing requirement (LCR).[24] Because both the LCR and PRMR must both be enforced, CIL may be further limited to ECIL, which is calculated as PRMR-LCR=ECIL. Mr. Burgdorf testified that he calculated a current ECIL of 164 MW, of which approximately 80 MW could be allocated to DTE. He cautioned, however, that because there is no allocation process, even the 80 MW is uncertain to be available for import use by DTE.

According to Mr. Burgdorf, Zone 7 resources have increased modestly from the 2017/18 planning year to the projected 2019/20 planning year, and that the amount MISO is projecting for 2019/2020 is reasonable for planning years 2020/21 and 2021/22. He further noted that the per unit LRR has been increasing from 114.1% in 2017/18 to 117.2% in 2019/20 due to changes in the resource mix in Zone 7. For purposes of the IRP modeling, Mr. Burgdorf held the forecasted peak demand, LRR, and CIL at the 2019/20 amounts of 21,350 MW, 117.2%, and 3,211 MW respectively.[25] Mr. Burgdorf warned that Zone 7 capacity resources may be very tight if generators retire sooner than expected.

Mr. Burgdorf presented DTE's existing capacity resources in Exhibit A-44, and he explained how UCAP is calculated for each resource, including PPAs and DR. Finally,

[23] "The LRR represents the minimum amount of unforced capacity [UCAP] for an LRZ to meet its LOLE without considering transmission ties to systems outside of the LRZ. The LRR is a part of the equation to calculate the LCR. Holding all else equal, a higher LRR results in a higher amount of capacity resources required to be located in a MISO Zone. . . . LCR = LRR – CIL."

[24] The LCR "is the minimum amount of unforced capacity (the amount of capacity assigned to a resource utilizing historic availability) that must be physically located within a LRZ. Simply stated, to reliably serve load a minimum amount of capacity must be located near the load due to the limitations of the transmission system to import additional capacity." 4 Tr 792.

[25] See, Table 4, 4 Tr 798.

Mr. Burgdorf discussed ancillary service products and compensation, noting that these services were not evaluated in the IRP due to their relatively small value.

Mr. Burgdorf provided rebuttal testimony to MEC/NRDC/SC witnesses on assumptions about the CIL.

Keegan O. Farrell, a Principal Supervisor – Demand Response for DTE Energy Services,[26] LLC discussed DTE's existing DR programs, current and future pilot DR programs, and he described the demand response assumptions used in the company's IRP process. Mr. Farrell also provided forecasts of customer participation and the impact on peak demand of the existing and proposed DR programs included in the IRP.

Mr. Farrell explained that DR programs are intended to reduce energy usage by participating customers during periods of peak demand. Mr. Farrell described the company's current DR portfolio, one of the largest in the United States, consisting of both dispatchable (e.g., interruptible air conditioning (IAC) and interruptible hot water heating for residential customers and interruptible tariffs for commercial and industrial (C&I) customers) and non-dispatchable programs (e.g., time-of use (TOU) rates) available to all customer classes. Mr. Farrell provided Table 1[27] demonstrating participation numbers and number of MWs registered as load modifying resources (LMRs) in MISO for the company's DR tariffs. Mr. Farrell noted that DTE's Capacity Release Rider (Rider 12) is not registered in MISO because no customers are currently taking service under that rate. Nevertheless, Mr. Farrell indicated that based on customer surveys in 2019, the company expects to enroll customers and include Rider 12 as an LMR beginning in 2020.

[26] Mr. Farrell's direct testimony is transcribed at 6 Tr 1656-1680, and his rebuttal testimony is available at 6 Tr 1682-1692. He sponsored Exhibits A-22 through A-26.
[27] 2 Tr 1665.

Mr. Farrell described DTE's non-dispatchable programs, explaining that in the IRP, these programs are treated as an offset to peak load, which reduces the company's capacity requirement. Mr. Farrell noted that the non-dispatchable programs are not registered as LMRs because they do not meet certain requirements for event notification and targeted energy use reduction.

Mr. Farrell testified that DTE is conducting DR pilots for residential, commercial, and industrial customers, and it expects to identify additional DR programs for implementation in the future. Mr. Farrell highlighted bring-your-own-devise (BYOD) and programmable communicating thermostat (PCT) pilots as potentially significant programs that may be added to the residential DR portfolio. Mr. Farrell stated that although these programs are currently non-dispatchable, potential modifications to the programs may allow them to qualify as LMRs in the future. Mr. Farrell testified that the company completed a pilot in 2018 in conjunction with NextEnergy and Enbala, encompassing several specific customer assets, that it hopes to deploy at additional locations. And Mr. Farrell described DTE's partnership with the Electric Power Research Institute (EPRI) on a transportation pilot program (EPRI pilot) to streamline the management of EV charging.

Mr. Farrell testified that DTE continues to examine the potential for battery storage as a DR tool, noting that based on the State of Michigan Demand Response Potential Study[28] battery storage was not considered cost-effective and was therefore screened out of the IRP modeling. Despite the cost, Mr. Farrell testified that DTE considers it appropriate to conduct battery storage pilots to assess the technology.

[28] See, Exhibit A-24.

Turning to the DR resources contained in the IRP, Mr. Farrell explained that the starting point assumed 732 MW (UCAP) of DR in 2019, increasing to 863 MW in 2024, with no increase after 2024. In the defined PCA, the existing portfolio was updated (in accordance with DTE's capacity demonstration in Case No. U-20154) to 709 MW in 2019, increasing to 859 MW (all in UCAP) in 2024. Mr. Farrell testified that in the flexible PCA, only pathway C includes additional DR, 100 MW, to be obtained from the implementation of future pilot programs. Mr. Farrell presented Exhibit A-22, which demonstrates the projected growth of existing DR resources from 2019 through 2040. Mr. Farrell described the various undertakings that DTE plans in order to achieve the projected growth in DR by 2024. For non-dispatchable programs, Mr. Farrell reiterated that the MW reductions are reflected as offsets to peak load.

With respect to modeling of DR, Mr. Farrell testified that because the costs of DR are mostly operations and maintenance (O&M), the effect of reducing the capital costs of DR by 35%, in the ET scenario, had little effect on the overall costs of the program. In the IRP market valuation analysis, the model selected variable peak pricing (VPP), demand buyback, real-time pricing (RTP) and TOU as demonstrating a net benefit. Mr. Farrell noted that VPP (via the PCT program) is currently being piloted, and DTE offers TOU rates. The demand buyback program is what the company offers under Rider 12. Mr. Farrell testified that DTE does not offer, and does not plan to offer, RTP.

Mr. Farrell explained that, consistent with Ms. Chang's testimony, there are risks to increased dependence on DR, including the need to ensure that DR responds when called and the fact that DR is not available year-round. Finally, Mr. Farrell testified that

DTE is requesting pre-approval of capital costs of $24 million from May 1, 2020 through December 31, 2022. Future capital cost projections will be refined in later rate cases.

Mr. Farrell filed rebuttal testimony to the Staff, Soulardarity, and GLREA on DR cost recovery, LMRs, and low-income customer access to DR programs.

Kelly A. Holmes, Principal Financial Analyst - Regulatory Economics, in Regulatory Affairs,[29] provided an estimate of the impact on average customer rates of the PCA, including an analysis of how customer rates are expected to change as a result of the Tier 2 unit retirements and the addition of the Blue Water Energy Center (BWEC) plant over the first ten years of operation. Ms. Holmes explained that costs associated with the IRP will be recovered in future general rate cases as well as in EWR and renewable energy plan (REP) proceedings. Ms. Holmes discussed Exhibit A-45, which calculates the overall rate impact of the IRP on bundled customers, based on the maximum revenue requirement for pathway C of the flexible PCA compared to the reference scenario. Overall, Ms. Holmes testified that her analysis showed a maximum increase of 0.08 cents per kWh to a maximum decrease of 0.11 cents per kWh, with an average increase in the first five years of the PCA of 0.04 cents per kWh.

Ms. Holmes explained that on page 2 of Exhibit A-45, she calculated the change in revenue requirement resulting from the retirement of the Tier 2 units coupled with the addition of the BWEC. Ms. Holmes noted that the addition of the BWEC, along with additional EWR savings, will reduce customer rates over the first 10 years that the plant operates.

[29] Ms. Holmes direct testimony is transcribed at 2 Tr 282-291. Cross-examination of Ms. Holmes begins at 2 Tr 292 and ends at 2 Tr 313.

Jestin M. Hunnell, a Specialist of Market Operations for DTE,[30] described DTE's collaboration with ITC, the local transmission owner, in developing the IRP. Mr. Hunnell testified that DTE met with ITC representatives on several occasions to establish the scope of a transmission study ITC was asked to perform,[31] as well as specific scenarios that were relevant to the IRP. ITC and DTE agreed on seven scenarios, all of which assumed the operation of the BWEC, the retirement of the Tier 2 units, the retirement of Belle River after 2028, as well as a range of solar capacity amounts. The study evaluated system conditions (thermal and voltage violations) both on- and off-peak for all seven scenarios. Mr. Hunnell testified that ITC estimated that transmission investments of $20 million to $30 million will be necessary to accommodate all the scenarios; however, he cautioned that much more detailed analysis would be required to fully identify and quantify transmission costs. Nevertheless, ITC's preliminary analysis indicated that transmission costs associated with the PCAs are relatively low.

Mr. Hunnell testified that for purposes of the IRP, the MISO LOLE for 2019-2020 was used, resulting in a CIL of 3,211 MW and CEL of 1,358. Mr. Hunnell explained that MISO has forecasted an increase in CIL to 4,287 MW in 2023-2024; however, he testified that he did not anticipate any increase to CIL from 2019 through 2022. ITC's analysis did evaluate CIL under three different levels of solar penetration, with and without an adjustment to the voltage criteria at Fermi.[32] Mr. Hunnell testified that ITC's CIL analysis

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[30] Mr. Hunnell's direct testimony is transcribed at 6 Tr 1457-1471, and his rebuttal testimony is transcribed at 6 Tr 1473-1482. Cross-examination of Mr. Hunnell begins at 6 Tr 1483 and concludes at 6 Tr 1537. He sponsored Exhibits A-38.1, A-38.2, A-39, and A-40 and rebuttal Exhibits A-60 and A-61.
[31] See, Exhibit A-39.
[32] See, Table 1, 6 Tr 1466

illustrated the importance of resolving the voltage issue at Fermi, and it demonstrates that DTE's plan to add significantly more solar generation will not adversely affect CIL.

Mr. Hunnell testified that through MISO's Attachment Y retirement studies, several reliability issues were identified related to the retirement of coal units located at Saint Clair, River Rouge 3 (RR3), and Trenton Channel, and he discussed long- and short-term mitigation measures.

Mr. Hunnell filed rebuttal testimony to clarify DTE's coordination with ITC during the IRP process and to address claims concerning the use of MISO's out-year CIL assessment.

Markus B. Leuker, Manager of Corporate Energy Forecasting for DTE,[33] provided the company's electric sales, maximum demand, and system output forecast for 2019 through 2040. He described how DTE developed the forecast of electric sales considering the business and economic climate in the company's sales territory, explaining that sales forecasts were created using industry standards for electric forecasting for each customer class, with some classes disaggregated into specific sectors. Mr. Leuker also discussed the forecasts he used for electric choice sales, DG, EWR, and for electric vehicle (EV) adoption. Mr. Leuker testified that DTE developed its peak demand forecast using the Hourly Electric Load Model (HELM) based on an average peak-day mean temperature over a 30-year period.

Mr. Leuker described Exhibits A-31 and A-32, which show weather-normalized sales from 2014 through 2018, and which demonstrate a compound annual growth rate

[33] Mr. Leuker's direct testimony is transcribed at 4 Tr 987-1009, and his rebuttal testimony is transcribed at 4 Tr 1010-1033. Cross-examination, redirect, and recross of Mr. Leuker begins at 4 Tr 1034 and ends at 4 Tr 1089. Mr. Leuker sponsored Exhibits A-31 through A-37 and rebuttal Exhibits A-57 through A-59.

(CAGR) of -0.4% over that period, mainly due to EWR impacts and the expiration of wholesale for resale contracts. Similar to the sales decrease, Mr. Leuker testified that weather-normalized peak demand has also declined, with a CAGR of -0.2% over the five-year period. For the IRP period, Mr. Leuker forecast a 0.10% annual decrease.

Mr. Leuker listed the starting point sales and peak demand used in the IRP for residential and C&I classes, along with outlooks for those classes and C&I subclasses. Mr. Leuker also outlined six alternative forecasts he prepared including: (1) high load growth; (2) 50% return of choice load; (3) high EV forecast; (4) 25% choice cap; (5) 24% EV sales by 2030; and (6) 100% of choice returns to bundled service.[34]

Finally, Mr. Leuker explained the methods DTE uses to validate both its forecasts and forecasting methods. Mr. Leuker testified that, as shown in Exhibit A-36, for 2014-2018, the absolute percentage variance for total sales, forecast compared to actual, was 1.06% and 1.01% for residential sales. In addition, he testified that, based on benchmark studies, DTE achieves very high forecast accuracy, both on a total and customer class basis, compared to peer utilities.

Mr. Leuker provided rebuttal testimony to several intervening witnesses concerning C&I forecast methods, embedded energy efficiency in C&I sales, the EV sales forecast, and the DG forecast.

Barry J. Marietta, Manager – Environmental Strategy in Environmental Management & Resources of DTE Energy Corporate Services LLC,[35] discussed the impact of environmental regulations on the company's existing power plants and the

[34] See Exhibit A-35 for sales and peak demand for these forecasts.
[35] Mr. Marietta's direct testimony is transcribed at 4 Tr 915-931, and his rebuttal testimony can be found at 4 Tr 933-939. Cross-examination of Mr. Marietta begins at 4 Tr 940 and ends at 4 Tr 981.

impacts of compliance options. Mr. Marietta testified that certain regulations, namely the Steam Electric Effluent Limitation Guidelines (ELG) rule, National Ambient Air Quality Standards (NAAQS), the Coal Combustion Residuals (CCR) rule, and Cooling Water Intake regulations (316(b) regulations) require significant capital expenditures for the company's fleet. Mr. Marietta described each of the rule requirements and explained which plants were subject to each rule, noting that the cost of compliance with the ELG rule was a significant factor in the decision to retire RR3, St. Clair, and Trenton Channel. Mr. Marietta also provided inputs to the modeling for capital costs associated with environmental compliance at Monroe and Belle River.

With respect to greenhouse gas (GHG) emissions, Mr. Marietta discussed the status of the Clean Power Plan and its proposed replacement, the Affordable Clean Energy (ACE) rule, observing that despite the uncertainty around carbon regulation at the federal level, DTE has established a plan to transition to low- or zero-emitting sources.

Mr. Marietta described the annual net short method DTE used in the IRP to account for CO_2 both from the company's resources and from purchased power. Mr. Marietta explained that this is a more accurate approach to calculating the carbon intensity of electricity delivered to customers. Mr. Marietta also testified that all four pathways under the flexible PCA allow the company to meet its carbon emissions goals while reducing NO_X and SO_2 emissions over the life of the plan, with PM and mercury expected to decline at the same rate as SO_2.

Mr. Marietta provided rebuttal testimony to several intervenor witnesses concerning air emissions in non-attainment areas, compliance costs, and post-conversion emissions from RR3.

Matthew T. Paul, Vice President Fossil Generation Plant Operations for DTE Electric,[36] described the characteristics of DTE's fossil, nuclear, peaking, and pumped storage assets, both existing and under construction (i.e., the BWEC combined cycle plant and the Ford CHP plant). Mr. Paul provided a retirement schedule for the company's existing coal fleet, which was established in Case No. U-18419, and was used in the starting point of the IRP analysis. Mr. Paul added that there were three retirement sensitivities analyzed as part of the IRP: (1) moving the retirement of Trenton Channel 9 and St. Clair 7 from 2023 to 2022; (2) moving the retirement of St. Clair 1, 2, 3, and 6 from 2022 to 2021 and St. Clair 7 and Trenton Channel 9 from 2023 to 2022; and (3) moving Belle River 1 retirement from 2029 to 2025 and Belle River 2 from 2030 to 2026. The company's IRP was updated consistent with the changed retirement dates for Trenton Channel and St. Clair. Mr. Paul testified that since the IRP analysis was completed, DTE decided to retire St. Clair 1 in March of 2019 due to the need for extensive turbine repairs. Mr. Paul further testified that RR3, originally slated for retirement in 2020, will be converted to operate on recycled industrial gasses from May 2020 through May 2022. Mr. Paul explained that continued operation of RR3 will provide reliability benefits both locally, and in Zone 7 generally, and it will allow the River Rouge community to prepare for lost tax revenues when the plant closes. Mr. Paul cautioned that retirement dates for the St. Clair and Trenton Channel units are contingent upon the successful start-up of the BWEC in 2022 and, for Trenton Channel, certain grid reliability issues will need to be resolved.

[36] Mr. Paul's direct testimony is transcribed at 5 Tr 1104- 1124, and his rebuttal testimony can be found at 5 Tr 1126-1130. Mr. Paul sponsored Exhibits A-10 through A-16, A-17.1, A-17.2 and Exhibits A-48 through A-52. Cross-examination of Mr. Paul begins at 5 Tr 1131 and ends at 5 Tr 1201.

Mr. Paul also discussed forecasted base and major maintenance O&M costs and base and major environmental capital costs, which were inputs to the IRP starting point and sensitivity analysis for coal plant retirements, as shown in Exhibits A-13 through A-16. Mr. Paul explained that, for unit retirements, base O&M is reduced by 25% the year the unit is retired to reflect the need for make-safe activities and employee transition. In years two through six after retirement, O&M is reduced by 90%.

Mr. Paul filed rebuttal testimony in response to a GLREA witness's recommendation concerning the RR3 conversion.

Ryan C. Pratt, Supervisor, Planning and Procurement, within DTE's Fuel Supply department[37] described DTE's existing generating facilities by type of fuel, DTE's fuel procurement practices and supply arrangements for each generator, and associated costs including those for the BWEC plant and the Ford CHP plant.

Mr. Pratt also discussed the fossil fuel price forecasts used in the company's IRP, explaining that gas supply costs were added to transportation costs to arrive at a total delivered cost of gas. Gas supply cost was based on forecasted prices at various hubs in Michigan. For the near term, DTE used Chicago Mercantile Exchange (CME) and New York Mercantile Exchange (NYMEX) futures prices. For 2020-2022, the forecast transitioned from NYMEX/CME prices to PACE Global prices, which were used after 2023. Mr. Pratt testified that the PACE forecast has historically been more accurate than that provided by the Energy Information Administration (EIA) Annual Energy Outlook (AEO), as shown in Exhibit A-41, which compares actual Henry Hub prices to EIA AEO projections from 2009-2017. Mr. Pratt testified that DTE has been using PACE Global

[37] Mr. Pratt's testimony is transcribed at 6 Tr 1695-1709. He sponsored Exhibits A-41 through A-43.

forecasts since 2014, noting that for 2014-2017, the PACE forecast, while 24% higher than actuals, still outperformed the EIA AEO, which was 43% higher than actual, as shown in Exhibit A-43.

Mr. Pratt testified that similar to its approach to forecasting gas cost, the company used existing coal contracts and forecasted market prices in the near term, then used the PACE Global forecast for projections after 2023. Transportation costs were based on existing contract rates, adjusted consistent with contract terms or defined indices. The approach to the oil forecast mirrored that used for coal and gas, and petcoke prices were based on current contracts and market forwards through 2023, with a 2.5% escalator applied for 2024-2026. For potential future gas-fired resources, combustion turbines (CTs) as well as CCGTs, Mr. Paul testified that costs were based on forecasted costs for the Belle River peakers or the BWEC.

Terri L. Schroeder, [38] Manager of Business Development, Renewable Energy for DTE, discussed the company's existing renewable energy generating assets and described the renewable energy assumptions (cost, capacity factors, and O&M) specific to utility- scale wind and solar resources utilized in the IRP starting point. Ms. Schroeder also explained the updated renewable portfolio standard (RPS) and overall energy goals from 2016 PA 342, additional renewable energy objectives, and DTE's VGP program plans.

Ms. Schroeder testified that in the IRP starting point, DTE included renewable resources to meet the 15% RPS, additional renewables to meet the company's clean

[38] Ms. Schroeder's revised direct testimony is transcribed at 5 Tr 1278-1301, and her revised rebuttal testimony is transcribed at 5 Tr 1303-1323. Cross-examination of Ms. Schroeder begins at 5 Tr 1324 and continues through 6 Tr 1451. She sponsored Exhibits A-18, A-19 (revised) and rebuttal Exhibit A-53.

energy and carbon reduction goals, and resources for the MIGreenPower and VGP programs. She noted that the renewables assumptions included in the IRP are consistent with DTE's amended REP filed in Case No. U-18232.

Ms. Schroeder testified that DTE assumed that new wind and solar resources would be developed in Michigan. For wind, DTE based its costs on amounts contained in the National Renewable Energy Laboratory (NREL) 2018 Annual Technology Baseline (ATB) publication mid-level forecast, with costs assumed to decrease 35% in the EP scenario and 17.5% in the ET scenario. For wind capacity in the reference case, Ms. Schroeder testified that the company used the NREL ATB forecast for techno-resource group (TRG) -7 mid, assuming that future wind parks will likely be built outside the Thumb region. For wind O&M, Ms. Schroeder also used NREL ABT TRG-7 mid. For the wind Ms. Schroeder also discussed the company's assumptions about the phase-out of the production tax credit (PTC).

For solar installed costs, DTE's IRP used the 2018 NREL ABT for Chicago-mid, and again assumed 35% and 17.5% cost reductions, respectively, for the EP and ET scenarios. Ms. Schroeder explained that DTE assumed a net capacity factor of 22.9% for solar, again using the NREL ATB forecast for Chicago. DTE also assumed $18.50 per kW-year for O&M and capital maintenance. Finally, Ms. Schroeder discussed the phase-out of the solar investment tax credit (ITC).

Ms. Schroeder filed rebuttal testimony to Staff and several intervenor witnesses on renewable energy cost and capacity assumptions, VGP pricing and credits, competitive bidding, renewable energy credit (REC) requirements under the RPS, and DTE's calculation of its green energy goal.

Don Stanczak, Vice President, Regulatory Affairs for DTE Energy Corporate Services, LLC,[39] described the criteria used in determining the existence of a capacity need. Mr. Stanczak explained that per documentation filed in December 2018, in Case No. U-20154, DTE does not expect to make any capacity purchases from the MISO PRA through 2029-2030, and it does not have a persistent capacity need for the next 10 years. Mr. Stanczak discussed the importance of a persistent capacity need with respect to cost considerations, opining that short-term or intermittent capacity shortfalls can be addressed most economically through market purchases. For purposes of PURPA capacity payments, Mr. Stanczak recommended that the Commission consider a five-year outlook, rolling forward five years in succeeding IRPs. Mr. Stanczak emphasized that resource additions to meet statutory requirements (e.g., RPS) or customer needs (e.g., VGP programs) should not be considered persistent capacity needs for purposes of PURPA.

Mr. Stanczak also discussed the company's position regarding the appropriate standard offer contract threshold for qualifying facilities (QFs) under PURPA, maintaining that the standard offer should only be available to QFs up to 150kW, consistent with the limits on the DG program under MCL 460.1173.

Mr. Stanczak filed rebuttal testimony to several intervenors addressing DTE's near-term capacity need, PURPA capacity purchases, and avoided cost determinations in this case.

[39] Mr. Stanczak's direct testimony is transcribed at 2 Tr 255-264, and his rebuttal testimony is transcribed at 2 Tr 266-270. Cross-examination of Mr. Stanczak begins at 2 Tr 271-277.

Yujia Zhou, the Manager of Investment and Reliability Strategy in Distribution Operations,[40] discussed the CVR/VVO pilot program including the assumptions used in the IRP process. Ms. Zhou explained that VVO manages voltage levels and reactive power flow to reduce losses, manage voltage variability from intermittent generation, or for optimization of operating parameters or power factors. CVR manages customer voltage levels at the lower level of the allowable voltage range reducing losses, peak demand, or consumption.[41] Ms. Zhou testified that DTE engaged Burns & McDonnell to study and provide a report on CVR/VVO on several of DTE's circuits, which were grouped by certain characteristics.[42] The report provided a cost estimate, ranging from $300-$500 to $500,000-$650,000 per kW for implementation of CVR/VVO for each of five groups of circuits. DTE found that CVR/VVO may be cost effective for groups 1- and 2-type circuits, but not for groups 3-5-type circuits. While cautioning that the results may vary from the numbers reported in the Burns & McDonnell study, Ms. Zhou testified that DTE decided to conduct a pilot CVR/VVO implementation on 20 randomly selected circuits in 2019-2020, at a cost of approximately $0.7 million. Additional CVR/VVO is included in Pathways A and C of the Flexible PCA.

Ms. Zhou discussed the potential avoided transmission & distribution (T&D) capacity values for DTE's EWR program, the methodologies used to produce the range of values, and key considerations in using these values. Ms. Zhou explained that there is no standard methodology for calculating avoided T&D capacity values, largely because the value is significantly dependent on load, customer mix and behavior, and program

[40] Ms. Zhou's direct testimony and revised rebuttal testimony can be found at 6 Tr 1713-1751. She sponsored Exhibits A-27 through A-30 and rebuttal Exhibits A-55 and A-56.
[41] See 6 Tr 1720, Figure 2.
[42] See, Exhibit A-27; Table 1 at 6 Tr 1721-1722.

offerings. Using one method described in the 2018 Alternative Energy Systems Consulting, Inc. (AESC) report, DTE calculated and avoided T&D capacity value of zero, because DTE has declining load growth. Nevertheless, due to economic growth in certain areas of the DTE system, there are possible T&D savings resulting from peak load reduction in those areas. Using an alternative method, which looked at general load relief projects and reductions on individual substations and circuits, Ms. Zhou calculated a system-wide avoided capacity value of $7 per kW-year.[43] Thus, Ms. Zhou supported values ranging from $0 to $7 per kW-year for avoided T&D due to EWR in the IRP analysis.

B. Commission Staff

The Staff presented testimony of 12 witnesses.

Paul Proudfoot, Director of the Energy Resources Division,[44] introduced other Staff witnesses and outlined their testimony in the case. Mr. Proudfoot also provided an overview of the IRP requirements, scope of the IRP, and cost approvals requested by the company. Mr. Proudfoot testified that DTE has met the IRP requirements set forth in the statute and Commission orders, and he recommended that the Commission approve the IRP with certain changes proposed in Staff testimony.

Mr. Proudfoot recommended that any cost approvals be limited to the first three years of the current plan and that the Commission open a comment docket to solicit suggestions for best practices for competitive bidding and utility procurement of resources. He suggested that the company should be directed to engage with the Staff

[43] See, Exhibit A-30.
[44] Mr. Proudfoot's testimony can be found at 7 Tr 3206-3224. He sponsored Exhibit S-1.0.

to develop RFPs, and review the bidding and award process.[45] Mr. Proudfoot further recommended that utilities file PPAs, project purchase agreements, and engineering, procurement and construction (EPC) contracts for Commission approval in the most recent IRP docket.

Nicholas G. Luciani, a Public Utilities Engineer in the Generation and Certificate of Need section of the Commission's Energy Resources Division,[46] testified that the Staff reviewed DTE's IRP application and requested additional information for certain aspects of the plan. Mr. Luciani also explained Staff's recommendations for updating the filing requirements and for future IRPs.

Sarah A. Mullkoff, a departmental analyst in the Generation and Certificate of Need Section of the Energy Resources Division,[47] made recommendations for improving DTE's IRP webpages as a means to improve public outreach and stakeholder involvement. Ms. Mulkoff testified that DTE complied with the Michigan workforce requirement under MCL 460.6t(8)(b), and she recommended that DTE directly address how it is facilitating the use of a Michigan workforce in future IRP filings.

Ms. Mullkoff also recommended that the company file (at minimum) annual reports on the status of any resource additions which the Commission approves as part of this IRP and that the company communicate with the Staff if there are any significant changes to the PCA. Ms. Mullkoff provided a template for the reports in Exhibit S-3.0.

Ms. Mullkoff discussed competitive procurement of resources, referencing sections of 2008 PA 295, the Commission's Temporary Order in Case No. U-15800, a

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[45] Mr. Proudfoot recommended that the RFP process he outlined be applied to new renewable resources.
[46] Mr. Luciani's testimony is available at 7 Tr 3227-3238. He sponsored Exhibit S-2.0.
[47] Ms. Mullkoff's testimony is transcribed at 7 Tr 3241-3256. Ms. Mullkoff sponsored Exhibits S-3.0 and S-3.1.

Staff study on competitive bidding, and Attachment A to the settlement agreement in Case No. U-20165, as providing some guidance in the RFP process. Ms. Mullkoff observed that although MCL 460.6j no longer requires Commission approval of long-term contracts, Staff nevertheless recommends that utilities file PPA's and EPC contracts for approval.

Olumide O. Makinde, a Departmental Analyst in the Resource Adequacy and Retail Choice Section of the Energy Resources Division,[48] testified that DTE's projected load growth was consistent with general trends in the industry, the company's most recent PSCR case, and with EIA projections. Mr. Makinde also testified that Staff examined the company's methods for deriving long-term forecasts and found them reasonable. Nevertheless, Mr. Makinde recommended that DTE calculate and report the mean absolute percentage error (MAPE) on monthly energy sales and peak load, as a means to refine the company's models. Mr. Makinde also recommended that DTE conduct future peak load and sales forecasts on an hourly basis as recommended by the Institute of Electrical and Electronics Engineers (IEEE).

Mr. Makinde testified that while it was appropriate to use 30-year normalized temperature data in forecasting weather trends, this method could be improved by using a shorter normalization period or weighted 30-year average to account for more recent trends.

Mr. Makinde observed that although the company's forecasts accounted for EV growth, DG resources, and EWR effects, the forecasts did not incorporate DR program effects. Mr. Makinde testified that in future IRPs, DTE should incorporate AMI data on hourly use of customers on DR tariffs and apply this information to its forecasting models.

[48] Mr. Makinde's testimony is transcribed at 7 Tr 3259-3275. He sponsored Exhibit S-4.0.

Finally, Mr. Makinde discussed DTE's stochastic risk assessment and recommended that in future IRPs, the company explicitly include its PCA in the risk assessment to evaluate the impact of key drivers on the chosen portfolio.

Anna N. N. Schiller, a Public Utilities Engineer in the Resource Adequacy and Retail Choice Section of the Energy Resources Division,[49] testified that Staff has concerns about DTE's assumptions regarding the retirement of its fossil-fueled peaking units. Ms. Schiller noted that DTE indicated that it has no intention of retiring any of these units before 2040, and according to Exhibit A-12, 75% of the units are between 48 and 50 years old and are already operating beyond their 30-year useful lives. Ms. Schiller stated that Staff's concern arises from the potential for increased O&M costs, which are not reflected in the IRP, that result from extended operation of these older units. Ms. Schiller recommended that DTE address these increased costs in future IRPs.

Ms. Schiller testified that the Staff verified the cost assumptions for new and existing fossil used by the company in developing its IRP, however, given the sheer volume of data and the complexity of the modeling, the Staff was only able to focus on the principal IRP assumptions and may have overlooked some inconsistencies or errors in the inputs.

Ms. Schiller provided an overview of DTE's plan to convert RR3 from coal to natural gas/recycled industrial gas fuel. Ms. Schiller noted that DTE's current industrial gas contract is with an affiliate, and she therefore recommended that if the contract changes in the future, it should be reviewed in a PSCR case. Ms. Schiller added that DTE is not requesting cost recovery for the conversion from coal to gas in this case. She

[49] Ms. Schiller's testimony is transcribed at 7 Tr 3278-3289. She sponsored Exhibit S-5.0.

emphasized that approval of the conversion of RR3 in this case does not guarantee cost recovery in the event recovery is requested in another proceeding.

Roger A. Doherty, a Public Utilities Engineer in the Resource Adequacy and Retail Choice Section 6 in the Energy Resources Division,[50] provided a high-level analysis of DTE's modeling along with recommendations for decreasing complexity, and increasing transparency, in the modeling approach. Although the company's method was reasonable for this IRP, in future IRPs, Mr. Doherty recommended using a different platform that would allow for both capacity expansion and production cost analysis, rather than relying on multiple programs.

Next, Mr. Doherty critiqued DTE's presentation of a "flexible" PCA that sets out four possible pathways to achieving its commitments to retire Belle River and increase its renewable resource portfolio. Mr. Doherty opined that the company's presentation is not consistent with the requirements of Section 6t, which requires a plan to meet the company's load obligations in five, 10, and 15 years. While recognizing that the future is uncertain, Mr. Doherty expressed the Staff's preference that the company present a single PCA representing the company's assumptions about the future based on current information.

Mr. Doherty explained that DTE's starting point for all scenarios included near-term resources including the BWEC, renewables planned to meet the 15% RPS, and additional renewables to meet the company's clean energy goals. While this method assures that the company will meet its carbon reduction goals under all scenarios, it does not allow for analysis or optimization of these resources, thus reducing the value of the modeling. Mr.

[50] Mr. Doherty's testimony is transcribed at 7 Tr 3292-3309. He sponsored Exhibits S-6.0, S-6.1,S-6.2, and S-6.3

Doherty testified that it is appropriate for DTE to include already-approved resources (i.e., BWEC), as well as renewables to meet the 15% RPS, in its starting point.[51] It is also reasonable to include three 1x1 CCGT units as a placeholder for the replacement of the Monroe plant in 2040. However, Mr. Doherty raised concerns about the company's inclusion of renewables for its clean energy goals in the starting point analysis. The Staff therefore requested an additional modeling run that did not include additional renewable energy, the results of which are shown in Exhibit S-6.2. Mr. Doherty testified that, even with the additional modeling, the results are not conclusive when compared to the non-optimized results presented by DTE, ranging from a savings of $44 million to a cost of $105 million over the four scenarios.

In light of DTE's failure to fully optimize the technologies to meet its clean energy and carbon reduction goals, Mr. Doherty recommended that the Commission direct DTE to file its next IRP three years after the Commission's order is issued. This will allow the company time to undertake a proper analysis of additional renewables that were not optimized in this case.

Finally, Mr. Doherty testified that DTE complied with all requirements under the MIRPP, along with additional modeling runs as requested by stakeholders and the Commission's directives in Case No. U-18419.

April M. Stow, a Departmental Analyst in the Renewable Energy Section of the Energy Resources Division,[52] supported DTE's proposal to add VGP resources during the near-term PCA and flexible PCAs. Ms. Stow testified that the company has already

[51] Mr. Doherty noted that this is consistent with the MIRPP, which specifies that only resources under construction or already approved.
[52] Ms. Stow's testimony is transcribed at 7 Tr 3312-3317.

contracted 372 MW of the total 465 MW for the PCA in its large customer VGP program, and based on additional customer interest in the program, the company's VGP proposals are reasonable.

David S. Walker, a Public Utilities Engineer Specialist in the Energy Waste Reduction Section of the Energy Resources Division,[53] testified that DTE's proposed $103 million in capital costs for EWR in the first three years of the IRP is reasonable. Mr. Walker testified that the range of EWR savings, from 1.65% to 2.5%, as calculated using the USRCT, showed that benefits of EWR spending exceed the costs at all levels of savings. Based on this calculation, Mr. Walker stated that there were several reasons that the company should, consistent with the Staff's recommendation, endeavor to achieve energy savings of 2.0%. Although recognizing that there are challenges to achieving higher EWR savings, Mr. Walker opined that DTE's approach in the IRP is more conservative than it has been in past EWR plans, noting that the company has consistently achieved sufficient energy savings to earn a maximum financial incentive since 2009. In addition, Mr. Walker pointed out that the company considered that adjustments to its EWR plan might be necessary if costs are higher than projected, but it failed to consider the possibility that EWR costs may decrease. In that circumstance, EWR levels in the IRP should be higher. Mr. Walker further observed that Consumers projects lower per MWh costs for EWR than DTE did in this case.

David W. Isakson, a Departmental Analyst in the Rates and Tariff Section of the Commission's Regulated Energy Division,[54] testified that the Staff does not take issue

[53] Mr. Walker's testimony is available at 7 Tr 3319-3326. He sponsored Exhibit S-7
[54] Mr. Isakson's testimony is transcribed at 7 Tr 3329-3341. He sponsored Exhibits S-8.0 (Confidential), S-8.1, and S-8.2.

with DTE's proposed capital spending for DR programs for IAC switch replacement or PCTs, nor does the Staff contest projected MW savings from DR.

Mr. Isakson testified that spending for new pilot programs should not be approved as part of this IRP, because the proposals are not sufficiently defined for the Staff to review the prudency of the pilots. Mr. Isakson explained that, consistent with the three-phase method the Commission uses for DR cost recovery, the company can propose additional DR program spending in rate cases or in DR reconciliations when the pilots are better defined. Mr. Isakson explained that the three-phase approach reduces the risk that utilities face when considering new DR programs. Mr. Isakson specified that on-going pilots (e.g., BYOD and the EPRI Pilot) should have funding approved in the instant case.

Mr. Isakson recommended that DTE revise language in Rate D1.8 (Dynamic Peak Pricing), to shorten the notification time so that the DR resource can be qualified and registered as an LMR in MISO. Similarly, Mr. Isakson recommended that the BYOD pilot be modified to qualify as an LMR, and it should be offered into the market as a DR resource once the pilot has 25,000 participants. Finally, Mr. Isakson explained the difference between the Commission's order requiring on- and off-peak summer rates for capacity as a default rate and TOU rates used for DR. Mr. Isakson testified that on- and off-peak default capacity rates are designed to better reflect cost-causation and are not intended to shift demand as is the case with TOU programs.

Zachary C. Heidemann, a Public Utilities Engineer in the Generation and Certificate of Need Section of the Energy Resources Division,[55] reviewed the IRP filing requirements for transmission alternatives and DTE's compliance with those

[55] Mr. Heidemann's testimony is transcribed at 7 Tr 3344-3353. Mr. Heidemann sponsored Exhibits S-9.0 and S-9.1.

requirements and MCL 460.6t(5)(h). Mr. Heidemann testified that Staff recommends that DTE continue to work with ITC to review and address the effects of generation additions and retirements on the transmission system.

Cody S. Matthews, a Public Utilities Engineer Specialist in the Renewable Energy Section of the Energy Resources Division,[56] testified that DTE's modeling inputs for wind and solar resources are reasonable, and he echoed Mr. Doherty's concerns that DTE should not have "forced" a certain level of wind and solar into the model, rather than allowing the model to optimize the resources. Mr. Matthews testified that Staff also considers the company's energy storage assumptions to be reasonable, but he noted that the company screened out DR with storage, for economic reasons, on the basis of the Staff's Demand Response Potential Study. Mr. Matthews testified that while the study found storage too costly at the time it was issued in 2017, energy storage costs have continued to decrease. Accordingly, Mr. Matthews testified that the Staff encourages DTE to continue to evaluate DR with storage and consider implementing pilot programs. Mr. Matthews added that additional storage can be used to mitigate the effects on spinning reserves associated with the retirement of conventional units. The costs and benefits of storage should be reevaluated and presented in the company's next IRP.

Mr. Matthews quoted the July 18, 2019 order in Case No. U-18232, where the Commission found that DTE did not adequately support its proposal to own all new generation after the PTC is reduced. The Commission questioned whether company-owned renewables would necessarily be the most cost-effective way to acquire new renewable generation and ordered renewable generation that is not eligible for 100% of

[56] Mr. Matthews' testimony is transcribed at 7 Tr 3356-3365.

the PTC to be addressed in this IRP. Mr. Matthews testified that, consistent with the July 18 order and the settlement agreement in Case No. U-20165, he recommended that the company own no more than 50% of future renewable energy, and that third-party PPAs be procured through a competitive bidding process for the remaining 50%. Finally, Mr. Matthews testified that treatment of PURPA issues in this case should be consistent with Staff's recommendations in Case No. U-18091.

Tayler Becker, a Public Utilities Engineer in the Electric Operations Section,[57] provided an overview of DTE's proposed CVR/VVO pilot, including capital costs, pilot objectives, implementation timeline, and information gathering. Mr. Becker agreed that the information on CVR/VVO that the company intends to compile is necessary to evaluate the program, but he recommends additional reporting as shown in Exhibit S-10.0.

Mr. Becker indicated that Staff is generally supportive of DTE's CVR/VVO proposal, but he also raised specific concerns about certain aspects of the program. Mr. Becker testified that if the Commission approves the CVR/VVO pilot as part of the defined PCA, Staff's recommendations for modifying the program should also be adopted. In future IRP cases, Mr. Becker suggested that DTE align distribution investments proposed in the IRP with those contained in the company's five-year distribution plan. In addition, the company should provide more detailed information about CVV/VVO on a circuit and substation basis.

[57] Mr. Becker's testimony can be found at 7 Tr 3368-3378. He sponsored Exhibits S-10.0 and S-10.1.

C. Attorney General

The Attorney General filed the testimony of[58] **David E. Dismukes, PhD.**, a Consulting Economist with the Acadian Consulting Group.[59] Dr. Dismukes recommended that the Commission reject the company's sales forecast and adopt the alternative forecast he presented in Exhibit AG-4. He testified that the company's commercial and industrial forecasts were not particularly robust, featuring an array of different forecasting models that appeared arbitrary and inconsistent. He noted that the company has changed several of its forecast models since its previous filing in Case No. U-18419, without documentation justifying the changes. Dr. Dismukes also took issue with DTE's forecast of EV sales contending that it was unreasonable to assume EV sales in Michigan will mirror sales growth in other states where incentives for EVs are available. Dr. Dismukes therefore recommended that the Commission review and validate DTE's forecasting methods to ensure that future forecasts are consistent with industry best practices.

For long-term planning, Dr. Dismukes testified that DTE's methods, and the PCA's resulting from these methods, suffered from numerous shortcomings including potentially biased assumptions, over-reliance on corporate goals rather than least-cost planning, and a failure to consider a number of least-cost resource options. Dr. Dismukes highlighted DTE's assumption, in both the near and long term, that CIL will remain at the current 3,211 MW throughout the planning period, thus resulting in higher capacity prices. Dr. Dismukes testified that this assumption is unreasonable given that both MISO and ITC project higher capacity import capability for Zone 7 by 2024 or 2028.

[58] The Attorney General also sponsored the testimony of Mr. Evans in conjunction with MEC/NRDC/SC.
[59] Dr. Dismukes' testimony is transcribed at 7 Tr 2338-2388.

Dr. Dismukes claimed that DTE's fixed and flexible PCAs are driven more by the company's clean energy goals than by least-cost planning and that DTE failed to consider alternatives to a new gas plant in 2029. He further noted that DTE's retirement analysis focused only on its aging coal fleet and did not consider retiring Greenwood Unit 1, an older gas peaker that costs more to operate, and produces more emissions, than several of the company's coal units. Dr. Dismukes also took issue with the company's assumption that all new renewable generation would be company-owned as well as its failure to consider the purchase of unbundled RECs or the purchase of renewable energy outside its service territory, opining that options other than utility-ownership may be more cost-effective. Accordingly, Dr. Dismukes recommended that the Commission decline to approve any newly proposed renewable projects until the company issues an RFP or clearly demonstrates the cost-effectiveness of company-ownership.

D. Michigan Environmental Council/Natural Resources Defense Council/Sierra Club

MEC/NRDC/SC presented the testimony of nine witnesses.

George W. Evans, President of Evans Power Consulting, Inc., testified on behalf of the Attorney General and MEC/NRDC/SC,[60] about the numerous problems in DTE's IRP including: (1) there is no specific IRP identified after 2024; (2) the company's process and output is not transparent; (3) too much of the IRP was manually coded (i.e., amounts of EWR, VGP, DR, gas build in the flexible PCA pathways) and therefore the plan was not optimized; (4) DTE's PCA is biased toward dispatchable resources without justification, resulting in significant excess capacity in two of the four flexible PCA

[60] Mr. Evans' testimony can be found at 7 Tr 2457-2477. Mr. Evans sponsored Exhibits MEC-1 through MEC-5, Confidential Exhibit MEC-6C, and MEC-7.

pathways; and (5) there were numerous inaccuracies in DTE's inputs leading to erroneous results.

Mr. Evans testified that he defined a pathway, using minimal manual intervention, that resulted in a lower-cost plan than any of the pathways that DTE proposed, thus demonstrating the company failed to define the optimal (least-cost) plan and that, based on his model, Belle River may not need to be replaced when it retires.

Mr. Evans testified that, based on actual operation of DTE's system from 2014-2018, DTE significantly underestimated capacity purchases and sales from and to MISO for 2019-2022.[61] Mr. Evans claimed that this discrepancy indicated that DTE may have failed to review and verify its modeling results.

Mr. Evans explained that he found two significant errors in DTE's Strategist input data: (1) DTE included the portion of Belle River generation that should be attributed to the MPAA; and (2) DTE's hourly generation for solar indicates generation occurring overnight. Mr. Evans testified that including MPAA energy in the modeling assumes that this energy is available to serve DTE customer load and will therefore make Strategist less likely to add resources, conflicting with an optimal expansion plan. Mr. Evans also pointed out that DTE failed to run an End Effects analysis (i.e., the evaluation of resources over a time beyond the study period), noting that the failure to consider end effects can bias the results against adding capital intensive projects near the end of the study period. Mr. Evans testified that by adding an End Effects analysis to two of DTE's modeling runs, Strategist selected wind and solar to replace Belle River.[62]

[61] See, Chart 1, 7 Tr 2468 and Chart 2 7 Tr 2469.
[62] See, Exhibit MEC-7, Case Nos. 2 and 3 in Table 1.

Mr. Evans testified that, based on information provided by other witnesses, he developed alternative resource plans and retirement dates. Mr. Evans described the changes or corrections he made to DTE's modeling as well as the results from his Strategist runs.[63] Finally, Mr. Evans listed a number of improvements that he recommended DTE implement in its next IRP.

Robert M. Fagan, a Vice President at Synapse Energy Economics,[64] took issue with DTE's assumption that the current CIL of 3,211 MW will persist throughout the study period. Mr. Fagan testified that by the end of 2023, when voltage concerns related to Tier 2 plant retirements are resolved, there will likely be a significant increase in CIL, which will in turn lower LCR. Mr. Fagan pointed to the 2019 LOLE Working Group report that estimates Zone 7 CIL at 4,287 MW, as well as ITC's analysis of high solar penetration showing a CIL of 5,437 MW. Mr. Fagan opined that it was unreasonable for DTE to simply assume that CIL will not increase over the course of the plan, noting that such assumption prevents the possible early retirement of Belle River in the modeling as well as affecting capacity pricing assumptions. Specifically, Mr. Fagan testified that, with an increase in the CIL, the company could take advantage of abundant and less costly wind resources outside of Zone 7 through bi-lateral contracts, thereby lowering the cost of the IRP.

Avi Allison, a Senior Associate with Synapse Energy Economics, Inc.,[65] testified that in its IRP, DTE failed to adequately analyze alternative retirement scenarios for Belle

[63] See, Exhibit MEC-7, Tables 1 and 2.
[64] Mr. Fagan's testimony is transcribed at 7 Tr 2480-2508. He sponsored Exhibits MEC-8 through MEC-14.
[65] Mr. Allison's testimony is available at 7 Tr 2514-2580. A portion of Mr. Allison's testimony is confidential. He sponsored Exhibits MEC-16 through MEC-43.

River and failed to analyze Monroe retirement at all. In addition, Mr. Allison testified that even in the retirement sensitivities that the company did perform for Belle River, DTE did not include the correct capacity of the units in the early retirement scenario, and it understated the fixed costs of continued operation of the units, thereby biasing the results in favor of running the Belle River units longer.

Mr. Allison also testified that DTE made significant calculation errors and used outdated assumptions for renewables and demand-side resources, again biasing the results of the modeling. Mr. Allison pointed to the incorrect costs, capacity factors, and capacity credits DTE used for wind and solar resources as well as the inability of the model to select near-term renewables to take advantage of tax credits. Mr. Allison questioned DTE's reliance on the outdated Strategist model, and he testified that in light of the significant flaws in this IRP, it is unreasonable for the company to wait until 2025 to file its next IRP. Mr. Allison therefore recommended that DTE file a new IRP in 2021. As part of that filing, DTE should correct the errors identified in this IRP, present the results of an all-resource RFP, and conduct a comprehensive economic assessment of the retirement of Belle River and Monroe. Finally, DTE should begin immediately evaluating alternatives to Strategist for use in its next IRP.

Chris Neme, a co-founder and Principal of Energy Futures Group,[66] testified regarding DTE's analysis of EWR in its IRP. According to Mr. Neme, DTE's approach to modeling EWR suffers from a number of defects including: (1) DTE made simplifying assumptions that missed energy savings opportunities; (2) DTE's modeling results in an "end effects" problem wherein virtually all of the costs of EWR implemented in later years

[66] Mr. Neme's testimony is transcribed at 7 Tr 2658-2707. He sponsored Exhibits MEC-44 through MEC-52.

are included in the analysis but long term benefits are not because the modeling ends in 2040; (3) DTE's EWR cost inputs erroneously assume that administrative costs increase in proportion to program costs; (4) the company assumes reduced line losses of 6.8% for EWR, DTE's system average, which does not reflect EWR savings on-peak; instead, DTE should have applied higher marginal line loss savings, which would result in the selection of more EWR; and (5) DTE's load forecast overstates the amount of embedded energy efficiency savings for C&I customers from 2009-2016. As a result of these flaws, Mr. Neme concluded that DTE's IRP selects a less-than-optimal level of EWR, and the errors also affect the company's capacity and retirement analyses.

Douglas B. Jester, a Partner of 5 Lakes Energy LLC,[67] recommended that the Commission reject DTE's IRP on several grounds including: (1) given the flaws in DTE's analysis, the plan does not represent the most reasonable and prudent means to meet the company's energy and capacity needs over the next 15 years; (2) DTE's erroneous claim that it does not have a persistent capacity need over the next 10 years should be rejected; (3) DTE's avoided costs for both the VGP programs and PURPA contracts should be the same and should be calculated using the Partial Displacement Differential Revenue Requirement method; (4) an all-resource RFP should be issued prior to any future IRP; and (5) DTE's analysis of energy storage was far too simplistic in the context of this IRP.

Mr. Jester testified that one of the principle flaws in DTE's IRP was planning to meet only the company's capacity need and not both its energy and capacity needs as required under Section 6t. According to Mr. Jester, had DTE planned for both energy and

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[67] Mr. Jester's testimony is transcribed at 7 Tr 2711-2779. He sponsored Exhibits MEC-53 through MEC-63.

capacity, certain resources would have been selected at a time when there was no capacity need (superfluous resources), which would nevertheless result in a lower net present value of revenue requirement (NPVRR) than preventing the model from adding resources when there was no additional capacity required.[68]

Next, Mr. Jester took issue with the company's failure to issue an RFP for new resources prior to filing its IRP. Mr. Jester opined that the resources included in the fixed PCA, including those designed to meet Act 295 RPS requirements and customer needs in the VGP program, trigger the requirement that an RFP be issued. He added that the results of a competitive solicitation would provide updated cost information that could assist in the Commission's determination as to whether the IRP is the most reasonable and prudent course of action. Mr. Jester explained that while he continues to support the use of publicly-available information for long-term cost projections, for near-term resource acquisition, an RFP is far more accurate and, based on his experience, will have lower costs than estimates based generic units.

Mr. Jester testified that DTE failed to reasonably consider CHP as a potential supply-side resource in its IRP. After describing the benefits of CHP, Mr. Jester noted that DTE eliminated the technology from its analysis on economic grounds based on the cost of a "generic" CHP. Mr. Jester stated that in the case of CHP particularly, a survey of large customers gauging their interest in CHP, or an RFP, could have provided more concrete cost information that would have allowed CHP to be modeled as part of the IRP.

Mr. Jester criticized DTE's modeling of solar resources, noting that the company modeled a fixed tilt, rather than single-axis tracking, solar system resulting in a lower

[68] See, Exhibit MEC-7, Case 4.

capacity credit assigned to the resource in the analysis. Mr. Jester opined that this was a significant error that justifies redoing DTE's entire analysis.

Mr. Jester explained the relationship between DTE's request for a finding that the company has no persistent capacity need for the next 10 years and the company's ongoing PURPA avoided cost proceeding in Case No. U-18091. Mr. Jester described the time horizon for determining a capacity need, persistent or otherwise, as a red herring, recommending that DTE establish a queue of capacity offers from QFs that can then be contracted at full avoided cost if there is a capacity need that arises at any point. Mr. Jester made recommendations for calculating capacity credits under the VGP program, including the use of the partial displacement differential revenue requirements method for calculating avoided costs under both PURPA and the VGP program.

Mr. Jester disputed DTE's claim that it has no capacity need for the next 10 years as shown in Exhibit A-6. Mr. Jester points out that some information in the exhibit is unexplained and appears to show a near-term capacity need. Mr. Jester adjusted the company's exhibit, as shown in Exhibit MEC-59, and found capacity shortfalls ranging from 6 MW to 82 MW in 2023/24, 2024/25, and 2025/26, belying DTE's claim that it has no capacity need until 2029/30. Finally, Mr. Jester made specific recommendations for modeling various storage options along with recommendations for better assessing DG as a potential resource option.

Michael Milligan, Principal at Milligan Grid Solutions, Inc.,[69] raised concerns about the Brattle Report,[70] which he characterized as unreasonably conservative, relying

[69] Mr. Milligan's testimony can be found at 7 Tr 2783-2802. He sponsored Exhibits MEC-64 through MEC-74.
[70] See, Exhibit A-47.

on assumptions that are speculative. As a result, the Brattle Report leads to an erroneous conclusion that the electrical system in Michigan will be weakened by the addition of significant amounts of renewable energy in 2031 and 2040.

Mr. Milligan testified that the Brattle Report discusses two main concerns: (1) the potential decrease in the CIL; and (2) a decline in ramping capability due to the retirement of dispatchable units. According to him, the Brattle Report identifies a decrease in CIL as a risk, but it fails to address the likelihood that a decrease will occur. In addition, MISO projects that CIL will increase over the coming years, contrary to the assumption contained in the Brattle Report.

In addition to the assumptions about CIL, Mr. Milligan discussed other aspects of the Brattle Report including the provision of voltage and other grid support services by wind and solar as well as the dispatchability of these resources, the effectiveness of the MISO market in delivering low-cost energy, and the rapid advancement of battery storage coupled with steep cost declines. Mr. Milligan suggested that the modeling performed in support of the report does not include the contribution wind and solar can make to ramping needs, the changes in load shape due to adoption of EVs (including flexible DR) and building electrification. And he noted that the solar resources modeled in the report were fixed-tilt rather than single-axis tracking systems that were used in DTE's Strategist modeling.

Dale Osborn, a consulting electrical engineer with specialization in transmission planning,[71] testified regarding DTE's transmission analysis. Mr. Osborn concluded that DTE's failure to model imports from outside of Zone 7, its failure to take advantage of

[71] Mr. Osborn's corrected public testimony is transcribed at 7 Tr 2805-2838. He sponsored Exhibits MEC-75 through MEC-84 and Confidential Exhibit MEC-81C.

opportunities to increase CIL through the installation of static var compensators (SVCs), and the company's decision to adopt a voltage criterion of 0.92 at Fermi, results in an insufficient analysis of transmission options and, in turn, produced an unreasonable and imprudent IRP.

Mr. Osborn described DTE's interconnections to the MISO, PJM, and Ontario (IESO) markets, noting that both PJM and IESO appear to have significant excess capacity that could be imported to Michigan and that MISO imports energy from both PJM and IESO on a daily basis. Mr. Osborn testified that because prices for IESO exports are lower than PJM or Michigan MISO prices, it would be reasonable for DTE to enter into a firm capacity purchase agreement for some portion of the IESO power that is already flowing into MISO. However, according to Mr. Osborn, it does not appear that DTE has explored that option. Mr. Osborn testified that customers in MISO Zone 7 experience higher prices than customers in other MISO zones, primarily due to the desire of Michigan utilities to focus on in-state generation rather than connecting the state to the rest of the grid.

Mr. Osborn reviewed statutes, Commission orders, and the Statewide Energy Assessment (SEA)[72] as they relate to transmission considerations in the IRP. Mr. Osborn testified that DTE did not evaluate potential purchases from outside Zone 7 as part of this IRP because the company was not certain that uncommitted resources were available outside the zone, the limited ECIL, and the likelihood that resources located either inside or outside of Zone 7 would cost the same. Mr. Osborn stated that DTE's assertions are

[72] Michigan Statewide Energy Assessment, Final Report, September 11, 2019. Available at https://www.michigan.gov/documents/mpsc/2019-09-11_SEA_Final_Report_with_Appendices_665546_7.pdf

not supported by evidence: the company did not investigate or solicit resources outside of Zone 7 as part of its IRP, and wind PPA prices are significantly lower in interior MISO zones than they are in the Great Lakes region.

With respect to DTE's concerns about CIL, Mr. Osborn testified that for the most part, power transfer into Zone 7 is voltage-limited, and certain actions by DTE, specifically the amount of reactive power DTE is drawing from the system, may negatively impact the CIL by producing voltage constraints. Mr. Osborn recommended changing the approach to transmission design and operation in Michigan, including the addition of SVCs at specific substations, to address this concern. He further noted that ITC has been studying ways to increase the CIL and has determined that the installation of three to five SVCs could allow for an increase in CIL. However, DTE has decided to implement a non-transmission alternative at Fermi.

George D. Thurston, a Professor of Environmental Medicine at the New York University School of Medicine,[73] documented the adverse health impacts arising from exposure to various pollutants emitted by fossil-fueled generation units, citing epidemiological population-based and cohort studies that demonstrate that exposure to air pollution leads to decreased lung function, increased instances of childhood asthma, asthma symptoms, and asthma and heart attacks, increased visits to emergency rooms and hospitalizations, and higher death rates. At the same time, Dr. Thurston discussed other studies that have demonstrated that a reduction in air pollution levels can result in improvements in public health.

[73] Dr. Thurston's testimony is transcribed at 7 Tr 2881-2912. He sponsored Exhibits MEC-85 through MEC- 87.

Dr. Thurston testified that it is quite feasible for a utility to evaluate public health impacts in an IRP, noting that DTE has comprehensive information on emissions and plant operations. For the evaluation of economic impacts to public health from air pollution, Dr. Thurston cited the US EPA approved Environmental Benefits Mapping and Analysis Program (BenMAP), which relates changes in air pollution levels with changes to health, as well as other tools and places where these tools have been applied. Dr. Thurston concluded that in future IRPs, DTE should be required to assess public health impacts, and their costs, as part of its planning for fossil generating units.

Kindra Weid, the Coalition Coordinator for MI Air MI Health,[74] observed that while DTE has planned retirement of several of its coal-fueled units by 2022, several others are slated to run much longer. Ms. Weid testified that based on her review of the emissions data that DTE provided in this case,[75] the conversion of RR3 from coal to recycled industrial gas will not result in a reduction of emissions from this unit from 2018 rates to 2020 rates for all pollutants.

Similar to Dr. Thurston, Ms. Weid described and discussed the health impacts of various air pollutants including PM, SO_x, NO_x, ozone, and volatile organic compounds (VOCs), and she testified regarding Michigan-wide estimates of the impacts of air pollution on morbidity and mortality, noting that more detailed would be required to apply these estimates to DTE's air emissions. Ms. Weid testified that several cities in Southeast Michigan rank in the top 25 for excess deaths due to ozone and PM according to the American Thoracic Society. Ms. Weid recommended that the Commission include health

[74] Ms. Weid's testimony is transcribed at 7 Tr 2922-2943. She sponsored Exhibits MEC-88 through MEC-92.
[75] See, Exhibits MEC-89 through MEC-91.

impacts in its evaluation of the IRP, recognizing that the externalities she described represent real costs to certain communities in DTE's service territory, which should be taken into consideration in the IRP.

E. Environmental Law and Policy Center, et al.

ELPC et al. presented the testimony and exhibits of six witnesses.

James P. Gignac, Lead Midwest Energy Analyst for the Union of Concerned Scientists,[76] introduced the other witnesses testifying on behalf of ELPC et al.; he summarized ELPC et al.'s evaluation of the IRP, and he recommended that DTE's request for approval of the IRP be denied. Mr. Gignac explained that ELPC et al. was most concerned with DTE's starting point for its IRP analysis and the issues that emerged from the assumptions made at the beginning of the planning. Mr. Gignac testified that DTE also overestimated the costs of solar and underestimated the benefits of EWR; the company relied too much on VGP resources, and it failed to analyze ramping resources, competitive procurement of resources, or the retirement of aging peaker plants.

Dr. Eric Woychik, an executive consultant with Strategy Integration, LLC,[77] described DTE's starting point that was used in all four modeling scenarios. According to Dr. Woychik, the starting point largely fixed the company's plan for the future, and it cannot be changed. Moreover, Dr. Woychik testified that the starting point resources were not based on the lowest-cost resources, which then prevented the model from picking the optimal, lowest cost portfolio in the future.

[76] Mr. Gignac's testimony is transcribed at 7 Tr 1880-1897. He sponsored Exhibit ELP-17.
[77] Dr. Woychik's testimony is transcribed at 7 Tr 1899-1950. He sponsored Exhibits ELP-2 through ELP-9.

Dr. Woychik testified that, among other things, DTE failed to include the fixed and variable O&M costs or the significant investments required for environmental upgrades and power replacement at Belle River and Monroe. As a result of these deficiencies, Dr. Woychik found that DTE's IRP results were distorted and that potentially lower cost resource options were not included. Thus, Dr. Woychik opined that DTE failed to deliver the robust IRP analysis required under Section 6t and by the Commission.

Dr. Woychik testified that in 2016, DTE performed an economic analysis of its Tier 2 coal units and determined that these units should be closed because the costs to safely operate the plants and comply with new environmental regulations were not favorable. According to Dr. Woychik, the same type of analysis could have been performed for Monroe and Belle River, but instead the company assumed that the units would operate until 2030 and 2040 without considering the possibility of earlier retirement. Dr. Woychik further testified that, given the downward cost trajectory of renewable resources and DERs, Monroe would be unlikely to remain part of the resource mix, especially if all costs, including environmental retrofit costs, were modeled.

Next, Dr. Woychik testified that DTE significantly underestimated growth in EV adoption and therefore underestimated the amount of EV load and EV load control available to the company. Dr. Woychik contended that DTE relied on dated sources for its EV forecast, pointing to 2018 data from EIA that projects rapid EV growth from 2018-2050.

Dr. Woychik testified that DTE also overestimated the future costs of battery storage, citing a recent article from BloombergNEF showing steeply declining costs for lithium-ion batteries from 2010 through 2018 and an analysis by the International Energy

Agency projecting significant declines in costs for batteries from 2020 through 2040. He added that DTE failed to account for declining cost trends for solar and wind, again pointing to a Bloomberg analysis. Dr. Woychik further noted some examples of cost-competitive renewables plus storage systems, highlighting the fact that batteries can provide the ramping capacity that coal units lack and that DTE will require in the future. Dr. Woychik opined that given likely cost increases for Belle River and Monroe, DTE could acquire cost-competitive renewables plus storage to replace these units in the next four years.

Dr. Woychik questioned whether DTE had complied with the Commission's order in Case No. U-18419, which in part directed the company to evaluate a portfolio comprised of energy efficiency, renewables, DR, and storage to replace Belle River in 2029. According to Dr. Woychik, DTE instead analyzed the capacity need from the retiring units by including an alternative to keep Belle River running for an additional four years. Dr. Woychik recommended that the Commission decline to adopt DTE's proposals for an additional CCGT in 2029, citing gas price risk, greenhouse gas emissions costs, ramping needs that are limited to the proposed plant's location, and the likelihood that a gas plant will eventually be a stranded asset given the cost reductions for renewables.

Kevin Lucas, the Director of Rate Design for the Solar Energy Industries Association,[78] testified that despite all its modeling efforts, DTE did not base its IRP on its modeling results. Instead, the company coded most of the renewable build, market capacity purchases, and retirement assumptions into its starting point, limiting the scope of the output results, which were narrowly focused on the replacement of Belle River

[78] Mr. Lucas's testimony is transcribed at 7 Tr 1955-2103, and his surrebuttal testimony can be found at 7 Tr 2233-2235. He sponsored Exhibits ELP-10 through ELP-66.

capacity in 2029. Mr. Lucas further testified that DTE overestimated the cost of solar energy by arbitrarily selecting inputs from varying sources and by failing to model single-axis tracking systems, instead modeling lower-capacity fixed-tilt solar. Mr. Lucas contended that when the solar assumptions are corrected, nearly 2 gigawatts (GW) of solar should be added at a savings of almost $1 billion. DTE also failed to optimize the blend between wind and solar resources in either the fixed or flexible PCA.

Mr. Lucas testified that DTE's failure to model its peaking fleet was a significant omission in its analysis, noting that these older units are unreliable and could be economically replaced with solar plus storage. Mr. Lucas also criticized DTE's assumption that all new renewables, including those added for the VGP program, will be company-owned, opining that this ownership structure will likely be more costly for customers.

Joseph Daniel, a Senior Energy Analyst with the Union of Concerned Scientists,[79] focused on the modeling of existing resources, the treatment of EWR, and topics related to energy affordability and the health impacts of coal-fired power plants.

Mr. Daniel testified that DTE's over-reliance on a "must-run" designation for its existing fossil plants, which forces the model to accept a certain amount of energy and capacity from those units, despite what might be most economical. Mr. Daniel further observed that the company applied a "min-cap" designation to its existing units, representing the minimum level of name-plate capacity at which each plant must operate, again, regardless of economics.

[79] Mr. Daniel's testimony is transcribed at 7 Tr 2160-2195. A portion of Mr. Daniel's testimony is contained in a confidential record. He sponsored Exhibits ELP-67 Confidential Exhibits ELP-68 and ELP-69, and ELP-70.

Mr. Daniel explained that recent analyses have shown that the use of a “must-run” designation (i.e., self-committing) for actual operations, can lead to uneconomic outcomes. He pointed to studies performed by Power Bureau in 2017 for an Illinois unit in MISO, Bloomberg New Energy Foundation looking at all coal-fired units in the U.S., and a study he performed for the Southwest Power Pool, all of which indicated that some “must-run” units are operating uneconomically some of the time. Mr. Daniels further noted that public utilities commissions in Minnesota and Missouri have opened investigations into self-committing to see if the practice is in the customer interest. Mr. Daniels recommended that DTE remove the “must-run” designation from its non-nuclear units in order to accurately evaluate the economics of these units in comparison to alternatives.

Mr. Daniel discussed a modeling run performed by Ms. Sommer, in which the “must-run” designation was removed from DTE’s non-nuclear units. He observed that for most years, the modeled generation by these units is lower without the “must-run” constraint, and for certain units, the amount of generation is considerably lower.

Mr. Daniel took issue with DTE’s modeling of EWR in the IRP, noting that the company failed to include the full range of benefits from energy efficiency, including avoidable T&D losses, capital costs, and energy and capacity costs. Mr. Daniel testified that for most of its modeling runs, DTE assumed avoided T&D costs of $0/kW, and for some, it input $7.00/kW, noting that the company used project data from 2017 and 2018, a very limited approach given that there can be large variations in T&D line losses from one year to the next. Mr. Daniel further testified that other jurisdictions using much more extensive data sets reported much larger values, adding that even regions with declining loads report higher avoided T&D costs than DTE.

Mr. Daniel testified that, contrary to Ms. Zhou's claim, assigning an avoided T&D cost of $0 is not appropriate, and the language in the AEEI Report she cites refers to also states that an avoided T&D cost of $0 is conservative, and the report recommends a median value of $20/kW. Mr. Daniel also testified that DTE's valuation of avoided line losses is underestimated because line losses increase exponentially during peak periods. Thus, marginal, not average, line loss rates should be used. Because DTE does not have information on marginal line losses, Mr. Daniel recommended adjusting the average line loss amount by multiplying it by 1.5.

Mr. Daniel listed additional benefits of EWR, including its potential to defer or displace planned or existing units. Mr. Daniel further testified that DTE's own evidence shows that EWR is cost-effective (e.g., showing a benefit cost ratio greater than 1) at levels as high as 2.5%. Mr. Daniel recommended that DTE model EWR of 2.5% in its base case and analyze higher EWR levels as well in order to arrive at the most reasonable and prudent plan.

Citing a recent study from the University of Michigan, Mr. Daniel discussed the energy burden borne by low-income households in the State. Mr. Daniel explained how more EWR programs and funding focused on low-income customers would be of substantial benefit, even if less cost-effective than programs targeted at higher-income customers. Mr. Daniel also discussed the indirect benefit of EWR to low-income households, testifying that EWR can displace power plants, which in turn reduces pollution and the health effects, and costs, associated with air emissions.

Will Kenworthy, Regulatory Director, Midwest for Vote Solar,[80] discussed eight principles for evaluating utility-owned DG (UDG) programs, including: (1) UDG should provide customers with economic benefits; (2) UDG should be accessible by all customers, especially those most affected by fossil generation; (3) UDG should allow both customers and the utility to meet sustainability and clean energy goals; (4) UDG should not undermine competition; (5) UDG should provide benefits to the grid; and (6) UDG should be closely monitored by regulators to ensure that benefits are actually delivered.

Mr. Kenworthy described DTE's current VGP programs, the statutory underpinning for the programs, and Commission guidance on content and implementation. Mr. Kenworthy recommended that the Commission revisit the subscription costs of the MIGreenPower program in its 2020 review. For the large customer VGP program, Mr. Kenworthy opined that the capacity credit for solar resources is significantly undervalued and participating customers are therefore undercompensated, adding that the credit for customers in the MIGreenPower program is calculated differently than the VGP credit.

Mr. Kenworthy reviewed the renewable resources included in DTE's starting point and recommended that the Commission require DTE to develop a PCA that optimizes the resources in the model, rather than simply embedding assumptions and a plan as the starting point. Mr. Kenworthy added that DTE failed to evaluate behind-the-meter generation in its modeling, despite the MIRPP requirement that it perform such an analysis.

Mr. Kenworthy testified that the MIGreenPower program could grow considerably if the capacity credit were calculated correctly, and that the company only performed a

[80] Mr. Kenworthy's testimony is transcribed at 7 Tr 2108-2155. He sponsored Exhibits ELP-71 through ELP-75.

cursory evaluation of community solar, noting that this program will also be offered at a premium price. Similarly, he testified that DTE's estimates about potential expansion of the large customer VGP program may be understated because of the inflated cost of the program. Nevertheless, Mr. Kenworthy opined that DTE's PCA relies too heavily on utility-owned VGP programs, ignoring the opportunities for customers to benefit from customer-owned renewables or competitive markets for meeting demand for clean energy. Mr. Kenworthy questioned whether the utility-ownership model assumed by DTE is truly the most cost-effective alternative, observing that the utility cost of capital may be higher and regulatory accounting requirements may make utility-owned assets more expensive.

Finally, Mr. Kenworthy urged the Commission to evaluate the extent to which DTE's voluntary programs are designed to be accessible to low-income customers, listing the benefits of such programs including tangible economic benefits, reduction in household energy burden, and local economic opportunities when projects are sited properly.

Anna Sommer, a Principal with Energy Futures Group,[81] discussed the Strategist modeling she performed for this case for Mr. Lucas (modifying solar inputs), Mr. Daniels (changing the "must-run" designation), and Mr. Jester (allowing the model to add superfluous units), and she explained key aspects of Strategist's capabilities. Ms. Sommer also raised a specific concern about DTE's modeling of new and existing peaking units as well as new gas units. Ms. Sommer testified that because DTE modeled these units to run at specific minimum and maximum capacities, rather than using capacity segments, the model was biased in favor of constructing a new unit.

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[81] Ms. Sommer's direct testimony is transcribed at 6 Tr 1760-1772. Cross-examination of Ms. Sommer begins at 6 Tr 1791 and continues through 6 Tr 1848.

Ms. Sommer explained that Strategist is a well-known tool that has been used for decades, but the program has a number of limitations that make true optimization of resources difficult. She noted that while there are two methods for dealing with some of these concerns, DTE did not appear to fully implement either method.

Finally, Ms. Sommer made recommendations on options for DTE's future modeling efforts. She testified that Strategist's vendor will no longer be supporting the software, which presents an opportunity for DTE to transition to a more appropriate model with greater capabilities. She cautioned, however, that some more up-to-date platforms are less transparent and accessible at a time when transparency should be increasing.

F. Association of Businesses Advocating Tariff Equity

ABATE presented the testimony of one witness.

Brian C. Andrews, Senior Consultant with Brubaker & Associates,[82] testified that contrary to the intent of Section 6t, DTE failed to undertake a comprehensive look at supply-side resources, and that the company included significant REP and VGP resources that have not been approved by the Commission in the starting point for its modeling. Mr. Andrews noted that these resources were included at zero cost, thus depriving the Commission of the opportunity to evaluate the reasonableness and prudence of the investments.

Mr. Andrews also took issue with DTE's proposal to increase its EWR savings from 1.50% currently to 1.75% by 2021. Mr. Andrews contended that it was not clear how the company arrived at this level, noting that the least-cost plan in DTE's reference scenario

[82] Mr. Andrews' testimony is transcribed at 7 Tr 3037- 3048. Mr. Andrews sponsored Exhibits AB-1 through AB-5.

results in EWR savings of 1.5%. Mr. Andrews agreed with DTE that the increase in EWR savings from 1.50% to 1.75% results in significant additional costs and additional risks.

G. International Transmission Company

ITC sponsored the testimony of **Charles Marshall**, Director of Transmission Planning for ITC Holdings Corp.'s MISO operating companies.[83] Mr. Marshall explained ITC's experience with DTE's IRP process and discussed why DTE's information on transmission was deficient. Mr. Marshall testified that based on the results of MISO's 2019/2020 PRA, Zone 7 does not currently appear to have adequate import capability and the addition of substantial renewable resources could exacerbate resource adequacy concerns absent a complementary transmission system.

Mr. Marshall testified that recent data from MISO, coupled with continued support for RPSs, indicates that there will be a significant amount of renewable energy capacity available in the MISO market in years ahead, adding that additional transmission resources will be necessary for Michigan to take advantage of the economic and reliability benefits of renewables outside Zone 7. Mr. Marshall explained that to promote the reliable delivery of energy, coordination and communication of information are necessary, especially in the early part of the planning process. Mr. Marshall testified that ITC views the best solution to Michigan's import capability problem is an extra high (EVH) transmission system capable of handling dynamic flows from intermittent generators.

Mr. Marshall testified that after a review of DTE's IRP, ITC recommended the placement of an SVC at the Fermi substation to address voltage issues resulting from certain components of the plan. Subsequently, ITC submitted plans to MISO to

[83] Mr. Marshall's testimony is transcribed at 7 Tr 2239-2249. Cross examination of Mr. Marshall begins at 7 Tr 2250 and ends at 7 Tr 2284.

implement the SVC solution. However, according to Mr. Marshall, DTE then changed the operating parameters at Fermi, eliminating the need for the SVCs.

Mr. Marshall concluded that the IRP process could be improved by incorporating additional filing requirements that address transmission options and by ensuring true coordination between utilities and transmission companies. Mr. Marshall emphasized that transparency and information sharing on actual scenarios and future plans is essential for the development of an accurate and useful IRP. Mr. Marshall pointed to the regional transmission organization (RTO) planning process as a possible model for coordination between utilities and transmission companies for future IRPs.

H. Energy Michigan

Energy Michigan sponsored the testimony of one witness.

Alexander J. Zakem, an independent consultant experienced in utility matters,[84] testified in response to DTE's claims about the ECIL and the Commission's concerns about increasing import capacity from outside Michigan. Mr. Zakem explained that even without increasing the physical capability to import energy, or CIL, ECIL (i.e., the usable CIL) can be increased appreciably by revising the LCR standard and computation method in the MISO Module E-1 tariff. Mr. Zakem testified that this would significantly change options for resource acquisition in the IRP.

I. Great Lakes Renewable Energy Association

GLREA sponsored the testimony and exhibits of three witnesses.

[84] Mr. Zakem's testimony can be found at 7 Tr 2950-2980. He sponsored exhibits EM-1 through EM-4.

Dr. Emily Prehoda, a member of GLREA's IRP Committee and the Policy and Innovation Director of Chart House Energy, LLC,[85] testified that DTE's IRP does not appropriately balance the factors in Section 6t(8); and therefore, the Commission cannot find the plan to be reasonable and prudent.

Dr. Prehoda opined that DTE's IRP is dependent on costly, centralized power, despite a general shift toward incorporating DG and other third-party resources that are less expensive than utility-owned plants. Dr. Prehoda added that DTE's plan does not ensure reliability, citing a recent report from the Citizens Utility Board that provides data showing that DTE's reliability, in terms of outages, is one of the worst in the country. Dr. Prehoda testified that smart technology coupled with distributed generation could help reduce the number and scope of customer outages. Dr. Prehoda pointed to a number of utilities that are addressing reliability through increased renewable generation.

Dr. Prehoda testified that DTE's IRP is not affordable, observing that DTE did not evaluate PPAs as a lower-cost resource compared to company ownership. Dr. Prehoda pointed to the IRP filed by Consumers Energy, which extensively addresses PURPA contracts that can reduce cost and risk to the utility and its customers. She supported the settlement agreement in the Consumers IRP, which provides for a 50/50 split in ownership between Consumers and third-party developers.

Dr. Prehoda testified that although natural gas is cleaner than coal-fired generation, it is not the cleanest option for meeting energy and capacity needs. She added that DTE's reliance on gas generation in the future represents environmental and economic risks, especially if natural gas commodity prices increase. She opined that DTE

[85] Dr. Prehoda's direct testimony is transcribed at 7 Tr 3054-3069, and her rebuttal testimony is transcribed at 7 Tr 3071-3084. She sponsored Exhibit GLREA-1.

did not sufficiently explore EWR or energy storage in its modeling and questioned whether DTE's PCA is as flexible as the company claims or whether the company fully considered community impacts of its IRP.

Dr. Prehoda filed rebuttal to the Staff's recommendation that the IRP be approved subject to refiling in three years, as well as specific recommendations made by Staff for future IRPs.

John Richter, Policy Analyst and member of the Board of Directors of GLREA,[86] testified that DTE could satisfy its REC requirements under Act 295 by purchasing unbundled RECs or via PPAs with third-parties, either of which may be a lower cost alternative to the company's proposal to own all renewable facilities. Mr. Richter pointed to a recent third-party purchase of solar energy and capacity by Consumers that had a lower levelized cost of energy (LCOE) than what DTE assumed for wind energy in this IRP. Mr. Richter listed several additional benefits that could be derived from third-party solar including the higher availability of solar at peak times and reduced economic risk for the company and its customers. Mr. Richter also recommended that DTE consider more customer-owned DG facilities in meeting its requirements, again listing the benefits that these facilities provide.

Mr. Richter took issue with DTE's failure to model additional energy from QFs in its IRP, noting that even if the company does not have a capacity need, under PURPA, the company is still required to purchase energy from QFs at avoided cost. Mr. Richter discussed the number of possible QFs in DTE's interconnection queue, noting that at least 10% of these projects, totaling 171 MW, will likely be completed and should have

[86] Mr. Richter's direct testimony is transcribed at 7 Tr 3089-3136, and his rebuttal testimony is transcribed at 7 Tr 3139-3168. He sponsored Exhibits GLREA-2 and GLREA-3.

been included in the IRP modeling. Failure to include energy from QFs could mean that DTE will overinvest in EWR, DR, and CVR/VVO to the detriment of ratepayers.

Next, Mr. Richter disputed DTE's request for a finding that the company does not have a capacity need for the next 10 years. Mr. Richter points to the fact that DTE is requesting preapproval for spending on DR and CVR/VVO, as well as increasing its spending on EWR programs, all as a means to replace capacity from retiring coal units. Thus, according to Mr. Richter, DTE's own IRP shows that the company has a capacity need in the short term, yet the company refuses to pay QFs full avoided cost.

Mr. Richter expressed skepticism about capacity or energy savings from DTE's pilot CVR program, and he recommended that the Commission deny approval of funding until the company demonstrates that the assumed load response will occur. Mr. Richter also questioned DTE's assumptions about LCOE for wind, noting that the costs used in this case are significantly higher than those testified to in the company's PURPA case.

Next, Mr. Richter questioned the company's projections for gas prices, noting that the PACE forecast shows significantly lower prices over the course of the plan than the EIA forecast, especially in later years. Mr. Richter testified that the NPVRR of any plan that includes a gas plant is highly dependent on continued low commodity costs, which in turn depend on the company's forecast.

Mr. Richter testified that the IRP provides insufficient information on DTE's proposal to convert RR3 to waste industrial gas and natural gas. Mr. Richter noted that the combustion values of blast furnace gas and coke oven gas compared to natural gas are much lower and questioned whether DTE may ultimately rely more on higher cost natural gas fuel rather than the alternatives. In that case, the economics of operating RR3 may materially change.

Mr. Richter testified that DTE underestimated the ELCC of solar under MISO rules, contending that DTE's older facilities demonstrate an ELCC of 60%, which should be expected with newer facilities as well. As a result of this and other erroneous inputs, Mr. Richter testified that DTE overestimated the LCOE for solar resulting in wind as the preferred renewable resource. Mr. Richter further observed that an LCOE comparison between wind and solar is misleading because solar produces less energy but much more capacity than wind.

Finally, Mr. Richter provided critiques of errors and omissions in the IRP, including: (1) the failure to use a sufficiently high value for a future CO_2 tax; (2) the failure to consider the potential for methane regulation in the risk analysis; (3) the IRP does not conform to the Paris Accord on Climate change, despite DTE's claims to the contrary; (4) DTE's plan does not fully incorporate or address environmental compliance costs; (5) PCA and ratepayer risks could be reduced by including more contracted resources; (6) the IRP does not sufficiently analyze transmission options that could result in lower cost energy and capacity; (7) DTE failed to analyze TOU rates with a higher on-peak/off-peak rate differential, which could reduce DTE's capacity requirements and therefore costs; and (8) had DTE included public health benefits resulting from less reliance on fossil fuels, its retirement analysis would have called for earlier retirement of its coal units.

Mr. Richter filed rebuttal testimony to the Staff's recommendation that the Commission approve DTE's IRP subject to changes in the company's next IRP filing. He also provided comments expressing agreement with several intervenor witnesses.

Robert Rafson, a member of GLREA IRP Committee and the owner of Chart House Energy, LLC,[87] testified regarding the need for fair rates, the lack of public engagement by DTE, and DTE's failure to adequately evaluate PURPA and DG as part of its IRP analysis.

Mr. Rafson characterizes DTE's IRP as a "business-as-usual" approach to planning, in clear contrast to the more forward-thinking approach by Consumers. Mr. Rafson advocated planning focused on decentralized resources including DG; digitalization for better load control and power quality; and decarbonization. Mr. Rafson testified that, contrary to DTE's claim, the company does have a capacity need in the next five years, based on the planned retirement of coal units offset by the capacity of the BWEC in 2022. Mr. Rafson recommended annual capacity reviews and made specific recommendations with respect to PURPA contracts (length and project size for the standard contract), the advantage of PPAs over utility ownership of assets, environmental justice, and the DG tariff structure.

Mr. Rafson filed rebuttal testimony to the Staff's position on the IRP, and he provided testimony in support of the recommendations of other intervenor witnesses.

J. Soulardarity

Jackson Koeppel, Executive Director of Soulardarity,[88] testified about the need for low-income communities and communities of color to have access to renewable energy through community-based energy projects. Mr. Koeppel further testified that DTE's IRP is particularly harmful to low-income communities, citing public health impacts

[87] Mr. Rafson's corrected direct testimony is transcribed at 7 Tr 3172-3189, and his corrected rebuttal testimony is transcribed at 7 Tr 3191-3202.
[88] Mr. Koeppel's testimony is transcribed at 7 Tr 2287-2333. He sponsored Exhibits SOU-1 through SOU-27.

of fossil power plants located in or near low-income areas. According to Mr. Koeppel, among other things, DTE failed to consider the health effects and costs of ozone pollution in non-attainment areas in developing its IRP. Mr. Koeppel highlighted issues in Highland Park, characterizing the community as a “microcosm” of problems in the relationship between DTE and low-income communities.

Next, Mr. Koeppel discussed the importance of renewable energy for low-income communities and communities of color, pointing out environmental, health, and safety benefits, access to energy (thereby promoting “energy democracy”) and grid resilience, which is of particular benefit to more vulnerable populations. Mr. Koeppel further stressed the importance of community-owned energy projects, noting the opportunity to better engage, and provide a sense of investment for, low-income communities.

Mr. Koeppel described DTE’s public outreach in advance of its IRP filing as “shamefully poor,” opining that the sessions were not really designed to receive public input and noting that the outreach meetings were not advertised in low-income areas, translators were not always available, and meetings were held during the day when many interested persons were unable to attend. Mr. Koeppel testified that it was especially important to solicit input from low-income communities that have unique perspectives and energy needs.

Mr. Koeppel took issue with DTE’s commitment to renewable energy and de-carbonization of its electric fleet, pointing to Consumers plans to increase solar energy generation and reduce carbon emissions by 90% by 2040. Mr. Koeppel raised concerns about DTE’s IRP after 2024, noting that although the long-term plan includes substantially more solar, two of the four pathways include a new gas plant. Mr. Koeppel testified that

that DTE's flexible PCA is not as flexible as it first appears given that several of the alternative pathways will require significant investment years in advance.

Mr. Koeppel criticized DTE's failure to analyze DG as part of its IRP, highlighting the availability of rooftops for solar generation in Highland Park that could produce sufficient energy to meet almost all of that community's residential and commercial demand. Mr. Koeppel also outlined the benefits of community-based energy projects that contribute to energy democracy, energy justice, economic development, public health, and energy reliability, noting particularly that low-income communities have disproportionately borne the costs of conventional generation.

Mr. Koeppel took issue with the December 20, 2017 order in Case No. U-15896, where the Commission determined that public health impacts are more appropriately addressed in a CON filing, opining that the scope of a CON proceeding is not sufficiently encompassing to properly consider the health and environmental impacts of the company's entire fleet.

Mr. Koeppel testified that DTE's EWR plan does not allocate sufficient funding to low-income programs, pointing out the high energy burden electric rates impose on low-income customers. Mr. Koeppel explained that because of the large opportunity for energy savings for low-income customers, DTE should be required to focus much more effort and funding on these customers. Mr. Koeppel suggested that, given the age of the housing stock, low-income EWR programs should be focused on weatherization and should be broadened to include home repair and asbestos and lead abatement. Mr. Koeppel also raised concerns about DR programs that might limit participation by low-income customers.

Finally, Mr. Koeppel made a number of suggestions for increasing public engagement and participation in the IRP process including: (1) having community leaders, rather than DTE officials, host public meetings; (2) DTE should clearly explain how community and stakeholder input will inform the IRP; (3) DTE should hold more public meetings in communities that are most impacted by the IRP; (4) DTE's focus group, which developed the company's planning principles, should not be comprised solely of DTE employees; and (5) the Commission should sponsor more public forums in advance of the IRP, and the hearings on the case should be held in DTE's service territory, not in Lansing, where few community members can attend.

K. City of Ann Arbor

Ann Arbor provided the testimony of one witness.

Dr. Missy Stults, Sustainability and Innovations Manager for the City of Ann Arbor,[89] provided testimony outlining the city's concerns regarding the reasonableness and prudence of DTE's PCA. Dr. Stults listed several deficiencies in DTE's proposal including: (1) a mismatch between the amount of renewable energy the company is proposing and the demand for renewable resources, particularly solar energy, by Ann Arbor and other municipalities with sustainable energy goals; (2) the PCA's failure to recognize and address the urgency of climate change; (3) the failure to address the current impacts of climate change through a focus on resiliency in the PCA; (4) although DTE included a small carbon tax in several modeling runs, the company should have also included the much higher social cost of carbon in every modeling scenario; (5) DTE's failure to include details on its long term plans, which affects Ann Arbor's ability to develop

[89] Dr. Stults' testimony is transcribed at 7 Tr 2982-3001. Dr. Stults sponsored exhibits AA-1 through AA-4.

its own plans; and (6) DTE's failure to include programs for low-income customers in its IRP, thereby perpetuating inequalities in the energy system.

Dr. Stults reviewed Ann Arbor's clean energy goals, and she discussed meetings the city has held with DTE regarding the implementation of these goals. Dr. Stults testified that DTE has been amenable to assisting the city in powering municipal operations with clean energy but has been much less helpful in planning and implementing community goals. Dr. Stults noted that DTE's IRP is inappropriate for Ann Arbor because it does not transition quickly enough to renewable energy, and it fails to include microgrids, community solar, or sufficient battery storage.

Dr. Stults assessed DTE's VGP and MIGreenPower programs as costly and therefore exclusionary. She further testified that allowing DTE to rely on voluntary programs for the majority of renewable energy additions permits the company to avoid its responsibility to transition its fuel mix. Dr. Stults also observed that the proposals for renewable energy, DR, and energy efficiency in DTE's IRP do not align with the company's commitment to reduce its carbon emissions by 50% in 2030.

L. Geronimo Energy

Geronimo provided the testimony of one witness.

Betsy Engelking, Vice President of Strategy and Policy for Geronimo Energy, LLC,[90] offered a critique of DTE's PCA and provided an alternative proposal as permitted under MCL 460.6t(6). According to Ms. Engelking, in its order in Case No U-18232, the Commission found that DTE needs to fill an additional 1,062 MW of capacity and that this capacity requirement should be addressed in this proceeding. Ms. Engelking added that

[90] Ms. Engelking's direct testimony can be found at 7 Tr 3004-3012. Her rebuttal testimony is transcribed at 7 Tr 3014-3018 Ms. Engelking sponsored Exhibits GE-1 through GE-4.

Geronimo has been discussing a 20 MW solar project with DTE, which could be used to help fill the capacity need.

According to Ms. Engelking, DTE's IRP is not the most reasonable and prudent means to meet the utility's energy and capacity needs because it does not include competitive pricing; there is insufficient diversity in generating resources, and because the IRP does not adequately analyze all reasonable options. Ms. Engelking raised particular concerns about DTE's assumption that company-owned generation resources are the least cost option, characterizing the assumption as unsupported.

M. Michigan Energy Innovation Business Council/Institute for Energy Innovation

EIBC/IEI provided the rebuttal testimony of one witness.

Laura Sherman, a senior consultant with 5 Lakes Energy L.L.C.,[91] testified regarding the importance of RFPs for the IRP process, noting that Section 6t(6) requires the issuance of an RFP for any supply-side capacity resources included in the first three years of the plan. Ms. Sherman agreed with the Staff that DTE has not demonstrated that utility ownership of the renewable resources that it intends to add over the next five years is the most reasonable and prudent means to meet the company's objectives and that an RFP should be issued for 50% of these assets. She further concurred with Staff witnesses that future generation resources should be procured through a competitive bidding process and that the Commission should establish a proceeding to identify best practices related to RFPs. In addition, because of rapid advances in technology development, Ms. Sherman testified that all technologies that can meet specific capacity

[91] Ms. Sherman's rebuttal testimony is transcribed at 7 Tr 3021-3034. She sponsored Exhibits EIB-1 and EIB-2.

or energy requirements, including CHP and battery storage, should be included in any competitive process.

III.

POSITIONS OF THE PARTIES

A. DTE Electric

DTE asserts that its IRP (set forth in Exhibit A-3 Revised), and the resulting defined and flexible PCAs, should be approved as the most reasonable and prudent means to meet the company's future energy and capacity needs. DTE argues that the flexible PCA, comprised of four possible pathways, is consistent the IRP filing requirements, which reference "resource plans" rather than a single plan. In addition, DTE maintains that flexibility in future years is desirable given the rapidly evolving energy landscape.

DTE contends that in developing its IRP, it complied with all statutory requirements as well as various Commission orders related to IRP filing and modeling, as shown in Exhibit A-1 Revised. DTE dismisses criticisms of its modeling process, contending that it met all statutory, filing, and modeling requirements existing at the time of its filing and that any attempts to change or expand these requirements should be rejected as unlawful. Further, DTE argues that claims about purported errors in its modeling were either misplaced or, when corrected, made little difference in the overall results of the optimization. DTE also responded to criticisms of its transmission analysis, defending its decision to assume that CIL will remain unchanged over the course of the plan period.

DTE maintains that, based on its analysis, the company does not have a capacity need until 2030, when the Belle River plant is expected to retire. DTE argues that neither RPS nor VGP requirements should be considered as meeting a capacity need, in light of the fact that the company and its customers have alternatives to building new assets. In addition, DTE asserts that although asset ownership issues are not appropriately addressed in this proceeding, company-owned assets are generally more cost-effective than assets owned by third-parties.

DTE requests that the Commission pre-approve capital costs for EWR, DR, and CVR/VVO for projects or programs that the company intends to commence within the next three years. DTE states that the company's next IRP should be filed five years after the Commission's order in this case and that in the interim, it will evaluate different modeling tools for possible implementation.

B. Staff

Although the Staff takes issue with DTE's starting point analysis, its failure to undertake a competitive procurement process prior to filing its IRP, and the company's reliance on a flexible PCA for later years, it nevertheless finds that these flaws are not fatal to the company's case. Instead, the Staff recommends that the Commission approve the current plan, with certain changes, and that DTE be required to file an IRP, consistent with the Staff's proposals, in three years rather than five years.

The Staff recommends that DTE increase its EWR goal from 1.75% to 2%, and that in its next IRP, the company only include resources that are approved or that are legislatively mandated in its starting point. All other resources should then be optimized as part of the company's modeling. The Staff also proposes that the company evaluate the costs to continue operating its peaker fleet through 2040, considering the increased O&M costs due to the age of several of the units. The Staff indicates that the company's load forecast is reasonable, but makes some suggestions for improvement in the next

IRP. The Staff determined that the company's transmission analysis met the requirements of Section 6t and the Commission's requirements. Nevertheless, the Staff recommended that the Commission update the filing requirements to provide more guidance on how transmission constraints should be modeled.

The Staff also recommends that the Commission approve DTE's DR proposals, and funding, except for proposed capital costs for pilot programs that are not yet defined. The Staff also agrees with the company that $103 million in EWR capital expense and $0.7 million for CVR/VVO pilots are reasonable and should be approved.

Finally, the Staff urges DTE to explore alternative modeling programs, noting the complexity of the current process, as shown in Exhibit S-1.0.

C. Attorney General

The Attorney General makes four specific recommendations. First, she recommends that the Commission reject DTE's load forecast and adopt the forecast provided in Exhibit AG-4. The forecast that the Attorney General sponsors adjusts the EV forecast to one consistent with the EIA AEO projection for EVs. In addition, she recommends that the Commission require the company to update its forecast methods to reflect best practices, raising particular concerns about the use of different historical periods for different commercial markets.

Next, the Attorney General recommends that the Commission reject the company's proposed construction of renewable projects in the defined PCA. She observes that the Commission's order in Case No. U-18232 was issued in mid-July 2019, and DTE has not had time to issue an RFP for new resources, nor has the company provided sufficient analysis in this case to demonstrate that company-owned renewables constitute the most reasonable and prudent approach to acquiring new renewable generation.

The Attorney General recommends that in its next IRP, the Commission require the company to analyze all reasonable alternatives to meeting energy and capacity needs, including transmission alternatives and the repowering of existing facilities, to determine the most cost-effective energy supply. Finally, in future IRPs, the Commission should require DTE to: (1) develop its IRP using a more transparent and defined process; (2) avoid hard coding resources into the modeling or manually selecting resources; (3) remove biases toward dispatchable resources in the flexible PCA; (4) reevaluate whether any resources are needed for replacement of Belle River; (5) demonstrate that the company's IRP modeling software produces results consistent with DTE's actual operations; and (6) account for end effects in its modeling.

D. MEC/NRDC/SC

MEC/NRDC/SC support DTE's plans to accelerate certain coal plant retirements and the company's proposed (albeit too small) increases in EWR, DR and renewables integrated into is system. They also support the company's CVR/VVO pilot program. But, MEC/NRDC/SC oppose DTE's plan to continue to run RR3 on recycled industrial gasses for two years, the company's assumptions that Belle River and Monroe will continue to operate until 2030 and 2040 respectively, DTE's decision to limit EWR savings to 1.75%, and its assumption that all new renewable generation will be company-owned.

MEC/NRDC/SC characterize DTE's IRP as "fatally flawed" because its scope is too limited, and because it does not comply with the requirements of Section 6t. Specifically, MEC/NRDC/SC contend that DTE's IRP does not fully comport with MCL

460.6t(3), (5), and (8) which require the company to include its plan to address environmental regulations, costs for environmental compliance, and estimates of various air emissions. MEC/NRDC/SC also take issue with DTE's starting point analysis, which included a fixed retirement plan for existing units as well as a number of unreviewed, unapproved resources that were presumed as part of the company's carbon reduction plan but that were never optimized in the modeling. Because of DTE's inappropriate starting point assumptions, MEC/NRDC/SC contend that the Commission is precluded from making the requisite determination under Section 6t(8)(a).

MEC/NRDC/SC criticize DTE's framework regarding capacity purchases from QFs under PURPA, contending that DTE's "persistent capacity need" construct does not exist under PURPA, and it was recently rejected by the Commission in Case No. U-18091. MEC/NRDC/SC recommend that DTE look to QF capacity whenever a capacity shortfall occurs. They also recommend that DTE consider available QF capacity for filling the VGP program.

MEC/NRDC/SC argue that DTE has overstated the amount of embedded energy efficiency contained in its C&I load forecast, thereby overstating both total annual demand and peak demand. In addition, MEC/NRDC take issue with DTE's analysis of wind resources, arguing that DTE underestimated the capacity factor and overestimated the cost of new wind as well as failing to consider out-of-state wind as an alternative to in-state resources. MEC/NRDC/SC further note that after correcting certain assumptions in the company's modeling, 2% EWR savings, rather than the company-selected 1.75% level, is the economically optimal level of EWR across all scenarios. MEC/NRDC/SC also question whether DTE's assessment of the value of energy storage was adequate in this

IRP, and they raise issues concerning how the company modeled solar and DG resources.

MEC/NRDC/SC maintain that DTE's transmission analysis does not comply with the Commission's directives in Case No. U-18419, nor does it reflect recent findings from the SEA. MEC/NRDC/SC note multiple deficiencies in DTE's purported study of transmission options and urge the Commission to reject the analysis. MEC/NRDC/SC also question the value of the Brattle Report on resource adequacy, given its lack of focus on potential solutions, including costs and benefits, to integrating large amounts of renewables to Zone 7. Finally, MEC/NRDC/SC assert that DTE failed to provide a transparent and straightforward analysis of rate impacts from its IRP, and they contend that the company violated Section 6t(6) by failing to issue an RFP for new supply-side resources prior to filing its IRP.

MEC/NRDC/SC reiterate that because of the significant deficiencies in its current filing, the Commission should reject the IRP and direct the company to refile within two years of the order in this proceeding. MEC/NRDC/SC make a number of recommendations for improving the IRP process, and they specifically highlight the need to integrate health impacts and costs into the IRP, consistent with the requirements of the Michigan Environmental Protection Act, MCL 324.1705 *et seq*.

E. Environmental Law and Policy Center et al.

ELPC et al. contend that DTE's IRP is insufficient to demonstrate that the proposed PCA is the most reasonable and prudent means to meet the company's future energy and capacity needs. ELPC et al. point to the flawed starting point, and the incorrect assumptions that carried through the entire analysis, which resulted in IRP modeling that was constrained from selecting the most cost-effective set of resources. ELPC et al. add that DTE's IRP overestimates the costs of solar and undervalues the benefits of increased energy efficiency. ELPC et al. argue that DTE failed to analyze the costs of continuing to operate its peaker plants without considering replacing these plants with cleaner resources.

F. Association of Businesses Advocating Tariff Equity

ABATE contends that DTE's IRP was deficient in several ways. First, ABATE takes issue with the company's starting point portfolio, which included a number of unapproved resources at zero cost. Thus, the IRP "failed to consider *all* supply and demand-side resource options on equal merit or include in its analysis the viability of *all* reasonable options available to meet projected energy and capacity needs."[92] As such, DTE's modeling provides no basis to determine that its PCAs are the most reasonable and prudent means to meet future energy and capacity needs.

ABATE also raises concerns about DTE's EWR proposal, describing it as risky and uneconomic. According to ABATE, it is not clear how the company's goal of EWR savings of 1.75% by 2021 was arrived at, and DTE's own testimony indicates that reaching that goal will be extremely challenging.

G. International Transmission Company

ITC urges the Commission to carefully consider the impact of the CIL in the context of the IRP, noting that Zone 7 currently has deficient import capability based on the most recent MISO PRA. ITC argues that increasing the CIL will alleviate cost pressures in Zone 7 and will permit the state to realize the reliability and economic benefits of access

[92] ABATE's brief, p. 7.

to renewable energy outside of Zone 7. ITC nevertheless cautions that transmission planning and implementation require a significant lead time and substantial data. Thus,

> [i]f ITC has better visibility into the future locations of proposed generation, it can adjust plans to ensure the right transmission will be available by the generation's targeted commercial operation date. "Likewise, transmission can be rightsized, preventing an investment made 5 years prior becoming obsolete due to the necessity of more robust backbone infrastructure. Furthermore, the system can be designed in a manner to optimize and leverage both imports and exports." (7 Tr 2245-2246).[93]

ITC also recommends that DTE be required to increase its collaboration with ITC with a goal of ensuring that the utility provides accurate and up-to-date information about future plans so that beneficial transmission solutions can be developed. ITC advocates the implementation of an RTO-type planning process as a means to increase transparency and system coordination.

H. Energy Michigan

Energy Michigan observes that resource adequacy is a key feature of DTE's IRP, and it discusses the interplay between the MISO PRMR, LCR, CIL, ECIL, and physical transmission resources. Energy Michigan describes concerns about declining ECIL that were recognized in the Commission's initial and final SEA reports, and it contends that MISO's current, erroneous method of determining LCR is severely limiting ECIL. Consistent with this observation, Energy Michigan proposes that the MISO Module E-1 Tariff be amended to correct the errors and inconsistencies in the LCR calculation. Energy Michigan further recommends that the Commission lead an effort to find a solution to the issues in the MISO tariff with respect to LCR. Energy Michigan points out that "potential options in an IRP are being limited by the deficiencies of MISO's current

[93] ITC's brief, p. 4.

determination of LCR and the consequent restriction on ECIL. These deficiencies can be corrected and must be corrected if Michigan is to develop optimal IRPs."[94]

I. Great Lakes Renewable Energy Association

GLREA [95] disagrees with DTE's capacity forecast, contending that the company's position is self-serving and designed to exclude contributions from PURPA generators and DG customers. GLREA argues that DTE clearly has a capacity need in the next 10 years, as evidenced by its plan to add hundreds of megawatts of wind energy, the BWEC, and additional EWR and DR to its portfolio.

GLREA asserts that DTE's modeling is so error-filled that it is not credible. Specifically, GLREA contends that DTE's model was designed to achieve a particular end result; the modeling was not transparent or subject to validation, and it relies on erroneous inputs that ignore viable sources of capacity like QFs and behind-the-meter solar generators.

GLREA concurs with Soulardarity that the company's public outreach and engagement were deficient, and it maintains that DTE failed to perform an adequate transmission analysis that considered the potential for imports outside of Zone 7. GLREA argues that the IRP contains overly-optimistic assumptions about the potential for EWR,

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[94] Energy Michigan's brief, p. 17.

[95] GLREA's 113 page initial brief is comprised of approximately 90 pages block quotes of its witnesses' testimony, in violation of Mich Admin Code, R 792.10434(3), and the Commission's prior admonitions in that regard. See, June 9, 2016 order in Case No. U-17792, p. 18, n. 4:

> Over half of GLREA's brief contains block quoted testimony from the transcript. Mich Admin Code R 492.10434 provides that "factual allegations claimed to be established by the evidence shall include a reference to the specific portions of the record where the evidence may be found." Simply repeating a witness' testimony in briefing does not satisfy this requirement.

In addition, GLREA's citations to direct and rebuttal testimony by other parties' witnesses are to page numbers in the prefiled testimony, and not to the transcript, which is the official record, also contrary to the above-cited rule.

DR, and CVR/VVO to provide capacity, as well as the company's assumption that utility-ownership is the most cost-effective means to add renewable resources, and it recommends that DTE instead should rely on competitive bidding. Finally, GLREA recommends that the Commission reject the IRP and require the company to file a significantly improved IRP, consistent with GLREA's recommendations, within three years.

J. Soulardarity

Soulardarity argues that DTE's analysis of renewable energy was flawed for numerous reasons. First, DTE failed to model DG, including PURPA facilities and community solar. In addition, DTE's program relies far too heavily on VGP resources that Soulardarity characterizes as "expensive, inadequate, and exclusive."[96] Soulardarity contends that, although DTE modeled the various scenarios mandated by the Commission, it dismissed the results from the ET and EP scenarios as inconsistent with the company's internal projections and experience. Further, Soulardarity argues that DTE only modeled utility-scale solar, based on the utility's assumption that large solar is more cost-effective than DG. However, DTE failed to recognize the benefits of renewable energy owned by third parties and therefore failed to undertake any meaningful analysis of these options.

Soulardarity argues that DTE relies on its VGP program resources for much of its flexible PCA, despite the fact that enrollment is uncertain. Soulardarity also criticizes the program for its high cost that inhibits participation by low-income customers. Soulardarity

[96] Soulardarity's brief, p. 9.

contends that if the VGP program fails to meet its goals, DTE will use this shortcoming to justify the construction of a new gas plant in 2029.

Soulardarity contends that DTE failed to engage the public in a meaningful manner, providing inadequate information and declining to act on the input it received. Soulardarity contends that DTE did not provide information about its planning principles, modeling scenarios, or PCAs at its public meetings, and the company could not identify and specific assumptions that were modified as a result of public input. Soulardarity also criticizes the public meetings as inaccessible, noting that, although DTE's service territory spans twelve counties, the three public meetings were held in only one county. Soulardarity urges the Commission to require DTE to make more targeted efforts to engage communities affected by the company's decision-making.

Soulardarity argues that DTE's planning principles are incomplete, imprecise, and the company failed to explain how it applied its planning principles in arriving at the PCA, except in vague terms. Soulardarity points out that DTE appropriately considers community impacts in planning but the company fails to include community health impacts as part of that planning principle. Soulardarity also criticizes DTE's limited definition of reliability, and the restricted number of factors it considers in its "flexible and balanced" and "reasonable risk" planning principles. Soulardarity also questioned how DTE derived its four flexible pathways, based on its ranking of the different plans using the planning principles, noting that certain plans with better cumulative scores were passed over.

K. <u>City of Ann Arbor</u>

Ann Arbor contends that DTE did not demonstrate that its PCA is the most reasonable and prudent alternative as required under Section 6t. Ann Arbor maintains that DTE's IRP does not include sufficient renewable energy to meet customer demand, citing the city's significant clean energy goals, and the plans do not adequately recognize, or address, climate change issues.

Ann Arbor also argues that DTE's IRP should have focused more on investments in grid resilience, given the impacts of climate change that the city is already experiencing. Ann Arbor highlights the advantages of solar plus storage and microgrids deployed particularly in locations that provide emergency and critical services. Ann Arbor also points out that DTE failed to include the social cost of carbon in any of its scenarios, thereby devaluing the importance of renewables and energy efficiency in its modeling. Ann Arbor raises a concern that DTE's IRP offers too little to low income customers, focusing instead on costly voluntary programs. Finally, Ann Arbor contends that DTE's focus on near term planning conflicts with the city's ability to meet its sustainability goals.

In light of the shortcomings of DTE's IRP, Ann Arbor requests that the Commission deny approval of the IRP and PCA. Alternatively, Ann Arbor requests that the Commission make changes to the IRP consistent with the city's recommendations.

L. Geronimo Energy

Like several other intervenors, Geronimo takes issue with DTE's assumption that utility-ownership of new resources would be the most cost-effective means to acquire renewable power, and therefore third-party ownership was never modeled. Geronimo points out that MCL 460.6t(a)(iv) requires the Commission to evaluate diversity of generation supply, not fuel supply. Because ownership is an important characteristic of generation supply, and DTE undertook only a cursory analysis of alternatives to utility ownership in the rebuttal phase of the proceeding, the company failed to show that its

PCA is the most reasonable and prudent option for ensuring that capacity and energy needs are met.

Next, Geronimo discusses recent Commission orders in DTE's PURPA case, Case No. U-18091, and in Case No. U-20156, a complaint proceeding filed by a Geronimo affiliate, Greenwood Solar (Greenwood). In light of the findings in these two cases, Geronimo posits that DTE should be required to negotiate a PPA with Greenwood before it builds any utility-owned projects. Geronimo points out that although the Commission found that RPS requirements do not constitute a capacity need, because those requirements could be fulfilled with the purchase of unbundled RECs, to the extent that the company intends to build generation for the RPS, it should be required to consider QF power. "To determine otherwise is to open a backdoor for the utility to unacceptably evade PURPA compliance under the cloak of the state RPS program."[97]

Geronimo states that it supports the Staff's recommendation to obtain new resources under a competitive solicitation, provided that QF rights under PURPA are addressed. Geronimo argues that the Commission must decide if the PCA is the most reasonable and prudent way to meet energy and capacity needs, and because this determination is inherently comparative it requires an RFP.

Geronimo recommends that: (1) the Commission reject DTE's assumption that company-owned resources are at least as cost-effective as third-party ownership based on the record in this case; (2) require the company to negotiate with Greenwood for capacity and energy before building its own resources; (3) affirm that any assets that the

[97] Geronimo's brief, p. 7.

utility would build or contract for represents a capacity need that could be filled by QF capacity; and (4) require that an RFP be issued before any IRP filing.

M. Michigan Energy Innovations Business Council/Institute for Energy Innovation

EIBC/IEI argue that DTE failed to meet the statutory mandate under Section 6t(6), as well as Commission directives, which require the utility to issue an RFP for supply-side resources prior to filing its IRP. According to EIBC/IEI, the Commission should reject DTE's claims that because RPS, VGP, and renewable resources to meet the company's clean energy goals are not built to serve load they do not come under the aegis of the Section 6t(6) requirement that the company issue an IRP. EIBC/IEI maintain that VGP and company renewables are clearly intended to serve load, and DTE's other claims regarding the inadvisability of issuing an RFP should likewise be dismissed. EIBC contends that issuance of an RFP would have provided more realistic and accurate pricing for PPAs and for other possible resources including CHP, which DTE eliminated from its analysis on grounds that its evaluation of a generic CHP showed that it would be uneconomic. EIBC/IEI lists the benefits of CHP to both the operator of the plant and to the electric system generally, and cited a recent study identifying opportunities for CHP integration in Michigan.

Next, EIBC/IEI critiques DTE's presumption that the company will own all new resource additions, contending that DTE failed to show that utility ownership is the most reasonable and prudent approach to resource acquisition. Because the company failed to prove the ownership model was the most economical approach, the Commission should deny DTE's request for approval of its near-term PCA. EIBC/IEI further indicates that it supports the Staff's recommendation to limit the company's ownership of new renewable resources to 50%, with the remainder acquired through PPAs with various resource providers. EIBC/IEI also supports Staff's recommendation to open a docket to establish best practices for competitive procurement, and the Commission should ensure that RFPs include all resources that can meet the specific energy and capacity requirements.

Relying on Mr. Jester's analysis and testimony, EIBC/IEI contend that, contrary to the company's claims, DTE does in fact have a capacity need in the next 10 years, as demonstrated in Exhibit MEC-59, and EIBC/IEI concurred with Mr. Jester's recommendations for pricing of capacity and energy for the VGP program.

IV.

LEGAL REQUIREMENTS

The framework governing IRP filings, and the Commission's review thereof, is set forth in MCL 460.6t. Prior to the filing of an IRP, Section 6t(1) describes certain undertakings by the Commission:

> (1) The commission shall, within 120 days of the effective date of the amendatory act that added this section and every 5 years thereafter, commence a proceeding and, in consultation with the Michigan agency for energy, the department of environmental quality,[98] and other interested parties, do all of the following as part of the proceeding:
>
> (a) Conduct an assessment of the potential for energy waste reduction in this state, based on what is economically and technologically feasible, as well as what is reasonably achievable.[99]
> (b) Conduct an assessment for the use of demand response programs in this state, based on what is economically and technologically feasible, as well as what is reasonably achievable. The assessment shall expressly account for advanced metering infrastructure that has already been

[98] Per Executive Order No. 2019-02, the Michigan Agency for Energy was abolished, and the Department of Environmental Quality was renamed the Department of Environment, Great Lakes, and Energy (EGLE).
[99] Documents concerning energy waste reduction (EWR) potential for the Upper and Lower Peninsulas are available at: https://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406251--,00.html.

installed in this state and seek to fully maximize potential benefits to ratepayers in lowering utility bills.[100]

(c) Identify significant state or federal environmental regulations, laws, or rules and how each regulation, law, or rule would affect electric utilities in this state.

(d) Identify any formally proposed state or federal environmental regulation, law, or rule that has been published in the Michigan Register or the Federal Register and how the proposed regulation, law, or rule would affect electric utilities in this state.

(e) Identify any required planning reserve margins and local clearing requirements in areas of this state.

(f) Establish the modeling scenarios and assumptions each electric utility should include in addition to its own scenarios and assumptions in developing its integrated resource plan filed under subsection (3), including, but not limited to, all of the following:

(i) Any required planning reserve margins and local clearing requirements.

(ii) All applicable state and federal environmental regulations, laws, and rules identified in this subsection.

(iii) Any supply-side and demand-side resources that reasonably could address any need for additional generation capacity, including, but not limited to, the type of generation technology for any proposed generation facility, projected energy waste reduction savings, and projected load management and demand response savings.

(iv) Any regional infrastructure limitations in this state.

(v) The projected costs of different types of fuel used for electric generation.

(g) Allow other state agencies to provide input regarding any other regulatory requirements that should be included in modeling scenarios or assumptions.

(h) Publish a copy of the proposed modeling scenarios and assumptions to be used in integrated resource plans on the commission's website.[101]

(i) Before issuing the final modeling scenarios and assumptions each electric utility should include in developing its integrated resource plan, receive written comments and hold hearings to solicit public input regarding the proposed modeling scenarios and assumptions.

Sections 6t(3) and 6t(5) provide additional requirements for IRP filings:

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[100] *State of Michigan Demand Response Potential Study*, September 29, 2017, is available at: https://www.michigan.gov/documents/mpsc/State_of_Michigan_-_Demand_Response_Potential_Report_-_Final_29sep2017__602435_7.pdf.

[101] *See,* https://www.michigan.gov/documents/mpsc/11-21-2017_MIRPP_Final_606706_7.pdf for final modeling scenarios, parameters, and required sensitivity analyses.

(3) Not later than 2 years after the effective date of the amendatory act that added this section, each electric utility whose rates are regulated by the commission shall file with the commission an integrated resource plan that provides a 5-year, 10-year, and 15-year projection of the utility's load obligations and a plan to meet those obligations, to meet the utility's requirements to provide generation reliability, including meeting planning reserve margin and local clearing requirements determined by the commission or the appropriate independent system operator, and to meet all applicable state and federal reliability and environmental regulations over the ensuing term of the plan. The commission shall issue an order establishing filing requirements, including application forms and instructions, and filing deadlines for an integrated resource plan filed by an electric utility whose rates are regulated by the commission. The electric utility's plan may include alternative modeling scenarios and assumptions in addition to those identified under subsection (1).[102]

* * *

(5) An integrated resource plan shall include all of the following:
(a) A long-term forecast of the electric utility's sales and peak demand under various reasonable scenarios.
(b) The type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including projected fuel costs under various reasonable scenarios.
(c) Projected energy purchased or produced by the electric utility from a renewable energy resource. If the level of renewable energy purchased or produced is projected to drop over the planning periods set forth in subsection (3), the electric utility must demonstrate why the reduction is in the best interest of ratepayers.
(d) Details regarding the utility's plan to eliminate energy waste, including the total amount of energy waste reduction expected to be achieved annually, the cost of the plan, and the expected savings for its retail customers.
(e) An analysis of how the combined amounts of renewable energy and energy waste reduction achieved under the plan compare to the renewable energy resources and energy waste reduction goal provided in section 1 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001. This analysis and comparison may include renewable energy and capacity in any form, including generating electricity from renewable energy systems for sale to retail customers or purchasing or otherwise acquiring renewable energy credits with or without associated renewable energy, allowed under section 27 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1027, as it

[102] IRP filing requirements (Filing Requirements) are set forth in the December 20, 2017 order in Case No. U-15896 and U-18461, Attachment A.

> existed before the effective date of the amendatory act that added this section.
> (f) Projected load management and demand response savings for the electric utility and the projected costs for those programs.
> (g) Projected energy and capacity purchased or produced by the electric utility from a cogeneration resource.
> (h) An analysis of potential new or upgraded electric transmission options for the electric utility.
> (i) Data regarding the utility's current generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation for each facility in the portfolio.
> (j) Plans for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments, including any transmission or distribution infrastructure that would be required to support the proposed construction or investment, and power purchase agreements.
> (k) An analysis of the cost, capacity factor, and viability of all reasonable options available to meet projected energy and capacity needs, including, but not limited to, existing electric generation facilities in this state.
> (l) Projected rate impact for the periods covered by the plan.
> (m) How the utility will comply with all applicable state and federal environmental regulations, laws, and rules, and the projected costs of complying with those regulations, laws, and rules.
> (n) A forecast of the utility's peak demand and details regarding the amount of peak demand reduction the utility expects to achieve and the actions the utility proposes to take in order to achieve that peak demand reduction.
> (o) The projected long-term firm gas transportation contracts or natural gas storage the electric utility will hold to provide an adequate supply of natural gas to any new generation facility.

Section 6t(6) sets out certain additional requirements in the event the utility proposes to add supply-side resources; it provides for intervention and for submission of proposals by existing generators, and it addresses the Commission’s treatment of these proposals:

> (6) Before filing an integrated resource plan under this section, each electric utility whose rates are regulated by the commission shall issue a request for proposals to provide any new supply-side generation capacity resources needed to serve the utility's reasonably projected electric load, applicable planning reserve margin, and local clearing requirement for its customers in this state and customers the utility serves in other states during the initial 3-year planning period to be considered in each integrated resource plan to be filed under this section. An electric utility shall define qualifying

> performance standards, contract terms, technical competence, capability, reliability, creditworthiness, past performance, and other criteria that responses and respondents to the request for proposals must meet in order to be considered by the utility in its integrated resource plan to be filed under this section. Respondents to a request for proposals may request that certain proprietary information be exempt from public disclosure as allowed by the commission. A utility that issues a request for proposals under this subsection shall use the resulting proposals to inform its integrated resource plan filed under this section and include all of the submitted proposals as attachments to its integrated resource plan filing regardless of whether the proposals met the qualifying performance standards, contract terms, technical competence, capability, reliability, creditworthiness, past performance, or other criteria specified for the utility's request for proposals under this section. An existing supplier of electric generation capacity currently producing at least 200 megawatts of firm electric generation capacity resources located in the independent system operator's zone in which the utility's load is served that seeks to provide electric generation capacity resources to the utility may submit a written proposal directly to the commission as an alternative to any supply-side generation capacity resource included in the electric utility's integrated resource plan submitted under this section, and has standing to intervene in the contested case proceeding conducted under this section. This subsection does not require an entity that submits an alternative under this subsection to submit an integrated resource plan. This subsection does not limit the ability of any other person to submit to the commission an alternative proposal to any supply-side generation capacity resource included in the electric utility's integrated resource plan submitted under this section and to petition for and be granted leave to intervene in the contested case proceeding conducted under this section under the rules of practice and procedure of the commission. The commission shall only consider an alternative proposal submitted under this subsection as part of its approval process under subsection (8). The electric utility submitting an integrated resource plan under this section is not required to adopt any proposals submitted under this subsection. To the extent practicable, each electric utility is encouraged, but not required, to partner with other electric providers in the same local resource zone as the utility's load is served in the development of any new supply-side generation capacity resources included as part of its integrated resource plan.

Next, Section 6t(7), *inter alia*, sets time limits for the Commission’s decision to accept, reject, or propose modifications to the IRP as well as certain procedural requirements. In addition, this section provides for an opportunity for a utility to update its costs during the course of the proceeding:

Not later than 300 days after an electric utility files an integrated resource plan under this section, the commission shall state if the commission has any recommended changes, and if so, describe them in sufficient detail to allow their incorporation in the integrated resource plan. If the commission does not recommend changes, it shall issue a final, appealable order approving or denying the plan filed by the electric utility. If the commission recommends changes, the commission shall set a schedule allowing parties at least 15 days after that recommendation to file comments regarding those recommendations, and allowing the electric utility at least 30 days to consider the recommended changes and submit a revised integrated resource plan that incorporates 1 or more of the recommended changes. If the electric utility submits a revised integrated resource plan under this section, the commission shall issue a final, appealable order approving the plan as revised by the electric utility or denying the plan. The commission shall issue a final, appealable order no later than 360 days after an electric utility files an integrated resource plan under this section. Up to 150 days after an electric utility makes its initial filing, the electric utility may file to update its cost estimates if those cost estimates have materially changed. A utility shall not modify any other aspect of the initial filing unless the utility withdraws and refiles the application. A utility's filing updating its cost estimates does not extend the period for the commission to issue an order approving or denying the integrated resource plan. The commission shall review the integrated resource plan in a contested case proceeding conducted pursuant to chapter 4 of the administrative procedures act of 1969, 1969 PA 306, MCL 24.271 to 24.287. The commission shall allow intervention by interested persons including electric customers of the utility, respondents to the utility's request for proposals under this section, or other parties approved by the commission. The commission shall request an advisory opinion from the department of environmental quality regarding whether any potential decrease in emissions of sulfur dioxide, oxides of nitrogen, mercury, and particulate matter would reasonably be expected to result if the integrated resource plan proposed by the electric utility under subsection (3) was approved and whether the integrated resource plan can reasonably be expected to achieve compliance with the regulations, laws, or rules identified in subsection (1). The commission may take official notice of the opinion issued by the department of environmental quality under this subsection pursuant to R 792.10428 of the Michigan Administrative Code. Information submitted by the department of environmental quality under this subsection is advisory and is not binding on future determinations by the department of environmental quality or the commission in any proceeding or permitting process. This section does not prevent an electric utility from applying for, or receiving, any necessary permits from the department of environmental quality. The commission may invite other state agencies to provide testimony regarding other relevant regulatory requirements related to the integrated resource plan. The commission shall permit reasonable discovery after an integrated resource plan is filed and during the hearing

> in order to assist parties and interested persons in obtaining evidence concerning the integrated resource plan, including, but not limited to, the reasonableness and prudence of the plan and alternatives to the plan raised by intervening parties.

Section 6t(8) sets forth the findings the Commission must make in order to approve an IRP:

> The commission shall approve the integrated resource plan under subsection (7) if the commission determines all of the following:
> (a) The proposed integrated resource plan represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs. To determine whether the integrated resource plan is the most reasonable and prudent means of meeting energy and capacity needs, the commission shall consider whether the plan appropriately balances all of the following factors:
>> (i) Resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement.
>> (ii) Compliance with applicable state and federal environmental regulations.
>> (iii) Competitive pricing.
>> (iv) Reliability.
>> (v) Commodity price risks.
>> (vi) Diversity of generation supply.
>> (vii) Whether the proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective. Exceeding the renewable energy resources and energy waste reduction goal in section 1 of the clean and renewable energy and energy waste reduction act, 2008 PA 295, MCL 460.1001, by a utility shall not, in and of itself, be grounds for determining that the proposed levels of peak load reduction, renewable energy, and energy waste reduction are not reasonable and cost effective.
>
> (b) To the extent practicable, the construction or investment in a new or existing capacity resource in this state is completed using a workforce composed of residents of this state as determined by the commission. This subdivision does not apply to a capacity resource that is located in a county that lies on the border with another state.
> (c) The plan meets the requirements of subsection (5).

Sections 6t(9) and 6t(10) address circumstances where the Commission denies an IRP and provide for additional proceedings if this occurs:

(9) If the commission denies a utility's integrated resource plan, the utility, within 60 days after the date of the final order denying the integrated resource plan, may submit revisions to the integrated resource plan to the commission for approval. The commission shall commence a new contested case hearing under chapter 4 of the administrative procedures act of 1969, 1969 PA 306, MCL 24.271 to 24.287. Not later than 90 days after the date that the utility submits the revised integrated resource plan to the commission under this subsection, the commission shall issue an order approving or denying, with recommendations, the revised integrated resource plan if the revisions are not substantial or inconsistent with the original integrated resource plan filed under this section. If the revisions are substantial or inconsistent with the original integrated resource plan, the commission has up to 150 days to issue an order approving or denying, with recommendations, the revised integrated resource plan.

(10) If the commission denies an electric utility's integrated resource plan, the electric utility may proceed with a proposed construction, purchase, investment, or power purchase agreement contained in the integrated resource plan without the assurances granted under this section.

Sections 6t(11) and 6t(12) address cost approvals associated with the IRP:

(11) In approving an integrated resource plan under this section, the commission shall specify the costs approved for the construction of or significant investment in an electric generation facility, the purchase of an existing electric generation facility, the purchase of power under the terms of the power purchase agreement, or other investments or resources used to meet energy and capacity needs that are included in the approved integrated resource plan. The costs for specifically identified investments, including the costs for facilities under subsection (12), included in an approved integrated resource plan that are commenced within 3 years after the commission's order approving the initial plan, amended plan, or plan review are considered reasonable and prudent for cost recovery purposes.

(12) Except as otherwise provided in subsection (13), for a new electric generation facility approved in an integrated resource plan that is to be owned by the electric utility and that is commenced within 3 years after the commission's order approving the plan, the commission shall finalize the approved costs for the facility only after the utility has done all of the following and filed the results, analysis, and recommendations with the commission:
(a) Implemented a competitive bidding process for all major engineering, procurement, and construction contracts associated with the construction of the facility.
(b) Implemented a competitive bidding process that allows third parties to submit firm and binding bids for the construction of an electric generation

> facility on behalf of the utility that would meet all of the technical, commercial, and other specifications required by the utility for the generation facility, such that ownership of the electric generation facility vests with the utility no later than the date the electric generation facility becomes commercially available.
> (c) Demonstrated to the commission that the finalized costs for the new electric generation facility are not significantly higher than the initially approved costs under subsection (11). If the finalized costs are found to be significantly higher than the initially approved costs, the commission shall review and approve the proposed costs if the commission determines those costs are reasonable and prudent.

Section 6t(15) provides the Commission with discretion to award a financial incentive for power purchase agreements (PPAs) with unaffiliated electric generation providers:

> (15) For power purchase agreements that a utility enters into after the effective date of the amendatory act that added this section with an entity that is not affiliated with that utility, the commission shall consider and may authorize a financial incentive for that utility that does not exceed the utility's weighted average cost of capital.

Finally, Sections 6t(17) and 6t (18) address recovery of costs associated with an IRP:

> (17) The commission shall include in an electric utility's retail rates all reasonable and prudent costs specified under subsections (11) and (12) that have been incurred to implement an integrated resource plan approved by the commission. The commission shall not disallow recovery of costs an electric utility incurs in implementing an approved integrated resource plan, if the costs do not exceed the costs approved by the commission under subsections (11) and (12). If the actual costs incurred by the electric utility exceed the costs approved by the commission, the electric utility has the burden of proving by a preponderance of the evidence that the costs are reasonable and prudent. The portion of the cost of a plant, facility, power purchase agreement, or other investment in a resource that meets a demonstrated need for capacity that exceeds the cost approved by the commission is presumed to have been incurred due to a lack of prudence. The commission may include any or all of the portion of the cost in excess of the cost approved by the commission if the commission finds by a preponderance of the evidence that the costs are reasonable and prudent. The commission shall disallow costs the commission finds have been incurred as the result of fraud, concealment, gross mismanagement, or lack

of quality controls amounting to gross mismanagement. The commission shall also require refunds with interest to ratepayers of any of these costs already recovered through the electric utility's rates and charges. If the assumptions underlying an approved integrated resource plan materially change, or if the commission believes it is unlikely that a project or program will become commercially operational, an electric utility may request, or the commission on its own motion may initiate, a proceeding to review whether it is reasonable and prudent to complete an unfinished project or program included in an approved integrated resource plan. If the commission finds that completion of the project or program is no longer reasonable and prudent, the commission may modify or cancel approval of the project or program and unincurred costs in the electric utility's integrated resource plan. Except for costs the commission finds an electric utility has incurred as the result of fraud, concealment, gross mismanagement, or lack of quality controls amounting to gross mismanagement, if commission approval is modified or canceled, the commission shall not disallow reasonable and prudent costs already incurred or committed to by contract by an electric utility. Once the commission finds that completion of the project or program is no longer reasonable and prudent, the commission may limit future cost recovery to those costs that could not be reasonably avoided.

(18) The commission may allow financing interest cost recovery in an electric utility's base rates on construction work in progress for capital improvements approved under this section prior to the assets' being considered used and useful. Regardless of whether or not the commission authorizes base rate treatment for construction work in progress financing interest expense, an electric utility may recognize, accrue, and defer the allowance for funds used during construction.

In addition to the legal requirements quoted above, the IRP filing requirements, and the Michigan Integrated Resource Planning Parameters approved in Case No. U-18418, the Commission also set forth certain additional requirements or analyses to be included in this IRP as part of its approval of the company’s certificate of need (CON) proceeding for the BWEC in the April 27, 2018 order in Case No. U-18419:

(1) One additional scenario evaluating a specific portfolio ramping up over the years preceding 2029 that could replace the capacity and energy lost due to the retirement of the Belle River Power Plant;

(2) An updated rate impact analysis related to the BWEC;

(3) Demonstrate collaboration with MISO and ITC on reliability planning for coal retirements;

(4) Assume the renewal of existing Public Utility Regulatory Policies Act (PURPA) contracts;

(5) Include a better evaluation of storage options; and

(6) A straightforward analysis of the rate impact of retiring Tier 2 coal plants and adding BWEC.

With these legal requirements and Commission directives in mind, the PFD turns to the disputed issues in the case.

V.

INTEGRATED RESOURCE PLAN

A. Proposed Course(s) of Action and Approvals (MCL 460.6t(3))

As described in Sections I and II, DTE provided PCAs comprised of a defined plan for 2020-2024, and a flexible plan that includes four possible pathways beginning in 2025. As also noted above, the company's application stated that the defined PCA is fully integrated and "requires approval in its entirely, [sic]" whereas the flexible PCA "is by its nature undefined and may be separately approved."[103] In its initial brief, DTE reiterates that the defined PCA must be approved in its entirety. But the company appears to have modified its initial statement that the undefined, flexible PCA could be approved in other proceedings, and it now requests approval of the PCA, both the defined and flexible parts, in this proceeding.

The company supports its approach by pointing out that for the years beyond 2025, it is most reasonable to present a range of possible plans, given the uncertainty of future

[103] Application, p. 3.

developments and the fact that the company does not forecast a capacity need until 2030. DTE further contends that deciding on a long-term plan now could potentially influence the company's decision-making, causing it to commit to a plan that limits opportunities in the future. DTE also maintains that the flexible portion of the PCA is consistent with the Filing Requirements, which refer to "resource plans to satisfy . . . the objectives identified in MCL 460.6t."[104] All that notwithstanding, DTE anticipates providing an updated IRP in 2025 containing "the mix of resources to best fill the capacity need expected to arise in 2030."

The Staff takes issue with the company's bifurcated approach to the PCA, stating its preference that DTE provide a single resource plan, even though the future is uncertain. The Staff observes that, according to DTE, none of the four pathways described in the flexible PCA is necessarily expected to come to fruition,[105] and the purpose of the company's presentation was simply to illustrate a range of possible futures.

The Staff contends that the company's reliance on a flexible PCA does not comport with the Filing Requirements, noting that while the requirements do refer to "plans" in the introduction, Section XVI of the Filing Requirements make clear that the company is to present a "preferred resource plan"[106] for review and approval. The Staff argues that in the company's next IRP, it should provide one plan based upon its best assessment of future requirements and the means to meet those requirements.

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[104] IRP Filing Requirements, p. 11.
[105] See, Exhibit S-6.0.
[106] Filing Requirements, p. 20.

MEC/NRDC/SC express some confusion about the flexible PCA, stating, "it is unclear what may be approved."[107] They add:

> Putting aside the practical challenges that the Flexible PCA presents for the Commission and stakeholders, what DTE presents as its IRP "Flexible PCA" approach offers only an abstraction of a plan – the modeled results of potentialities developed apparently only for regulatory purposes. This "Flexible PCA" approach at best checks the box for an IRP under Section 6t.[108]

While DTE's position is understandable—it is indeed impossible to predict with much certainty the circumstances the company will be facing in 10, 15, or 20 years—the ALJ nevertheless finds that DTE's IRP, specifically the flexible PCA for 2025 and beyond, does not comply with language and intent of Section 6t, or with the IRP Filing Requirements.

As the Staff points out, the mention of "plans" in the Filing Requirements seems to refer to the various PCA components (i.e., EWR plan, DR program plan, supply-side resources, etc.), and it is apparent in reading the subsection as a whole that the company is expected to file a single PCA. The Filing Requirements are consistent with Section 6t(3), which mandates that the company file an IRP "that provides a 5-year, 10-year, and 15-year projection of the utility's load obligations and **a plan** to meet those obligations[.]" (Emphasis supplied). The language of MCL 460.6t(3) is unambiguous and requires that the utility file one plan covering all three time periods.

Finally, Section 6t(8) requires the Commission to approve the IRP if it determines, *inter alia*, that "[t]he proposed integrated resource **plan** represents the **most** reasonable and prudent means of meeting the electric utility's energy and capacity needs."

[107] MEC/NRDC/SC brief, p. 20. In its reply brief, p. 4, MEC/NRDC/SC concurred with the Staff's recommendation that in future IRPs, the company only present one plan for approval.
[108] Id.

(Emphasis supplied). The use of the superlative “most” denotes that the Commission must find that the proposed IRP presents the single plan that best meets the criteria for approval. Here, DTE proposes five different plans, one for the near term and four possibilities for the longer term, without designating which of the four “flexible” pathways is most reasonable and prudent based on current projections.

Consistent with the discussion above, for its next IRP, the Commission should direct DTE to provide a single PCA (including any caveats regarding future possibilities that the company deems necessary) for review and potential approval. Because the company’s IRP beyond 2025 is undefined, this PFD will focus on issues raised with respect to the fixed PCA for 2020 through 2025, along with any issues that might affect future IRP inputs or modeling processes.[109]

B. Pre-IRP Request for Proposals/Ownership Issues (MCL 460.6t(6))

A number of parties raised concerns about DTE’s failure to issue an RFP before filing its IRP. DTE contends that it was not required to do so because the company did not identify a “persistent” capacity need until 2029/2030, and because the resources contained in the first three years of the IRP are intended to meet RPS requirements and VGP customer requests, and not to serve load. DTE points out that Section 6t(6) provides:

> Before filing an integrated resource plan under this section, each electric utility whose rates are regulated by the commission shall issue a request for proposals to provide any new supply-side generation capacity resources **needed to serve the utility’s reasonably projected electric load,** applicable planning reserve margin, and local clearing requirement for its customers in this state and customers the utility serves in other states during the initial 3-year planning period to be

[109] The Brattle Report, for example, addresses potential system conditions in 2031 and 2040 as more renewables are potentially added to Zone 7. Since the PCA in those years is undefined, this PFD finds that further discussion of the report, and critiques thereof, is unwarranted.

> considered in each integrated resource plan to be filed under this section. (Emphasis supplied).

EIBC/IEI argue that Section 6t(6) requires the issuance of an RFP if the company is adding supply-side resources to meet demand over the first three years of the plan, and the company's claim that RPS and VGP resources are somehow excused from the RFP requirement should be rejected. They further contend that the results of the RFP provide essential information on costs for the accurate modeling of resources.

MEC/NRDC/SC similarly assert that:

> [Section 6t(6)] applies with equal force to all new supply-side resources needed to serve load in the initial three years of an IRP. The Michigan Legislature did not include any exemptions, a point previously affirmed by the Commission when issuing its IRP filing guidelines. Rejecting a DTE Electric request to exempt certain resources from this RFP requirement, the Commission explained that "Act 341 does not set forth an exemption for small capacity and [renewable energy] resources governed by Act 295 [Michigan's Clean and Renewable Energy and Energy Waste Reduction Act]."[110]

In its reply brief, DTE reiterates that:

> There is no merit in assertions that MCL 460.6t(6) required DTE Electric to issue RFPs before filing its IRP . . . The entire argument is based on [the] incorrect assumption that any generation source that a utility adds is a result of a need to support load. Instead, the Company has other needs and obligations, as the Commission has recognized (2T 88-89)[.] . . . There is similarly no merit in ELPC and MEC/NRDC/SC's assertions that the Company should have issued an RFP to provide information on resource pricing for modeling purposes[.]

EIBC/IEI respond:

> Importantly, even though the Commission determined in Case No. U-18091, DTE Electric's PURPA case, that renewable resources the Company procures to meet the statutory 15% Renewable Portfolio Standard ("RPS") are not to be included in the determination of its capacity need for purposes of PURPA, the same rationale cannot justifiably be applied to the legislature's requirements in Sec. 6t(6) that a utility must issue a pre-filing RFP "for any new supply-side generation

[110] MEC/NRDC/SC brief, p. 176, quoting December 20, 2017 order in Case Nos. U-15896 and U-18461, p. 4.

> capacity resources" needed to serve its reasonably projected electric load during the first three years of its IRP. This is a broad, but clear, legislative requirement. It is not limited to a PURPA "capacity need." It also specifically refers to an "RFP," not an internal Company-run survey of "publicly-available sources," as DTE Electric claims should suffice in lieu of issuing an RFP. It also does not limit the supply-side generation resources to certain uses and not others.[111]

This PFD finds that DTE made a serious misstep in failing to issue an RFP before filing this IRP. As shown in Exhibit A-7, it appears that the wind and solar resources included in DTE's starting point[112] are counted toward meeting the company's PRMR in the first three years of the plan, so they fall within the ambit of Section 6t(6), which includes supply-side resources "needed to serve the utility's reasonably projected . . . applicable planning reserve margin." In addition, the company claims that it currently has no capacity need, and it does not anticipate such a need until Belle River is retired in 2029-2030. Yet, DTE's plan calls for the retirement of all its Tier 2 coal units between 2019 and 2022, and it appears that at least some of the lost capacity will be replaced by the renewables included in the first few years of this IRP. In its discussion of these planned unit retirements DTE states:

> The Company plans to replace those coal plants with clean forms of energy, including wind and solar renewable energy. Pine River (a new 161 MW wind farm) became operational in 2019 and other renewable energy projects (wind and solar) are planned into the future, which is consistent with both the renewable portfolio standard of 15% by 2021 and the Company's carbon and clean energy commitments.[113]

Moreover, as MEC/NRDC/SC and others point out, the Commission has already rejected DTE's request to exempt smaller (under 50 MW) renewables from the RFP requirement. Despite its obligations under the statute, and without considering the

[111] EIBC/IEI reply brief, p. 3 (fn. omitted).
[112] DTE's starting point is discussed below.
[113] DTE's brief, p. 48.

Commission's previous determinations, DTE relies on a particularly narrow reading of Section 6t(6), and on the fact that it recently issued an RFP,[114] to justify its approach. The company's rationale is rejected. Therefore, the PFD finds that DTE failed to comply with MCL 460.6t(6) in developing its IRP, and that in its next IRP, if the company forecasts adding supply-side options to meet load, PRMR, and LCR, an RFP should be conducted, and the results should be provided with the company's application.

While DTE does not explicitly tie its failure to issue an RFP to its views on asset ownership, DTE's preference for utility-ownership of renewables appears to have informed the company's decision and process here. In its initial brief, DTE argues that "it is inappropriate to address asset-ownership issues in a general sense in this IRP case. Each project is different and should be evaluated on its own merits, and the Commission should refrain from requiring a certain percentage of ownership or PPAs for generation going forward."[115] Moreover, while not quite taking opposing positions, DTE maintains that, although it assumed that the company will own all new resources, its modeling was based on "generic" resources, thus ownership is not relevant to meeting the standard under Section 6t(8).

Nevertheless, DTE disputes claims by other witnesses, including Messrs. Lucas, Kenworthy, Prehoda, and Rafson, that third-party PPAs would result in lower costs for customers. In part, these witnesses point to the Commission's February 15, 2017 *Report on the Implementation of the P.A. 295 Renewable Energy Standard and the Cost-*

[114] This resulted from the Commission's partial disapproval of DTE's amended REP in Case No. U-18232. In the order issued on July 18, 2019, p. 21, the Commission found: "DTE Electric has not sufficiently supported its entire plan to rely exclusively on company-owned generation assets, and to limit participation in the company's RFP to build-transfer contracts only." The Commission did approve three near-term, company-owned wind projects that qualify for 100% of the PCT, however.
[115] DTE brief, p. 88.

Effectiveness of The Energy Standards, p. 19, which found that "for each year in which there were both company-owned projects and purchased power agreements, the weighted average cost of the purchased power agreements was lower than the company-owned projects in that respective year."[116]

DTE points to rebuttal testimony by Ms. Schroeder and Ms. Pfeuffer, and Exhibit A-53, to support its contention that, all other things being equal, utility ownership would results in costs (LCOE) that are 10-15% lower than a cost of a PPA over the life of the project for both wind and solar.

The company's LCOE analysis of the ownership issue is not persuasive. Although it is reasonable to assume that the initial equipment cost is equal, the analysis also appears to assume that the rate of return on investment is equal, even though DTE provides no evidence to show that a third-party owner would expect the same (or more, or less) of a return than what DTE earns on its company-owned renewable projects under Act 295.[117] If the return for a third-party developer is less, it may be sufficient to offset the financial incentive mechanism (FIM) that the Commission <u>may</u> authorize for a PPA.[118] If the return a third-party developer expects is more, then DTE may be correct in its analysis. There is insufficient evidence in this record to weigh DTE's claim, and this presents another area where a pre-IRP RFP would have been informative.

[116] See, Exhibit MEC-140, p. 19.

[117] While DTE's current return on equity (ROE) overall is 10.0%, per MCL 460.1047(1), the company earns, and will continue to earn, an 11.0% ROE on all company-owned renewable projects used to comply with the 15% RPS. See Case No. U-20172, Exhibit A-11, line 6.

[118] Ms. Schroeder testified that the FIM included in her analysis was based on the FIM approved for Consumers Energy in the settlement agreement in Case No. U-20165. However, on cross-examination, she admitted that the FIM for Consumers was tied to Consumers' agreement to limit its ownership of renewables to 50%, with the remaining 50% obtained through third-party PPAs. 5 Tr 1380-1381.

In its analysis of ownership structures, in addition to the FIM, DTE included a $3.00 to $4.00 risk adder, which assumes that when a PPA ends in 20 years, the company will have to re-contract for the same capacity and energy at a higher cost. There are two problems with this assumption. First, although 20-year PPAs are apparently standard in the industry, there is no requirement that the length of the contract be 20 years, rather than the 30-year depreciable life of the project.[119] Second, although DTE bases its assumption on a PACE forecast of capacity and energy for MISO Zone 7 for years 21-30, market risk cuts both ways. As Mr. Richter points out, the cost of renewables may continue to fall, or they may increase in 15 or 20 years, as the company contends.

DTE's analysis of solar ownership is even more problematic. While including the same basic assumptions about project cost, rate of return, FIM and market risk, the company does recognize the 30% investment tax credit (IT credit), which reduces the initial cost of a third-party owned project, resulting in a third-party PPA for solar that is less costly than a utility-owned project.[120] DTE addresses this by positing an "alternative financing option that would not result in a requirement to normalize investment tax credits[,]" thus, "there would be no cost disadvantage to utility ownership due to investment tax credit normalization[.]" However, DTE could not provide any specifics on this alternative financing approach. Ms. Schroeder could only name two utilities that have implemented such an alternative, and she had no additional details (including location of the utilities that have purportedly done so or whether there had been government approval of this financing option.)[121]

[119] See, 5 Tr 1316-1321.
[120] DTE receives the same 30% IT credit (current credit amount); however, due to regulatory accounting requirements, the company must account for the credit over the 30-year life of the project.
[121] 6 Tr 1433-1435.

As noted above in Section II, Mr. Proudfoot, Mr. Matthews, Mr. Lucas and Mr. Prehoda advocated that utility-ownership of new renewable assets should be limited to 50%, as it was under Act 295 before the Act 342 amendments. DTE contends that this is inconsistent with Act 342. The company implies that the amendment to Act 295, which removed the 50% limit on utility ownership, is significant "because: 'We cannot presume that the legislature would do a useless thing.'"[122] The ALJ agrees that the change to Act 295, specifically the removal of the 50% limitation on utility ownership, is significant because post-Act 342 renewables can now be owned, in any proportion, by either the utility or by third-parties. Thus, the inquiry must default to a determination of what is most reasonable and prudent for customers, on a case-by-case or project-by-project basis, properly informed by an RFP.

Most of the intervenors concur with the Staff's recommendation to establish a stakeholder process to evaluate best practices in RFPs and competitive procurement. DTE indicates that it is open to engaging with Staff and others on this topic; however, it cautions that time is limited if the company wants to take advantage of a higher PTC or IT credit, in light of expected phase out of these programs.[123] The ALJ finds the Staff's recommendation, supported by other intervenors, to be reasonable.

[122] DTE's brief, p. 91, quoting *Dearborn Twp v Tail*, 334 Mich 673, 684; 55 NW2d 201 (1952).

[123] With respect to taking advantage of the IT credit (which is 30% for 2019, decreasing to 26% in 2020, 22% in 2021, and 10% in 2022) several witnesses, and Geronimo, point out that DTE could avail itself of QF projects in the company's PURPA queue thereby taking advantage of the 26%-30% IT credit available through 2020. The ALJ observes that although DTE was keen to have company-owned wind resources eligible for 100% of the PTC approved in Case. No. U-18232, it appears to be taking a much more measured approach to adding solar resources to its system, planning to add only 11 MW of solar between now and 2024, ramping up significantly after that.

C. Modeling Introduction

Although the parties' briefs are organized with separate sections on modeling inputs and outputs, for brevity's sake, this PFD first addresses some general modeling issues raised by the parties, and then takes a PCA portfolio approach, discussing both inputs and outputs by component (e.g., supply side resources (wind and solar); and demand side resources (DR, EWR, CVR/VVO).

As outlined above in Section II, Ms. Pfeuffer provided an extensive overview of the IRP modeling process, set forth in detail in Exhibit A-3 Revised, and Ms. Mikulan discussed the various modeling platforms, and how the various models interact, as summarized in Staff Exhibit S-1.0.

D. Starting Point (MCL 460.6t(5)(i)) and (k)

DTE's starting point assumptions were highly contested in the case. The Attorney General, MEC/NRDC/SC, ELPC et al. Staff, and ABATE all raised concerns about the starting point, which are addressed below in subsection 1. In addition, there were issues raised about the company's retirement sensitivity, the results of which were included in the PCA. These issues are addressed in subsection 2.

1. Starting Point Resources

Ms. Mikulan testified that DTE's starting point included current generating resources and planned retirement dates, approved new units (e.g., the BWEC and the Ford CHP), the company's REP, 1.5% EWR, and planned DR program additions. Specifically, DTE started with the following resources included in each of its initial scenarios:

•1.5% EWR savings target.

•732 MW in 2019 increasing up to 863 MW total DR in 2024 and beyond.

•855 MW incremental wind and 538 MW incremental solar between 2019 -2030.

•300 MW incremental wind and 2,000 MW incremental solar between 2031-2040.

•300 MW VGP wind in 2021.

•1,150 MW BWEC CCGT addition in 2022.

•34 MW Dearborn CHP addition in 2020.

•Retirement dates:

- •River Rouge in 2020
- •St. Clair 1-3, 6 in 2022
- •St. Clair 7, Trenton 9 in 2023
- •Belle River 1 in 2029
- •Belle River 2 in 2030
- •Monroe before 2040[124]

DTE explains that it was required to file an amended REP after the enactment of Act 342, to demonstrate its plan for compliance with the 15% RPS. The amended REP was filed in March of 2018 in Case No. U-18232, and this case was filed in March of 2019, several months before the Commission issued an order in the REP case. DTE adds that the inclusion of renewables for RPS compliance is mandated by the Filing Requirements.

DTE further explains that it presented its starting point resources to stakeholders at the technical conferences and that no one questioned the company's decision to include additional renewables consistent with the company's clean energy goals. DTE asserts that it later updated the model to allow starting point resources to be optimized,

[124] 3 Tr 405.

and it found no significant cost difference and still no capacity need until 2029.[125] DTE highlights the fact that it ran multiple scenarios and sensitivities using the same starting point and that it updated several assumptions (i.e., ELCC for wind, DR forecast, PRMR, and Tier 2 retirement dates), resulting in a number of least-cost build plans.

Although generally supportive of the IRP, even the Staff had concerns about the company's starting point. Mr. Doherty testified that although it was appropriate to include resources to satisfy the 15% RPS, as well as planned resources like the BWEC, he found the company's inclusion of resources to satisfy of its own clean energy goals problematic. Mr. Doherty explained:

> The Company uses the same starting point resources for each modeling scenario. Including these resources in the starting point ensures that the Company meets its stated goals but also results in no modeling analysis of these resources. The model is not allowed to optimize to fill the capacity and energy needs served by these resources. This reduces the value of the modeling. Exhibit S-6.1 Resource Additions ("Forced in" vs Optimized) lists the new resources being added to DTE's portfolio from the present through 2040. As shown in Exhibit S-6.1, the Company's entire integrated resource plan adds over 7,000 MW of resources, of which only about 700 MW was allowed to be optimized by their original modeling.
>
> * * *
>
> Even with the additional modeling provided by the company, the costs (or benefits) from a ratepayer perspective are not conclusive The modeling shows a range of present value of the revenue requirement (PVRR) deltas, between the plans that include the starting point renewable resources and the fully optimized plans. This range is from a savings of $44 million to a cost of $105 million, over the four different scenarios (ET, EP, BAU, DTE REF), depending on the market conditions and cost assumptions used. The fully optimized model was only used to fill capacity needs and not allowed to add superfluous units. In most cases, the renewable resources added to meet the clean energy goals were not needed to fill a capacity need as they were superfluous, but there are market conditions possible where the additional renewable resources would lead to a lower PVRR. The after- the-fact nature of these fully optimized runs also means the build plans generated from the fully optimized runs are excluded from the robust analysis of DTE's IRP and supporting testimony.

[125] DTE's brief, pp. 35-36.

* * *

> By pre-disposing the resources needed to meet its clean energy and carbon goals, the Company did not allow for the mix of renewable resources to be optimized for cost.[126]

In its brief, the Staff points out that DTE's presentation of its starting point consisted of one slide in a deck of 80 and another slide in a deck of 50 presented at two of the technical conferences. The Staff further observes that the text on the slides was ambiguous, referring to the renewables in the IRP as being "consistent" with the company's REP. Staff adds: "More to the point, the stakeholder sessions do not take the place of this contested case."[127]

Mr. Lucas and ABATE witness Mr. Andrews were also critical of DTE's approach to its IRP starting point. Mr. Lucas testified:

> In the end, DTE has failed to support its PCA through its modeling or analyses or to show that it is in the best interests of its customers. The Company's starting point $7 billion renewable build was not even based on this case's analysis or modeling results. . . . It further muddies its modeling analysis by hardcoding as initial conditions much of its intended plan. Even in its updated analysis that attempted to undo some of this rigidity, the Company effectively prevents Strategist from optimizing its fleet across all years, and with its path largely predetermined, the model has few opportunities to demonstrate that DTE's proposal is in the best interests of its customers.
>
> The Commission should . . . require DTE to support its proposals based on optimized modeled results and not simply allow the Company to hardcode its preferred plan and solve for replacement capacity in one year out of twenty, and for the Company to provide a meaningful analysis on different ownership and contractual arrangements for new capacity.[128]

Mr. Andrews similarly testified:

> DTE has assumed as its starting point a portfolio of resources that have not been approved. As discussed on page 75 of her direct testimony, Ms. Mikulan shows that DTE assumes that 855 MW of new wind will be added

[126] 7 Tr 3298-3301.
[127] Staff's brief, p. 22.
[128] 7 Tr 1960.

> between 2019 and 2030; 538 MW of new solar will be added between 2019 and 2030; and 300 MW of VGP wind will be added in 2021. Further, these resources were modeled in Strategist at zero ($0.00) cost. See Exhibit AB-1, which contains DTE's response to ABDE-3.30; confirming this zero-cost modeling. DTE uses this starting point of resources to falsely claim it has no persistent resource need until the retirement of Belle River in the 2029/2030 timeframe. On the contrary, Exhibit A-7 shows significant increases to Company-owned intermittent resources providing zonal resource credits to offset DTE's forecast capacity need.[129]

In its reply brief, DTE states that it agrees with Staff that in future IRPs it will only include resources that are "planned with firm certainty, (such as resources needed to meet a legislative requirement)," and those that are already approved, or under construction. The company maintains, however, that:

> The starting point's inclusion of renewables related to DTE Electric's clean energy and carbon reduction commitments made no practical difference here. There was not a substantial cost difference when the Company later addressed the concerns about its starting point by running scenarios that allowed the starting point renewables to be optimized (7 T 3359-60). Removal of the starting point renewable resources, which had been added to meet the clean energy and carbon reduction commitments, also did not result in a capacity need until 2029 (3T 481; Exhibit S-6.2).[130]

DTE observes that MEC/NRDC/SC concur in part with the Staff's recommendation regarding the starting point, but they do not appear to agree that resources that are "planned with firm certainty" should also be included. DTE maintains that these resources should be contained in the starting point and adds that unit retirement dates should also be part of the initial modeling assumptions.

The PFD finds that DTE's inclusion of substantial amounts of unapproved resources in its IRP starting point is not consistent with the requirements of Section 6t. Specifically, MCL 460.6t(5)(k) requires an IRP to contain, "[a]n analysis of the cost,

[129] 7 Tr 3041-3042.
[130] DTE's reply brief, p. 24.

capacity factor, and viability of all reasonable options available to meet projected energy and capacity needs, including, but not limited to, existing electric generation facilities in this state." (Emphasis supplied). In DTE's IRP, only 700 MW of 7,000 MW of total resource additions are in fact analyzed as part of the plan, limiting the amount of resources that are actually optimized to only 10% of planned additions. As ABATE points out:

> 2016 PA 341 and multiple Commission Orders require an IRP to include modeling of any resources that reasonably could address DTE's need for additional generation capacity, including an equal analysis of the viability of all reasonable options. DTE's modeling, however, started with an improper foundation by forcing hypothetical, unapproved resources into its starting point. That is, DTE's IRP wrongly assumes that certain unapproved and prospective resources already exist – when they do not – and then erroneously concludes that DTE does not have a resource need until the 2029/2030 timeframe. DTE further compounds that error by modeling its preferred but unapproved and prospective resources at zero cost which is an impossibility. These errors effectively resulted in no modeling analysis of DTE's favored resources, as the model was not allowed to optimize to fill the capacity and energy needs served by these conjectural resources. In other words, DTE's modeling did not analyze all resources that could address its generation capacity needs, nor did it consider their viability with equal merit.[131]

The company contends that, after additional modeling requested by the Staff,[132] the least-cost build results remain essentially the same. The PFD disagrees, noting that Mr. Doherty's testimony indicates that the results of the modeling without the additional resources forced in were inconclusive and dependent on the assumptions used.[133]

This PFD also agrees with Staff that it is appropriate to include already-approved resources, such as the BWEC and the Ford CHP, in the starting point of the IRP. As for resources "planned with firm certainty," imprecise language that might include more than

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131 ABATE's brief, p. 1.
132 See, Exhibit S-6.2.
133 7 Tr 3300.

just resources necessary to meet legislative requirements, this terminology should be much more carefully defined to ensure that only legal mandates are included in the starting point. In addition, it is not clear why legal requirements, for example a 15% RPS, could not be built-in as a modeling constraint, thereby allowing the various renewable resource possibilities to be optimized, rather than forcing in a specific plan to meet the 15% RPS mandate.

As noted above, this PFD finds that DTE's IRP does not comply with MCL 460.6t(5)(k). In its next IRP, DTE should be required to include only previously approved resources, those required to meet a statutory mandate (preferably optimized), and unit retirements as evaluated in a retirement analysis.

2. Retirement Analysis

DTE provided a separate retirement sensitivity analysis of its remaining Tier 2 units (Trenton Channel, St. Clair Units 1 and 7, RR3), finding, as a result of its optimization, that the planned retirements of Trenton Channel and St. Clair Unit 1 could be accelerated by one year, to 2022, assuming that the BWEC begins operation as planned and a transmission issue at Trenton Channel is resolved. There was no objection to the company's accelerated retirement plans for Trenton Channel and St. Clair. Parties did raise concerns about the adequacy of DTE's analysis of the Belle River and Monroe retirements, the proposed conversion of RR3 from coal to waste industrial gas, and the lack of any evaluation of DTE's peaking units.

a. Belle River Retirement

Ms. Mikulan discussed the company's starting point retirement analysis for Belle River, which began with the same 2029/2030 retirement date assumption that was used in Case No. U-18419. At the request of Sierra Club, Ms. Mikulan testified that DTE ran an additional analysis to evaluate a 2025-2026 retirement date:

> In this sensitivity, the Belle River coal units were retired in the Strategist® optimization in 2025 and 2026, instead of 2029 and 2030 as planned. Then the capacity need was optimized with the Strategist® model and filled with IRP alternatives including the coal units themselves, running for an additional four years, until 2029/2030.[134]

Ms. Mikulan explained that:

> The least-cost plan was the plan that replaced the 2025-2026 retirement of Belle River with coal units at Belle River that retired in 2029 and 2030, which means it was more economic to leave the retirement dates as currently planned. The first plan that retired Belle River in 2025-2026 and replaced it with an alternative, selected demand response as well as a CCGT, and was $39 million costlier than keeping Belle River running until 2029-2030. An important point is that Belle River is co-owned with the Michigan Public Power Agency (MPPA). The optimization results shown above include only DTE's costs, which are 81.39% of the total costs for Belle River. MPPA's portion of the cost increase was not included. MPPA will also have costs to replace their capacity when Belle River retires.[135]

MEC/NRDC/SC argue that DTE's analysis of an earlier retirement of Belle River was incomplete and inaccurate. According to them, DTE only evaluated one alternative retirement date for the units as part of is flexible PCA, and it did not include the most up-to-date information in its analysis. MEC/NRDC/SC also question assumptions about capital spending on the units, noting, "in the years leading up to retirement, DTE modeling analysis assumed that the Company would spend nearly four times as much for base capital on each of the Belle River units as it projects it would spend on Trenton Channel 9 or St. Clair 7."[136] MEC/NRDC/SC point to modeling by Mr. Evans (Case 5) that updated or corrected DTE's assumptions for EWR, sales, and wind and solar capacity,

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[134] 3 Tr 417.
[135] 3 Tr 418; see, Table 15, 3 Tr 418-419.
[136] MEC/NRDC/SC's brief, p. 124.

and which showed that a 2025/2026 retirement date for Belle River would have a lower NPVRR than operating the plant until 2029/2030.

ELPC et al. also criticized DTE's retirement analysis of Belle River. Dr. Woychik testified that in modeling the Belle River (and Monroe) retirements all costs for these units, including environmental retrofit costs, coal ash handling, and fuel price risk, would be necessary to include to capture the actual economics of various retirement scenarios.

In response, DTE points to Ms. Mikulan's rebuttal that explains that the company in fact performed two retirement analyses: one as required by the MIRPP and the other as requested by the Commission in its order in Case No. U-18419. DTE further criticizes Mr. Allison's and Mr. Evans' assumptions and modeling, citing numerous errors including the double counting of variable O&M by Mr. Evans.

This PFD finds that DTE's retirement analysis of Belle River was inadequate. While DTE did undertake the additional analyses requested by the Commission and Sierra Club, the company could have looked at additional retirement dates between 2025/2026 and 2029/2030. In addition, it appears that DTE's retirement analysis did not take into account potential avoided environmental compliance costs that would result from earlier retirement of Belle River. Thus, the PFD concludes that DTE should undertake a more careful, complete, and transparent analysis of Belle River retirement as part of its next IRP.

b. Monroe Retirement

The PFD agrees with DTE that for this IRP, the company was not required to evaluate the retirement of the Monroe units. Under the Emerging Technologies Scenario, the MIRPP states:

> Company-owned resource retirements may be defined by the utility, however, a meaningful analysis of whether coal units should retire ahead of business as usual dates should be performed. Retirements of all coal units except the most efficient in the utility's fleet should be considered, and those coal units owned by the utility that are not explicitly assumed to retire during the study period shall be allowed to retire in the model based upon economics. Retirement of older fuel oil-fired generation should also be considered in this scenario. Units that are not owned by the utility shall not retire during the study period unless affirmative, public statements to that effect are made by the owner of the generation asset.[137]

The PFD also agrees with DTE and the Staff that alternative scenarios for retirement of the Monroe units should be addressed in a future IRP.

c. River Rouge Unit 3 Conversion

GLREA contends that the Commission should reject DTE's proposal to convert RR3 from coal to recycled industrial gas. Mr. Richter testified that given the significantly lower combustion value of blast furnace and coke oven gas, DTE's financial analysis is questionable, and the company needs to provide answers to these concerns before the Commission approves the conversion. In response, DTE maintains that it answered any questions about fuel economics and environmental compliance costs, and it further contends that cost issues are irrelevant here because the company is not requesting recovery in this proceeding.[138]

MEC/NRDC/SC support GLREA's position, albeit for different reasons. In its brief, MEC/NRDC/SC contend:

> If DTE Electric retired River Rouge 3 in 2020, as planned in its previously approved IRP, the unit would cause zero air emissions after 2020. But the Company has proposed a new plan. Instead of getting to zero emissions from River Rouge 3 by the end of May 2020, now the Company seeks approval to continue operating the unit. This change will result in an across-the-board emission increase irrespective of the fuel burned. Mr. Marietta dubiously testified that "operation of the unit on [industrial gases] will emit

[137] See, MIRPP, p. 18.
[138] DTE's reply brief, p. 15.

> significantly less than operating the unit with coal . . ..” But that is a false comparison. If the Company were proposing to make this fuel shift and retire the unit by May 31, 2020, Mr. Marietta’s comparison would be appropriate. But that is not what the Company proposes to do. Every pound of emissions occurring after May 2020 represents an emissions increase.[139]

MEC/NRDC/SC add that this calls into question the company’s commitment to actually retire the unit in 2022, further noting the Commission’s denial of capital expenses for RR3 in the company’s last rate case.

Staff asserts that the Commission should clarify that DTE should not assume that cost recovery for the RR3 conversion is ensured. Staff notes that the NPV analysis for this project was not fully detailed, and the contract for industrial gas will be with a company affiliate, triggering additional scrutiny. The Staff contends:

> Due to the nonspecific capital costs of the project and the affiliate nature of the proposed transaction, Staff believes that cost approval should be sought in other proceedings such as a PSCR or rate case. Staff witness Schiller testified that approval of the project in this IRP does not guarantee cost approval in future proceedings; any future request for cost recovery would be subject to a review by the Commission to ensure costs were reasonable and prudent. (7 TR 3289.)[140]

DTE responds that its plan to convert RR3 from coal to waste industrial gas is reasonable from an environmental, economic, and community impact standpoint, explaining that:

> This plan allows for use of the recycled industrial gases to produce electricity instead of flaring these gases directly into the environment, economically supports the surrounding community in River Rouge, and allows additional time to resolve reliability concerns related to plant retirements in the south area of DTE Electric’s service territory (2T 48; 3T 388-89; 5T 1110, 1116-20; Exhibit A-17.2).[141]

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[139] MEC/NRDC/SC brief, p. 15.
[140] Staff’s brief, p. 78.
[141] DTE’s brief, pp. 24-25 (fn. omitted).

As DTE points out, the company is not requesting pre-approval of cost recovery as part of this case, and it agrees with Staff that conversion costs can be recovered in other proceedings. That said, the PFD agrees with Staff that the record in this proceeding provides insufficient detail on the proposal and, contrary to DTE's claims, the economics of continuing to operate RR3 on waste industrial gas are not clear.[142] Accordingly, the PFD recommends that the Commission undertake a much more thorough review of the proposed conversion of RR3 in proceedings where cost recovery is in issue.

d. Fossil Peaking Units

The Staff, the Attorney General, and ELPC et al. raised issues with respect to DTE's peaker fleet. Ms. Shiller testified that many of the company's peaker units are already past their useful lives, yet they are assumed to operate throughout the entire IRP period. Ms. Shiller testified that DTE failed to evaluate the increased costs of operating these aging units, recommending that the company include an analysis of the increased O&M costs associated with operating the company's peaking units past their useful lives in its next IRP.[143]

Attorney General witness Dismukes points out that DTE's Greenwood Unit 1, a gas-fired steam plant operated as a peaking unit, is one of the company's most expensive units and, he asserts that it produces more emissions than the Monroe plant.[144] ELPC et al. also had concerns about the company's failure to assess its peaker fleet:

> DTE entirely fails to evaluate the viability of its existing peaking units, preventing the model from replacing old peaker units with more modern, reliable, and economic resources. (7 TR 2024). DTE does not consider retirement or replacement of any peaking units and assumes they run through 2040 with no degradation in outage rates. (Ex. ELP-39). Witness

[142] See, 5 Tr 1186-1194 and Exhibit MEC-129.
[143] 7 Tr 3281-3282; 3284.
[144] 7 Tr 2376-2377; Exhibits AG-6 and AG-7.

> Lucas analyzed the performance of DTE's aging peaker units, and demonstrated that DTE's assumptions are flawed, and that solar or solar plus storage provide a feasible and cost-effective alternative for the oldest units in DTE's peaker fleet. (7 TR 2026).[145]

In response to ELPC et al.'s claims that solar plus storage is more cost-effective than the company's current peaking units, DTE points to Ms. Mikulan's explanation that the LCOE of the company's peaker fleet is relatively low, and considerably lower than the $600 million cost of replacing the older peakers in the fleet with a solar plus storage alternative.

In response, ELPC et al. point out that because DTE's entire peaking fleet was included in the IRP starting point, there was no cost information available for comparison to Mr. Lucas' recommendations concerning the replacement of older, less reliable units with solar plus storage.

There does not appear to be any dispute that DTE failed to include any assessment of its peaking units as part of this IRP, although Section 6t(k) appears to require such an analysis. And while the LCOE of DTE's peaker fleet, based on current operations, appears reasonable, as the Staff points out, the company failed to account for increased capital and O&M costs associated with operating these units beyond (in some cases well beyond) their useful lives. In its next IRP, DTE should undertake an evaluation of these units, including projections of increased costs for older units, and should also provide an up-to-date analysis of a solar plus storage alternative to replace the company's oldest or least reliable units.

[145] ELPC's brief, p. 18.

e. Public Health Impacts

MEC/NRDC/SC sponsored the testimony and exhibits of Dr. Thurston and Ms. Weid as outlined above in Section II. These witnesses provide convincing testimony, not only on the adverse health impacts of air emissions from fossil generation (which are not in dispute) but also on methods (i.e., BenMAP) that can be used to quantify the costs of these health effects. MEC/NRDC/SC argue that, although the Commission does not currently include public health impacts of resource decisions in evaluating the IRP, there is nothing preventing DTE from including public health effects and costs in its IRP. They also contend that the Commission has an obligation under the Michigan Environmental Protection Act (MEPA) to consider public health in evaluating the IRP.

In its initial brief, DTE argues:

> Several of the Intervenors have argued throughout this case that the Company has not considered the public health effects of carbon-emitting generating resources. They are wrong. In applying the Company's planning principles in the risk analysis, one of those planning principles is "Clean." Clean includes following state and federal environmental laws and regulations, which are specifically designed to be protective of the health and welfare of the public. In addition, our "Clean" planning principle focuses on reducing carbon and other environmental impacts that drive climate change as well as potential impacts on public health. With a sharpened focus on both public health and the environment, the Company has advanced aggressive carbon-reduction commitments in this proceeding that would reduce the Company's carbon emissions by 80% by 2040. Finally, it has recently been made clear that the Company's goal is to reduce carbon emissions to net zero by 2050 (2T 124; Exhibit MEC-97).[146]

And in its reply brief, DTE voices strong objections to MEC/NRDC/SC's recommendations:

> MEC/NRDC/SC's Initial Brief, at pages 187-220, presents a lengthy argument essentially urging the Commission to incorporate "public health impacts and associated economic costs" of fossil-fuel emissions into the

[146] DTE's brief, pp. 95-96.

> IRP process. However, this issue is outside the scope of this case. MEC/NRDC/SC acknowledge: "Consideration of the public health impacts of resource decisions is not part of DTE's IRP or the Commission's current IRP review framework" (MEC/NRDC/SC Initial Brief, p 191, topic heading 3). DTE Electric reserves all rights to further address this matter if it were to become an issue before the Commission, however, and notes its general disagreement with MEC/NRDC/SC's suggestions regarding how the Commission might have legal authority to bestow upon itself the health and environmental powers that they propose (MEC/NRDC/SC Initial Brief, pp 208-216). Their suggestions also raise Commerce Clause, Supremacy Clause and other constitutional concerns. MEC/NRDC/SC also acknowledge (Initial Brief, pp 214, 218) that the Commission has previously declined to duplicate matters managed by EGLE, and rejected their position on the Michigan Environmental Protection Act ("MEPA"), MCL 324.1701 et seq. MEC/NRDC/SC neglect to mention, however, that their initial brief in Case No. U-18419 similarly raised a last-minute MEPA argument, which the Commission rejected (April 18, 2018 Opinion and Order in Case No. U-18419, pp 123-25).[147]

Leaving aside DTE's ambiguous constitutional claims, and MEC/NRDC/SC's assertions about the applicability of MEPA to this proceeding, which were rejected by the Commission in Case No. U-18419, this PFD recommends that public health impacts, to the extent these impacts can be identified, assigned, and the associated costs quantified, should be recognized as part of the retirement analysis in future IRPs. As is the case with fixed and variable O&M and environmental capital costs, health costs are real, quantifiable costs, as explained at length in Dr. Thurston's and Ms. Weid's testimony and exhibits. However, unlike O&M and capital expense, these costs are externalities, which by definition are not paid directly by DTE or its ratepayers. Nevertheless, certain DTE customers living in proximity to the company's fossil generating plants are certainly paying healthcare costs associated with exposure to air pollutants emitted by these units, again, as discussed in Dr. Thurston and Ms. Weid's testimony.

[147] DTE's reply brief, pp. 81-82 (fn. omitted).

In an order addressing filing requirements for a CON under MCL 460.6s, issued on May 11, 2017 in Case No. U-15896, the Commission incorporated a requirement that the following information be included in a request for a CON for a new generation facility:

> The expected annual emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, volatile organic compounds, oxides of nitrogen, mercury, and other hazardous air pollutants per year and over the life of the facility or contract, and **an assessment** of whether some or all of the anticipated emissions and their **anticipated health impacts** could be eliminated or reduced through the use of feasible and prudent alternatives[.][148]

While this filing requirement does not specifically compel the type of quantitative analysis that MEC/NRDC/SC suggest, it would not be much of a stretch to require at least a basic analysis of the public health costs associated with the retirement analysis that informs the PCA. Alternatively, in future IRPs, DTE could provide a more complete assessment of its "clean" planning principle that includes the costs and benefits of its unit retirement plan in a way that recognizes and, to the extent possible, quantifies public health impacts for different retirement dates.

E. Sales Forecast and Peak Demand (MCL 460.6t(5)(a))

DTE presented its sales forecast and peak demand projections through the testimony of Mr. Leuker.[149] As described above, Mr. Leuker developed a starting point forecast as well as forecasts for several additional scenarios based on alternative assumptions for load growth.[150] The Attorney General and ELPC et al. raised issues concerning the company's C&I forecasting method and projected EV sales. MEC/NRDC/SC contends that the company's assumptions about embedded energy

[148] Order, p. 6, Order Attachment A, Part VII. A. 6 (emphasis supplied).
[149] 4 Tr 993-998; Exhibit A-36. Mr. Leuker's forecasts and forecasting methods for the different customer classes are summarized in DTE's brief, pp. 43-44.
[150] See, Exhibit A-35.

efficiency/EWR in the C&I forecast is overstated.[151] Staff also made uncontested recommendations for fine-tuning the forecast in future IRPs. These issues are addressed below.

1. Electric Vehicle Forecast

Mr. Leuker testified that the EV outlook was based on "Plug-in Electric Vehicle Sales Forecast Through 2025 and the Charging Infrastructure Required," by EEI (EEI Report), applied to Michigan's current EV sales.[152] The Attorney General and ELPC et al. take opposite views on projected EV growth, with the Attorney General contending that DTE's forecast for EV load is too high and ELPC et al claiming that the company's projection is too conservative.

Dr. Dismukes testified that the EEI Report cites state government incentives, available in 30 states, as an impetus to the development of EV charging. He noted that Michigan has no such incentives, and in fact, has instituted a fee for EV owners to offset forgone gas tax revenue. He added that, "while the national market share for EVs and plug-in hybrid vehicles . . . has been 0.57 percent and 0.46 percent respectively over the past five years, the market shares of these vehicles in Michigan have lagged behind at 0.11 percent and 0.37 percent."[153] In light of these statistics, the Attorney General maintains that it is unreasonable to assume that EV adoption in Michigan will be as pervasive as is likely in other states. Dr. Dismukes recommended that the more

[151] GLREA's claims about the treatment of DG in the IRP are addressed below.
[152] 4 Tr 997, n. 1.
[153] 7 Tr 2366, citing "Alliance of Automobile Manufacturers. Advanced Technology Vehicle Sales Dashboard." Data compiled by the Alliance of Automobile Manufacturers using information provided by HIS Markit. Available online at: https://autoalliance.org/energy-environment/advanced-technology-vehicle-sales-dashboard/

conservative EIA AEO forecast be used for the EV load forecast.[154] Dr. Dismukes adjusted DTE's forecast consistent with his EV estimate and recommended that the Commission adopt the forecast shown in Exhibit AG-4, rather than DTE's forecast.

In contrast, Dr. Woychik characterizes DTE's forecast as far too conservative, based on outdated information from a national survey. According to him, "Mr. Leuker's approach constrains electric vehicle charging to prior circumstances, which directly ignore the boom in electric vehicle growth DTE will face immediately in coming years."[155] Dr. Woychik points to a recent EIA reference case projection that shows electric battery powered vehicle sales increasing dramatically through 2050.[156]

In rebuttal, Mr. Leuker testified that the EEI Report represents the average of three reports from Barclay's PLC, Navigant Consulting, Inc., and the EIA, adding that "[e]lectric vehicle adoption rates are highly uncertain at this time, and the IEI/EEI's averaging of three forecasts reduces the risk inherent in relying on a single forecast, as, for example, Witness Dismukes recommends by advocating for the adoption of the EIA's forecast alone."[157]

DTE's forecasting method and forecast for EV load are reasonable for this IRP. As Mr. Leuker explained, the forecast relies on a recognized industry source and, as an average of three different outlooks, the projections for EV growth are neither optimistic nor pessimistic. In addition, as DTE points out, it is difficult to predict new markets, and updated information about EV adoption in DTE's service territory will be available for use

[154] 7 Tr 2387, Exhibit AG-4 contains the load forecast adjusted for lower EV sales.
[155] 7 Tr 1925.
[156] Id. at 1926.
[157] 4 Tr 1028.

in the company's next IRP. Therefore, DTE's balanced approach to its EV forecast is appropriate until better information about EV adoption in Michigan is available.

2. Commercial and Industrial Forecast

Dr. Dismukes described his concerns with DTE's C&I load forecasting methods, describing the company's approach as "not particularly robust."[158] He highlighted the fact that for different commercial sectors, for example "Restaurant" versus "Other Medical" DTE projected sales based on CAGRs over very different time periods. In addition:

> [T]he Company's regression analysis models are inconsistent between the 10 separate market estimations, and often contain confusing specifications. For example, the "Other Services" sales are regressed on Southeast Michigan's leisure and hospitality employment, but "Lodging" sales are instead regressed on Southeast Michigan's population. The "Other Grocery" sector is regressed on Southeast Michigan's real personal income, but the "Supermarkets" sector is instead forecast with a simple moving average. Perhaps most confusing, the Company's estimation of "Commercial Manufacturing" sales was estimated based on Southeast Michigan's motor vehicle production, even though vehicle manufacturing is estimated in the Company's examination of future projected industrial loads.[159]

Dr. Dismukes opined that although there is no standard requiring the use of the same historical periods in the regression analysis, he nevertheless advocated for consistency in the forecasting methods, noting that a single year change in the historical period can alter the forecast from a negative growth rate to a positive growth rate. Although Dr. Dismukes did not make a specific adjustment to the C&I forecast based on his critique of the company's presentation, he did recommend that the Commission review DTE's forecasting methods to ensure that the company's approach complies with industry

[158] 7 Tr 2363.
[159] 7 Tr 2363-2364.

best practices. In addition, in future IRPs, any changes to a particular forecasting method should be documented and explained.

In rebuttal, Mr. Leuker provided detailed responses to Dr. Dismukes' claims about inconsistencies and changes in the various subsector forecasts, highlighting the overall historical accuracy of DTE's sales projections.[160]

Mr. Neme testified that DTE's assumptions about embedded energy efficiency/EWR savings in its C&I forecast is overstated. According to him, DTE mistakenly assumed average C&I EWR savings of 1.15% from 2009-2016, when actual C&I savings were much lower. In addition:

> For most C&I market segments, the Company's forecasts are based on data going back much further than 2009. For example, its forecasts are based on data going back to 1992 for schools, to 1995 for government buildings, to 1995 for retail businesses, to 1996 for office buildings, to 1996 for the auto industry, and to 2000 for hospitals. In fact, on a sales weighted average basis, DTE's C&I forecasts are based on data from more years without efficiency programs than on years with efficiency programs. The Company's assumption that the amount of new annual efficiency program savings embedded in its C&I regression-based forecasts is equal to the average savings achieved during the eight efficiency program years of 2009 to 2016 ignores the effects of data from all the other non-program years on those forecasts. That is not reasonable.[161]

Mr. Leuker countered that, contrary to Mr. Neme's claims, there were C&I energy efficiency programs in place prior to 2009; thus, pre-Act 295 energy efficiency savings are appropriately embedded in the forecast.[162] In addition, Mr. Leuker testified that Mr. Neme:

> disregards the Company's demonstrated strong historical forecasting accuracy measures; (2) ignores actual sales results in 2017 and 2018 that are inconsistent with the argument he attempts to put forward; (3) ignores the overall impact to sales forecasts when compared to DTE's historical

[160] 4 Tr 1024-1027; Exhibit A-59.
[161] 7 Tr 2697.
[162] 4 Tr 1013.

> sales performance and (4) ignores the overall impact to sales forecasts when compared to the forecasts of Consumers Energy and other third party forecasters for MISO Zone 7.[163]

In its initial brief, MEC/NRDC/SC argues that the assumptions about C&I energy efficiency, both before and after 2009, "result in the IRP analysis overstating 'both the annual amount of electricity the Company will need to produce or acquire for its customers as well as the amount of peak generating capacity it will need to have in all future years.'"[164] MEC/NRDC/SC therefore contend that the embedded energy efficiency savings in DTE's sales forecast should be reduced by half.

The Attorney General's and MEC/NRDC/SC's arguments are not persuasive. Whatever esoteric methods DTE uses in deriving its forecasts for different C&I sectors, the end result is what matters for purposes of this IRP. Thus, even if the company uses different time periods for its regression analyses for different types of customers, or if it cannot fully account for the embedded energy efficiency incorporated into its forecast, the PFD nevertheless finds that DTE has amply demonstrated that its forecasting accuracy, at least in the recent past, is quite high, both on a total sales and customer class basis.[165] The ALJ also finds persuasive Mr. Leuker's testimony regarding a comparison of regional load forecasts, which shows Mr. Neme's projection as a clear outlier.[166]

Consistent with the above discussion, this PFD finds DTE's sales and peak demand forecasts and forecasting methods to be reasonable.

[163] Id.
[164] MEC/NRDC/SC's brief, pp. 39-40, quoting 7 Tr 2700.
[165] See, Figure 2, 4 Tr 1019 and Table 1, 4 Tr 1020. See also, Exhibit AG-1.
[166] See, Figure 4, 4 Tr 1023.

3. Staff Recommendations

Staff witness Makinde made three recommendations for improving the company's future sales forecasts: (1) DTE should determine and report MAPE on monthly energy sales and peak load in its next IRP; (2) the company should use a shorter historical period for weather normalization; and (3) DTE should increase the granularity of the data used in its regression models. In its reply brief, DTE indicated that it will report MAPE evaluation going forward and that the suggestion to use a shorter weather-normalization period may have merit. DTE states that it will evaluate this recommendation in 2020 and, absent any issues, will implement it in 2021. Finally, DTE states that it is working on increasing the granularity of the data it uses for forecasting, but that it may not have all of the forecasting models updated and evaluated in time for its next IRP.[167]

The PFD finds that the first two of Staff's recommendations should be adopted, and the company should report in its next IRP on the implementation of these proposals. DTE should also provide an update in its next IRP on the company's progress in increasing the granularity of data used for forecasting.

F. Capacity Need and PURPA Issues

Mr. Stanczak testified that based on DTE's analysis, for planning purposes, the company does not have a "persistent" capacity need for 10 years until the retirement of the Belle River units in 2029/2030. While acknowledging the Commission's rejection of DTE's "persistent" capacity need construct in the September 16, 2019 order in Case No. U-18091,[168] DTE maintains that "the concept behind the definition remains important,

[167] DTE's reply brief, pp. 31-32.

[168] "The Commission finds that DTE Electric's use of and reliance on the phrase 'persistent capacity need' in its implementation of its PURPA obligations is not appropriate and contravenes the intent of PURPA. The Commission has not implemented such a definition or standard for capacity need in its implementation

however it is defined."[169] According to DTE, absent a "persistent" capacity need, the company is not required to pay full avoided cost (capacity plus energy) to QFs.

Based on plan assumptions, and Mr. Stanczak's formulation of capacity need, Ms. Mikulan provided DTE's capacity position in her direct and rebuttal testimony. After updating to account for the retirement of St. Clair 1 and the closure of the Greater Detroit Resource Recovery Facility (GDRRF), with which the company had a PPA, DTE found a capacity shortfall of 67 MW for 2019/2020, and a surplus for the next four years.[170] The 2019/2020 capacity shortfall was replaced with purchases from the MISO PRA.

Many of the intervenors disagree, arguing that DTE does, in fact, have a near-term capacity need. Mr. Jester examined DTE's Exhibit A-6, finding that many of the resource additions the company includes are unexplained or inappropriate:

> Close examination of the workpaper used by the Company to prepare Exhibit A-6 shows permanent additions of 7 MW in PY 2020-21 and 16 MW in PY 2023-24 that are included in Line 9 of Exhibit A-6, labeled as "Company-Owned, In-State, Non-Intermittent, ZRC" and are unexplained by testimony. Subtraction of these from the Company's net position as shown in Line 37 of Exhibit A-6 causes the Company to have a capacity deficiency of 23 MW ZRC in PY 2023-24. This subtraction is shown in Line 38 of Exhibit MEC-59. Although this deficiency is overcome by other changes in subsequent years and the Company would thereby show a surplus until PY 2029-30, it is notable that the Company chose to acquire permanent resources at these times even as it claims that it should not have to accept and pay for capacity from PURPA QFs during the same time periods. These unexplained capacity additions are just enough to conveniently ensure that DTE shows no capacity need until Belle River retirements begin.[171]

* * *

of PURPA for other rate-regulated electric providers in Michigan and it is not now convinced that adopting such a definition for capacity would result in non-discriminatory treatment of QFs. The Commission agrees that the company's definition of 'persistent capacity need' is vague in that 'significant' is an ambiguous term subject to multiple interpretations that could potentially result in the company finding that a projected shortfall would not be significant so as to avoid its obligation to purchase energy and capacity from QFs."

[169] DTE's brief, p. 40.

[170] See, Exhibit A-67.

[171] 7 Tr 2759.

> In Exhibit MEC-59, I show the cumulative ZRCs from Company-Owned wind resources from Workpaper LMK-37 in Line 39 and the cumulative nameplate capacity of Company-Owned wind resources in Line 41. I also show the cumulative ZRCs from Company-Owned solar resources from Workpaper LMK-37 in Line 47.[172]

However, Mr. Jester went on to testify that many of the starting point wind and solar resources in Exhibit A-6 were not approved and therefore should not have been included in DTE's capacity determination:

> [O]nly those resources already approved for cost recovery by the Commission are appropriate to include because any other resources only reflect the Company's intent and not its approved position. To my knowledge, at the time this case was filed, none of the solar resources shown on Line 47 of Exhibit MEC-59 had been approved nor have they been subsequently approved by the Commission, so I also identify those in Line 48 as solar ZRCs included in Line 15 of Exhibit A-6 that have not been approved by the Commission. [173]

Mr. Jester then explained that after the Commission issued its order in DTE's amended REP, Case No. U-18232, he updated his analysis to include the three wind parks that the Commission approved. As result of his adjustments, "For purposes of the Integrated Resource Plan, [DTE] had a 2018 Starting Point capacity need of 82 MW in PY 2023-24, 55 MW in PY 2024-25, 6 MW in PY 2025-26, and 389 MW in PY 2029-30."[174]

With respect to DTE's PURPA obligations, MEC/NRDC/SC recommend that when a capacity need arises, the company should be required to pay full avoided capacity cost to QFs with legally enforceable obligations in DTE's PURPA queue up to the point where the capacity need is filled and for as long as the capacity need exists.

[172] 7 Tr 2761.
[173] Id. at 2761-2762.
[174] Id. at 2764; Exhibit MEC-59. Mr. Jester's analysis does not appear include the loss of capacity from the GDRRF or St. Clair 1.

In arguing for consideration of VGP resources as representing a capacity need, EIBC/IEI contend that "the Commission should not automatically determine the Company's capacity need, or alleged lack thereof, on the supposed use of the resources. To the extent that DTE Electric will be utilizing renewable resources to backfill planned capacity retirements, the Commission should find that those resources fill a capacity need."[175]

DTE counters, pointing to the Commission's determination in Case No. U-18091, pp. 46-47, that renewable energy for RPS purposes should not be considered a capacity need because an electric provider can meet the RPS by means other than generating renewable energy. DTE maintains that the same reasoning should apply to the VGP program because participants in the program can meet their sustainability goals in other ways and, "in the absence of such voluntary programs the Company would not build these assets, so no capacity costs are avoided by acquiring VGP assets[.]"[176] Finally, consistent with the company's position in Case No. U-18091, DTE recommends that the standard offer cap be decreased to 150kW.

In the September 16, 2019 order in Case No. U-18091, the Commission adopted DTE's five-year time horizon for determining whether the company has a capacity need and found, based on the record in that case, that DTE had no capacity need for the next five years. Nevertheless, the Commission directed that DTE's capacity position should be reexamined in this case, and it indicated that the PURPA standard offer cap of 550kW should be reevaluated here as well.

[175] EIBC/IEI brief, p. 32.
[176] DTE's brief, p. 41.

The PFD finds that, because of DTE's decision to include both unexplained and unapproved resources in its IRP starting point, the company was able to avoid showing a capacity need, persistent or otherwise, over the first 10 years of the plan.[177] Moreover, as MEC/NRDC/SC point out, this has been DTE's approach for some time: forecast a capacity need, develop a plan to address the need with company-owned resources, and then declare that there is no capacity need. The Commission addressed this issue squarely in the April 27, 2018 order in Case No. U-18419, p. 78:

> If the utility states in its PURPA proceedings that it does not forecast capacity needs from PURPA qualifying facilities because it has plans to acquire non-PURPA capacity, while at the same time the utility states in a Certificate of Necessity proceeding that it does not forecast PURPA resources in its integrated resource planning and therefore must build other resources, were the Commission to accept both statements, this may result in sanctioned discrimination by the utility against PURPA qualifying facilities and fully undermine PURPA's intent.

Based on the foregoing discussion, this PFD finds that DTE does have a capacity need in the next five years; however, the amount of capacity required is not entirely clear. At a minimum, DTE needs to replace the 44 MW of capacity from the GDRRF and possibly the capacity lost with the closure of St. Clair 1. As such, DTE should consider replacing that capacity with QF energy and capacity from the providers who have filed interconnection applications with the company. The Commission should also consider Mr. Jester's recommendation for addressing capacity need in the future:

> If the Company does not have a capacity need at the time a PURPA QF establishes a legally enforceable obligation for the Company to purchase power from the QF, and does not forecast a capacity need during some fixed period thereafter, it does not absolve the Company from paying avoided capacity costs at such time as the Company does have a capacity need. Indeed, when the Company has a capacity need that the PURPA QF can satisfy or partially satisfy, and if the PURPA QF has established a legally enforceable obligation for the Company to acquire that capacity, then

[177] Exhibits A-6, A-7, A-67, MEC-59 and Mr. Jester's discussion thereof.

the Company is obligated to do so at a price not to exceed the avoided cost of capacity.[178]

Finally, with respect to the standard offer cap of 550kW, Mr. Stanczak testified that the cap should be reduced to 150kW, consistent with the DG program under MCL 460.1173.[179] In response, GLREA points out the company appears to be confusing PURPA QFs with customers taking service under the DG tariff, a program completely unrelated to PURPA.[180]

The PFD recommends that the Commission retain the 550kW cap for standard offer contracts, which was affirmed less than two months ago. The PFD finds no compelling reason to alter the cap at this time, noting that GLREA is correct that the DG program for DTE customers is unrelated to PURPA, thus DTE's recommendation to cap the size of the standard offer at the DG size limit should be rejected.

G. Supply-side Resources (MCL 460.6t(5)(j))

DTE included various input assumptions about wind and solar resources in its IRP. As discussed above, DTE's cost assumptions for the near term should have been based on an RFP. The parties raised additional concerns about inputs and appropriate data sources that apply to resources beyond the first three years of the plan.

1. Wind Resources

Again, an RFP issued prior to developing the IRP would have addressed the near-term costs and other assumptions about new wind resources. In addition, the PFD agrees with MEC/NRDC/SC that DTE should have provided some assessment of the cost of a PPA with a third-party wind generator located outside of Zone 7. As MEC/NRDC/SC point

[178] 7 Tr 2752.
[179] 2 Tr 263-264.
[180] GLREA's brief, p. 33.

out, Iowa wind and Indiana wind, under most circumstances, is between $3.00 and $9.00 lower cost than Michigan wind costs.[181] But there was no pre-filing RFP, nor was there any inquiry into the cost or feasibility of importing wind.

The remaining issues concern the appropriate inputs to be used for modeling generic wind resources for the company's longer-term plan. As outlined above, Ms. Schroeder testified that DTE used the NREL 2018 ATB mid-level forecast, and then assumed certain cost reductions consistent with the EP and ET scenarios.[182] For the capacity factor and O&M for future wind parks, Ms. Schroeder used NREL 2018 ATB forecast for TRG-7.

Mr. Allison testified that DTE's forecast relied on an inappropriate source, noting that TRG-7 is "one of the worst-performing and most expensive wind resource types" in the NREL forecast, resulting in higher installed costs and lower capacity factors for wind energy.[183] MEC/NRDC/SC point to the installed capital cost of DTE's recent Isabella wind project ($1,498/kW), the 2019 MTEP Report that assumes onshore wind installed costs of $1,505/kW, and Lazard's 2017 analysis which indicates capital costs ranging from $1,200 to $1,700/kW, all of which were lower than DTE's assumption of $1,702/kW.[184]

MEC/NRDC/SC also dispute the applicability of the TRG-7 30.8% capacity factor, noting that the average capacity factor for DTE wind parks from 2011-2018 is 38%.[185] They further observe that DTE assumed a 41% capacity factor for wind in Case No. U-18419. Finally, using installed cost and capacity factor for TRG-7, Mr. Allison estimated

[181] MEC/NRDC/SC brief, p. 57, citing cross-examination of Mr. Burgdorf 4 Tr 883, 887-888.
[182] 5 Tr 1297.
[183] 7 Tr 2539.
[184] MEC/NRDC/SC brief, p. 54.
[185] Exhibit MEC-134.

an LCOE of $54/MWh, which MEC/NRDC/SC contend, DTE did not dispute. MEC/NRDC/SC again argue that this LCOE differs considerably from other reference sources and evidence in this record.

DTE disagrees, pointing to Ms. Schroeder's testimony that the location of new wind resources will be in TRG-7, not TRG-6.[186] DTE contends that Mr. Allison chose only the best-performing, least costly wind resources for his comparisons, noting that, "the weighted average net capacity factor of the [recently approved] Isabella I, Isabella II, and Fairbanks wind projects is 31%, which corresponds to TRG-7 (5T 1310-11, 1347)."[187]

The PFD finds DTE's assumptions about installed cost and net capacity for new wind projects to be reasonable based on this record. Ms. Schroeder fully explained why the company used NREL assumptions for TRG-7, including the public opposition to new wind development in the TRG-6 zone, and DTE's own wind speed data that "show annual wind speeds of 6.0 [meters per second] m/s– 6.7 m/s at 92 meter hub height, with no data points hitting TRG-6's average speed of 6.9 m/s."

As discussed above, the costs of near-term wind resources should be based on an RFP, assuming that the company intends to add wind resources in the first three years of the plan. In the company's next IRP, the Commission should reevaluate the information sources used for wind generation modeling inputs. Although the TRG-7 inputs DTE used are not unreasonable, MEC/NRDC/SC's LCOE analysis demonstrates that DTE's assumed wind costs may be inflated, thus affecting the optimization results.

[186] 5 Tr 1309-1310.
[187] DTE brief, p. 36

2. Solar Resources

As described above in Section II, Ms. Schroeder used NREL's 2018 ATB forecasts in forecasting solar costs and capacity, and again assumed cost reductions for certain scenarios.[188]

ELPC et al. argue that DTE "arbitrarily selected solar input values from multiple data sources, impacting the three major inputs for solar: capital costs, . . . O&M costs, and capacity factors. (7 TR 1958:10-13)." They maintain that this resulted in solar costs that were overstated by 39%, and that the LCOE for solar should be modeled at $50.09/MWh rather than $69.48/MWh. ELPC et al. assert that the NREL ATB forecast for solar is too conservative, because it fails to recognize the rapid advances in solar technology and the decreasing costs. In addition, ELPC points out that:

> [W]hen converting the ATB data to a linear forecast, DTE chooses a starting year that results in solar costs that are too high and are inconsistent with the rest of DTE's analysis. (7 TR 1990). The ATB forecasts are non-linear, and because Strategist cannot use non-linear data, DTE needed to convert the ATB to a linear forecast. DTE's process for converting the ATB hinged on its choice to start with the 2018 ATB number and create a linear forecast by applying an inflator of 2.5%. (7 TR 1989:18-1999:23). By using the 2018 number and inflating the value from that point, DTE overlooks the cost decreases that occur in the early years of the ATB forecast. (7 TR 1990:24-1991:6).
>
> * * *
>
> Because DTE does not expect to bring any solar projects online until late 2020, Mr. Lucas recommends that the Company use the average of the ATB 2021 – 2024 data for the near term linear forecast and then use the ATB 2025 data point as a Starting Point for a future growth trajectory. (7 TR 1993:6-10).[189]

ELPC et al. also contend that DTE's projected O&M costs for solar are too high. According to them, although DTE used the NREL ABT for wind O&M, the company used

[188] 5 Tr 1298-1299, Exhibit A-19.
[189] ELPC et al.'s brief, pp. 29-30. The problem with converting the ATB forecast to a linear series also affects the O&M projection.

a different source, the Q1 2017 U.S. Solar PV System Benchmark, which reported a higher O&M amount. ELPC et al. point out that DTE justifies its decision based on conversations with NREL, which are not in the record, and the company's own limited experience with solar. ELPC et al. further observe that DTE uses an exceptionally high inflation rate of 2.5% for both capital and O&M costs for solar. They recommend that DTE use the same PACE CPI inflation adjustment that the company uses for the rest of its projections.

ELPC et al. also dispute DTE's O&M escalation rate of 2.13% based on the company's solar maintenance contracts. Finally, ELPC et al. take issue with DTE's solar panel degradation factor. They point out that although DTE used a solar capacity factor of 22.9% in its Strategist modeling, the company used a capacity factor of 22.5% in its LCOE analysis. In addition, ELPC et al. argue that DTE uses a panel degradation factor of 0.5% annually, however, panel degradation is expected to decrease significantly in the future. ELPC et al. recommend using a panel degradation factor of 0.35%, "which is reflective of panels currently on the market."[190] Finally, ELPC et al. summarized the modifications it made to DTE's solar inputs, resulting in a reduction in the LCOE from $69.48/MWh to $50.09/MWh.[191]

DTE responds that the company used the NREL ABT-mid for the solar degradation factor, which starts at 0.75% and reduces to 0.5% in 2050. The company uses the lower factor throughout the study period, adding that ELPC et al.'s 0.35% degradation factor is not from a publicly available source. DTE further explains that the primary driver of O&M cost escalation and that DTE's O&M service contracts escalate according to the CPI.

[190] ELPC et al., brief, p. 34.
[191] ELPC et al. brief, p. 35 Table 1.

DTE points out that Staff found DTE's solar inputs to be reasonable. The company adds that "any alleged uncertainty in assumptions or imprecision in modeling is addressed by using different scenarios that provide a range of results."[192]

The PFD agrees in part with ELPC et al. First, the PFD agrees with the adjustment to convert NREL ABT capital and O&M costs to linear data for input into Strategist. The recommendation to use NREL ABT data, rather than alternative source, for O&M costs should also be adopted. DTE's use of an alternative source appears cherry-picked and, in any event, is not well-supported on this record. The PFD also agrees with ELPC et al. that DTE should use the same PACE CPI inflation factor for solar as it does throughout its analysis, and that the LCOE analysis should use the same degradation factor as was used in the Strategist modeling. All other inputs used by the company were supported and should be adopted. The adjustments recommended here should be incorporated in the company's solar modeling in its next IRP.

Another issue raised by MEC/NRDC/SC and ELPC et al. is the company's assumed 50% ELCC for solar until 2024, decreasing by 2% per year until 2030. ELPC et al. explain:

> ELCC is a measure of how well resources can meet the peaks in system load. (7 TR 2008:4-5). MISO bases the calculation on the average performance of a PV system from 3-6 PM EDT during June, July, and August of the three previous years. (7 TR 2008:11-12). If a system has not been in service long enough to establish a performance level, MISO assumes a 50% ELCC. (7 TR 2008:12-17). New systems have no more than one year where their ELCC is based on the default 50%, and after their first year of operation ELCC is based on historic performance. (7 TR 2008:10-17). The 50% number is for fixed-tilt systems, and single-axis tracking systems like the ones DTE is modeling have higher ELCC. (Ex. ELP-31; 7 TR 2009:7-17). Mr. Lucas reviewed information for single-axis trackers from suitable sites in Michigan and concluded that they had an

[192] DTE's reply brief, p. 37-39 citing 3T 498-499.

average ELCC of 65.8% under MISO's current methodology. (7 TR 2009:7-17).

MEC/NRDC/SC also take issue with DTE's assumption on the same grounds: that newer single-axis tracking systems have a higher ELCC than the older fixed-tilt systems. Mr. Allison estimated that a single-axis tracking system in Detroit would have an ELCC of 66%.[193] In addition, MEC/NRDC/SC argue that DTE acknowledged that it used a fixed-tilt generation profile shape when modeling a single-axis tracking system,[194] and the company used a simple average of capacity factor and credit in its modeling rather than a levelized factor and credit. MEC/NRDC/SC explain:

> Solar resources produce the most energy at the start of their life, and gradually decline over time. So DTE's use of a simple average of capacity factor underestimates these resources' energy production in the near term when the resource is new, and overestimates it in the long term, at the end of the resource's life. But energy and capacity provided now is more valuable than energy and capacity provided at the end of the resource's life, decades from now.[195]

In response, DTE maintains that it "incorporated reasonable and prudent assumptions for the . . . ELCC of solar, given the substantial uncertainties and potential risks to ratepayers. . . . The alternative solar ELCC values proposed by certain Intervenor witnesses ignore the realities of the system and over-estimate the capacity value of solar. The Company selected a reasonable and prudent assumption for solar ELCC values that considers the increased penetration of solar in MISO, and the uncertainties with the future resource adequacy construct."[196]

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[193] 7 Tr 2547-2548
[194] 3 Tr 491
[195] MEC/NRDC/SC's brief, pp. 118-119 (fn. omitted).
[196] DTE's brief, p. 62 citing 3Tr 517-524.

The PFD finds that DTE's use of a 50% ELCC, based on an older fixed-tilt system, is inconsistent with the company's modeling of a single-axis tracking system, which will have a higher ELCC. Accordingly, an ELCC of 65.8%, based on Mr. Lucas's review of single-axis tracking projects in Michigan, should be adopted and incorporated in the solar modeling in DTE's next IRP.

3. Distributed Generation

Ms. Mikulan testified that DG, including customer-owned solar and behind-the-meter CHP, were screened out of the analysis because these small installations are more costly than utility-scale projects.[197] In addition, DTE asserts that:

> DG is generally not a resource that a utility would select to meet a future capacity need with its current technology and generation profile. This is because DG typically is either a behind-the-meter facility built in connection with a particular customer and specific to that customer's needs, or it is not dispatchable or schedulable and does not coincide with system or local peak demand. Most grid-connected DG needs to be disconnected from the grid during outage situations for safety considerations, limiting its benefit to local customers.[198]

DG was, however, reflected in Mr. Leuker's sales forecast as a reduction in demand.

Several intervenors take issue with DTE's treatment of DG resources. Soulardarity, GLREA, and Ann Arbor contend that DG could provide significant reliability and other system benefits including ancillary services, on-peak capacity, resource diversification, and a reduction in the extent and duration of outages.

In response, DTE points to Ms. Zhou's testimony explaining that DG would increase reliability challenges and require greater investments in distribution. Ms. Zhou referenced an EPRI report on the problems associated with rapid deployment of solar in

[197] 3 Tr 508-509.
[198] DTE's reply brief, pp. 43-44.

Germany and a report from the Massachusetts Institute of Technology describing similar reliability problems.

> Ms. Zhou further explained that for DG to offset infrastructure investments, DG generation needs to be coincident with area peak. The EPRI report and patterns observed on DTE Electric's system indicate, however, that solar generation could just slightly shift the system peak. The impacts on system peak from high penetration of solar is small, so there is a limited ability for solar generation to offset infrastructure investments. In addition, for DG to offset infrastructure investments, it must be schedulable and dispatchable (available when needed and ready to perform). It also must be placed where it is needed on the system. Most DG currently in DTE Electric's service territory does not meet these criteria (6T 1748-50).[199]

The PFD finds that DTE's decision to screen out DG as too costly was not well supported. While it is true that economies of scale apply here (e.g., on a per kW basis, a 2 MW solar system will cost less than a 2 kW system), that is not the end of the inquiry. As GLREA elicited in its cross-examination of Ms. Pfeuffer, the capital costs of behind-the-meter generation are not costs borne by the utility.[200] That is not to say that DTE pays none of the costs of DG energy; under the company's DG tariff based on the "inflow-outflow" method, the company pays an amount less than retail for energy delivered to DTE from a DG system. Thus, a more complete analysis of the actual cost of DG to the utility and ratepayers is warranted. The Commission signaled as much in the November 21, 2017 order in Case no. U-18418, p. 88:

> The Commission expects a planning process that is transparent, thorough, and open to considering evolving technologies, ownership structures, and innovative solutions to meet customer needs. In applying the "most reasonable and prudent" standard, it is essential to fully evaluate alternatives ranging from conventional or distributed generation, transmission or distribution, energy storage, and EWR or DR programs.

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[199] DTE's reply brief, p. 45.
[200] GLREA's brief, p. 97, citing 2 Tr 242-243.

The remaining claims regarding the significant costs or benefits of DG are hypothetical at best. GLREA, Ann Arbor, and Soulardarity provide a list of possible DG benefits that are purely speculative and without the support of reliable studies specific to DTE's service territory. At the same time, DTE's reliance on problems with rapid and widespread solar deployment in Germany, to support its claim that DG is far more trouble than it is worth, is utterly disconnected from the reality of DG penetration (<< 1%) in its service territory.

In future IRPs, DTE should provide a more transparent analysis of the true costs and benefits of DG, including CHP, as a supply-side resource. The various DG technologies may still be screened out on cost grounds, but a much more thorough assessment would be necessary to support that conclusion.

4. Voluntary Green Energy

Issues regarding DTE's VGP programs ranged from a concern that the IRP relies too much on VGP resources, to claims by Ann Arbor and Soulardarity that the costs of the VGP and MIGreenPower programs are prohibitive and should be reduced for low-income customers,[201] to a specific proposal by Mr. Jester for modifying the calculation of the VGP credit, to a recommendation by EIBC/IEI that VGP resources be considered a capacity need for purposes of PURPA.

[201] In its reply brief, p. 14, DTE argues that providing a benefit to one group of customers could increase costs to others. DTE adds that "The fact that some ratepayers have the interest and ability to voluntarily purchase additional renewable energy beyond the statutory requirements has a positive effect on all stakeholders wanting more renewable energy from a resource planning perspective." The company also points to a proposal for a low-income pilot "designed to gauge interest in voluntary renewable energy by the Company's low-income customers, determine whether there are other obstacles to enrollment that exist once the price premium for incremental renewable energy is removed[.]" Id. at fn. 11.

This PFD finds that VGP issues are not appropriately addressed here and should be considered in DTE's next VGP review.

H. Demand-side Resources

1. Energy Waste Reduction (MCL 460.6t(5)(d))

As outlined above in Section II, Mr. Bilyeu explained the various cost assumptions and inputs that DTE used in modeling EWR. DTE recommended using tiered incentive costs (e.g., the higher the cost of the measure, the higher the incentive) and it included program administration costs escalated by inflation. DTE evaluated EWR levels ranging from a 1.5% starting point to 2.25% in .25% increments,[202] and it applied an average line-loss rate of 6.8% to EWR savings. As a result:

> The defined PCA increases the EWR level to 1.75%, starting with an increase to 1.625% in 2020, and full implementation of 1.75% in 2021 through 2024. The flexible PCA identifies four pathways (A, B, C, and D) with various levels of EWR. Pathways A, B and D continue the 1.75% EWR level from 2025 through 2040. Pathway C increases the EWR level to 2.00%, starting with an increase to 1.875% in 2025, and full implementation of 2.00% in 2026 through 2040 (6T 1566).[203]

MEC/NRDC/SC and ELPC et al. contend that several aspects of DTE's EWR analysis biased the results of the IRP against increased levels of energy efficiency. MEC/NRDC/SC posit that: (1) DTE's analysis fails to recognize "end effects" of EWR benefits that extend beyond the study period (although costs that are paid during the study period are included); (2) DTE's non-program EWR cost increases are tied linearly to program cost increases; (3) DTE's use of average line losses for all hours, rather than

[202] See, Exhibit A-21.
[203] DTE's brief, p.49, fn.53.

marginal line losses with on- and off-peak considerations, was error; and (4) DTE misses opportunities to optimize EWR.[204]

MEC/NRDC/SC maintain that because EWR costs tend to be front-loaded, whereas the energy savings benefits can extend for years, DTE should have incorporated long-term benefits in an end effects assessment of EWR. Failure to do so results in an understated benefit-cost ratio for EWR. MEC/NRDC/SC explain:

> [I]n its economic modeling, DTE limited its analysis to a timeframe of 2019 through 2040 without ensuring that such an approach would capture approximately the same proportion of the costs and benefits of the EWR programs. In fact, DTE's modeling captured virtually all of the difference in costs between the various levels of EWR savings that were evaluated, but did not consider all of the differences in the benefits between those levels of savings.[205]

DTE responds that Ms. Mikulan acknowledged that Mr. Neme's claim was correct, but all of the modeling was cut off at 2040 for simplification and that "EWR was treated like the other resource alternatives in the Strategist model, none of which had benefits counted past 2040. Mr. Neme's suggestion to include the 'end effects' benefits for only EWR would be inappropriate and result in unfair bias towards that resource."[206]

The PFD finds MEC/NRDC/SC's arguments on this issue persuasive. Although DTE contends that all resources were treated equally in the modeling; thus all costs and all benefits were terminated at the end of the study period, this approach does not take into account that EWR, unlike a supply-side resource, generally does not match costs and benefits over the useful life of the resource. MEC/NRDC/SC correctly point out that EWR costs are significantly front-loaded, while the benefits of energy efficiency accrue

[204] MEC/NRDC/SC brief, p. 59, citing 7 Tr 2664-2673.
[205] MEC/NRDC/SC brief, p. 115, citing 7 Tr 2675.
[206] DTE's brief, p. 63, citing 3 Tr 529.

over 10 or 20 years or more. Contrast this with a gas plant where the costs of the plant are spread over the 30- to 40-year life of the asset, and the benefits of the electricity produced accrue over the same period. Thus, a failure to include end effects results in bias against EWR investments.

While DTE contends that, even with end effects included, the results of the EWR optimization are unchanged, the ALJ finds this unconvincing. As MEC/NRDC/SC argue:

> Mr. Neme calculated that DTE's modeling of EWR captured more than 99% of the costs of the efficiency programs but only approximately 85% of the benefits of those programs. Using DSMore, the same software that DTE uses to analyze the cost-effectiveness of energy efficiency programs, witness Neme found that as a result of the end effects problem, DTE had overestimated the NPVRR of the different levels of EWR by between $718 million (for 1.5% EWR) and $946 million (for 2.25% EWR). Accounting for end effects also changed the comparative NPVRR rankings of the different EWR savings levels. In particular, while DTE's flawed analysis had identified the 1.5% EWR scenario as having the lowest NPVRR, after the end effects problem is correct, the 2.0% EWR savings had the lowest NPVRR and, as such, was the economically optimal option for customers.[207]

Moreover, adding this error with respect to end effects to additional oversights in the company's approach to EWR modeling, discussed below, leads to results that call into question the company's claim that a 1.75% level of EWR is most reasonable and cost-effective.[208]

MEC/NRDC/SC further contend that non-program costs should not be assumed to grow at the same rate as program costs, noting that:

> Many of the efficiency programs a utility would run at the 1.50%, 1.75%, 2.00%, 2.25% and 2.50% EWR levels would be the same – targeting the same markets, promoting the same measures, using similar program approaches, etc. Once one is already at the 1.50% savings level, most of the differences in program portfolios under more aggressive savings targets would likely be associated with offering higher incentives and/or more

[207] MEC/NRDC/SC brief, p. 115 (fn. omitted), citing 7 Tr 2674-2678.
[208] Id.

aggressive marketing effort so that more customers would participate. However, that should not affect evaluation costs.[209]

MEC/NRDC/SC maintain that it is more reasonable to tie non-program costs to savings above the 1.5% level, rather than cost increases above the base level. According to them, "if portfolio-level administration costs were to grow in proportion to savings (e.g., they would be one third higher for a 2.00% EWR savings level than for a 1.50% savings level), this would reduce the cost difference between the 1.50% EWR savings level and the 1.75%, 2.00% and 2.25% EWR levels by $29 million, $70 million and $114 million, respectively[.]"[210]

DTE responds that the amounts that it projects for non-program costs are consistent with Commission orders and the company's EWR plan filings. Moreover, it cannot be assumed that increased incentive levels or more aggressive marketing efforts will result in more energy savings, as DTE is experiencing some saturation of existing programs and will need to develop new programs that may increase non-program costs. DTE adds that Exhibit A-21 shows that DTE's evaluation, measurement, and validation (EV&M) budget is 5% of total EWR spending, significantly lower than the 8% allowed in the December 4, 2008 order in Case No. U-15800. DTE further contends that Mr. Neme's comparison to other utilities' EV&M spending is misleading because these utilities have EV&M programs that differ considerably from DTE's.

This PFD finds MEC/NRDC/SC's position persuasive. While setting a certain percentage of EWR program spending aside for non-program costs was a reasonable approach when Act 295 was first implemented, DTE now has over a decade of experience

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[209] MEC/NRDC/SC brief, pp. 61-62, quoting 7 Tr 2684.
[210] MEC/NRDC/SC brief, p. 63, citing 7 Tr 2686.

in implementing these programs and should see more stability in non-program costs. Accordingly, MEC/NRDC/SC's recommendation to tie education, EV&M and other non-program costs to energy savings, rather than EWR spending, is a more reasonable approach to modeling EWR.

Next, MEC/NRDC/SC dispute DTE's assumption that EWR savings should be grossed up by the average system line loss rate, rather than the marginal line loss rate. They explain:

> When electricity is generated, it must be sent through the utility's transmission and/or distribution (T&D) system infrastructure to residential and business customers, and some electricity is lost in the process. The amount of electricity that needs to be generated is thus greater than the amount of electricity that is ultimately consumed by residential and business customers. The amount lost through T&D is the line loss rate. EWR targets are established at the customer meter level (customer's home or business), so in order to translate EWR savings into generation-level savings, EWR savings are multiplied by the line loss rate to calculate generation level savings.
>
> Rather than applying a marginal line loss rate, and differentiating between line losses during peak and non-peak periods, DTE grossed up EWR savings to the generation level using an annual average line loss across all hours. DTE has not calculated marginal loss rates, though the Company has been aware of the data gap since at least 2015. Using average rather than marginal line losses biases the IRP against higher levels of efficiency, and modeling runs applying a reasonable, assumed marginal loss rate and peak marginal loss rate show the magnitude of bias.[211]

MEC/NRDC/SC contend that the application of marginal, rather than average, line-loss savings for EWR is well-supported by authoritative publications on evaluating EWR cost-effectiveness,[212] and they point to testimony in DTE's CON proceeding, Case No. U-18419, where the company and its consultant admitted that marginal line-losses would

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[211] MEC/NRDC/SC brief, pp. 65-66 (fn. omitted).
[212] MEC/NRDC/SC brief, p. 69, referencing *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements*, by the Regulatory Assistance Project and *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources*

be more appropriate to apply to EWR savings than average line losses.[213] However, because actual measurements of marginal line losses on DTE's system are not available, Mr. Neme assumed a marginal line loss rate of 10.2% for energy savings and 20.4% for demand savings.[214]

DTE responds the MEC/NRDC/SC's position is erroneous because "most measures provide savings across many hours of the year, not just during on-peak hours. The Company has only 800 peak load hours in a year (out of a total of 8,760). 88% of EWR savings occur during off-peak hours over the course of the entire IRP timeframe where marginal line losses may be significantly lower."[215] DTE adds that:

> [T]he American Council for an Energy-Efficient Economy (ACEEE) 2017 Utility Scorecard referenced by Mr. Bilyeu adjusts both energy and demand savings by applying average line losses to energy efficiency savings. The average of the line loss factors for the 51 utilities included in the scorecard was 6.4%.The scorecard also states that the average of the EIA's estimated US transmission and distribution losses for 2005-2015 is 6%. These values are significantly lower than Mr. Neme's line loss assumptions and are more in line with the Company's average line loss rate of 6.8%.[216]

The PFD finds that MEC/NRDC/SC's claim has merit. They correctly point out that EWR savings occur on the margin and thus should be evaluated using marginal line loss rates. And they point to two publications, as well as the 2018 EWR Potential Study that all indicate that energy efficiency savings should be grossed up by marginal, rather than average, line losses, on- and off-peak. The difficulty is, there is no information on DTE's marginal line loss rate, and even the company's average line loss amount dates from 2007. Mr. Neme's approach to addressing this problem, multiplying DTE's average line

[213] Id.
[214] 6 Tr 2691.
[215] DTE's brief, p. 55, citing 6 Tr 1590-1592.
[216] Id. at 55, citing 6 Tr 1567 fn. 3.

loss rate by 1.5%, appears reasonable for now.[217] In future IRPs, absent actual data on marginal line losses for DTE, the parties could propose alternatives to this multiplier that might more precisely reflect DTE's line loss rates.

In a related issue, ELPC et al. contend that DTE underestimated avoided T&D capital costs from EWR. Mr. Daniel testified that one meta-analysis of avoided T&D capital costs estimated a range from $32 to $200 per kW, thus, the company's use of $0 for avoided T&D capital cost was unreasonable.[218] Mr. Daniel further pointed out that even in areas where load is decreasing, there can still be significant avoided T&D investments.[219]

DTE responds that Ms. Zhou addressed Mr. Daniel's claim, testifying that Mr. Daniel failed to consider DTE's system conditions, where load growth is occurring in specific areas, mostly related to C&I customer requests. According to DTE, these costs cannot be avoided through EWR. DTE adds that the majority of its distribution investments are related to replacing aging infrastructure and again, cannot be addressed through EWR for the most part. Finally, DTE contends that Mr. Daniel selected utilities with high T&D avoided capacity values, based on very specific system conditions, for comparison to DTE. Accordingly, DTE's use of $7.00/kW-year is reasonable for avoided system-wide T&D costs.[220]

The PFD finds DTE's input for avoided T&D capital costs reasonable for purposes of this IRP. While ELPC et al. do point to some areas and situations where avoided T&D

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[217] As discussed in Mr. Neme's testimony, this ratio between average and marginal line loss rates was derived from an independent third-party analysis: Lazar, Jim and Xavier Baldwin, *Valuing the Contribution of Energy Efficiency to Avoided Marginal Line Losses and Reserve Requirements*, Regulatory Assistance Project, August 26, 2011.
[218] 7 Tr 2180
[219] Id.
[220] DTE's reply brief, pp. 41-42, citing 6 Tr 1735-1736, 1743-1744; Exhibit A-30.

costs may be much higher despite declining load, they fail to point to any circumstances where DTE could avoid significant T&D investments, given the current characteristics of DTE's load conditions, customer mix, customer behavior, program offerings, and T&D capital investment priorities.

MEC/NRDC/SC contend that DTE missed savings opportunities by assuming that EWR ramps up and stays at the same level throughout the study period. Relying on modeling by Mr. Evans, MEC/NRDC/SC increased EWR levels "to 1.75%, 2% or 2.25% through 2025, and then reduced EWR levels to 1.5% after 2025 through 2040." Mr. Evans' approach, using DTE's REF case and tiered EWR incentives, resulted in decreases to NPVRR ranging from $28 million (Case 7) to $313 million (Case 9).[221]

In response, DTE relies on Ms. Mikulan's testimony that it is unclear why the company would run its EWR programs in this manner, adding that "the benefits of Case 8 as compared to Case 7 do not materialize until the year 2034, and the benefits past 2034 are only an accumulated $4 million NPVRR by 2040."[222]

The PFD finds MEC/NRDC/SC's suggestions, supported by Mr. Evans' modeling, to be reasonable. In response to DTE's query as to why it would ever do this (significantly increase EWR savings in early years then decrease to 1.5% savings later), the answer is, "why not?" In addition to being a less costly option than DTE's proposal, on an NPVRR basis, MEC/NRDC/SC's suggestion to ramp EWR savings up in early years, then back down later, could also address some of the concerns that the company expresses about saturation, and the implied reduction in "low-hanging fruit" as EWR programs mature.

[221] MEC/NRDC/SC's brief, p. 79, citing 7 Tr 2474-2475; Exhibit MEC-7 (Cases 7, 8, and 9).
[222] DTE's brief, pp. 66-67, citing 3 Tr 558-559.

Finally, ABATE raises a concern that even a 1.75% EWR amount is unattainable and will be too costly. The Staff urges the company to set a goal of achieving 2% EWR savings, pointing to the fact that DTE has consistently met or exceeded its energy savings goals since 2009. Soulardarity criticizes a purported lack of EWR programs and program funding for low-income customers. The ALJ notes that, based on USRCT scores, all levels of EWR examined in this proceeding are cost-effective, and the ALJ agrees with Staff that DTE's approach to EWR modeling was more conservative than it has been in past EWR proceedings. Soulardarity's concern was addressed by DTE:

> Mr. Bilyeu disagreed, citing statistics including the Company's $13.8 million total low-income spend in 2018, which was an increase of more than 100% from the prior year, and ranks in the top 10 largest low-income programs by spend in the nation (6T 1594). In the 2020-2021 EWR Plan filing (Case No. U-20373), the Company plans to spend 24% of the residential budget on low-income programs. The planned low-income budget continues to grow to $14.7 million in 2020, and $15.5 million in 2021. The Company also proposed implementing a low-income health and safety pilot with the Company's existing non-profit partners focused on home repairs and structural updates that cause weatherization deferral issues. Mr. Bilyeu also provided further details on the Company's low-income efforts to correct Mr. Koeppel's apparent misperceptions (6T 1594-98; Exhibit A-54).[223]

In summary, the PFD finds that in its next IRP: (1) DTE should be directed to incorporate an end effects analysis as part of its EWR optimization; (2) DTE should tie its assumptions about non-program cost increases to increased savings rather than increased spending; (3) whether directly or via a proxy method, DTE's line-loss savings should be based on marginal on- and off-peak savings rather than average line losses; and (4) DTE should evaluate different approaches to ramping EWR savings up and down over the course of the IRP period to determine if there are cost-savings to such approach.

[223] DTE's brief, p. 56.

2. Demand Response (MCL 460.6t(5)(f))

As outlined above, Mr. Farrell explained that DTE's fixed PCA proposes to continue and expand the company's current DR portfolio. As shown in Exhibit A-26, DTE is requesting pre-approval of $24 million in DR capital expenditures from May 1, 2020 through December 31, 2022.[224]

Staff agrees with the company's proposed capital spending on the IAC switches and PCT thermostats,[225] as well as with the funding for pilots that are currently underway, albeit with some recommended program changes.[226] Staff recommends updating tariff language for Rate D1.8 so that the company can bid the PCT pilot into MISO as an LMR,[227] and likewise recommends that the company alter the BYOD pilot so that it too may be offered into the MISO market as a DR resource.[228] Staff also disagrees with DTE's assertion that what the Commission approved in Case No. U-20162 – "a TOU rate for all residential customers" – should be considered like traditional TOU rates in the context of DR. Mr. Isakson testified that the Commission-approved transition to a summer on-peak rate as the default residential rate does not constitute a DR rate because it is designed to more accurately reflect costs, not to change behavior as DR rates are.[229]

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[224] 6 Tr 1680.
[225] 7 Tr 3331.
[226] 7 Tr 3333.
[227] 7 Tr 3337. Mr. Isakson recommends that the tariff change take place in either the company's recently filed DR reconciliation case, or in an ex parte case filed within three months of the conclusion of this IRP case; whichever is earlier, adding that if the Commission does not want the change in Rate D1.8 to also apply to current dynamic peak pricing customers who are not on the PCT pilot, the tariff should specify that exception. Id.
[228] Id. After the pilot reaches its maturity with an enrollment of 25,000 customers, Staff argues that the pilot should be offered as a DR resource of DTE's choosing to MISO, and if the pilot develops into a full program, it should also be bid into MISO beginning in 2022.
[229] 7 Tr 3339-3340.

Staff recommends that the Commission deny DTE's request for preapproval of capital spending for DR pilots, except for the on-going BYOD and EPRI pilots.[230] Mr. Isakson testified that the pilots are not well-defined and that preapproval of the company's requested amount, "essentially creates a $2M annual budget for DR pilots" which DTE "may feel pressured into spending regardless of the prudency of new pilots." Staff adds that the company has multiple opportunities to request recovery for DR pilot capital spending when more details are known.[231] Mr. Isakson explained that the risk of success or failure of fully implemented programs has been greatly reduced through the implementation of three-phase DR framework, whereby DTE can show the Commission that unexpected variation in costs, customer enrollment, or DR resource size is reasonable and prudent, and it allows for consistent recovery through annual reconciliation proceedings.[232]

Staff's proposed adjustment for "other pilots" reduces DTE's projected total DR capital spending in 2020 by the difference between the BYOD and EPRI pilots cost and $2.1M and will also reduce the DR capital request by $2M in both 2021 and 2022.[233]

In response to Staff's recommended adjustment, Mr. Farrell explained the need to undertake pilots prior to implementing full-scale programs. He testified that a capital

[230] Id.
[231] 7 Tr 3334.
[232] 7 Tr 3335-3336. Mr. Isakson described the three-phase DR framework set forth in the September 15, 2017 order in Case No. U-18369 as follows:
The first phase of the DR framework calls for the Company to propose a high-level plan for DR, including capital spending but not O&M, in its IRP. The second phase involves including the approved capital spending from the IRP in a general rate case, followed by the third phase consisting of a reconciliation case that ties total annual DR spending to the high-level IRP-based plan. Any adjustments between the actual DR outcomes (i.e. spending, customer enrollment, MW achieved) made in the reconciliation would then pass through to the Company's following general rate case.
[233] Id. The adjustment related to the cost of the BYOD and EPRI pilots is provided in confidential Exhibit S-8.0.

budget for pilots allows DTE "to remain at the forefront of new demand response technologies" and "to quickly switch directions if a pilot is not demonstrating the expected results or investigate whether new and upcoming technologies provide any additional benefit without setting specific program goals."[234] Mr. Farrell disagreed that the three-phase DR process reduces the risk associated with cost recovery and approval, opining that the development of new DR pilots could be significantly delayed if the $2.0 million for battery storage pilots is not approved as part of the IRP. As an alternative to reducing the DR funding, Mr. Farrell suggested periodic, informal meetings where DTE could update Staff on DR pilot initiatives and progress and receive necessary feedback.

Mr. Farrell did not disagree with Mr. Isakson's recommendation regarding qualification of the DPP Rate, BYOD, and PCT programs as LMRs in MISO, noting only that the company intends to do so in the 2020/2021 MISO planning year, rather than in 2022.

Soulardarity also raised concerns about the DR component of the IRP. Mr. Koeppel testified that it critical for low-income customers that DTE implement a robust DR program, because these customers spend a much larger percentage of their income on monthly energy bills than do higher-income people.[235] Mr. Koeppel opined that strong DR programs reduce overall energy demand, which in turn reduces the need for new energy-generating facilities that produce pollution, which disproportionately harms low-income people.[236]

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[234] 6 Tr 1684.
[235] 7 Tr 2331.
[236] Id.; Exhibit SOU 27.

Because low-income customers often live in older, poorly-insulated homes, Mr. Koeppel explained that a DR program that remotely increases or decreases the temperature of a home based on the reading of a smart thermostat may cause these older homes to reach significantly colder or hotter temperatures than intended. Mr. Koeppel also offered several reasons why low-income customers may not want to participate in DR programs, including being wary of having a utility employee in their home, not having the digital resources to support the new technology, being concerned that smart technology would enable the utility to shut off their electricity automatically if they're unable to pay, and a fear that smart technology in their home will be used to monitor their activity.[237]

Mr. Koeppel adds that DTE can allay some of the concerns about its DR programs by giving people "an ownership stake in the broader electricity system."

> The three things that will most allay concerns about DR programs are ownership, affordability, and shutoff protections. As mentioned above, ownership and stakeholdership give people comfort through better understanding of changes made to their energy system. Affordability can be achieved through community ownership and the proliferation of distributed generation sources. Finally, in its most vulnerable communities served, DTE could provide more and more robust shutoff protections and more aggressively and equitably address system reliability problems to ensure these communities are less likely to experience outages and that any outages that do occur are more promptly redressed.[238]

In rebuttal, Mr. Farrell asserted that Mr. Koeppel "mischaracterizes and provides inaccurate information" about how DTE's current DR programs are implemented.[239] With respect to thermostat control of temperature, Mr. Farrell notes that customers can override the utility set-point or even opt-out of the event in its entirety. Mr. Farrell adds

[237] 7 Tr 2332.
[238] 7 Tr 2333.
[239] 6 Tr 1689.

that DTE is experimenting with a pre-cooling of the customer's home, which will help the customers' home remain at a more comfortable level during the event, making them less likely to override their thermostats during the event.[240]

Regarding concerns about utility representatives entering a customer's house, Mr. Farrell explained that most customers who participate in these programs have done so without the need for the utility to enter their homes." Similarly, regarding the concern that low-income customers don't have the digital resources to support the new technology, Mr. Farrell counters that DTE is not aware of any information that supports the assertion that such customers do not have solid WI-FI connections. He also notes that any customer can participate in a non-dispatchable DR program regardless of the technology in their household.[241]

GLREA also offered concerns about DTE's proposed DR component of the IRP. Mr. Richter testified that the Commission should not provide cost pre-approval for DTE's proposed DR investment through 2022, on grounds that DTE insistence that the company have no persistent capacity need ignores the near certainty of legally required purchases of capacity and energy from QFs that would displace the need for additional DR.[242] Mr. Richter also agrees with Staff's recommendation to disallow the capital requests for 'other DR pilots' from 2020-2022.[243] And he recommends that the Commission increase the cost differential between on- and off-peak rates.

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[240] Id.
[241] 6 Tr 1691.
[242] The Commission has recently addressed this argument, finding that "for the purposes of PURPA, QF generation competes with supply-side resources, not demand side resources." September 26, 2019 order in Case No. U-18091, p. 47.
[243] 7 Tr 3161. Citations omitted. It must be noted that GLREA's brief fails to provide any citation to the transcript for this referenced testimony.

In response to Mr. Richter's recommendation to increase the differential between on- and off-peak rates, Mr. Farrell pointed to the Commission's order in DTE's last rate case, which addressed this concern.

This PFD recommends that the Commission find the DR elements of the IRP reasonable and prudent, albeit with changes proposed by the Staff. DTE's current DR portfolio is effective, and the Staff has no issues with the reasonableness and prudency of DTE's on-going DR programs and pilots. However, preapproval of recovery of capital spending on the other pilots is unreasonable. As Staff notes, the company has not provided adequate evidence that the other pilots are prudent especially given that these are still in the exploratory stage. In addition, DTE is not precluded from making a future request for DR pilot capital spending, in a rate case or DR reconciliation, when more specifics about the pilot are available for review.

This PFD finds that Soulardarity's concerns are well taken as a general matter. However, the issues it raises with respect to DR are not framed in terms specifically applicable to DTE's IRP and may be better addressed in a rate case or other DR proceeding.

3. Battery Storage

Ms. Mikulan explained that, because of DTE's part ownership of Ludington, which comprises over 1,000 MW of storage for DTE, additional storage has limited value. Nevertheless, the company did include a 100 MW lithium-ion battery for selection by Strategist and evaluated a solar plus storage sensitivity in its ET scenario.

MEC/NRDC/SC and ELPC et al. contend that DTE's analysis of storage was lacking. ELPC et al. point to Mr. Lucas' and Dr. Woychik's testimony regarding storage as a potential replacement for aging peakers and the significant decline in the cost of solar plus renewables. MEC/NRDC/SC describe DTE's approach to modeling the values of solar as "exclusively based on bulk power price arbitrage. And, "[f]or its solar plus storage projects, DTE modeled battery storage as disconnected from solar, lessening the economic benefits."[244] Staff witness Matthews testified that although DTE's methods for modeling energy storage were reasonable for this IRP, "Staff believes the Company should continue to investigate the use of storage in demand response programs and develop storage-based programs as the costs continue to fall and the efficiency of storage continues to increase year over year."[245] He further observed that the proposed changes in DTE's generation mix, resulting in an increased reliance on intermittent resources, requires continuing analysis of energy storage "to address potential reliability and power quality issues[.]"[246]

MEC/NRDC/SC point to Mr. Jester's recommendation for battery storage analysis in future IRPs:

> Mr. Jester recommends that the Commission expect DTE to specifically include aspects of storage that affect the bulk power system, and he offers a method to accomplish that without requiring a detailed geographic analysis. He recommends focusing primarily on two aspects of storage: "(1) the operating rule set for the storage, and (2) position in the transmission and distribution system hierarchy." Using a typology of five operating rule sets and two positions in the transmission and distribution system hierarchy, the utility could develop a closer approximation of storage capacity's real value in the bulk power system without undue complexity. Using this methodology, the Company could efficiently assess the value of storage as an integrated part of its system.[247]

[244] MEC/NRDC/SC's brief p. 92, citing 7 Tr 2749.
[245] 7 Tr 3360.
[246] Id. at 3361.
[247] MEC/NRDC/SC's brief, p. 93 (fn. omitted), quoting 7 Tr 2774-2776.

DTE did not object to the Staff's or MEC/NRDC/SC's suggestions. Accordingly, in future IRPs, DTE should be directed to undertake an updated and more comprehensive analysis of all the values of storage consistent with Mr. Jester's recommendation.

4. Conservation Voltage Reduction/Volt-Var Optimization

As outlined above, DTE's proposes to conduct a CVR/VVO pilot program, beginning in 2019 and to be completed in 2020, in order to verify the feasibility and cost effectiveness of such a program.[248] DTE asserts that the CVR/VVO pilot program "will give the Company a better understanding of how it may be able to leverage this new technology to benefit customers."[249] If the pilot is successful – that is, if the energy and capacity savings exceed the investments – the company expects to start implementing the CVR/VVO program for targeted areas in 2026.[250]

Ms. Zhou describes the CVR/VVO program as follows:

> Volt Var Optimization (VVO) manages system-wide voltage levels and reactive power flow to achieve one or more specific operating objectives. The objectives can include reducing losses, managing voltage volatility due to intermittent renewable generation, optimizing operating parameters and/or optimizing power factors, etc.
>
> Conservation Voltage Reduction (CVR), as one of the VVO options, is designed to maintain customer voltage levels in the lower portion of the allowable voltage ranges, thus reducing system losses, peak demand or energy consumption.
>
> CVR is achieved by utilizing various electrical equipment including transformer load tap changers (LTC), overhead line regulators, and capacitor banks. In addition, supervisory control and data acquisition (SCADA) monitoring devices and line sensors are used to ensure customer voltage levels are maintained in allowable voltage ranges; advanced telecommunication and optimization tool can also be used to achieve optimal savings in the system.[251]

[248] 6 Tr 1717.
[249] DTE brief, p. 27.
[250] 6 Tr 1717; Exhibit S-10.1, p. 6.
[251] 6 Tr 1718.

Ms. Zhou testified that DTE selected two types of circuits for implementation of the pilot, based on an economic analysis of potential peak demand and energy reduction.

Ms. Zhou cautioned that there are some limitations to the CVR/VVO study. For example, some targeted circuits may require more, cost-prohibitive modifications. In addition, the CVR/VVO potential was modeled assuming customers require constant currents, rather than constant energy, for which load will increase current to compensate for the lower voltage, producing little to no demand and energy reductions. However, Ms. Zhou added that a range of savings was developed to compensate for the limitations, and this range will be assessed in detail prior to field implementation.[252] The pilot program is expected to cost approximately $0.7 million of capital, for which DTE requests preapproval.[253]

The Staff is generally supportive of the proposed CVR/VVO program, and considers the current projected costs and capacity reductions to be reasonable. As such, Staff considers the pilot program to be a "prudent step in allowing DTE to evaluate the feasibility and cost effectiveness of the program".[254]

However, Mr. Becker testified that there are "areas that have apparently not been explored or considered that could significantly impact the CVR/VVO circuits' feasibility and cost effectiveness in the near and long-term future if not considered in the pilot stages of the program."[255] Mr. Becker describes Staff's concerns with the proposed CVR/VVO program as follows:

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[252] 6 Tr 1727-1728.
[253] 6 Tr 1728, Exhibit A-29; 6 Tr 1730. DTE plans to recover this expenditure in its next rate case. Exhibit S-10.1, p. 5.
[254] 7 Tr 3375
[255] Id.

1) DTE's ability to stay within the 120-114V range in all areas of the circuit to optimize the capabilities of each CVR/VVO circuit;

2) DTE's motivation to leverage existing equipment in the system to support the CVR/VVO program;

3) the amount of information DTE plans to obtain/track as part of the CVR/VVO pilot program; and

4) DTE's lack of a DER planning model or forecast at the distribution circuit level in the future to effectively accommodate DERs without impacting the program's scheme.[256]

Accordingly, the Staff makes several recommendations if the CVR/VVO pilot program is approved. First, Staff recommends that DTE consider existing investments such as grid modernization infrastructure when selecting CVR/VVO circuits, and that DTE fully utilize the potential and capabilities of existing infrastructure to make CVR/VVO successful. Second, Staff recommends that DTE establish Distributed Energy Resource (DER) penetration forecasting on their circuits to be used in selecting CVR/VVO circuits.[257] Mr. Becker testified that that cost effective and/or successful CVR/VVO circuits enabled today may be subject to distribution voltage profile changes through increasing DER in the future which could require "additional investments and make the circuit(s) no longer cost effective."[258] Third, Staff recommends that DTE incorporate circuits using DERs into the pilot program to evaluate the impacts to the electric system and CVR/VVO enabled circuit(s).[259]

Finally, the Staff recommends DTE file annual CVR/VVO-specific reporting in this docket consisting of the information in Exhibit S-10.0, in accordance with MCL

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[256] Id.
[257] Id. 7 Tr 3376
[258] Id.
[259] 7 Tr 3377.

460.6t(14).[260] Mr. Becker states that a circuit-level tracking mechanism allows for comparing the company's projected spending and capacity levels with actuals levels, which will assist Staff and the Commission in assessing the performance of the program, and in reviewing capital costs associated with the CVR/VVO program in future rate case(s).[261] In its brief, Staff recommends DTE update Staff annually in a standardized format agreed upon by Staff and DTE.[262]

In rebuttal, DTE disagreed with Staff's recommendations. Regarding the recommendation that DTE establish DER penetration forecasting on its circuits, Ms. Zhou testified that DTE does not have tools or a methodology that can effectively forecast DER penetration at a circuit level, and that the low level of DER penetration in DTE's service territory would make it "challenging to develop an accurate predictive algorithm based on the characteristics of specific customers on individual circuits." She adds that circuits for the CVR/VVO pilot in 2019-2020 have already been selected.[263]

Regarding Staff's recommendation that DTE incorporate circuits using DERs into its pilot program, Ms. Zhou counters that most circuits for the pilot program reflect DER penetration that is typical of the rest of the system. She adds that if DTE were to change selected circuits to those with much higher DER penetration, the pilot program would be delayed beyond the proposed timeframe to accommodate higher DER penetration modeling and design challenges, and could skew the results of the pilot program.[264]

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[260] Id. Exhibit S-10 identifies requested information for each circuit including the capital improvements, the energy reduction, the peak demand reduction, the minimum and maximum voltages, and the number, causes and duration of any variances outside of the applicable household voltage range. MCL 460.6t(14) provides that an electric utility shall file reports to the commission regarding the status of any projects included in the initial 3-year period of an approved integrated resource plan.
[261] 7 Tr 3377.
[262] Staff Initial Brief, p. 77.
[263] 6 Tr 1740.
[264] 6 Tr 1740-1741.

Regarding the recommendation that DTE file annual CVR/VVO-specific reporting, Ms. Zhou testified that annual CVR/VVO-specific reporting will not be needed until a CVR/VVO program is started on circuits beyond the pilot program. However, she adds that DTE can provide an informal update or a one-time report regarding the findings and results of the pilot. In addition, Ms. Zhou argues that the information in Exhibit S-10.0 could be difficult and expensive to collect, and involve hiring a third-party for evaluation, measurement and verification.[265]

GLREA argues that the Commission should deny DTE's request for pre-approval of capital costs for the CVR/VVO pilot program.[266] Mr. Richter asserts that the CVR/VVO program is "intended to reduce capacity needs", thereby demonstrating that an "underlying capacity need is projected".[267] Mr. Richter asserts that some if not all of the requested funding for CVR (together with EWR and DR) will "prove to be unnecessary from a capacity perspective, due to new QF supplies."[268]

In addition, Mr. Richter argues that the CVR program modeling is based on a false assumption – that the CVR/VVO program was modeled assuming customers require "constant currents" – when, in fact, "motors are not constant current loads".[269] Accordingly, Mr. Richter asserts that the Commission should not pre-approve costs for CVR program "until the validity of the stated load response assumption is firmly established."

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[265] 6 Tr 1741.
[266] 7 Tr 3162.
[267] 7 Tr 3107.
[268] 7 Tr 3104. Again, demand side resources do not compete with supply side resources and therefore do not supplant QF capacity and energy.
[269] 7 Tr 3114-3115.

Finally, Mr. Richter testifies that GLREA agrees with Staff's four recommendations for DTE's CVR/VVO program.[270] Mr. Richter adds that he also agrees with Mr. Becker that DTE's IRP does not provide a clear breakdown in its proposed CVR/VVO spending, which GLREA asserts "is a serious flaw and merits correction."[271]

The PFD finds that the CVR/VVO pilot program proposed by DTE is reasonable. The program is based upon a comprehensive study conducted by a third-party which indicates that such a program applied to certain circuits could be cost effective. In addition, as the Staff notes, the projected costs and capacity reductions for the pilot are reasonable. And the pilot appears to be a prudent method to verify the feasibility and cost effectiveness of the program.

In addition, two of Staff's recommendations are well taken. The company should consider existing investments and infrastructure when selecting CVR/VVO circuits for the program. And, annually filing CVR/VVO-specific reporting – which DTE has agreed to do[272] -- will help all parties to better assess the cost effectiveness of the proposed program.

The Staff's other recommendations are not reasonable at this time. To require DTE to accurately forecast DER penetration at a circuit level is currently not feasible, as Ms. Zhou testified. Regarding the recommendation that DTE include circuits employing DER's, DTE offers that most of the circuits chosen for the pilot program reflect DER penetration that is typical of the rest of the system.

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[270] 7 Tr 3149.
[271] Id.
[272] DTE Reply Brief, p. 73.

GLREA's assertion that Staff agrees that failure of the IRP to provide a clear breakdown in its proposed CVR/VVO spending constitutes a "serious flaw" is a misstatement. While Mr. Becker does acknowledge that DTE's projected pilot program capital expenditure is based on estimates derived from information gleaned from the study, Mr. Becker testified that Staff "considers the current projected costs and capacity reductions to be reasonable."[273]

Similarly, GLREA's assertion that DTE's CVR/VVO initial modeling is faulty because it is based on an assumption that its customers require constant currents, is misplaced. Ms. Zhou acknowledged that this assumption constitutes a "limitation" of the study and that if its customers require a "constant energy load", "little to no demand and energy reductions" will be produced.[274] Moreover, it is because of this limitation (and others) that a "range of savings" was developed, a range that DTE asserts "will narrow as individual circuits are studied in detail prior to filed implementation."[275] Indeed, GLREA's overarching assertion that DTE's request for pre-approval of the projected pilot program capital costs be denied unless DTE provides more evidence that "the circuits will respond as predicted", overlooks the very purpose of a pilot program; that is, to "verify [the CVR/VVO program's] feasibility and cost effectiveness".[276]

I. <u>Transmission Analysis (MCL 460.6t(5)(h) and (j))</u>

MCL 460.6t(5)(h) states that an IRP shall include "an analysis of potential new or upgraded electric transmission options for the electric utility." MCL 460.6t(5)(j) requires an IRP to include "[p]lans for meeting current and future capacity needs with the cost

[273] 7 Tr 3375.
[274] 6 Tr 1727.
[275] 6 Tr 1728.
[276] 6 Tr 1717.

estimates for all proposed construction and major investments, including any transmission or distribution infrastructure that would be required to support the proposed construction or investment, and power purchase agreements." Finally, the Filing Requirements provide:

> In accordance with MCL 460.6t(5)(h), the utility shall include an analysis of potential new or upgraded electric transmission options for the utility. The utility's analysis shall include the following information:
>
> a) The utility shall assess the need to construct new, or modify existing transmission facilities to interconnect any new generation and shall reflect the estimated costs of those transmission facilities in the analyses of the resource options;
>
> b) A detailed description of the utility's efforts to engage local transmission owners in the utility's IRP process in an effort to inform the IRP process and assumptions, including a summary of meetings that have taken place;
>
> c) Current transmission system import and export limits as most recently documented by the RTO and any local area constraints or congestion concerns;
>
> d) Any information provided by the transmission owner(s) indicating the anticipated effects of fleet changes proposed in the IRP on the transmission system, including both generation retirements and new generation, subject to confidentiality provisions;
>
> e) Any information provided by the transmission owner(s), including cost and timing, indicating potential transmission options that could impact the utility's IRP by:
>
> > (1) increasing import or export capability;
> > (2) facilitating power purchase agreements or sales of energy and capacity both within or outside the planning zone or from neighboring RTOs;
> > (3) transmission upgrades resulting in increasing system efficiency and reducing line loss allowing for greater energy delivery and reduced capacity need; and
> > (4) advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources.

Finally, In the April 27, 2018 order in Case No. U-18419, at pages 115-116, the Commission stated:

> [I]n DTE Electric's 2019 IRP, the Commission expects a far more robust analysis of transmission opportunities that might defer, displace, or optimize the amount, type, and location of additional generation based on up-to-date information about current and expected transmission system conditions and import/export capabilities. To ensure alternatives are fully considered in future IRP proceedings, and the system is optimized from a cost and reliability standpoint, the Commission also expects DTE to work closely and collaboratively with ITC and other transmission owners to explore transmission solutions and to work toward integrating the company's distribution planning efforts with resource planning.

1. Transmission Analysis

DTE presented the testimony of Mr. Hunnell and Mr. Burgdorf in support of its transmission analysis, which was undertaken by ITC (ITC Study), and which was provided in Exhibit A-39. The majority of Mr. Hunnell's and Mr. Burgdorf's direct and rebuttal testimony centers on the CIL and ECIL, which DTE expects to continue to be constrained in the future. DTE therefore assumed that the existing CIL of 3,211 MW will remain through the study period. Consistent with that assumption, DTE did not evaluate the potential for importing capacity or energy from outside Zone 7.

Mr. Hunnell explained DTE's coordination with ITC, noting that the company met with ITC six times, that it provided ITC with information on the four PCA pathways in the flexible PCA, and it requested that ITC examine any transmission concerns it might have with the company's proposal.[277] As a result of this coordination, the ITC Study indicated that there would be some need to update to transmission facilities to address new generation interconnection and unit retirements.

[277] 6 Tr 1460, 1474-1475; Exhibits A-38.1 and A-38.2.

In addition, per DTE's request, the ITC Study evaluated two scenarios: one with, and one without, a change to the voltage criteria at Fermi.[278] Each scenario was then analyzed assuming zero-, mid-, and high- levels of solar penetration. Under all of the scenarios in which the Fermi voltage criteria was changed, the CIL increased substantially: to 4,283 MW in the no-solar scenario; to 4,975 MW in the mid-solar scenario; and to 5,437 MW in the high-solar scenario.

ITC witness Marshall testified that the collaboration with DTE prior to the IRP filing was lacking in some respects. According to Mr. Marshall:

> I think DTE engaged ITC as they were expected to [engage] ITC as defined via the IRP process. Our concern is the nature of the flow of information and communication where there's a predefined scenario that ITC is asked to study and then produce results, and I think when it's packaged in that way, there's missed opportunities to better utilize the transmission system as part of the solution as opposed to just assessing what the impacts would be to the transmission system.[279]

Mr. Marshall further explained that, "as a result of ITC's analysis of the transmission system, ITC recommended the placement of an SVC at the Fermi substation to mitigate voltage issues resulting from the components of DTE's IRP[,]" which, in addition to solving a reliability problem, would have increased the CIL. ITC then submitted plans for the proposed SVC to MISO. However, Mr. Marshall explained that "[a]fter coordinating with ITC in the context of the IRP and after DTE's submission of its IRP to the Commission, DTE changed the operating parameters at Fermi and eliminated the need for the SVC solution that ITC had proposed."[280]

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[278] As discussed below, the change to the voltage criteria at Fermi appears to be a *fait accompli*.
[279] 7 Tr 2271-2272.
[280] 7 Tr 2247. In its brief, p. 73, fn. 72, DTE notes that "Mr. Hunnell acknowledged that the Company officially made this change after submitting its IRP but clarified that the Company's coordination with ITC included its investigation of this alternative (6T 1475; Exhibit A-38.1, p 13)."

MEC/NRDC/SC contend that the Commission has provided clear directives on what it expects to see in an IRP transmission analysis. Despite those directives, they argue that:

> DTE's testimony concerning transmission and capacity imports is mainly a series of arguments for why DTE refuses to comply with those directives. DTE refuses to consider or model imports of power from outside MISO Local Resource Zone 7. DTE refuses to model or evaluate resource plans using any capacity import limit other than the limit for the current MISO planning year. DTE refuses to acknowledge reliable projections of increases to the import limit in future years. DTE has not evaluated, and did not ask ITC to evaluate, any options to improve import capability for Zone 7. DTE even took steps to preclude an ITC project that would have substantially improved the current import limit. For these reasons, DTE's transmission is wholly insufficient – defiant even – and should be rejected outright.[281]

MEC/NRDC/SC point to DTE's interconnections with MISO, PJM, and IESO, and the large power flows between and among these markets every day. They emphasize testimony by Mr. Osborn and Mr. Fagan indicating that PJM and IESO project significant amounts of excess capacity and energy that could economically provide for DTE's future needs. But, according to them, DTE did not explore the possibility of entering PPAs for energy or capacity outside of Zone 7 on grounds that the company had no assurance that external resources will be available, the constraints on CIL and ECIL will persist, and public data indicates that there are unlikely to be differences in costs within and without Zone 7.

MEC/NRDC/SC assert that this reasoning is specious because DTE never looked into the availability of PPA resources for this IRP,[282] again noting the significant surplus in PJM and the large amount of renewable energy in the MISO queue. MEC/NRDC/SC

[281] MEC/NRDC/SC's brief, p. 129.
[282] See, Exhibit MEC-80.

maintain that DTE's assumptions about costs outside of Zone 7 are equally questionable, pointing to Mr. Osborne's testimony that "it is common knowledge in the industry that wind power PPA prices are significantly lower in nearby LRZs – particularly Zones 1 and 3."[283]

As for DTE's assumptions about CIL and ECIL, MEC/NRDC/SC posit that based on DTE's formulation of ECIL (PRMR-LCR where LCR=LRR-CIL), if CIL increases, all else being equal, ECIL will also increase. And, MEC/NRDC/SC contend that consistent with projections from MISO (4,287 MW in 2023-2024 PY) and the ITC Study discussed above, CIL will almost certainly increase in the coming years.

The crux of this issue is whether DTE's transmission analysis was consistent with the statute, Filing Requirements, and the Commission's order in Case No. U-18419. DTE, basing its argument mostly on the reasonableness of its assumptions about static CIL and ECIL, contends that it was compliant with all of these requirements. The Staff also maintains that the company complied with the statute and Sections XII(c), (d), and (e) of the Filing Requirements, "by providing the prompt year . . . CIL as well as out-year estimates provided by ITC." [284] Nevertheless, the Staff recommends that the requirements for the evaluation of transmission be updated for future IRPs to provide more specific guidance.

The Filing Requirements specify that the utility must provide information from transmission owners about potential transmission <u>options</u> that could increase CIL or facilitate PPAs for energy or capacity from outside Zone 7, among other things. The filing requirements do not appear to require any analysis of this information, only that it be presented.

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[283] MEC/NRDC/SC brief, p. 138, quoting 7 Tr 2819.
[284] Staff's brief p. 56, citing 7 Tr 3349.

The PFD finds that the company's compliance with the relevant part of Filing Requirements was *de minimis* at best. DTE did provide one option, which was the change to the voltage criteria at Fermi. And while DTE was fully apprised of ITC's plan to install an SVC to address a voltage problem at Fermi (and which would have increased CIL), DTE did not present this option in its filing, although it is in the record.

The statute is more prescriptive with respect to transmission. MCL 460.6t(5)(h) states that an IRP shall include "an analysis of potential new or upgraded electric transmission options for the electric utility." And MCL 460.6t(5)(j) requires an IRP to include "[p]lans for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments, including any transmission or distribution infrastructure that would be required to support the proposed construction or investment, and power purchase agreements." DTE did provide an "analysis" of one option, the voltage change at Fermi, in the ITC Report. But, as noted above, although DTE was aware of the SVC proposal, it chose not to evaluate this "potential new . . . transmission option" at all, despite the fact that it would also have increased import capability. Thus, DTE did not comply with MCL 460.6t(5)(h). However, because DTE never evaluated an exterior PPA option in its plan, there was no transmission construction cost estimate required to be submitted under Section 6t(5)(j).

Finally, there was the Commission's directive in the order in Case No. U-18419, which bears repeating:

> [T]he Commission expects a far more robust analysis of transmission opportunities that might defer, displace, or optimize the amount, type, and location of additional generation based on up-to-date information about current and expected transmission system conditions and import/export capabilities. To ensure alternatives are fully considered in future IRP proceedings, and the system is optimized from a cost and reliability

> standpoint, the Commission also expects DTE to work closely and collaboratively with ITC and other transmission owners to explore transmission solutions and to work toward integrating the company's distribution planning efforts with resource planning.

DTE's plan is utterly deficient with respect to a "robust analysis of transmission opportunities that might defer, displace, or optimize the amount, type, and location of additional generation . . ." DTE tacitly excuses itself from this requirement based on its view that CIL/ECIL will not increase and that the company risks reliability if it were to assume any increase in import capability. According to DTE:

> [T]he limited assumption of a potential increase in the CIL from proposed transmission improvements and the use of imported power does not provide a sound basis for planning because it would create price and reliability risk for DTE Electric customers(4T 805-806).This is because an increase in transmission into Zone 7 does not necessarily mean a decrease in the Local Clearing Requirement (LCR), the amount of resources MISO will require to be located within Zone 7 (4T 805-806). Even assuming possible future CIL increases suggested by witnesses Fagan and Osborn, expected Local Resource Requirement (LRR) increases might outweigh those increases (because LCR = LRR –CIL). (4T 795-96, 806-807).[285]

DTE's claims about the reasonableness of its assumption that there will be no changes to the CIL (or that an increase in the CIL would be otherwise offset) are not convincing. The only analyses of CIL in this case are the MISO out-year projection, which shows CIL increasing, and the ITC Report, which likewise shows a significant increase in CIL. DTE addresses the MISO forecast by noting that MISO warns against using these projections for resource planning purposes. And it contends that ITC's analysis does not consider whether CIL will change if the future is different than assumed in the ITC Report. The PFD finds that, at the very least, the MISO projection of CIL and the ITC Report should have triggered an analysis of the potential for imports from outside of Zone 7. DTE

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[285] DTE's reply brief, p. 61.

could have still warned against any assumption that CIL will increase, but the Commission would have a more complete and robust record on import options to weigh.

Consistent with this discussion, the ALJ finds that DTE did not comply with Section 6t(5)(h) or the Commission's directives set out in the order in Case No. U-18419 in its transmission analysis. In future IRPs, the PFD recommends that DTE (and other Commission-regulated utilities) should be required to undertake a transmission sensitivity analysis to assess potential plans that include increased and decreased CILs as well as potential imports from MISO and other areas.

2. Energy Michigan Proposal

Energy Michigan provides an interesting proposal for addressing the ECIL (i.e., the usable portion of the CIL) through modifying the MISO Module E-1 tariff. Mr. Zakem explained that DTE's concept of the ECIL has merit because it recognizes an inconsistency in the resource adequacy determinations made by MISO and because it has significant implications for the IRP.

Mr. Zakem noted the distinction between the current physical limitation on the import of resources (CIL) of 3,211 MW and the ECIL of 164 MW, which expresses an additional constraint on the amount of resources that can be imported into Zone 7. Mr. Zakem observed:

> The CIL for Zone 7 Michigan Lower Peninsula is 3,211 MW. The average CIL for MISO's ten zones is 4,210 MW, and the median is 3,773 MW. So Michigan has an appreciable amount of import capability and is not an "island" by any means. However, under the current rules of the MISO tariff, to be explained later, only a small part of the CIL physical limit of 3,211 MW – 164 MW, as DTE has stated – is usable when satisfying the MISO reliability obligations for the zone. I am proposing to increase the usable portion of the CIL, which would allow Michigan to import more resources from out of state in the process of satisfying MISO's reliability obligations. The obvious benefit of increasing the usable limit is opportunity –

opportunity to choose among and draw from a wider selection of resources.[286]

Mr. Zakem pointed to the 2019/2020 MISO PRA, where the capacity price for Zone 7 was 24.30/MW-year, an amount that was eight times higher than all of the other MISO zones. According to Mr. Zakem, "That difference in price translates into about $170 million more that MISO charges to the loads of Michigan suppliers."[287] Thus, Mr. Zakem testified that in addition to more options for resource acquisition in the IRP, increasing the ECIL could result in significantly reduced costs. This is especially true if ECIL were to decrease to zero, at which point Zone 7 capacity price would rise to the cost of new entry (CONE) of $243.37/ MW-day.

Mr. Zakem testified that the ECIL, which he defines as "the portion of a zone's physical Capacity Import Limit that can be used to satisfy MISO's resource adequacy standard"[288] is "not a term defined by MISO, it is not a physical limit but rather a creation of the MISO tariff rather than MISO statistical analysis or power flow modeling."[289] According to Mr. Zakem, the ECIL, "as determined by MISO's current method contains errors and inconsistencies" that should be corrected.[290]

Mr. Zakem explained that, "[d]espite the tariff definition specifying that the LCR should be set while 'fully using' the CIL, the tariff does not allow the full use of the CIL in satisfying PRMR obligations. Thus, the MISO tariff, in its specifications of the capacity obligation of a zone – the PRMR – incompletely and inefficiently uses the actual physical

[286] 7 Tr 2954.
[287] Id. at 2954-2955.
[288] 7 Tr 2958.
[289] Id. at 2957-2958.
[290] Id. at 2958.

transmission capability for importing capacity into the zone, the CIL."[291] While all MISO zones are affected by this construct, Zone 7 is most affected, allowing only 5% of the CIL to be used to satisfy the PRMR.

Mr. Zakem discussed the way that MISO determines resource adequacy, both PRMR and LCR, noting that in setting the LCR is set by modeling using different inputs than those used for setting the PRM. According to Mr. Zakem, "[t]hese differences [for calculating PRM and LCR] lead to inconsistencies between the MISO resource adequacy standard and the degree of reliability implied by the zonal LCRs."

Finally, Mr. Zakem provided a detailed proposal for how the full capability of the CIL (i.e., ECIL) could be used without sacrificing resource adequacy or reliability.[292] Consistent with Mr. Zakem's proposal, Energy Michigan recommends that the Commission take the lead in advocating for changes to the MISO tariff that will significantly increase ECIL.

The only party to respond to Mr. Zakem's recommendation was the Staff who stated:

> This proceeding is specific to DTE's IRP and the MISO tariff issues are beyond the scope of DTE's IRP. Staff supports further examination of the MISO resource adequacy tariff for errors and inconsistencies and believes the best place for that work is in conjunction with the work already being planned in response to the observations and recommendations of the Statewide Energy Assessment.

The PFD agrees in part. While this proceeding is specific to DTE's IRP, the company justified its limited transmission evaluation on the basis of its concerns about CIL and ECIL. These are the very issues that Energy Michigan addresses in its proposal.

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[291] Id. at 2962.
[292] 7 Tr 2973-2977; Exhibit EM-3.

That said, the Commission has already signaled its intent to evaluate capacity import in the SEA final report:

> Michigan utilities participate in RTO markets, which should result in the efficient use of both local and imported energy and capacity resources. On a daily and annual basis, there are significant imports of energy into Michigan based on the RTO's least-cost dispatch of generation across the region and available transmission capacity. However, the ability to rely on imported generation to meet MISO resource adequacy requirements is limited by MISO's tariff requiring a certain amount of generation to be physically within the local area and related to this, the transmission system's ability to import resources from outside the area. Thus, given power plant retirements and other factors, Michigan is faced with having to build additional local generation or expand transmission interconnections (or some combination) to continue to meet these resource adequacy requirements. As outlined in the Staff's report on capacity demonstrations filed in March of 2019, the effective capacity import limit into the lower peninsula (zone 7) is only 164 MW, decreased from approximately 1,500 MW one year ago based on MISO's assumptions, calculations and system modeling.
>
> The effective capacity import limit has recently been much lower than the amounts of actual imports coming into the Lower Peninsula. On average, Michigan's Lower Peninsula imported approximately 16.3% of the energy needed to serve load in Zone 7 for 2017 and 2018 which totals over 32 Million megawatt hours for the two-year period. During that same two-year period, Zone 7 imported more than 5,000 MW for 115 hours.
>
> Improving the MISO effective capacity import limit would allow more imports of capacity into Michigan during the peak, as well as other times throughout the year, thereby improving system resiliency and allowing customers to more fully realize the benefits of participation in RTO markets. CIL improvements have been proposed, but do not neatly fit MISO's definition of a reliability project, nor do they neatly fit MISO's definition for a market efficiency project.
>
> To address this gap in planning, utilities, electric transmission companies, Staff, RTOs, and stakeholders, should further investigate opportunities to expand Michigan's capability to import additional electricity to address short- and long-term reliability and resource adequacy needs in a more holistic manner as Michigan experiences additional power plant retirements. This effort should also consider a methodology to quantify the value of such projects and related cost allocation, as appropriate.[293]

[293] SEA Final Report, pp. 192-193.

The PFD recommends that the Commission take up Energy Michigan's proposal as part of its examination of improvements to resource adequacy requirements as outlined in the SEA.

J. Environmental Requirements (MCL 460.6t(5)(m))

Section 6t(5)(m) requires the IRP to demonstrate how DTE will comply with "all applicable state and federal environmental regulations, laws, and rules, and the projected costs of complying with those regulations, laws, and rules." As outlined above in Section II, Mr. Marietta provided detailed testimony concerning the various environmental regulations that affect the company's fossil units as well as projected compliance costs. He also provided an emissions average for the four PCA pathways.[294]

Mr. Koeppel testified that DTE has not implemented plans to reduce SO_2 emissions and ozone formation as evidenced by the fact that Wayne County and St. Clair County are non-attainment areas. In response, Mr. Marietta explained that DTE has, in fact, implemented plans to reduce SO_2 and address ozone, noting that ozone is a complicated environmental issue and that there are many industries in Southeast Michigan that contribute to the ozone problem.[295]

In its initial brief, MEC/NRDC/SC contend that DTE did not include significant environmental costs for the IRP after 2025, including post-closure compliance costs at Belle River. MEC/NRDC/SC add that, apparently as a result of a modeling error, DTE underestimated the amount of PM expected to persist over the course of the plan, noting that although Mr. Marietta claimed that PM would drop at the same rates as SO_2, his workpapers do not demonstrate that this is the case. MEC/NRDC/SC also point out that

[294] See, Figure 2, 4 Tr 929.
[295] 4 Tr 935.

the company's modeling of the flexible PCA show no emissions of PM, despite the fact that two of the pathways (B and D) include CCGTs that emit PM. Finally, MEC/NRDC/SC contend that DTE's analysis contains little information about greenhouse gas emissions.

In response, DTE contends that Mr. Marietta's testimony was extensive; the IRP was reviewed by EGLE, and the EGLE advisory opinion determined that, although actual monitoring will have to be performed in the future, the PCA will likely comply with all state and federal environmental requirements.[296]

Although MEC/NRDC/SC point to certain discrepancies in DTE's presentation, particularly with respect to future levels of PM, these concerns will presumably be addressed in the company's next IRP. The PFD finds that DTE reasonably complied with MCL 460.6t(5)(m) in this IRP.

K. Rate Impact (MCL 460.6t(5)(l))

DTE provided Exhibits A-8, A-9, and A-45, along with testimony by Ms. Holmes, to document the rate impacts of the IRP. As described in Section II, Ms. Holmes calculated revenue requirements for Pathway C[297] of the flexible PCA, which showed a maximum revenue increase of 0.08 cents per kWh to a maximum decrease of 0.11 cents per kWh over the life of the plan. Consistent with the Commission's order in Case No. U-18419, Ms. Holmes presented Exhibit A-9 and Exhibit A-45, page 2, which purport to show the revenue requirement of the BWEC and the retirement of the Tier 2 units.

MEC/NRDC/SC contend that DTE's presentation of rate impacts does not comply with Section 6t(5)(l) or with the Commission's order in Case No. U-18419. They

[296] See, MEC-117, pp. 6-7.
[297] Exhibit A-45, p. 1. Pathway C has the highest NPVRR, thus represents the most expensive of the four pathways.

point out that the purported rate impact analysis included in Exhibit A-45 does not identify current rates, nor does it contain the costs of the starting point resources that were included at zero cost, or the various other costs that the company excluded from its IRP. According to MEC/NRDC/SC:

> In order to estimate the actual incremental revenue requirement, one would need to add the costs for 4,664 MW of planned renewable resources, fixed O&M and ongoing capital expenses for all existing generation units, depreciation expense and closure costs related to all the Company's coal plants, rates of return, changes in rate base, and distribution costs. Knowing this, it was remarkably misleading for the Company's witnesses to claim, based on Exhibits A-45 and A-8, that the proposed IRP would result in a reduced revenue requirement.[298]

In addition, MEC/NRDC/SC assert that, despite routinely performing cost-of-service studies for rate cases, DTE chose not to include one here.

MEC/NRDC/SC next argue that the Commission found that the rate impact analysis for the BWEC "could be misleading" and directed the company to provide an analysis of the rate impacts resulting from both the new plant and the retirement of the Tier 2 units, including, "the impact to rates if some or all of the unrecovered book value associated with the coal plant retirements were removed from rate base and addressed through securitization or other financial measures, rather than recovery through traditional depreciation schedules."[299] According to MEC/NRDC/SC:

> Even a cursory review of the evidence claimed to fulfill the Commission's order from Case No. U-18419 shows the Company fell far short of the mark, again providing misleading and incomplete evidence of rate impacts. Most blatantly, the Company's analysis does not just fail to provide depreciation options, it excluded coal unit depreciation entirely. The Company provided no analysis whatsoever of how securitization might be used to address the unrecovered book value associated with the coal plant retirements. Such

[298] MEC/NRDC/SC's brief p. 165 (fn. omitted) citing 3 Tr 608-610; 2 Tr 289.
[299] MEC/NRDC/SC brief, p. 167, quoting April 27, 2018 order in Case No. U-18419, p. 120.

> information surely could have been included in this IRP filing, the Company simply failed to do so here.[300]

DTE responds that there is no requirement that the company include other cost items in its revenue impact calculation beyond what DTE included here. As for a securitization analysis, DTE asserts that it provided a section on securitization options in its April 25, 2019 status report filed in Case No. U-20419.

As discussed above, DTE's starting point included a significant number (90%) of planned new resources at zero cost, and it failed to include additional cost items, including environmental compliance, capital costs, and fixed O&M that should have been included. This error in DTE's starting point carried through the analysis such that the actual rate impacts of the IRP cannot be determined here.

As for securitization, the Commission's order in Case No. U-18419, page 127, Ordering Paragraph G, the Commission directed to "provide an updated rate impact analysis related to the approved project, consistent with the discussion in this order" in this IRP. In its discussion on page 120 of the order, the Commission stated:

> The Commission is not required to make any findings with respect to customer rates under Section 6s(4), but nevertheless finds that DTE Electric shall provide a straightforward analysis of how customer rates are expected to change as a result of the Tier 2 unit retirements and the addition of the NGCC plant over the first ten years of operation. The Commission is also interested in understanding the impact to rates if some or all of the unrecovered book value associated with the coal plant retirements were removed from rate base and addressed through securitization or other financial measures, rather than recovery through traditional depreciation schedules. While the Commission is not making a final determination on the unrecovered costs of the retiring plants, it is nevertheless interested in the impact that different options may have on customer rates.

[300] Id. at 167-168 (fn. omitted).

DTE did not request rehearing or clarification of the ordering paragraph, nor did it request a waiver of the requirement that it undertake an analysis that might be more complex than the Commission assumed. It simply did not include the analysis at all in this proceeding, relying instead on a section on securitization options, filed in another docket, as part of the BWEC status report.

Consistent with the above discussion, this PFD finds that DTE's IRP does not comply with Section 6t(5)(l).

L. <u>Michigan Workforce (MCL 460.6t(8)(b))</u>

MLC 460.6t(8)(b) requires that "[t]o the extent practicable the construction or investment in a new or existing capacity resource in this state is completed using a workforce composed of residents of this state as determined by the commission." There was no serious dispute that DTE intends to use a Michigan workforce as Ms. Pfeuffer discussed in her testimony. Staff recommends that the company continue to describe how it will implement the local workforce requirement in future IRPs. This PFD therefore finds that DTE complied with MCL 460.6t(8)(b).

M. <u>Cost Approvals (MCL 460.6t(11))</u>

Although this PFD recommends that the Commission reject the IRP for the reasons discussed above, the PFD nevertheless recommends that cost recovery for the CVR/VVO pilots be approved in the company's pending rate case. DR costs as proposed by the company, and adjusted by Staff, appear reasonable based on the record in this proceeding. These costs should also be approved in DTE's rate case or in a DR reconciliation proceeding as suggested by Mr. Isakson. EWR capital costs of $103 million should be approved in the company's next EWR plan case.

N. Other Issues

1. Community and Stakeholder Engagement

DTE maintains that it engaged in extensive public outreach via three public open houses and four technical workshops for stakeholders. DTE points out that its efforts were more than what is recommended in the Filing Requirements adding that "The intent was to implement a comprehensive, transparent, and participatory stakeholder engagement process. These events provided stakeholders with various opportunities to learn about the Company's resource options and plans to conduct the IRP analysis, and provide input on how to meet Michigan's future energy and capacity needs, including reviewing and commenting on IRP inputs, sensitivities, and technology options"[301]

Soulardarity maintains that DTE's public outreach was wholly inadequate, contending that the public open houses were not accessible to all customers, especially low-income customers. Soulardarity points out that childcare was not made available to participants, translation services were limited or not available at all, and all of the open houses were held in one county, despite the fact that DTE's service territory spans 12 counties. Soulardarity makes a number of recommendations for improving community outreach, including: (1) having meetings led by community leaders rather than DTE employees; (2) providing non-technical information about the IRP and the IRP process; (3) targeting outreach efforts to communities most affected by the decisions in the IRP, including low-income and communities of color; (3) making public meetings more accessible in terms of time, venue, and geographic scope; and (4) ensuring that public feedback is incorporated into the IRP in a transparent and meaningful fashion.

[301] DTE's brief, p. 69, citing 2 Tr 68-69, 99-101; 3 T4 349-50.

GLREA similarly argues that DTE's approach to community and stakeholder engagement "has been a 'top down' presentation or lecture at public meetings of DTE's IRP Plan, in contrast to a proactive grass roots exploration of public interest issues to be then incorporated in formulating the IRP."[302] Finally, the Staff claims that DTE "reasonably complied" with the requirements for stakeholder engagement and makes recommendations for improving outreach to the public and stakeholders.

The PFD agrees with the Staff and the company, that the company's outreach efforts comported with the Commission's requirements. In addition to the Staff's uncontested recommendations for improving engagement with stakeholders and the community, this PFD finds that community outreach, in particular, should be undertaken as early as possible in the process, so that community concerns can be incorporated into the IRP. This might also serve to address issues raised by Ann Arbor on the need to recognize community sustainability goals and

2. Reporting Requirements (MCL 460.6t(14))

Consistent with Section 6t(14), Staff recommended that DTE file annual reports using the template provided in Exhibit S-3.0, along with a narrative explaining any adjustments to the timing, scope, status, or costs associated with expense approvals for the first three years of the plan. In addition, Staff requested that DTE communicate immediately with the Commission if there is a significant change to the cost, timing, or size of any expected resource addition. DTE objected to the Staff's recommendations, pointing to Ms. Pfeuffer's testimony that the company intends to begin reporting in 2021 on DR, EWR, and CVR/VVO programs, further noting that the company already files

[302] GLREA's brief, p. 109.

annual reports for DR, EWR, and RPS, thus, Staff's recommendation is duplicative.[303] As for immediate communications with Staff in the event there are changes in costs, timing, or size of any of the proposed projects, Ms. Schroeder testified that project negotiations are often fluid with changes occurring frequently, and that once a negotiation is completed, the company will present the resulting contract to the Commission for review and approval.

In its reply brief, Staff disagrees that the requested reports are duplicative, asserting:

> [W]hile the reconciliation dates for each of the above-mentioned cases occurs annually, they take place at staggered times throughout the year. Providing data in a pre-approved reporting form at the time on an annual basis would help provide the Commission and Staff a more up-to-date picture of ongoing Capital, O&M, and MW projections and actuals. Staff believes this level of detail is useful to ensure prudency of spending and may have implications on related rate cases, as well as IRP Resource filings and reconciliation plans. Staff requests that the ALJ and Commission require DTE to use its 3-year reporting proposal.

The PFD finds the Staff's reporting requirements, and reporting template, to be reasonable. As Staff points out, the current reporting requirements for EWR, DR, and renewables occur at different times throughout the year, and consistent reporting (in some cases simply by updating the numbers in the previous annual report) will be useful in monitoring the progress of the various projects included in the IRP.

3. Next IRP Filing

MCL 460.6t(9) outlines a process if the Commission denies an IRP:

> If the commission denies a utility's integrated resource plan, the utility, within 60 days after the date of the final order denying the integrated resource plan, may submit revisions to the integrated resource plan to the commission for approval. The commission shall commence a new

[303] 2 Tr 99, Table 1.

> contested case hearing under chapter 4 of the administrative procedures act of 1969, 1969 PA 306, MCL 24.271 to 24.287. Not later than 90 days after the date that the utility submits the revised integrated resource plan to the commission under this subsection, the commission shall issue an order approving or denying, with recommendations, the revised integrated resource plan if the revisions are not substantial or inconsistent with the original integrated resource plan filed under this section. If the revisions are substantial or inconsistent with the original integrated resource plan, the commission has up to 150 days to issue an order approving or denying, with recommendations, the revised integrated resource plan.

The Staff expresses reservations about DTE's presentation, but nevertheless recommends that this IRP be approved, with Staff's modifications, and that the company be directed to file an updated IRP in three years. MEC/NRDC/SC contend that, "[t]he analyses and revisions necessary to correct the evidentiary deficiencies in this IRP filing are too great to be remedied within 60 days of a denial." Thus, the Commission should direct DTE to issue an RFP, include only existing and approved resources in its starting point, undertake a comprehensive reanalysis of its plan, and refile its IRP in two years.

DTE argues that even three years is too short a time period to file another IRP, especially if the company moves to a new software platform as suggested by numerous parties in the proceeding. According to DTE:

> MEC/NRDC/SC inaccurately suggest that Ms. Mikulan's time estimates totaled only 26 months . . . , but that was for only some of the activities that would be required if the Company moves to a new software platform. Other activities, such as the MIIRP collaborative process, potential studies, stochastic risk analysis of the PCA, and new required scenario and sensitivity development also add substantial time to the process, so three years from the final order in this case is the minimum possible timing for DTE Electric's filing of its next IRP (3T 583-87).[304]

The PFD agrees with MEC/NRDC/SC and finds that the significant errors and omissions in this IRP, as discussed above, cannot be addressed in the limited statutory

[304] DTE's reply brief, p. 80.

timeframe set forth in Section 6t(9). Accordingly, the Commission should reject DTE's IRP and direct the company to refile within 24 to 30 months of the final order in this case.

4. Strategist Issues

DTE assets that it has been using the Strategist program for IRP since 2006, but it recognizes that modeling tools have evolved since that time. Thus, DTE maintains that it will evaluate different models before filing its next IRP in five years.

As summarized by Ms. Mikulan, several witnesses and parties raised concerns about Strategist and made specific recommendations for processes or better platforms for future IRPs.[305]

The PFD agrees with the recommendations of the parties, and the lack of objection by DTE, that Strategist should be retired and replaced before the next IRP, if possible. Because of the complexity of the model, numerous errors were made, ELPC et al. attempted to test a hypothesis that using the "must run" designation in Strategist for certain units might keep uneconomic units from retiring earlier. Unfortunately, the Strategist results assumed these units could be operated as cycling units, an impossible operational outcome.[306] Two solar inputs were changed by Ms. Sommer, resulting in an "artifact" in the Strategist modeling that doubled the solar capacity factor. DTE attributes these outcomes to modeling error by the expert witnesses, but even the company's filing contained a mistake, which resulted in extending the schedule in the case by 30 days.

While the Commission has numerous ongoing stakeholder initiatives, the PFD recommends that the Commission consider convening a one or two-day technical

[305] See, Table 21, 3 Tr 584.
[306] This is not to say that Mr. Daniel's inquiry is frivolous, only that Strategist may not be the proper tool for exploring the issue. As he testified, the economics of using a "must-run" designation is being investigated in Minnesota and Missouri.

conference to discuss and evaluate a better tool for integrated resource planning for use in developing the company's next IRP.

VI.

RECOMMENDATIONS AND CONCLUSION

The ALJ recommends that the Commission adopt the following findings of fact and conclusions of law:

(1) DTE's presentation of a long-term flexible PCA, consisting of four possible pathways beginning in 2025 does not comply with MCL 460.6t(3);

(2) DTE's failure to issue an RFP prior to filing its IRP did not comport with the requirements under MCL 460.6t(6);

(3) DTE's ownership analysis should be rejected.

(4) DTE's starting point, which included significant amounts of unapproved, non-optimized resources over the entire planning period does not comply with MCL 460.6t(5)(i)) and (k).

(5) DTE's retirement analysis of Belle River was insufficiently robust, and the company failed to undertake any analysis of its peaker fleet, contrary to the requirement of MCL 460.6t(5)(k).

(6) DTE's proposal to convert RR3 from coal fired to burning waste industrial gas should be evaluated further in other proceedings.

(7) DTE does appear to have a capacity need within the next five years, although the amount of the shortfall is unclear. The Standard Offer cap should remain at 550kW.

(8) DTE should update its solar inputs and analysis in its next IRP consistent with the discussion in this PFD.

(9) DTE failed to undertake a complete analysis of DG resources, and should be directed to do so in its next IRP.

(10) Issues concerning the VGP programs should be addressed in the company's next VGP review.

(11) DTE should update its EWR analysis in its next IRP consistent with the discussion in this PFD.

(12) DTE should undertake a more rigorous assessment of battery storage in its next IRP, consistent with the discussion in this PFD.

(13) DTE's transmission analysis was incomplete and does not comply with the requirements of MCL 460.6t(5)(h) and the Commission's order in Case No. U-18419.

(14) DTE's rate impact analysis does not comport with MCL 460.6t(5)(l) or the Commission's order in Case No. U-18419.

(15) In light of the significant errors and omissions in DTE's IRP, MCL 460.6t(9) is not a workable remedy. Therefore the PFD recommends that DTE be required to file an updated IRP 24-30 months after the Commission issues its order in this case.

In all other respects, the PFD finds that the company's IRP complies with MCL 460.6t.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Sally L. Wallace

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Sally L. Wallace
Administrative Law Judge

December 23, 2019
Lansing, Michigan