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O L S O N , B Z D O K & H O W A R D

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May 19, 2022

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

***Via E-Filing***

RE: MPSC Case No. U-20836

Dear Ms. Felice:

The following is attached for paperless electronic filing:

Public Version of the Direct Testimony of Tyler Comings on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan;

Exhibits MEC-53 through MEC-73; and

Proof of Service.

Please note that the Confidential Version is only being served on those with a signed Nondisclosure Certificate on file in this case.

Sincerely,

Christopher M. Bzdok  
[chris@envlaw.com](mailto:chris@envlaw.com)

xc: Parties to Case No. U-20836

STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE  
ELECTRIC COMPANY** for authority to  
increase its rates, amend its rate schedules and  
rules governing the distribution and supply of  
electric energy, and for miscellaneous  
accounting authority

U-20836

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**PUBLIC**

**DIRECT TESTIMONY OF TYLER COMINGS**

**ON BEHALF OF**

**MICHIGAN ENVIRONMENTAL COUNCIL,  
NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB,  
AND CITIZENS UTILITY BOARD OF MICHIGAN**

**May 19, 2022**

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1     **I.   INTRODUCTION AND QUALIFICATIONS**

2     **Q.    Please state your name, business address, and position.**

3     A.    My name is Tyler Comings. I am a Senior Researcher at Applied Economics Clinic, located  
4           at 1012 Massachusetts Avenue, Arlington, Massachusetts.

5     **Q.    Please describe Applied Economics Clinic.**

6     A.    The Applied Economics Clinic is a 501(c)(3) non-profit consulting group. Founded in  
7           February 2017, the Clinic provides expert testimony, analysis, modeling, policy briefs, and  
8           reports for public interest groups on the topics of energy, environment, consumer  
9           protection, and equity, while providing on-the-job training to a new generation of technical  
10          experts.

11    **Q.    On whose behalf are you testifying in this case?**

12    A.    I am testifying on behalf of Michigan Environmental Council (MEC), Natural Resources  
13          Defense Council (NRDC), Sierra Club (SC), and Citizens Utility Board of Michigan,  
14          collectively referred to as “MNSC”.

15    **Q.    Please summarize your work experience and educational background.**

16    A.    I have 16 years of experience in economic research and consulting. At Applied Economics  
17          Clinic, I focus on energy system planning, costs of regulatory compliance, wholesale  
18          electricity markets, utility finance, and economic impact analyses. I have provided  
19          testimony on these topics in Arizona, Colorado, the District of Columbia, Hawaii, Indiana,  
20          Kentucky, Maryland, Michigan, Missouri, New Jersey, New Mexico, Ohio, Oklahoma,  
21          West Virginia, and Nova Scotia (Canada). I am also a Certified Rate of Return Analyst

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1 (CRRA) and member of the Society of Utility and Regulatory Financial Analysts  
2 (SURFA).

3 I have provided expertise for many public-interest clients including: American Association  
4 of Retired Persons (AARP), Appalachian Regional Commission, Citizens Action Coalition  
5 of Indiana, City of Atlanta, Consumers Union, District of Columbia Office of the People's  
6 Counsel, District of Columbia Government, Earthjustice, Energy Future Coalition, Hawaii  
7 Division of Consumer Advocacy, Illinois Attorney General, Maryland Office of the  
8 People's Counsel, Massachusetts Energy Efficiency Advisory Council, Massachusetts  
9 Division of Insurance, Michigan Agency for Energy, Montana Consumer Counsel,  
10 Mountain Association for Community Economic Development, Nevada State Office of  
11 Energy, New Jersey Division of Rate Counsel, New York State Energy Research and  
12 Development, Nova Scotia Utility and Review Board Counsel, Rhode Island Office of  
13 Energy Resources, Sierra Club, Southern Environmental Law Center, U.S. Department of  
14 Justice, Vermont Department of Public Service, West Virginia Consumer Advocate  
15 Division, and Wisconsin Department of Administration.

16 I was previously employed at Synapse Energy Economics, where I provided expert  
17 testimony and reports on coal plant economics and utility system planning. Prior to that, I  
18 performed research on consumer finance and behavioral economics at Ideas42 and  
19 conducted economic impact and benefit-cost analysis of energy and transportation  
20 investments at EDR Group (now EBP).

21 I hold a B.A. in Mathematics and Economics from Boston University and an M.A. in  
22 Economics from Tufts University.

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1 My full resume is attached as Exhibit MEC-53.

2 **Q. Have you previously testified before the Michigan Public Service Commission?**

3 A. Yes, on six past occasions. Most recently, I testified in Consumers Energy Company's  
4 2021 Integrated Resource Plan (IRP) case (No. U-21090) and Consumers' 2020 and 2021  
5 rate cases (No. U-20697 and U-20963). In January of 2020, I submitted testimony on the  
6 Indiana Michigan Power Company (I&M) Integrated Resource Plan (IRP) in Case No. U-  
7 20591. In 2018, I submitted testimony on Consumers' 2018 IRP (No. U-20165) and  
8 testified in Consumers' 2018 rate case (No. U-20134).

9 **Q. What is the purpose of your testimony?**

10 A. I address three main issues in my testimony. First, I address the future of DTE Electric  
11 Company's (DTE or the Company) Belle River and Monroe coal units, relying on  
12 retirement analysis provided by DTE in this case. Second, I address DTE's request for rate  
13 recovery of certain capital expenditures at these coal units. I recommend disallowances for  
14 several capital projects at the coal units, mainly given the possibility of early retirement.  
15 My recommendations include capital spending identified as avoidable by DTE and  
16 additional capital spending that I find to be avoidable and/or premature. Third, I  
17 recommend that the hydrogen pilot project put forth by DTE be disallowed in this case, in  
18 part because it is a resource decision that should be handled in the Company's upcoming  
19 IRP case later this year.

20 **Q. What information did you review in preparing your testimony in this case?**

21 A. I reviewed the Company's testimony, exhibits, workpapers, and discovery responses.

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1 **Q. Are you sponsoring any exhibits in this proceeding?**

2 A. Yes, I sponsor Exhibits MEC-53 through MEC-73:

- 3 Exhibit MEC-53: Resume of Tyler Comings
- 4 Exhibit MEC-54: U-20886 Staff Report
- 5 Exhibit MEC-55: AGDE-3.100a
- 6 Exhibit MEC-56: AGDE-5.128
- 7 Exhibit MEC-57: U-21090 Consumers Energy Settlement Agreement
- 8 Exhibit MEC-58: GLREADE-5.51c, d
- 9 Exhibit MEC-59: MNSCDE-1.19ai Belle River NPV Capital and OM `
- 10 Input
- 11 Exhibit MEC-60: MNSCDE-1.19cv
- 12 Exhibit MEC-61: MNSCDE-1.22a
- 13 Exhibit MEC-62: MNSCDE-1.5 WP SDB-2 Zone 7 Resource Forecast
- 14 Exhibit MEC-63: MNSCDE-1.6a with NDA\_ MNSCDE-1.6a Practice
- 15 Belle River and Monroe Analyses
- 16 Exhibit MEC-64: MNSCDE-5.3a
- 17 Exhibit MEC-65: MSNCDE-5.9d
- 18 Exhibit MEC-66: MNSCDE-8.1b
- 19 Exhibit MEC-67: MNSCDE-8.29b
- 20 Exhibit MEC-68: MNSCDE-8.3a
- 21 Exhibit MEC-69: MNSCDE-8.4b
- 22 Exhibit MEC-70: STDE-3.1a
- 23 Exhibit MEC-71: STDE-3.4a
- 24 Exhibit MEC-72: U-21090 Direct Testimony of Walz (excerpt)
- 25 Exhibit MEC-73: Proposed Disallowances Exhibit

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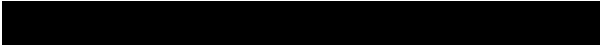
1 **Q. Please briefly describe DTE’s Belle River and Monroe coal units.**

2 A. The Company operates six coal-fired generating units at the Belle River and Monroe plants.  
3 The Belle River plant includes two similar units with a combined capacity of 1,270 MW  
4 of which the Michigan Public Power Agency (MPPA) owns 18.61 percent (236 MW) and  
5 the remainder is owned by DTE (1,034 MW).<sup>1</sup> The Monroe plant has four units at a total  
6 capacity of 3,066 MW, making it one of the largest coal plants in the U.S.

7 **Q. What is the current status of the Belle River plant?**

8 A. DTE has committed to stop burning coal at the Belle River plant by the end of 2028.<sup>2</sup> DTE  
9 looked at resource adequacy and a forward-looking economic analysis that evaluated 2026,  
10 2028, and 2030 retirement.<sup>3</sup> The Company estimated that retirement by 2028 would avoid  
11 \$55 million in compliance costs with the Effluent Limitation Guidelines (ELG) rule.<sup>4</sup> The  
12 future of the plant will be evaluated in the IRP filed later this year.

13 **Q. What is the current status of the Monroe plant?**

14 A. My understanding is that the plant’s current retirement date is 2040.<sup>5</sup> But the Company has  
15 evaluated earlier retirement dates as an option for compliance with the ELG rule.<sup>6</sup> The  
16 Company’s analysis (provided in discovery in this case) [[  
17 ]]. DTE stated that the portfolios modeled

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<sup>1</sup> MPPA owns 37.21 percent of Belle River unit 1 but is entitled to 18.61 percent of the energy and capacity from the whole plant. See: <http://www.mpower.org/Projects/ID/7/Belle-River-Unit-No1>

<sup>2</sup> Direct Testimony of Justin L. Morren, p. 18, lines 8-13.

<sup>3</sup> Direct Testimony of Shawn Burgdorf, p.26, Table 6; Morren Direct, p. 86, lines 2-6.

<sup>4</sup> *Id.*

<sup>5</sup> See: <https://dtecleanenergy.com/>.

<sup>6</sup> Exhibit MEC-61 (Data response to MNSCDE-1.22a).



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1           were “examples of potential sensitivities” for the upcoming IRP.<sup>7</sup> [[REDACTED]

2           [REDACTED]

3           [REDACTED]].<sup>8</sup>

4   **Q.    How are the retirement years of these coal units relevant to this rate case?**

5    A.    Prudent spending on generating units changes with the retirement year. Thus, if the  
6           retirement year is in flux, then what is considered prudent spending can vary as well. Some  
7           expenditures are “avoidable” if the units retire earlier because that planned spending is  
8           either no longer necessary or not cost-effective. If the units could be retired at an earlier  
9           date, then including “avoidable” costs in rates now would prevent ratepayers from realizing  
10          this savings in the event of that early retirement.

11 **Q.    Please summarize your findings and recommendations.**

12 A.    Based on my review and analysis, I conclude that:

- 13           **1. The Company’s analysis provides strong evidence for retiring Belle River in**  
14           **2026.** The Company is seeking recovery for capital spending that assumes the plant  
15           retires in 2028. But the Company has only committed to retirement by 2028 and  
16           has recently evaluated earlier retirement years. Indeed, it has presented compelling  
17           evidence that shows the plant should cease the burning of coal in 2026. The  
18           Company’s NPV analysis in this case shows that 2028 retirement only makes sense  
19           if one assumes that MISO capacity prices will persist at their maximum values (100  
20           percent of the CONE or cost of new entry) in the medium-term—which is

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<sup>7</sup> Exhibit MEC-63 (Data response to MNSCDE-1.6a).

<sup>8</sup> Exhibit MEC-63 (NDA\_U-20836 MNSCDE-1.6a Practice Belle River and Monroe Analyses).

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1           unrealistic, notwithstanding the most recent auction result. (The Company’s own  
2           forecast also predicts that MISO capacity prices are de minimis in the short-term.<sup>9</sup>)

3           [[ [REDACTED]  
4           [REDACTED]  
5           [REDACTED]  
6           [REDACTED]]<sup>11</sup>

7           **2. The Company’s assessment of resource adequacy in Zone 7 is unrealistic and**

8           **misleading; it should not be used to justify keeping Belle River on-line.** The  
9           Company tries to demonstrate that the zone will be tight on capacity in MISO  
10          planning year 2025/26 as a way of justifying keeping Belle River on-line.<sup>12</sup> But the  
11          plant’s capacity could be fully or partially replaced—if needed—by other resources  
12          with several years of lead time. [[ [REDACTED]

13          [REDACTED]] Also, the Company’s  
14          analysis of resource adequacy relies on an assumed decrease in zonal capacity given  
15          Consumers Energy’s original proposed course of action (PCA) in that company’s  
16          2021 IRP (U-21090); but the recent proposed settlement entered into by  
17          Consumers, Staff, and a number of intervenors in that docket would lead to  
18          substantially more capacity than DTE is accounting for in its analysis.<sup>13</sup> However,  
19          most importantly, the premise of the Company’s resource adequacy analysis is

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<sup>9</sup> Exhibit MEC-65 (Data response MNSCDE-5.9d).

<sup>10</sup> Exhibit MEC-63 (NDA\_U-20836 MNSCDE-1.6a Practice Belle River and Monroe Analyses).

<sup>11</sup> *Id.*

<sup>12</sup> Burgdorf Direct, p. 21-22.

<sup>13</sup> Exhibit MEC-57 (U-21090 Consumers Settlement Agreement).

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1           unrealistic and misleading by assuming that none of the Belle River capacity would  
2           be at least partially replaced if there were a capacity need.

3           **3. The Commission should disallow rate recovery for test year (2023) capital**  
4           **costs at Belle River that the Company has identified as “avoidable” if it were**  
5           **to cease coal operations in 2026.** The Company is seeking rate recovery for capital  
6           projects that assume the plant will retire in 2028. We know that the Company is  
7           contemplating ceasing coal at an earlier date, and indeed it has provided compelling  
8           evidence for that path. To that end, when asked in discovery in this case, DTE  
9           identified five capital investments (project IDs 17532, 17531, 17996, 15301, and  
10          15595) with “avoidable” test year spending of \$12.8 million if Belle River retired  
11          in 2026;<sup>14</sup> this spending should be disallowed in this case.

12          **4. The Commission should disallow rate recovery for the Belle River gas**  
13          **conversion study for being premature.** The Company is asking for rate recovery  
14          for the engineering for converting Belle River from coal to natural gas.<sup>15</sup> But as  
15          discussed above, the future of Belle River is in flux—including when the plant will  
16          stop burning coal and what would replace it in that event. The Company has  
17          confirmed that it does not know whether either coal unit at Belle River will be  
18          converted to gas if it ceases burning coal.<sup>16</sup> Approving costs for implementing gas  
19          conversion would be premature at this time because the decision to convert has yet

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<sup>14</sup> Exhibit MEC-60 (Data response MNSCDE-1.19cv).

<sup>15</sup> Morren Workpapers, PMP 17071 and PMP 18325.

<sup>16</sup> Exhibit MEC-70 (Data response to STDE-3.1a).

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1 to occur; therefore the \$2.5 million in costs, which mostly occur in the bridge year,  
2 should be disallowed.

3 **5. The Company is evaluating the early retirement of some or all of the Monroe**  
4 **units.** The Company stated that it has evaluated early retirement of Monroe as a  
5 means of complying with the ELG rule.<sup>17</sup> [[REDACTED]

6 [REDACTED]  
7 [REDACTED] [REDACTED]  
8 [REDACTED]]<sup>19</sup> The plant's future is likely to be a focus in that

9 upcoming IRP docket.

10 **6. The Commission should disallow rate recovery for the FGD wastewater**  
11 **project at Monroe because it is likely subject to the pending revision to the**  
12 **ELG rule.** The Company stated that the FGD wastewater project could have a  
13 compliance deadline as late as 2028. Because of this date, and the upcoming  
14 revisions to the ELG rule from the Biden Administration, these costs are premature  
15 at this time. The spending on this project of \$1.83 million in the bridge year and \$1  
16 million in the test year should be disallowed in this case.

17 **7. The Commission should disallow rate recovery for avoidable capital spending**  
18 **at Monroe.** The Company conducts internal rate of return (IRR) analyses for some  
19 of its capital investments that are not related to safety or regulatory compliance.<sup>20</sup>

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<sup>17</sup> Exhibit MEC-61 (Data response to MNSCDE-1.22a).

<sup>18</sup> *Id.* Exhibit MEC-63 (MNSCDE-1.6a).

<sup>19</sup> Exhibit MEC-63 (NDA\_U-20836 MNSCDE-1.6a Practice Belle River and Monroe Analyses).

<sup>20</sup> Data response to MNSCDE-1.10bi.

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1           These analyses project the savings and costs of the capital expenditure, providing a  
2           breakeven or “payback” period before which the investment is a net cost to  
3           ratepayers. I found that several planned capital projects (project IDs 14630, 18145,  
4           9327, and 9517) at Monroe would not break even until 2040 or later which means  
5           they would not provide net benefits to ratepayers even if the plant retired in the  
6           2030’s. The bridge year spending of \$29.8 million and test year spending of \$27  
7           million for these four projects should be disallowed.

8           **8. The Commission should disallow rate recovery of the hydrogen pilot project.**

9           The project represents a major resource decision to blend hydrogen at BWEC, at  
10          significant cost, that should be considered in the upcoming IRP. The Company has  
11          also not demonstrated a need for the project; nor has it conducted an economic  
12          assessment to justify this substantial investment; nor has it supported the claim that  
13          the hydrogen will be produced from clean energy sources. For these reasons, I  
14          recommend that the project’s costs of \$1.6 million in the bridge year and \$17.4  
15          million in the test year be disallowed.

16          **II. CAPITAL SPENDING AT BELLE RIVER THAT COULD BE AVOIDED WITH**  
17          **2026 RETIREMENT SHOULD BE DISALLOWED**

18          **Q. Please summarize your assessment of the Belle River coal plant.**

19          A. The Company is assuming that the Belle River plant will cease coal operations in 2028 (in  
20          the form of retirement or conversion to natural gas). But DTE has provided ample evidence  
21          in this case that this could or should occur at an earlier date. By extension, capital spending

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1 being requested in this case should account for the possibility of earlier retirement<sup>21</sup> so that  
2 ratepayers do not have to pay for costs that would be avoidable if the plant were to retire  
3 in the economically optimal year of 2026. In this section, I discuss: 1) the Company's  
4 retirement analysis of Belle River, which indicate that ceasing coal before 2028 was cost-  
5 effective; 2) the Company's resource adequacy analysis, which rests on a false premise that  
6 Belle River would not be replaced at all, and relies on outdated data regarding Consumers'  
7 IRP; and 3) those capital costs at Belle River that should be disallowed given the potential  
8 for earlier retirement.

9 **A. The Company's Own Analysis Supports Retirement of Belle River Before 2028**

10 **Q. In this case, is the Company effectively assuming that it will stop burning coal at Belle**  
11 **River in 2028?**

12 A. Yes. Prior to this filing, DTE committed to retirement of the Belle River plant by 2028, at  
13 the latest, with the possibility of converting the units to burn natural gas.<sup>22</sup> This decision  
14 was made in part to avoid spending \$55 million for retrofits needed to bring the plant into  
15 compliance with the Effluent Limitation Guidelines (ELG) rule.<sup>23</sup> The Company is now  
16 requesting rate recovery for capital investments in the plant that assume the latest date of  
17 this commitment: retirement in 2028. This is demonstrated by the fact that the Company

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<sup>21</sup> Throughout the testimony, I refer to "retirement" as a shorthand for ceasing coal operations through retirement of the unit(s) or conversion to natural gas.

<sup>22</sup> Morren Direct, p. 18, lines 8-13.

<sup>23</sup> *Id.*

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1 has identified capital spending that it seeks in this case which could be avoided with  
2 retirement prior to 2028.<sup>24</sup>

3 **Q. Has the Company provided analysis that evaluates the retirement date of Belle River**  
4 **coal units?**

5 A. Yes. The Company has provided analysis in this case that evaluates this question. In the  
6 initial application, DTE provided an analysis that projected the costs to customers of  
7 retiring the plant in 2023, 2026, 2028, and 2030. This analysis (which I will call the “Belle  
8 River economic analysis”) showed that retirement prior to 2028 was the lowest-cost option  
9 under most scenarios. [[

10 [REDACTED]  
11 [REDACTED]  
12 [REDACTED]  
13 [REDACTED]]]

14 **Q. Was the Company required to conduct a retirement analysis to inform the**  
15 **Commission’s decisions regarding Belle River in this case?**

16 A. Yes. In DTE’s previous rate case (U-20561), the Commission directed the Company to  
17 provide a retirement analysis in its next case to “assist in its reasonableness and prudence  
18 determination” of the Company’s planned spending at Belle River.<sup>25</sup> The order mentioned  
19 inclusion of a “2025/26 retirement date” but stated that the Company should consider

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<sup>24</sup> Exhibit MEC-60 (Data response MNSCDE-1.19cv).

<sup>25</sup> Case No. U-20561, May 8, 2020, Commission Order, pp. 81-82.

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1 “other dates to determine the most cost-effective and reasonable approach.”<sup>26</sup> Similarly, in  
2 its ruling on DTE’s most recent Integrated Resource Plan, the Commission noted that it  
3 would “continue to carefully scrutinize near-term capital expense and O&M costs as part  
4 of the economic analysis necessary to making these investment and cost recovery decisions  
5 in rate cases.”<sup>27</sup>

6 **Q. Please summarize the Company’s approach used in the Belle River economic analysis.**

7 A. DTE’s analysis looked at the economics of several retirement options at Belle River  
8 compared to market replacement. The Company projected fuel costs, operations and  
9 maintenance (O&M), capital costs, and other expenses at the plant under several scenarios  
10 including retirement in 2023, 2026, 2028, and 2030.<sup>28</sup> The 2023 retirement scenario,  
11 however, was used as a benchmark scenario where market energy and capacity purchases  
12 replaced the plant after 2023.<sup>29</sup> DTE then compared the costs of owning and operating  
13 Belle River under the other retirement scenarios in 2026, 2028, and 2030 to that  
14 benchmark.<sup>30</sup> DTE also calculated the cost of capacity under four sensitivities of MISO  
15 capacity auction prices: 1) zero, 2) 10 percent of CONE<sup>31</sup>, 3) 50 percent of CONE, and 4)  
16 100 percent of CONE. The Company then presented the net present value revenue

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<sup>26</sup> *Id.* at 82.

<sup>27</sup> Case No. U-20471, Feb. 20, 2020, Commission Order, p. 37.

<sup>28</sup> Burgdorf Direct, p. 22-26.

<sup>29</sup> Ex A-12, Schedule B6.1-3.

<sup>30</sup> *Id.* at 26, Table 6.

<sup>31</sup> CONE is the “cost of new entry” which is based on the annual cost of building and operating a new gas-fired combustion turbine.



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1 requirements (NPVRR) of the three retirement scenarios under those four capacity price  
2 sensitivities.

3 **Q. Please summarize the results of the Belle River economic analysis.**

4 A. In three out of the four sensitivities run by DTE, retiring the plant before 2028 is the lowest-  
5 cost option. The savings of retirement dates (relative to 2023 retirement and market  
6 replacement) are shown below in Figure 1. These results show that: 1) retirement of the  
7 plant in 2023 was the lowest-cost option under zero capacity prices and 10 percent of  
8 CONE; 2) retirement in 2026 was the lowest-cost option under 50 percent of CONE; and  
9 3) retirement in 2028 was the lowest-cost option only under 100 percent of CONE (i.e. the  
10 highest capacity price possible).

11 **Figure 1: DTE Estimated Savings of Retiring Belle River, relative to 2023**  
12 **Retirement (\$mil NPVRR)<sup>32</sup>**  
13

Bell River Sensitivity	Retirement Year			
	2023	2026	2028	2030
\$0 Forecast	\$0	(\$89)	\$205	\$357
10% CONE	\$0	(\$60)	\$159	\$296
50% CONE	\$0	\$58	\$26	(\$53)
100% CONE	\$0	\$205	\$256	\$250

14  
15 **Q. Are the savings from early retirement of Belle River partially driven by avoiding**  
16 **capital costs?**

17 A. Yes, in part. As shown in Figure 2, the Company’s projections of capital spending differ  
18 widely with the retirement date. This is not surprising, as one should expect that planning  
19 for retirement allows for avoiding spending that is no longer necessary or economically

<sup>32</sup> Burgdorf Direct, p. 26, Table 6.

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1 justified with a shorter life. DTE's projections of capital spending from 2022 through 2030  
2 under these four retirement scenarios are:<sup>33</sup>

- 3 • Retire in 2023: \$66.8 million
- 4 • Retire in 2026: \$130.9 million
- 5 • Retire in 2028: \$201.5 million
- 6 • Retire in 2030: \$323.8 million

7 Only the costs for 2030 retirement include investments for compliance with the ELG rule,  
8 which total \$55 million. But notably, there are \$70 million in capital cost savings when  
9 comparing 2026 versus 2028 retirement; more than half of this savings occurs in 2023  
10 while the IRP proceeding will be happening. Given this timing, this rate case is the best  
11 opportunity to avoid this spending and protect ratepayers.

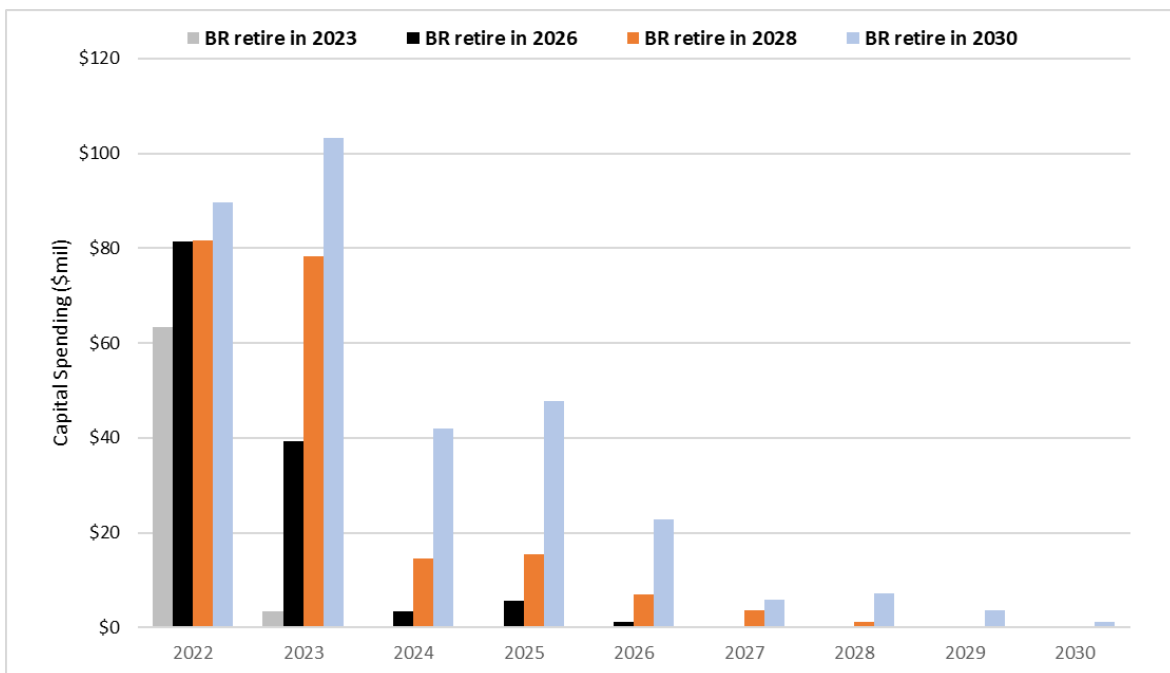
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<sup>33</sup> Exhibit MEC-59 (MNSCDE-1.19ai Belle River NPV Capital and OM Input).

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1  
2

**Figure 2: Capital Spending at Belle River under DTE Retirement Scenarios (\$mil)<sup>34</sup>**



3

4 **Q. What is the current status of Belle River, and how should that inform the**  
5 **Commission’s review of capital spending at the plant?**

6 **A.** The Company has not committed to a 2028 retirement date but maintains that the plant will  
7 cease coal burning by 2028 at the latest and that it will be analyzing the plant’s future in  
8 the upcoming IRP.<sup>35</sup> In discovery in this case, the Company provided an analysis that  
9 included “examples of potential sensitivities” for the upcoming IRP [[REDACTED]

10 [REDACTED] ■ [REDACTED]  
11 [REDACTED]]<sup>37</sup> I will address this preliminary IRP

12 analysis in the discussion of the Monroe plant, [[REDACTED]

<sup>34</sup> *Id.*

<sup>35</sup> Data response to MNSCDE-1.7aii.

<sup>36</sup> Exhibit MEC-63 (Data response to MNSCDE-1.6a).

<sup>37</sup> Exhibit MEC-63 (NDA\_U-20836 MNSCDE-1.6a Practice Belle River and Monroe Analyses).

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1 [REDACTED] In sum, retirement of Belle  
2 River prior to 2028 is a possible outcome of the upcoming IRP and already supported by  
3 DTE's economic analysis of Belle River provided in this case. With that in mind, further  
4 in my testimony, I recommend that the Commission disallow capital spending that could  
5 be avoided if the plant were to retire earlier than 2028.

6 **B. The Company's Assessment of Resource Adequacy is Unrealistic and**  
7 **Misleading; It Should Not Be Used to Justify Keeping Belle River On-line**

8 **Q. Do you agree with the Company's interpretation of its Belle River economic analysis?**

9 **A.** No. The Company focuses on the extreme capacity price sensitivity in its discussion of the  
10 Belle River economic analysis, in what appears to be justifying 2028 retirement:

11 ...the resource adequacy capacity projections indicate a Belle River Power  
12 Plant retirement would potentially cause MISO Zone 7 to lack sufficient  
13 resources to meet federal reliability standards. Insufficient resources will  
14 lead to higher capacity prices, reaching the Cost of New Entry (CONE). The  
15 most favorable outcome in the NPVRR analysis...at a capacity price of  
16 CONE is retiring Belle River Power Plant's coal-fired operations in 2028.<sup>38</sup>

17 The Company tries to justify keeping Belle River on-line to address resource adequacy and  
18 warns of sky-high capacity prices. But this depiction of resource adequacy in future years  
19 is alarmist and flawed. As I describe below: 1) Belle River capacity could be partially or  
20 fully replaced; 2) MISO capacity prices are unlikely to be at or near 100 percent of CONE  
21 in the medium-term; and 3) DTE witness Burgdorf's calculations of resource adequacy are  
22 inconsistent with recent changes in the Consumers IRP case.

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<sup>38</sup> Morren Direct, p. 85, line 21 through p. 86, line 2.

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1 **Q. Do you agree with the framing of DTE’s resource adequacy concern, quoted above?**

2 A. No, DTE’s framing of this issue is misleading and should be ignored. The Company is  
3 raising the specter of a Belle River retirement as a threat to reliability and causing sky-high  
4 capacity prices in MISO. But DTE’s characterization ignores the simple fact that the  
5 Company could replace any capacity need with new resources. There is no reason to sound  
6 the alarm because Belle River would not retire in a vacuum.

7 **Q. Do you agree with DTE’s characterization of the MISO capacity market in its Belle  
8 River economic analysis?**

9 A. No. DTE relies on a future where MISO capacity prices are at 100 percent of CONE for  
10 years to come as a means of justifying keeping Belle River operating until the end of 2028.  
11 But, as shown in Table 1, the MISO prices have been volatile but mostly cleared at a small  
12 percentage of CONE in the past. On average, the clearing price has been 27 percent of  
13 CONE in the nine auctions. I recognize that two of the recent auctions were near or at 100  
14 percent of CONE in Zone 7; but preceding both of those auctions the prices were quite low.  
15 There is little reason to believe that prices would stay at 100 percent of CONE for years to  
16 come, which is the only assumption that supports DTE’s selection of a Belle River  
17 retirement at the end of 2028 rather than 2026.

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**Table 1: MISO PRA Zone 7 Clearing Prices (\$/MW-day)<sup>39</sup>**

<b>MISO Planning Year</b>	<b>Zone 7 clearing price (\$/MW-day)</b>	<b>% of CONE</b>
2014/15	\$16.75	7%
2015/16	\$3.48	1%
2016/17	\$72.00	28%
2017/18	\$1.50	1%
2018/19	\$10.00	4%
2019/20	\$24.30	10%
2020/21	\$257.30	100%
2021/22	\$5.00	2%
2022/23	\$236.66	92%

There is a “feast or famine” nature of the MISO capacity market whereby prices are low when there is adequate capacity and, if short on capacity, prices are quite high. For most of the market’s history, however, there has been ample capacity. Indeed, DTE’s most recent forecast of MISO capacity prices expects prices of \$5/MW-day (2% of CONE) in the next four auctions.<sup>40</sup> When discussing the Belle River economic analysis, however, DTE claims that a future of 100 percent CONE prices is one where “no capacity exists to be procured” when the plant is retired.<sup>41</sup> But planning for retirement of generators, like Belle River, requires an assessment of replacement options years ahead of time, which is a critical subject explored in an IRP. The plant is not retiring today; it is likely retiring between four and six years from now. The most recent MISO capacity prices should not be relied upon

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<sup>39</sup> MISO 2022/23 PRA Results, p.15. Available at: <https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf>. MISO PRA 2014/25 Results, p. 1. Available at: <https://efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936258553>

<sup>40</sup> Exhibit MEC-65 (Data response to MNSCDE-5.9d).

<sup>41</sup> Exhibit MEC-56 (Data response to AGDE-5.128).

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1 to justify keeping the plant on-line. Even in the unlikely event that MISO prices remained  
2 sky high, the Company can plan for full or partial replacement of the megawatts at Belle  
3 River if there is a capacity need.

4 **Q. Please describe DTE's projections of MISO Zone 7 resource adequacy.**

5 A. In Table 5 of his testimony, Witness Burgdorf presents actual and projected values for the  
6 capacity position of MISO Zone 7 relative to the Local Clearing Requirement (LCR) for  
7 four MISO planning years. Mr. Burgdorf projects that without Belle River, Zone 7's  
8 capacity position relative to the LCR in planning year 2025/26 will range from a deficit of  
9 748 MW of unforced capacity (UCAP) to a surplus of 940 MW UCAP, depending on the  
10 Capacity Import Limit or CIL. This estimate is in part based on Mr. Burgdorf's projections  
11 of capacity available from Consumers and DTE.

12 For planning year 2022/23, Mr. Burgdorf calculated the LCR as the Local Reliability  
13 Requirement from MISO's 2022/23 Loss of Load Expectation (LOLE) Study Report,  
14 minus the CIL from the same report. He calculated the amount of Zone 7 resources  
15 available by starting with the values from the March 26, 2021 Staff report in the  
16 Commission's 2020-21 capacity demonstration docket (Case No. U-20886).<sup>42</sup> He adjusted  
17 those figures by adding known DTE resource changes since the date of the data submittals  
18 used in the Staff report. Finally, he subtracted the LCR from the adjusted Zone 7 resources  
19 to get the Zone 7 capacity position relative to the LCR.<sup>43</sup>

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<sup>42</sup> Ex MEC-54 at 5.

<sup>43</sup> Exhibit MEC-62 (MNSCDE-1.5 WP SDB-2 Zone 7 Resource Forecast).

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1 **Q. Describe how DTE calculated the projection of the capacity position in Zone 7 in**  
2 **2025/26 planning year?**

3 A. For planning year 2025/26, Mr. Burgdorf did the same calculations as described above,  
4 except rather than using a CIL value from the MISO LOLE report, he used a “historic  
5 range” of CIL values between 3,200 and 4,888 MW. To estimate Zone 7 resources, he  
6 again started with the Staff report in U-20886 and adjusted for known DTE resource  
7 changes, but he made other adjustments, including: subtracting 247 MW UCAP assuming  
8 that a planned DTE renewable project would be delayed, and subtracting another 923 MW  
9 UCAP based on his interpretation of Consumers Energy’s originally-filed proposed course  
10 of action (PCA) in its IRP, which occurred after the submittal of data for the Staff report  
11 in U-20886.<sup>44</sup> After calculating the range of capacity position relative to LCR for planning  
12 year 2025/26, Mr. Burgdorf then subtracted 1,215 MW UCAP for Belle River to obtain his  
13 range of a 748 MW deficit to a 940 MW surplus.

14 **Q. Is DTE’s adjustment for Consumers Energy resources important to his estimate of**  
15 **the capacity situation in Zone 7 in planning year 2025/26?**

16 A. Yes. His reduction in Consumers resources of 923 MW is larger than the maximum deficit  
17 on the low end of his range (-749 MW). Without the adjustment due to Consumers IRP,  
18 both values in Mr. Burgdorf’s range for planning year 2025/26 would show a surplus of  
19 capacity.

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<sup>44</sup> *Id.*



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1 **Q. Is this adjustment for Consumers Energy resources accurate?**

2 A. No, it is out of date and inaccurate. As explained by the Company, it relied on Consumers'  
3 planning year 2025/26 projection of 8,450 ZRCs of planning resources from Exhibit A-10  
4 of Consumers' 2021 PSCR Plan, filed in September 2020—a screenshot of which appears  
5 in the workpaper.<sup>45</sup>

6 To estimate Consumers Energy's resource changes since that filing, Mr. Burgdorf used  
7 page 5 of Exhibit A-14 in Consumers' IRP case (U-21090) which he took to be that  
8 company's PCA. He then calculated the difference in Consumers' capacity available since  
9 the Staff report, which resulted in an estimated reduction of 923 ZRCs from that company's  
10 contribution to zone 7. (ZRCs are identical to MW UCAP but I am using Consumers' IRP  
11 naming convention for ease of reference to that company's documentation.)

12 **Q. Are you familiar with Consumers Energy's IRP?**

13 A. Yes. I testified as a witness in that case on behalf of MNS.

14 **Q. Did Mr. Burgdorf use the correct information for Consumers' PCA in its IRP?**

15 A. No. Consumers witness Sara Walz testified that page 9 of Exhibit A-14 in U-21090  
16 presented the final Proposed Course of Action, or PCA.<sup>46</sup> Page 5 of that exhibit, which Mr.  
17 Burgdorf used in his workpaper, presents a different resource plan that was based on an  
18 alternative gas price forecast.

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<sup>45</sup> *Id.* Exhibit MEC-67 (Data response to MNSCDE-8.29b).

<sup>46</sup> Exhibit MEC-72 (U-21090 Direct Testimony of Walz at 3 TR 317).

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1 **Q. Does using the correct page of Exhibit A-14 make a difference to the calculation of**  
2 **Consumers Energy’s planning resources for the IRP?**

3 A. Yes. In Consumers’ originally-filed PCA, there are 7,602 ZRCs available in planning year  
4 2025/26, which is 74 ZRCs higher than the 7,528 ZRCs that Mr. Burgdorf used in his  
5 calculation.

6 **Q. Have there been other changes to Consumers Energy’s PCA in the IRP since the**  
7 **Company filed it?**

8 A. Yes. DTE relied on Consumers initial PCA filing in the IRP case. But the Company filed  
9 a settlement agreement in that docket with the Commission on April 20, 2022.<sup>47</sup> The  
10 settlement is pending before the Commission but it provides the most current picture of  
11 Consumers’ capacity resource plans and it has been signed by the vast majority of parties  
12 in the case, including MNS, Staff and the Attorney General. This settlement portfolio  
13 would provide a larger contribution to Zone 7 than was initially planned in Consumers’  
14 PCA.

15 The largest difference between Consumers’ initial filing and the settlement agreement for  
16 purposes of this discussion is that Consumers now intends to continue operating Karn units  
17 3-4 beyond 2023. Consumers projects that these units will now provide 784 ZRCs in  
18 planning year 2025/26. Another difference is a new battery storage investment that will  
19 add 14 ZRCs by 2025/26, with more coming later. The settlement agreement also provides  
20 for a competitive solicitation for Power Purchase Agreements (PPAs) that will provide  
21 capacity credit in Zone 7 starting in the 2025 planning year. The solicitation will have two

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<sup>47</sup> Exhibit MEC-57 (U-21090 Consumers Settlement Agreement).

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1 tranches, with the first being for up to 500 ZRCs of dispatchable, non-intermittent  
2 generation and the second tranche being for up to 200 ZRCs of clean capacity resources  
3 (including battery storage). To be conservative, I have assumed that the 500 ZRC  
4 solicitation will come from existing generation—and therefore not increase Zone 7  
5 capacity--but it is reasonable to assume that the second tranche will come from new  
6 resources that would increase capacity in Zone 7. In sum, Consumers' plans have changed  
7 substantially since their initial IRP filing, primarily by adding more capacity than originally  
8 planned. Mr. Burgdorf's analysis is, therefore, outdated and inaccurate.

9 **Q. Even if Mr. Burgdorf had accounted for these changes, do you accept the premise of**  
10 **DTE's resource adequacy analysis?**

11 A. No. Mr. Burgdorf's range of capacity in Zone 7 rests on the false premise that Belle River  
12 is retired but none of that capacity is replaced—thus it incorporates a reduction of 1,215  
13 ZRCs in Zone 7. As I have stated previously, Belle River would not retire in a vacuum and  
14 is likely to be replaced (partially or fully) with other resources. Because of this unrealistic  
15 premise, DTE's capacity position calculation should be ignored, and certainly not be used  
16 to justify keeping Belle River online.

17 **C. Some Capital Costs at Belle River Should Be Disallowed Because of the Potential**  
18 **For 2026 Retirement**

19 **Q. Has DTE justified keeping Belle River on-line until 2028?**

20 A. No. The Company's economic analysis in this case justifies an earlier retirement, and the  
21 Company's analysis of resource adequacy fails to support keeping the plant until that date.  
22 The Company has provided retirement analysis in this case that consider earlier retirement,  
23 and likely plans to analyze this question further in the upcoming IRP. However, DTE

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1 continues to request recovery of costs that could be avoided if the plant were to retire prior  
2 to 2028. If these avoidable costs are incurred now, but the Company subsequently decides  
3 to retire the plant, then ratepayers will not realize savings from avoiding those costs  
4 because they were included in rates—and these costs will become stranded.

5 **Q. Please summarize your evaluation of capital expenditures at the Belle River units.**

6 A. In reviewing the Company’s proposed capital expenditures for the Belle River units, I  
7 recommend that the Commission disallow rate recovery for capital spending on six  
8 projects, which total \$2.45 million in the bridge year and \$12.8 million in the test year (see  
9 Exhibit MEC-73). These projects include:

10 1. Avoidable expenditures identified by the Company in this case. DTE is  
11 requesting recovery of several 2023 test year expenditures that it acknowledges  
12 could be avoided if Belle River were to retire in 2023 or 2026. These include  
13 project IDs 17532, 17531, 17996, 15301, and 15595.

14 2. The Belle River natural gas conversion study. DTE is asking for recovery for  
15 engineering costs associated with the natural gas conversion, but the Company  
16 has not decided whether to convert the unit(s) at Belle River yet—or when the  
17 plant would cease burning coal. Because this issue will be likely be evaluated  
18 in the IRP, the Commission should disallow these costs because they are  
19 premature.

20 **Q. Has the Company identified avoidable capital costs in this case?**

21 A. Yes. The Company defines spending as avoidable if: “if an alternative or decision exists  
22 that reduces or eliminates the future costs associated with that project or another suitable

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1 alternative to the proposed work is more attractive.”<sup>48</sup> DTE was asked to identify capital  
2 spending at Belle River that is being requested for recovery in this case but would be  
3 avoidable with 2023, 2026, 2028, and 2030 retirement. The Company identified nine  
4 projects that would be avoided with a 2023 retirement, five that are avoidable with a 2026  
5 retirement, and none would be avoided with a 2028 or 2030 retirement.<sup>49</sup>

6 **Q. Given the possibility of the plant retiring in 2026, should those avoidable costs be**  
7 **included in rates?**

8 A. No. The Company has provided evidence that the economically optimal year for retiring  
9 the Belle River units is 2026 and is likely to address the issue further in the IRP. Because  
10 it is possible that the units will retire in 2026, and the evidence supporting such a retirement  
11 as the economic choice, the recovery of these avoidable costs should be disallowed as  
12 unreasonable and imprudent. This would also be consistent with previous disallowances of  
13 avoidable costs by this Commission.<sup>50</sup>

14 Exhibit MEC-73 shows the five projects with test year spending that should be disallowed  
15 because the expenditures are avoidable. In total, these avoidable projects represent \$12.8  
16 million in test year capital spending.

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<sup>48</sup> Data response MNSCDE-5.2a.

<sup>49</sup> Exhibit MEC-60 (Data response MNSCDE-1.19cv). The Company referred to these projects as both “avoidable” and “likely avoidable.” When later asked in MNSCDE-5.2b to confirm whether these projects were avoidable or not, the Company just referred back to that original response.

<sup>50</sup> See U-20697, Dec. 17, 2020, Commission Order, p. 77.

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1 **Q. How did you determine that the Belle River gas conversion spending was premature?**

2 A. The project rests on the premise that Belle River will be converted to natural gas if it were  
3 to cease coal operations. The project’s documentation states:

4 Belle River Power Plant will cease the use of coal to generate electricity by  
5 the end of 2028. If Belle River is to continue operating beyond 2028, the  
6 plant will have to convert to a different fuel source that meets current and  
7 future emission regulations.<sup>51</sup>

8 And the stated “project objective” is that the plant will “continue to operate and generate  
9 electricity beyond 2028.”<sup>52</sup> But DTE has also stated that it has not yet determined whether  
10 the plant would be converted to gas,<sup>53</sup> and as I have demonstrated throughout this  
11 testimony, the year that burning coal would stop at Belle River is uncertain. Thus, the  
12 project is not needed at this time, and I recommend it be disallowed for being premature.  
13 Exhibit MEC-73 shows the bridge year disallowance of \$2.45 million for this project.

14 **III. CAPITAL SPENDING AT MONROE THAT COULD BE AVOIDED WITH**  
15 **EARLY RETIREMENT SHOULD BE DISALLOWED**

16 **Q. Please summarize your assessment of the Monroe coal plant.**

17 A. The Company is assuming that the Monroe will retire in 2040 and planning its capital  
18 spending with that in mind. But as with Belle River, the Company has considered earlier  
19 retirement and there is potential that the retirement year will be reconsidered again in the  
20 upcoming IRP.<sup>54</sup> In this section, I argue that: [[REDACTED]]

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<sup>51</sup> Morren workpaper: WP-JLM-BLRPP, Belle River Fuel Conversion Engineering, PMP 18325.

<sup>52</sup> *Id.*

<sup>53</sup> Exhibit MEC-70 (Data response STDE-3.1a).

<sup>54</sup> Exhibit MEC-61 (MNSCDE-1.22a).

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1 [REDACTED]

2 [REDACTED]]; 2) the Commission should disallow some of the plant’s FGD  
3 wastewater project costs (for ELG rule compliance) for being premature; and 3) the  
4 Commission should disallow other capital spending that would no longer be justified with  
5 retirement prior to 2040.

6 **A. The Company’s Preliminary IRP Analysis Looks at Early Retirement**

7 **Q. Has the Company presented a preliminary analysis that looks at retirement of**  
8 **Monroe prior to 2040?**

9 A. Yes. The Company has provided what it calls a “practice” analysis that included modeling  
10 of alternative retirement dates at Belle River and Monroe. The Company modeled the  
11 following retirement options at those plants:

- 12 • [REDACTED]
- 13 • [REDACTED]
- 14 • [REDACTED]
- 15 • [REDACTED]
- 16 • [REDACTED]
- 17 • [REDACTED]

18 [REDACTED]

19 [REDACTED]

20 [REDACTED]] According to the  
21 Company, these model runs:

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<sup>55</sup> Exhibit MEC-63 (NDA\_U-20836 MNSCDE-1.6a Practice Belle River and Monroe Analyses).

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1                   ...were intended as illustrative examples of potential sensitivities that could  
2                   be evaluated in a future IRP while allowing the team to understand the  
3                   capabilities of the software.<sup>56</sup>

4                   The results, shown below on Table 2, show the [[ [REDACTED]  
5                   [REDACTED]  
6                   [REDACTED]  
7                   [REDACTED]  
8                   [REDACTED]  
9                   [REDACTED]]]

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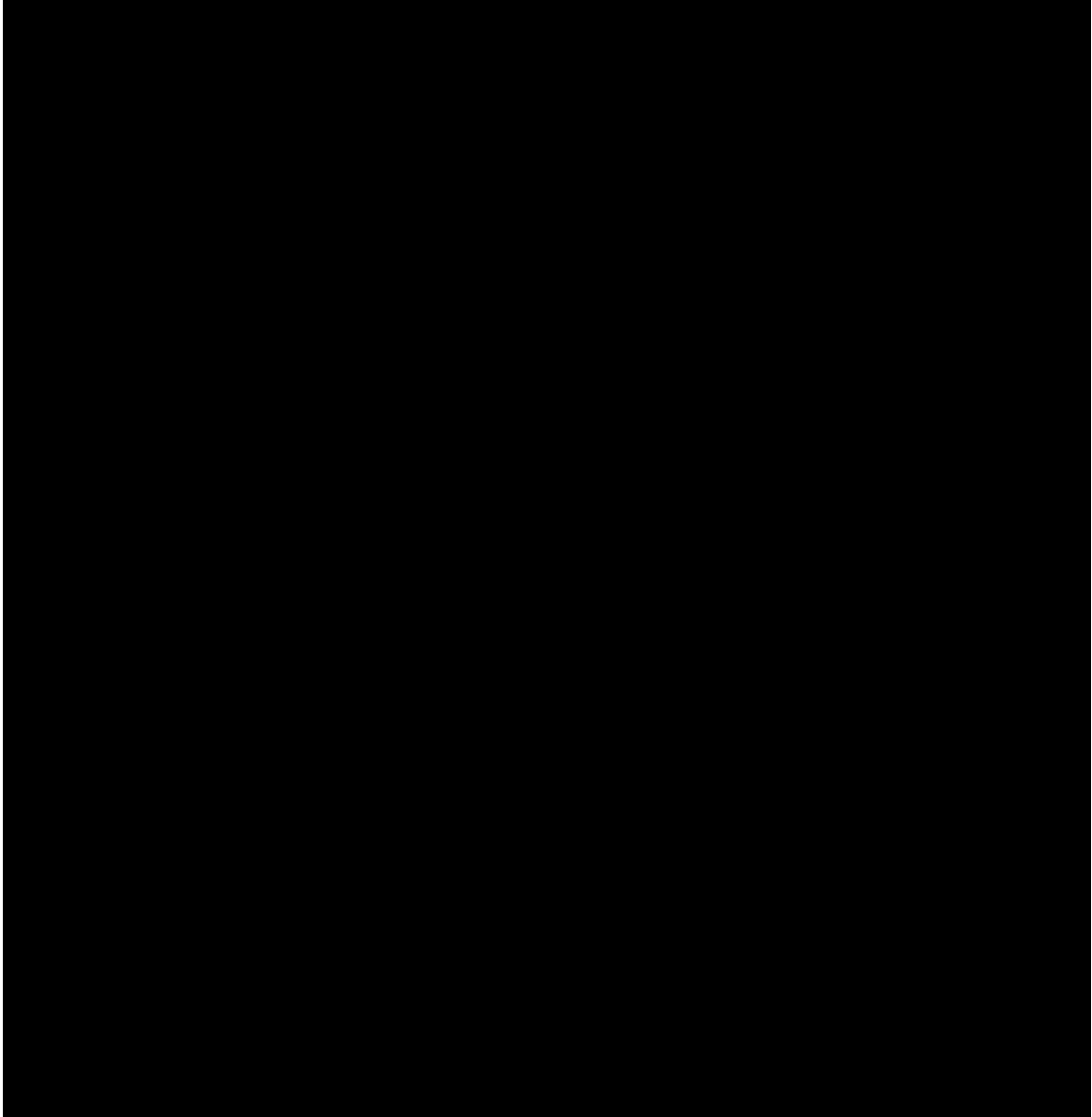
<sup>56</sup> Exhibit MEC-63 (Data response to MNSCDE-1.6a).



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**Table 2: Summary of Preliminary IRP Analysis (\$NPVRR mil)  
CONFIDENTIAL<sup>57</sup>**

1  
2  
3



4

5 **Q. Is it possible that Monroe partially or fully retires before 2040?**

6 A. Yes. The plant's future could be considered in the upcoming IRP docket. The Company  
7 has already evaluated early retirement of Monroe as a means of complying with the ELG

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<sup>57</sup> Exhibit MEC-63 (NDA\_U-20836 MNSCDE-1.6a Practice Belle River and Monroe Analyses).

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1 rule.<sup>58</sup> [[ [REDACTED]  
2 [REDACTED] ]]

3 **B. Some ELG Costs at Monroe Should be Disallowed**

4  
5 **Q. Please briefly describe the ELG rule, and its relevance to the Monroe plant.**

6 A. The ELG rule establishes technology-based effluent limits for steam electric generating  
7 units like those at the Monroe plant. EPA promulgated the rule in 2015.<sup>59</sup> These must be  
8 included in Clean Water Act permits (i.e., National Pollutant Discharge Elimination  
9 System or “NPDES” permits). One of the waste streams addressed by the ELG rule is  
10 bottom ash transport water.<sup>60</sup> EPA determined that the rule, including this zero-discharge  
11 standard for bottom ash transport water, will improve groundwater and surface water  
12 quality and reduce impacts to human health and wildlife.<sup>61</sup> The 2015 rule established that  
13 a compliance deadline for bottom ash transport water be no later than December 31, 2023.<sup>62</sup>  
14 In October 2020, EPA revised the ELG Rule. The 2020 revised rule made several changes  
15 relevant to discharges of bottom ash transport water.<sup>63</sup> First, under the 2020 rule, a

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<sup>58</sup> Exhibit MEC-61 (Data response to MNSCDE-1.22a).

<sup>59</sup> See U.S. EPA, Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category; 80 Fed. Reg. 67838 (Nov. 3, 2015).

<sup>60</sup> In the 2015 ELG Rule, EPA explained: “Bottom ash consists of heavier ash particles that are not entrained in the flue gas and fall to the bottom of the furnace. In most furnaces, the hot bottom ash is quenched in a water-filled hopper. . . Most plants use water to transport (sluice) the bottom ash from the hopper to an impoundment or dewatering bins. The ash sent to a dewatering bin is separated from the transport water and then disposed. For both of these systems, the water used to transport the bottom ash to the impoundment or dewatering bins is usually discharged to surface water as overflow from the systems, after the bottom ash has settled to the bottom.” 80 Fed. Reg. at 67846.

<sup>61</sup> See 80 Fed. Reg. at 67873-77.

<sup>62</sup> 80 Fed Reg. at 67896 (40 C.F.R. § 423.13(k)(1)(i)).

<sup>63</sup> U.S. EPA, Steam Electric Reconsideration Rule, 85 Fed. Reg. 64650 (Oct. 13, 2020).

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1 generating unit’s compliance date can be pushed back by two years – to as late as December  
2 31, 2025.<sup>64</sup> Second, if a generator commits to cease burning coal by December 31, 2028,  
3 the rule does not require the implementation of an ELG-compliant technology.<sup>65</sup> Third, the  
4 revised rule weakened the zero-discharge standard for bottom ash transport water transport.  
5 Under the revised rule, some discharge of pollutants in bottom ash transport water is  
6 authorized for certain specified activities.<sup>66</sup>

7 The ELG rule, including its substantive requirements and compliance deadlines, could soon  
8 be subject to further changes. In July of 2021, the Biden Administration announced its  
9 intention to further strengthen the ELG rule.<sup>67</sup> The U.S. EPA stated that it plans to issue a  
10 proposed revision to the rule in the fall of 2022.

11 **Q. Please describe the Company’s rate request for ELG compliance costs.**

12 A. According to DTE’s filing, it plans to spend \$105.3 million on ELG compliance at Monroe  
13 in the bridge year period and another \$30.6 million in the test year.<sup>68</sup> Below is the  
14 composition of this spending and the corresponding compliance deadlines:

- 15 • Monroe Dry Fly Ash Conversion: \$86.5 million in bridge year period and \$22.9  
16 million in test year. Requirements for dry ash handling were not changed with

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<sup>64</sup> 40 C.F.R. § 423.13(k)(1)(i).

<sup>65</sup> See 40 C.F.R. § 423.19(f) (establishing “[r]equirements for units that will achieve permanent cessation of coal combustion by December 31, 2028”).

<sup>66</sup> 40 C.F.R. § 423.13(k)(2)(i)(A). How large a volume may be discharged for such activities is left to the discretion of the permitting authority on a case-by-case basis, but may not exceed 10 percent of the primary bottom ash system volume on a monthly basis, using a rolling average. 40 C.F.R. § 423.13(k)(2)(i)(B).

<sup>67</sup> U.S. EPA, “EPA Announces Intent to Bolster Limits on Water Pollution from Power Plants,” press release, July 26, 2021. Available at: <https://www.epa.gov/newsreleases/epa-announces-intent-bolster-limits-water-pollution-power-plants>

<sup>68</sup> Morren Exhibit A-12, Schedule B5.1, p. 2.

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1 the 2020 revised rule. DTE claims that its compliance deadline for this aspect  
2 of the rule is December 31, 2023.<sup>69</sup>

- 3 • Monroe Bottom Ash Conversion: \$16.9 million in bridge year period and \$6.7  
4 million in test year. DTE also states that its compliance deadline for bottom ash  
5 handling is December 31, 2025.<sup>70</sup>
- 6 • Monroe FGD Wastewater: \$1.8 million in bridge year period and \$1 million in  
7 test year. Compliance could be December 31, 2025, or as late as December 31,  
8 2028 if DTE adopted a more stringent compliance option.<sup>71</sup>

9 **Q. Have the original compliance dates for the bottom ash conversion and FGD**  
10 **wastewater treatment shifted from when the projects were originally planned?**

11 A. Yes. The original project documentation for the bottom ash conversion project stated that  
12 the deadline for compliance was December 31, 2023; but a revision to that documentation  
13 in November of 2021 updated this to a December 31, 2025 compliance date (which the  
14 Company also verified in discovery).<sup>72</sup> The documentation for the FGD wastewater project  
15 also states a December 31, 2023 compliance date; but the Company stated in discovery that  
16 the current deadline is either end of 2025 or 2028, depending on the technology it chooses  
17 to deploy.<sup>73</sup>

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<sup>69</sup> Exhibit MEC-64 (Data response to MNSCDE-5.3a).

<sup>70</sup> *Id.*

<sup>71</sup> Exhibit MEC-71 (Data response to STDE-3.4a).

<sup>72</sup> Morren Workpaper, WP-JLM-MONPP, Monroe Bottom Ash Conversion (ELG), PMP 15134, p.1, 4. Exhibit MEC-64 (Data response to MNSCDE-5.3a).

<sup>73</sup> Morren Workpaper, WP-JLM-MONPP, Monroe Bottom Ash Conversion (ELG), PMP 15145, p.1, 4. Exhibit MEC-71 (Data response to STDE-3.4a).

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1 **Q. Should the Commission approve the request to recover the FGD wastewater project’s**  
2 **costs?**

3 A. No. Spending on the FGD wastewater project should be disallowed for two reasons. First,  
4 the compliance deadline could be as late as the end of 2028 and therefore possibly avoided  
5 in the near-term. Second, the project is premature because the compliance path for FGD  
6 wastewater is likely to change with the upcoming revision to the ELG rule that the EPA  
7 expects to release this fall. The Commission has previously held that when plans requiring  
8 expenditures in the test year are uncertain, the Commission will not approve rate recovery  
9 of such expenditures.<sup>74</sup> Indeed, such concerns prompted the Commission to disallow rate  
10 recovery of ELG costs in a Consumers’ 2020 rate case.<sup>75</sup> For similar reasons, the  
11 Commission disallowed recovery of Section 316(b) compliance costs, concluding that the  
12 “project is premature for inclusion in rate base.”<sup>76</sup>

13 **Q. What disallowances do you recommend regarding ELG compliance costs at Monroe?**

14 A. I recommend that the bridge year period and test year costs of the FGD wastewater project  
15 be disallowed in this case—as shown in my exhibit MEC-73.

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<sup>74</sup> See, e.g., Case No. U-20165, May 7, 2020, Order, p. 58 (disallowing costs where “it is uncertain that the company’s requested expenditures will be used as indicated in 2020”), p. 69 (disallowing recovery of costs for a coal ash basin closure project due to multiple uncertainties).

<sup>75</sup> Case No. U-20697, Dec. 17, 2020, Order, p. 74 (disallowing ELG costs as premature when contemplating a 2023 compliance deadline).

<sup>76</sup> Case No. U-20697, Dec. 17, 2020, Order, p. 93.

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**C. The Commission Should Disallow Other Capital Costs That Would Not Benefit Ratepayers if the Plant Retired Early**

**Q. Did you review other capital projects at Monroe?**

A. Yes, I also reviewed the internal rate of return (IRR) analyses of capital projects at the plant. These are economic assessments of the projects, whereby the Company projects the costs and savings to ratepayers and calculates an NPV and IRR that indicates whether the project results in net benefits to customers. These assessments are not required for all capital projects. The Company states that projects “required for safety, environmental compliance, or other regulatory compliance reasons will be executed.”<sup>77</sup> DTE conducts the IRRs as a means of assessing value to customers and prioritizes those projects on this basis, but the IRR must be higher than the utility’s cost of capital to be pursued.<sup>78</sup>

**Q. Did you determine when these projects would break even, i.e. provide a net benefit to ratepayers?**

A. Yes, if the project would result in net costs prior to the plant’s retirement, and is not necessary for safety or compliance reasons, then it should proceed only if it is reasonably projected to produce net benefits to ratepayers before the retirement date. I have found several projects at Monroe that do not produce net benefits until 2040. Because the plant may retire prior to that date, these costs should be disallowed at this time.

**Q. How did you calculate the net benefits or costs of these projects?**

A. Capital projects take time to justify themselves because the costs are often front-loaded while the benefits accrue over a long period. When assessing whether to make a capital

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<sup>77</sup> Data response to MNSCDE-5.1b.

<sup>78</sup> *Id.*

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1 spending decision, one looks into the future to anticipate whether the benefits are worth  
2 that upfront investment. With that in mind, I reviewed the IRRs that were available for  
3 capital projects at Monroe, including where the Company calculated a “discounted  
4 breakeven” value for the project. This metric determines how many years out the project  
5 will produce net benefits, factoring in the utility cost of capital. In some cases, where DTE  
6 did not calculate a discounted payback, I replicated the concept by calculating the  
7 cumulative NPV of benefits and costs to determine the discounted payback period.

8 **Q. Were there several projects that did not produce net benefits until 2040 or after?**

9 A. Yes. I found four projects that did not produce net benefits until the 2040 retirement date—  
10 or in the case of one project 2057, which is past the current retirement date of the plant.<sup>79</sup>

11 These projects include:

- 12 • Unit 1 LPA & LPB Turbine Rotor & Blades (project ID 14630): \$20.4 million  
13 in bridge year period and \$6.8 million in test year.
- 14 • Main Unit Transformer (project ID 18145): \$7.9 million in bridge year period  
15 and \$2.6 million in test year.
- 16 • Unit 1 Waterwall Tubes (project ID 9327): \$1.5 million in bridge year period  
17 and \$16.5 million in test year.
- 18 • Unit 3 Waterwall Tubes (project ID 9517): \$1 million in test year.<sup>80</sup>

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<sup>79</sup> Morren workpapers, WP-JLM-MONPP.

<sup>80</sup> Morren Exhibit A-12, Schedule B5.1, p.4-7. These projects were reported by DTE by calendar year. I have included 2021 and 2022 reported costs as the bridge year period and 2023 reported costs for test year.

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1 **Q. What do you recommend for these four projects?**

2 A. I recommend that the bridge year period spending of \$29.8 million and test year spending  
3 of \$27 million for these four projects should be disallowed. These projects' costs are listed  
4 in my disallowance exhibit MEC-73.

5 **IV. THE HYDROGEN PILOT PROJECT IS A LARGE AND UNSUBSTANTIATED**  
6 **RESOURCE DECISION THAT SHOULD BE DISALLOWED**

7 **Q. Please summarize the proposed hydrogen pilot project.**

8 A. The Company is proposing to build an electrolyzer that will produce hydrogen that would  
9 be used as fuel at Blue Water Energy Center (BWEC), a new natural gas combined cycle  
10 plant. The hydrogen pilot project would be built throughout 2023 and 2024 at a total cost  
11 of \$44.6 million (without risk contingency).<sup>81</sup> The Company claims that BWEC will be  
12 able to burn up to 5 percent hydrogen.<sup>82</sup>

13 **Q. Could the prudence of this project be addressed in the upcoming IRP?**

14 A. Yes, and that is the proper forum for making such a large resource decision. The Company  
15 is planning to construct a new facility to produce a new fuel that will also require  
16 modifications to an existing generator. The production of hydrogen itself represents a new  
17 technological venture that is purported to be part of the Company's meeting of emissions  
18 goals.<sup>83</sup> This major investment (and new direction) should be considered in the upcoming  
19 IRP where the Company should make the case for the net benefits of the project—which

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<sup>81</sup> Morren Workpaper, WP-JLM-BWEC, PMP 17600.

<sup>82</sup> Data response to AGDE-3.99.

<sup>83</sup> Morren Direct, pp. 41, lines 14-21.



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1           they have failed to do in this case. Below, I discuss several other reasons that the project  
2           should be disallowed in this case.

3   **Q.    The Company talks of 5 percent blending at BWEC, but on an annual basis how**  
4           **much of that plant’s fuel would be provided by the electrolyzer?**

5    A.    The electrolyzer will provide a much smaller percentage of the heat or volume of fuel  
6           burned at BWEC. In terms of fuel burned (MMbtu’s), the pilot project would only provide  
7           0.06 percent of the annual fuel use at BWEC; put differently, DTE still expects that the  
8           plant will burn 99.94 percent natural gas.<sup>84</sup> Hydrogen is less dense in fuel content than  
9           natural gas, so more volume is required to produce the same MMBtu’s. Accounting for that,  
10          I calculate that the pilot would still only provide 0.2 percent of fuel, in terms of volume  
11          (cubic feet or meters) per year.<sup>85</sup> Overall, the project is a large investment that only  
12          produces a de minimis impact on the fuel mix and by extension the emissions at BWEC.<sup>86</sup>

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<sup>84</sup> Exhibit MEC-66 (Data response to MNSCDE-8.1b) states that the pilot is expected to produce 31,776 MMBtu annually and data response to MNSCDE-8.1b state that the expected fuel consumption at BWEC in 2023 is 56,196,000 MMBtus.

<sup>85</sup> Hydrogen has roughly one-third the density of natural gas in terms of fuel (MMbtu) per volume (cubic feet or meters): see [https://www.engineeringtoolbox.com/heating-values-fuel-gases-d\\_823.html](https://www.engineeringtoolbox.com/heating-values-fuel-gases-d_823.html).

<sup>86</sup> [[



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1 **Q. Does DTE have plans to burn more hydrogen at BWEC than what is produced at**  
2 **the pilot?**

3 A. Not currently. The Company has stated that all of the hydrogen burned at BWEC will come  
4 from the electrolyzer, and that “no other sources of hydrogen fuel are currently being  
5 considered for BWEC.”<sup>87</sup>

6 **Q. Has the Company provided an economic justification for the project, or augmenting**  
7 **hydrogen use at BWEC, compared to other resource options?**

8 A. No. The Company has not developed the costs for generating hydrogen at the current pilot  
9 site.<sup>88</sup> It has also not located any sites where higher quantities of hydrogen could be stored  
10 if it were to expand use of the fuel at BWEC.<sup>89</sup> It has also not evaluated how hydrogen  
11 from other sites would be transported in that event.<sup>90</sup> The Company has also “not  
12 established a target levelized cost of hydrogen production and storage needed to consider  
13 the pilot project to be economically viable at its conclusion.”<sup>91</sup>

14 **Q. Has the Company demonstrated need for the hydrogen pilot project?**

15 A. No. The Company did not perform an assessment of the need for the project, nor did it  
16 quantify whether it would be a net benefit to ratepayers. The Company has admitted they

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<sup>87</sup> Exhibit MEC-68 (Data response to MNSCDE-8.3a).

<sup>88</sup> Exhibit MEC-55 (Data response to AGDE-3.100a).

<sup>89</sup> Exhibit MEC-58 (Data response to GLREADE-5.51d).

<sup>90</sup> Exhibit MEC-58 (Data response to GLREADE-5.51c).

<sup>91</sup> Data response to MNSCDE-8.2e.

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1           have not yet “conducted an analysis of the extent to which green hydrogen may be needed  
2           for the achievement of the Company’s future carbon reduction goals.”<sup>92</sup>

3   **Q.    Has the Company looked at other sources of funding?**

4    A.    No. The Company has not pursued non-utility funding for the proposed pilot.<sup>93</sup>

5   **Q.    Is there evidence showing that the electricity used to produce the hydrogen will be**  
6           **“green”?**

7    A.    No. The Company attaches the “green” claim to the hydrogen production at the pilot  
8           project. . However, this is insufficient to demonstrate that the electricity is in fact ”green.”  
9           First, DTE presupposes that a portion of the electricity used at the site would be sourced  
10          from “excess renewables,” which are defined as renewable energy that is in excess of  
11          customer demand and must be curtailed/not generated.”<sup>94</sup> But the Company acknowledged  
12          in discovery that such excess renewables were “minimal” in 2021 and that while “curtailed  
13          intermittent renewable resources are possible in the future . . . [t]he timing and amount of  
14          these excess resources cannot be accurately judged at this time.”<sup>95</sup> In fact, the Company  
15          argues that projecting availability and timing of curtailed power is not within its purview,  
16          nor within its control, and it thereby cannot make any assertions in relation to the extent to

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<sup>92</sup> Data response to MNSCDE-8.20.

<sup>93</sup> Data response to STDE-8.11.

<sup>94</sup> STDE-12.14b; MNSCDE-8.4c and – 8.7b.

<sup>95</sup> MNSCDE-1.14ci. Similarly, the Company contends that “No informed estimates of excess renewable energy available in MISO Zone 7 between 2024 and 2028 can be made by the Company at this time.” MNSCDE-8.7a.

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1           which the hydrogen produced would be powered by otherwise curtailed renewable  
2           electricity.<sup>96</sup>

3           When asked if the Company could explain the basis for its belief that there will be excess  
4           renewables, the Company falls back on the notion that they do not monitor or know much  
5           about excess renewables.<sup>97</sup> DTE then states that to the extent that curtailed renewable  
6           energy is unavailable it will purchase “MIREC accounted renewable sources.”<sup>98</sup> The  
7           MIREC system has been used for Michigan’s RPS compliance as a way of tracking  
8           renewable energy production. But buying one of these certificates does not mean that the  
9           MWh of energy produced would not have been produced regardless, nor that it would spur  
10          the need to build or generate additional renewable electricity, especially as Michigan’s RPS  
11          requirement ended in 2021. If one is purchasing a MIREC from a source that would have  
12          produced that MWh anyway, then the marginal energy provided to the grid could come  
13          from a non-green source. Therefore, there is a real risk that the hydrogen produced could  
14          be carbon intensive.

15   **Q.     Should the costs for this project be recovered in rates?**

16   A.     No. The project represents a major resource decision to blend hydrogen at BWEC, at  
17          significant cost, that should be considered in the upcoming IRP. The Company has also not  
18          demonstrated a need for the project; nor has it conducted an economic assessment to justify  
19          this substantial investment; nor has it supported the claim that the hydrogen will be

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<sup>96</sup> Exhibit MEC-69 (Data response to MNSCDE-8.4b); see also MNSCDE-8.7c and -8.8.

<sup>97</sup> MNSCDE-8.7c.

<sup>98</sup> Data response to MNSCDE-8.4c.

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1 produced from clean energy sources. At best, the project would deliver de minimis  
2 emissions reductions but at an exorbitant upfront cost to construct while the operating costs  
3 for producing hydrogen itself remain unknown. For these reasons, I recommend that the  
4 project's costs be disallowed.

5 **V. CONCLUSION AND RECOMMENDATIONS**

6 **Q. What do you recommend to the Commission?**

7 A. For the reasons explained above I recommend the following:

- 8 1. The Commission should continue to disallow the capital costs that the Company  
9 has identified as avoidable at Belle River should the plant retire in 2026.
- 10 2. The Commission should continue to disallow the capital costs for the Belle River  
11 natural gas conversion engineering because the plant's future is still being decided.
- 12 3. The Commission should disallow ELG compliance costs for FGD wastewater costs  
13 which may be avoided or are premature given compliance strategy changes with  
14 the pending EPA revision to the rule.
- 15 4. The Commission should disallow capital costs for several additional projects at  
16 Monroe that would not benefit ratepayers if the plant retired before 2040.
- 17 5. The Commission should disallow the costs for the hydrogen pilot project, primarily  
18 because it a major resource decision that should be addressed in the IRP.

19 **Q. Does this conclude your testimony?**

20 A. Yes.

## **Tyler Comings, Senior Researcher**

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### **PROFESSIONAL EXPERIENCE**

**Applied Economics Clinic, Arlington, MA.** Senior Researcher, June 2017 – Present.

Provides technical expertise on electric utility regulation, energy markets, and energy policy. Clients are primarily public service organizations working on topics related to the environment, consumer rights, the energy sector, and community equity.

**Synapse Energy Economics Inc., Cambridge, MA.** Senior Associate, July 2014 – June 2017, Associate, July 2011 – July 2014.

Provided expert testimony and reports on energy system planning, coal plant economics and economic impacts. Performed benefit-cost analyses and research on energy and environmental issues.

**Ideas42, Boston, MA.** Senior Associate, 2010 – 2011.

Organized studies analyzing behavior of consumers regarding finances, working with top researchers in behavioral economics. Managed studies of mortgage default mitigation and case studies of financial innovations in developing countries.

**Economic Development Research Group Inc., Boston, MA.** Research Analyst, Economic Consultant, 2005 – 2010.

Performed economic impact modeling and benefit-cost analyses using IMPLAN and REMI for transportation and renewable energy projects, including support for Federal stimulus applications. Developed a unique web-tool for the National Academy of Sciences on linkages between economic development and transportation.

**Harmon Law Offices, LLC., Newton, MA.** Billing Coordinator, Accounting Liaison, 2002 – 2005.

Allocated IOLTA and Escrow funds, performed bank reconciliation and accounts receivable. Projected legal fees and costs.

**Massachusetts Department of Public Health, Boston, MA.** Data Analyst (contract), 2002.

Designed statistical programs using SAS based on data from health-related surveys. Extrapolated trends in health awareness and developed benchmarks for performance of clinics for a statewide assessment.

## EDUCATION

**Tufts University**, Medford, MA

Master of Arts in Economics, 2007

**Boston University**, Boston, MA

Bachelor of Arts in Mathematics and Economics, Cum Laude, Dean's Scholar, 2002.

## AFFILIATIONS

**Society of Utility and Regulatory Financial Analysts (SURFA)**

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**Global Development and Environment Institute, Tufts University, Medford, MA.**

Visiting Scholar, 2017 – 2020

## CERTIFICATIONS

**Certified Rate of Return Analyst (CRR)**, professional designation by Society of Utility and Regulatory Financial Analysts (SURFA)

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Resume dated April 2022



# Capacity Demonstration Results

Planning Year 2024/25

Case No. U-20886

March 26, 2021

**MPSC Staff**



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## Executive Summary

All Michigan load serving entities (LSE) required to file capacity demonstrations with the Michigan Public Service Commission (MPSC or Commission) for planning year 2024/25 pursuant to MCL 460.6w and the August 2020 Commission Order in Case No. U-20886 have filed. Staff has audited the filings, contracts, and other materials and finds that all Michigan LSEs have satisfied the capacity demonstration requirements and have procured appropriate levels of resources for planning year 2024/25.

MPSC Staff (Staff) projects that the Midcontinent Independent System Operator, Inc. (MISO) Local Resource Zone (LRZ) 7, which consists of the lower peninsula of Michigan, excluding Indiana Michigan Power Company's (I&M) service territory in the southwest corner of the state, will have sufficient resources to meet its local clearing requirement (LCR) for the 2021/22 prompt year as well as the 2024/25 demonstration year based on the capacity demonstration filings and MISO publications at the time of this report. For MISO LRZ 1 and LRZ 2 in Michigan's Upper Peninsula, Staff doesn't have comprehensive enough data to accurately project zonal capacity positions because the majority of these two zones are located in other states not subject to MCL 460.6w. Based on the most recent Organization of MISO States (OMS) Survey, both LRZ 1 and LRZ 2 are projected to have sufficient capacity in 2021 as well as in 2024.<sup>1</sup> Additionally, Staff projects that the I&M service territory in Michigan, which is in PJM Interconnection LLC (PJM), will have sufficient levels of resources available to meet PJM's requirements.

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<sup>1</sup> [2020 OMS-MISO Survey Results](#) released in June 2020, accessed 03/12/2020.

## Background

On September 15, 2017 in Case No. U-18197, the Commission directed all Michigan LSEs to file capacity demonstrations annually pursuant to MCL 460.6w. This report outlines the results of the capacity demonstrations filed for planning year 2024/25 as directed by the Commission in Case No. U-20886 and represents the fourth annual capacity demonstration report. Prior reports are filed in Case No. U-18441, Case No. U-20154, and Case No. U-20590, respectively. In Case No. U-20886, the Commission ordered<sup>2</sup> rate regulated electric utilities<sup>3</sup> to submit capacity demonstrations by December 1, 2020 for the 2024/25 planning year and Alternative Energy Suppliers (AESs),<sup>4</sup> cooperatives,<sup>5</sup> and municipal utilities<sup>6</sup> to submit capacity demonstrations in the same docket for the 2024/25 planning year, on or before February 9, 2021. The purpose of these demonstrations is to ensure that each electric utility owns or has contractual rights to capacity sufficient to meet its capacity obligations as set by the MISO, PJM, or the Commission, as required by MCL 460.6w.

## Pre-Demonstration Process

Like the previous years, Staff offered LSEs the opportunity to meet with Staff to discuss the capacity demonstration requirements and review relevant materials prior to the final filing deadlines discussed above. A significant number of LSEs met with Staff and clarified the process before filing reports in the docket. Staff found that the pre-filing consultations were helpful in resolving questions prior to filing. Staff will continue to offer pre-filing consultations each year to resolve potential issues prior to the filing deadlines.

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<sup>2</sup> [August 20, 2020 MPSC Order](#) in Case No. U-20886, accessed 03/12/2021.

<sup>3</sup> Alpena Power Company, Consumers Energy Company, DTE Electric Company, Indiana Michigan Power Company, Northern States Power Company-Wisconsin, Upper Michigan Energy Resources Corporation, Upper Peninsula Power Company, and Wisconsin Electric Power Company.

<sup>4</sup> AEP Energy Inc, Calpine Energy Solutions LLC f/k/a Noble Americas Energy Solutions LLC, CMS ERM Michigan LCC, Constellation NewEnergy Inc, Dillon Power LLC, Direct Energy Business LLC, Direct Energy Services, EDF Energy Services LLC, Eligo Energy MI, LLC., ENGIE Gas & Power, Energy Harbor f/k/a FirstEnergy Solutions, Energy International Power Marketing Corporation, Energy Services Providers Inc., Interstate Gas Supply LLC, Just Energy Solutions Inc, Liberty Power Delaware LLC, Liberty Power Holdings LLC, MidAmerican Energy Services LLC, Nordic Energy Services LLC, Spartan Renewable Energy, Sunwave USA Holdings, Inc., Texas Retail Energy LLC, U.P. Power Marketing LLC, and Wolverine Power Marketing Cooperative Inc.

<sup>5</sup> Bayfield Electric Cooperative, Cloverland Electric Cooperative, Thumb Electric Cooperative, and Wolverine Power Supply Cooperative.

<sup>6</sup> City of Escanaba, City of Stephenson, City of Wakefield, Croswell Light and Power Department, Daggett Electric Department, Michigan Public Power Agency, Michigan South Central Power Agency, Newberry Water and Light Board, and WPPI Energy.

## Capacity Demonstration Filings

On or before December 17, 2020, capacity demonstration filings were received from Alpena Power Company, Consumers Energy Company, DTE Electric Company, Indiana Michigan Power Company, Northern States Power Company, Upper Michigan Energy Resources Corporation (UMERC), and Upper Peninsula Power Company (UPPCO). Most of the LSEs filed confidential information under seal as part of the electric utilities' filings. Staff reviewed this information and met with LSEs as needed.

On or before February 9, 2021, capacity demonstration filings were received from Calpine Energy Solutions, LLC., Constellation New Energy Inc., Direct Energy Business, Spartan Renewable Energy Inc., Wolverine Power Marketing Cooperative Inc., Energy Harbor LLC, Just Energy, City of Escanaba, City of Stephenson, City of Wakefield, Croswell Light and Power Department, Daggett Electric Department, Michigan Public Power Agency, Michigan South Central Power Agency, Newberry Water and Light Board, WPPI Energy, Thumb Electric Cooperative, and Wolverine Power Supply Cooperative. Cloverland Electric Cooperative filed their capacity demonstrations on February 12, 2020. Bayfield Electric Cooperative Inc. filed its capacity demonstration on February 17, 2020. Staff confirms receipt of capacity demonstration filing information from, or on behalf of, all LSEs currently serving load in Michigan.

Several AESs filed letters in Case No. U-20886 indicating that they are currently not serving customers in Michigan.<sup>7</sup> Staff confirms that all licensed AESs in Michigan have either filed capacity demonstrations or a letter indicating that they are not currently serving Michigan load.

Staff conducted an audit for each capacity demonstration filing received and requested additional information from the LSE when necessary. Staff has reviewed all contracts included in capacity demonstrations from AESs as well as most of the contracts from co-ops, electric utilities, and municipalities.

## Overview of Zonal Adequacy

As alluded to above, there are two regional transmission operators (RTOs) in Michigan; MISO and PJM. The majority of Michigan's load is in the MISO footprint. The exception is the southwest corner of the Lower Peninsula, which is I&M's service territory located within the PJM footprint. MISO and PJM have different resource adequacy constructs and capacity obligations. PJM has a

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<sup>7</sup> Eligo Energy MI, LLC., Liberty Power Holdings LLC, Liberty Power Delaware LLC, Nordic Energy Services LLC, ENGIE Gas & Power, Interstate Gas Supply LLC, Dillon Power LLC, Energy International Power Marketing Corporation, MidAmerican Energy Services LLC, EDF Energy Services LLC, Texas Retail Energy LLC, Energy Services Providers Inc., AEP Energy Inc., UP Power Marketing, and Sunwave Holdings LLC.

mandatory three-year forward capacity construct for its LSEs.<sup>8</sup> MISO's capacity construct is for the upcoming year (prompt year) only. Both MISO and PJM LSEs are subject to the requirements of MCL 460.6w requiring sufficient capacity for four years forward: in this case, for planning year 2024/25. PJM LSEs can demonstrate sufficiency simply by providing evidence that the LSE is compliant with its PJM obligations. MISO LSEs must demonstrate sufficient resources to meet its current prompt year requirement four years forward. For this reason, most of this section is focused on MISO.

MISO establishes capacity obligations for all LSEs based on peak load forecasts and a planning reserve margin percentage necessary to meet the North American Electric Reliability Corporation's (NERC) Loss of Load Expectation (LOLE) standard of 1 outage day in 10 years. LSEs within MISO can meet their capacity requirements either through a Fixed Resource Adequacy Plan (FRAP) or through the Planning Resource Auction (PRA). The PRA is a residual market for LSEs that choose not to use the FRAP or do not have enough capacity resources, either owned or purchased bilaterally, to satisfy their capacity obligations and thus need to purchase additional resources.

Within MISOs resource adequacy construct, there are two key resource requirements that must both be satisfied to meet the 1 day in 10 years LOLE standard: the Planning Reserve Margin Requirement (PRMR) and LCR. The PRMR is determined through LOLE modeling based on the coincident MISO peak forecast and resources adjusted as necessary to meet the 1 day in 10 years standard. PRMR resources are not location specific, i.e. they can come from outside an LSE's zone. Individual LSEs are responsible for their own share of the zone's PRMR. The ability to use imports to meet PRMR makes it highly likely all zones will meet this requirement. Failure to meet PRMR would only occur if there were not enough resources available within all of MISO's footprint or the resource need for a particular zone exceeded the zone's ability to import capacity.

Of greater interest to Staff is the LCR. Under MISO tariffs, the LCR is the minimum amount of capacity required to be located within an LRZ to meet the loss of load standard, fully accounting for the LRZ's ability to import. The MISO LCR is for the zone as a whole, as opposed to a requirement for individual LSEs, and is determined by MISO for the prompt year. Under MCL 460.6w, as upheld by case law, the MPSC may establish a forward locational capacity requirement for individual LSEs for the capacity demonstration compliance year in order to provide visibility into Michigan's ability to meet the MISO LCR in future planning years. However, there is no LCR requirement applicable to individual LSEs in Michigan pursuant to MCL 460.6w currently. The LCR is determined by performing a LOLE analysis on each zone individually to determine the Local Reliability Requirement (LRR), which is the amount of resources a zone would need to meet the

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<sup>8</sup> PJM's Base Residual Auction (BRA) for planning year 2022/23 will be completed by June 2021, See below for more discussion on this issue. Also, please note, the timing of MISO's and PJM's resource adequacy constructs don't align perfectly. PJM's base residual auction ordinarily would occur in May/June 2020, for PY 2023/24 is referred to as being "three years forward" but constitutes the same planning year at issue in U-20886 and the same planning year "four years forward" in MISO's resource adequacy construct (March/April 2020 auction for PY 2021/22).

loss of load standard if it were separated from the rest of MISO. Separately, an import study is performed to determine the Zonal Import Ability (ZIA) for each zone. For LRZ 7, the ZIA is currently (and historically) equal to the Capacity Import Limit (CIL) and the terms are often treated synonymously. The ZIA is then subtracted from the LRR to determine the LCR. If an LRZ doesn't have enough resources to meet its LCR (or PRMR), the PRA clearing price would be set at the Cost of New Entry (CONE) for that year. This occurred in PY 2020/21 for LRZ 7, when it was approximately 125 MW short of its LCR. This resulted in the auction clearing price for LRZ 7 being set at CONE, which was \$257.53/MW-Day or approximately \$94,000/MW-year for LRZ 7. CONE prices vary slightly from zone to zone and year to year. The PRA clearing price being set at CONE has economic ramifications and can provide a signal to stakeholders with responsibilities regarding resource adequacy within the zone. However, it is important to note that MISO's resource adequacy construct is based on probabilistic determinations and failure to meet the requirements of the resource adequacy construct does not mean that the LRZ in question will experience a loss of load event. It simply means the probability of such a loss of load event would exceed the generally accepted criteria that govern the resource adequacy planning process.

In addition to the required compliance year (PY 2024/25), most demonstrations filed included updates for the 2021/22 planning year through the 2023/24 planning year. These updates are voluntary and were not provided by all LSEs.<sup>9</sup> Staff appreciates the efforts made by LSEs to provide updated capacity resource data for these years as it allows Staff to update zonal resource adequacy projections for the prompt year and interim years, as well as the compliance year. It is important to note that the compliance year capacity obligations (PY 2024/25) that are demonstrated for in this case are based off an LSE's prompt year (PY 2021/22) requirement. Changes to load, resources, and MISO procedures in the upcoming years can lead to discrepancies between an LRZ having sufficient capacity to meet its four-year forward Michigan requirements and not having enough capacity to meet MISO's requirements when the prompt year arrives.

## **MISO – Local Resource Zone 7**

Figure 1 shows a comparison of LRZ 7 aggregated resources and MISO resource adequacy requirement projections for the next 4 years. These numbers represent Staff's current projection based on the capacity demonstration filings and MISO publications at the time of this report, although the information is subject to change for all years, including PY 2021/22. Unless otherwise noted, resources and resource requirements in this report are in Unforced Capacity (UCAP) Megawatts (MW), equal to Zonal Resource Credits (ZRCs).

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<sup>9</sup> The required demonstrations for planning years 2020/2021 and 2021/2022 were made in the 2018 capacity demonstration (Case No. U-18441). The required demonstration for planning year 2022/23 was made in the 2019 capacity demonstration (Case No. U-20154). The required demonstration for planning year 2023/2024 was made in the 2020 capacity demonstration (Case No. U-20590).

**Figure 1: U-20886 Results - LRZ 7 Capacity Position (ZRCs)**

Line #		PY 2021/22	PY 2022/23	PY 2023/24	PY 2024/25
1	Planning Reserve Margin Requirements (PRMR)	21,758	21,652	21,546	21,439
2	Local Reliability Requirement (LRR)	25,054	25,445	25,837	26,228
3	Capacity Import Limit (CIL)	4,888	4,888	4,888	4,888
4	Zonal Import Ability (ZIA)	4,888	4,888	4,888	4,888
5	Local Clearing Requirement (LCR)	20,166	20,557	20,949	21,340
6	Total Owned	16,588	16,882	16,789	16,838
7	Total PPA Contracts	2,749	2,140	2,412	2,606
8	Total ZRC Contracts	605	780	834	668
9	Total Qualified Demand Response	1,341	1,466	1,532	1,545
10	Total Resources (Line 6 + Line 7 + Line 8 + Line 9)	21,282	21,268	21,566	21,657
11	LCR Demonstrated Position (Line 10 - Line 5)	1,116	711	618	317
12	PRMR Demonstrated Capacity Position (Line 10 - Line 1)	-477	-384	21	218
13	Net Undemonstrated Zone 7 Capacity	350	175	120	286
14	Anticipated LCR Position (Line 11 + Line 13)	1,466	885	738	603
15	Anticipated PRMR Capacity Position (Line 12 + Line 13)	-127	-209	141	504

(1) PY 2021 PRMR from Preliminary PRA Data. PY 2024 PRMR calculated using the peak demand forecast from the 2021-22 LOLE Study Report and multiplying by the coincidence factor (95%) and reserve margin (108.8%). PY 2022 & PY 2023 calculated through interpolating PY 2021 & PY 2024.

(2) PY 2021 LRR from Preliminary PRA Data. PY 2024 LRR from the 2021-22 LOLE Study Report. PY 2022 & PY 2023 calculated through interpolating PY 2021 & PY 2024.

(3) PY 2021 CIL from the 2021-22 LOLE Study Report, held constant at prompt year value per MISO recommendation.

(4) PY 2021 ZIA from the MISO Preliminary PRA data, held constant at prompt year value per MISO recommendation

(5) LRR-ZIA=LCR

(6-10) Zone 7 resources included in capacity demonstrations sorted by resource type.

(11) LCR position based on demonstrated resources only.

(12) PRMR position based on demonstrated resources only.

(13) Net Undemonstrated Zone 7 Capacity is Staff's attempt to reconcile the capacity demonstration resources with the MISO PRA. There are resources located in Zone 7 that Staff anticipates will be in the PRA that were not included in any capacity demonstration as well as a small amount of resources included in the capacity demonstration that Staff expects are no longer available due to recent events.

(14) LCR Position after accounting for undemonstrated Zone 7 Capacity.

(15) PRMR position after accounting for undemonstrated Zone 7 capacity. A negative value means the Zone will need to import resources to meet its requirement. A positive value means the Zone may import resources based on economics but will not need to in order to meet its PRMR.

## Prompt Year (PY 2021/22)

For the prompt year (PY 2021/22), based on capacity demonstration filings and the 2021/22 LOLE report, Staff expects LRZ 7's PRMR to be 21,758 ZRCs and the LCR to be 20,166 ZRCs. The total LRZ 7 resources included in demonstration filings for the prompt year is 21,282 ZRCs. Staff is also aware of capacity resources in Zone 7 that were not included in capacity demonstration filings. Staff projects that an additional 350 ZRCs in LRZ 7, beyond what has been demonstrated for LRZ 7, will be available for the prompt year. Based on the demonstrated resources and projected undemonstrated resources Staff anticipates LRZ 7 will exceed its LCR by approximately 1,466 ZRCs for the 2021/22 planning year.

Line 12 of Figure 1 outlines the capacity position of LRZ 7 relative to the PRMR. Based on Staff's analysis of LSE filings in this docket, Staff expects that LRZ 7 will need to import 127 ZRCs to meet its PRMR for planning year 2021/22. This represents a fraction of LRZ 7 import limit and will not be an issue, unless the entire MISO territory was short resources, which is very unlikely. While Staff projects that LRZ 7 could meet its prompt-year PRMR with only 127 MW of imports, additional imports could occur based on resource prices. Once the LCR criteria is satisfied, additional resource requirements will be satisfied based on the marginal cost resource available in the market regardless of zonal location.

## Compliance Year (PY 2024/25)

Staff used the 2021/22 LOLE study report to project requirements for future planning years. These projections are subject to change. The projected PRMR for LRZ 7 for the compliance year (PY 2024/25) is 21,439 ZRCs. Staff determined this number by taking the forecasted peak demand for LRZ 7 in PY 2024/25 (20,360 MW) and accounting for LRZ 7's coincidence factor of 96.43% and the MISO reserve margin of 9.2%. This is a reduction of 319 ZRCs from the prompt year PRMR. Using the LOLE Study Report LRR for PY 2024/25 of 26,228 ZRCs and assuming the ZIA remains constant at 4,888, results in a projected LCR of 21,340 ZRCs for LRZ 7 in PY 2024/25.

Based on the resources included in the capacity demonstration filings for PY 2024/25 (21,657 MW) as well as Staff's estimate (286 MW) of additional LRZ 7 capacity that was not included in the demonstrations and the projected requirements, Staff projects LRZ 7 to have a surplus of 603 MW compared to the projected LCR in PY 2024/25.

## Interim Years (PY 2022/23 & PY 2023/24)

Figure 1 also includes data and projections for the interim years, PY 2022/23 & PY 2023/24. This information is derived using the same methodology as described for the compliance year with interpolation as necessary because the LOLE Study Report didn't provide specific LRZ analysis for the interim years. Comparing those projected requirements to the demonstrated and undemonstrated resources in LRZ 7 results in a capacity surplus of 885 ZRCs in PY 2022/23 and a surplus of 738 ZRCs in PY 2023/24 compared to the projected



LCRs. This information is based on the best information currently available to Staff but includes several assumptions and, again, is subject to change. Likely changes include new forecasts, unknown resource additions or subtractions, changes in generator performance, increased or decreased zonal import ability, and/or changes to MISO requirement methodology.

## Noteworthy for MISO Local Resource Zone 7

### 1. Capacity Requirements

Capacity requirements can change from year to year based on changes to calculation and modeling methodology, as well as changes to resource characteristics and load forecasts.

**PRM%:** The PRM% represents the resources required to meet the 1 day in 10 years loss of load standard compared to the MISO system peak demand as a percentage of the MISO system peak demand. The planning reserve margin percent (PRM UCAP) has increased from 8.9% for PY 20/21 to 9.4% for PY 21/22. The primary driver for this change is an adjustment to more realistic planned outages within the model, increasing the PRM% by 1.08 partially offset by changes to load profiles, resource mix, and monthly wind effective load carrying capability.

**LRR:** The LRR represents the amount of resources required for a particular zone to meet the 1 day in 10 years loss of load standard when modeled as an island (no imports). The LRR is comparable to the PRMR except that it is modeled for an individual zone instead of the entire MISO territory. LRZ 7 had an LRR of 25,051 MWs in the 2020/21 PRA Results. The 2021-2022 LOLE Study shows an LRR of 25,055 MWs for PY 2021/22. MISO is in the process of working with stakeholders on implementation of the realistically optimized planned outage schedule for the LRR analysis as part of the 2022/23 LOLE Study. This implementation will lead to an increase in LRZ 7's LRR. The 2021/22 LOLE Report projects the LRR for PY 2024/25 to be 26,228 MWs.

**CIL / ZIA:** The ZIA is defined as the ability of an LRZ to import capacity from areas outside of that LRZ. In LRZ 7, the ZIA is equal to the CIL. The 2021 CIL/ZIA has increased to 4,888 from 3,200 in 2020 after internal changes to MISO's transfer analysis methods. MISO has recommended Staff assume a constant CIL/ZIA for future year projections.

**LCR:** The LCR is the difference between the LRR and the ZIA. The LCR represents the minimum amount of resources that must be located within a specific zone for that zone to meet the reliability standard. The LOLE Data for 2021 shows an LCR of 20,166 ZRCs. Last year’s LCR was 21,851 ZRCs. Using the 2021/22 LOLE Report LRR and assuming a ZIA of 4,888 MW results in a projected LCR of 21,340 MW for PY 2024/25.

**2. Historical Requirements**

Figure 2 below shows data from the annual MISO LOLE study reports for LRZ 7. These numbers typically change slightly prior to the PRA but can be used to see how the capacity requirements have changed over time. Changes in these requirements can have economic and reliability impacts and will continue to be monitored.

**Figure 2: Annual MISO LOLE Report Data**

Source	LRR	CIL	LCR (ZRCs)
MISO 2013 LOLE Report	25,305	4,576	20,729
MISO 2014 LOLE Report	24,815	3,884	20,931
MISO 2015 LOLE Report	24,710	3,813	20,897
MISO 2016 LOLE Report	24,715	3,813	21,309
MISO 2017 LOLE Report	24,654	3,320	21,334
MISO 2018 LOLE Report	24,545	3,785	20,760
MISO 2019 LOLE Report	24,845	3,211	21,634
MISO 2020 LOLE Report	25,370	3,200	22,170
MISO 2021 LOLE Report	25,054	4,888	20,166

The increased CIL for PY 2021/22 results in a pause in the trend of decreasing margin between the PRMR and LCR for LRZ 7, as shown in Figure 3. This trend is likely to resume pending implementation of realistic planned outages in the LRR calculation methodology.

**Figure 3: MISO LRZ 7 LCR & PRMR Comparison**

<b>Year</b>	<b>LCR</b>	<b>PRMR</b>	<b>ECIL</b>	<b>Source</b>
PY 2013/14	21055	22702	1647	PRA Results
PY 2014/15	21293	22998	1705	PRA Results
PY 2015/16	21442	22679	1237	PRA Results
PY 2016/17	20851	22406	1555	PRA Results
PY 2017/18	21109	22295	1186	PRA Results
PY 2018/19	20628	22121	1493	PRA Results
PY 2019/20	21812	21976	164	PRA Results
PY 2020/21	21851	21945	94	PRA Results
PY 2021/22	20166	21758	1592	MISO 2021/22 LOLE Study & MPSC Staff Projection
PY 2022/23	20557	21652	1095	MISO 2021/22 LOLE Study & MPSC Staff Projection
PY 2023/24	20949	21546	597	MISO 2021/22 LOLE Study & MPSC Staff Projection
PY 2024/25	21340	21439	99	MISO 2021/22 LOLE Study & MPSC Staff Projection

The difference between a zone’s PRMR and its LCR is sometimes referred to as Effective Capacity Import Limit (ECIL). The ECIL is not a MISO defined term and is not representative of a physical import limitation. The ECIL is a product of the MISO resource adequacy construct and is an import limitation only within the constraints of the construct. To meet the loss of load standard and avoid the auction clearing price being set at CONE, a zone must have enough resources located within the zone to meet its LCR even if the LCR exceeds the PRMR.

### **3. Capacity Resource Changes**

In addition to expected variation in each generating unit’s unforced capacity from year to year, there were a few other noteworthy resource changes this year as compared to last year’s report.

#### **Ludington Upgrades**

Consumers Energy Company and DTE Electric Company plan to continue upgrades to the Ludington Pumped Storage facility to help support intermittent resources and provide a price hedge against variable market energy prices. The six units began undergoing a maintenance overhaul upgrade in 2015, one unit at a time. As

of the filing of DTE's Integrated Resource Plan (IRP) in Case No. U-20471, four of the unit upgrades had been completed. A fifth was completed in May 2019. According to DTE's IRP, the \$800 million upgrade project to replace each of the six unit turbines in the facility was scheduled to be completed in 2020.<sup>10</sup> However, due to the COVID-19 pandemic and difficulties with component manufacture, the completion date was pushed back to June of 2021 in the summer of 2020.<sup>11 12</sup>

### **Increased Utility Demand Response Programs**

The two LSEs in LRZ 7 will see consistent growth of several of their Demand Response (DR) programs from the prompt year to 2024. This growth amounts to a 185 MW total increase throughout the next four years. Specifically, DTE will see growth in their Interruptible Air Conditioning (AC) program as well as their unspecified new DR pilot programs. Consumers is expected to see growth in their Commercial & Industrial (C&I) DR program and Smart Thermostat Program.

### **Demand Response Aggregation**

Pursuant to a Commission Order in Case No. U-18369, the Commission affirmed that AESs may offer DR programs to their customers through a curtailment service provider (CSP) or third-party aggregator.<sup>13</sup> The Commission made this determination in the context of finding that it will continue to review DR programs offered by AESs as part of the capacity demonstration process.

As the Relevant Electric Retail Regulatory Authority (RERRA), the Commission approved the aggregation of 71.4 MWs of DR to be offered into the 2021 MISO capacity market, which is the same as what was approved for the previous year. While still a relatively small percentage of the total capacity, it is expected that aggregated DR will grow in future years.

### **MISO Resource Adequacy Construct Changes<sup>14</sup>**

The changing resource mix within the MISO footprint has highlighted issues with an annual capacity planning construct. With baseload generation that operates at a relatively high capacity factor, the traditional method of planning for a single, annual system peak worked well. As MISO moves to more intermittent resources, we are seeing inefficiencies through loss of load analysis which has prompted

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<sup>10</sup> MPSC Case No. U-20471, Direct Testimony of Laura J. Mikulan, Exhibit A-3, p. 287.

<sup>11</sup> "Turbine Upgrade Project Delayed at Ludington Pumped Storage Plant." David Bossick, Ludington Daily News. July 24, 2020.

<sup>12</sup> MPSC Case No. U-20590, Consumer's Energy Company's Capacity Demonstration for Planning Years 2020 Through 2023, p. 1.

<sup>13</sup> [September 15, 2017 MPSC Order](#) in Case No. U-18369, p. 5, accessed 03/23/2019.

<sup>14</sup> [Resource Adequacy and Need, MISO RASC](#), accessed 02/12/2021.

discussions within the MISO Resource Adequacy Sub-Committee (RASC) on ways to mitigate this risk. The change that is currently being discussed is changing from an annual resource adequacy construct to a seasonal construct that would require resource planning four times a year. In addition, MISO has proposed a conversion of Unforced Capacity (UCAP) to Available Capacity (ACAP). The ACAP conversion takes the UCAP of thermal resources and removes the external resources, wind, solar, and LMRs. After averaging the availability of these thermal resources using the top 5% tight margin hours over the prior three years, the calculation then divides this by the UCAP values. The PRMR and LCR ACAP is then multiplied by the conversion ratios.<sup>15</sup> These changes are currently being discussed within the MISO RASC and the RASC is expected to submit the tariff to FERC for review and approval in the second quarter of 2021, pending implementation beginning in the first quarter of 2022. This move to a seasonal model would affect all three MISO LRZ represented in Michigan, including LRZ 1 and LRZ 2.

## MISO – Local Resource Zone 2

MISO's LRZ 2 encompasses almost the entire Upper Peninsula (UP) of Michigan, as well as northern and eastern Wisconsin. MISO LRZ 2 has a CIL of 3,599 ZRCs for planning year 2020/21, but MISO does not define MW capacity imports or export limits between states within the boundaries of the same MISO LRZ. Considering LRZ 2 includes LSEs from Wisconsin (not subject to MCL 460.6w), the data available to Staff for LRZ 2 from capacity demonstration filings is not comprehensive enough to project a zonal capacity position as Staff did in its analysis of LRZ 7. Nevertheless, all Michigan LSEs serving load within MISO LRZ 2 demonstrated sufficient resources to meet their requirements.

### Noteworthy for MISO Local Resource Zone 2

MISO determined that there are limitations to the transmission system in the UP that require generation availability to reliably serve all of the load in the UP.

In its capacity demonstration, UPPCO discussed the mechanical failure and subsequent retirement of its Portage generating unit, one of its two fuel oil generators in the UP, in November of 2018. The Company intends to continue operation of the Gladstone fuel oil generator as approved in its IRP in Case No. U-20350.

In addition, the Michigan Department of Environment, the Great Lakes, and Energy is currently conducting stakeholder meetings as part of its Upper Peninsula Energy Task Force<sup>16</sup> established by Governor Whitmer in Executive Order 2019-14. The taskforce will identify and evaluate potential changes in the Michigan UP energy supply while formulating

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<sup>15</sup> [RAN Reliability Requirements and Sub-annual Construct](#), February 25, 2021, accessed 03/12/2021.

<sup>16</sup> [Upper Peninsula Energy Taskforce Homepage](#), accessed 03/16/2021.

alternative solutions for meeting future energy needs. The final report will be submitted on March 31, 2021. Potential changes to the energy infrastructure from the recommendations in this report may have overarching implications for the reliability of the Michigan portion of LRZ 2. The 2019 OMS-MISO Survey results indicate an installed capacity surplus of 100 MW in the 2020/21 planning year for LRZ 2, increasing to a surplus of 200-800 MW for 2024, for LRZ 2.<sup>17</sup> Notwithstanding the localized reliability issues in the UP, the results of the OMS-MISO Survey indicate that LRZ 2 is projected to have an adequate supply of capacity resources to meet its PRMR requirements for the planning years.

## MISO – Local Resource Zone 1

A very small fraction of Michigan’s UP load is in LRZ 1. Northern States Power, Bayfield Electric Cooperative, and the City of Wakefield municipal utility have less than 30 MW combined in MISO LRZ 1. The 2021 OMS-MISO Survey results indicate an installed capacity surplus of approximately 1,600 MW for the 2021 planning year and a similar capacity surplus projected for 2025.<sup>18</sup> LRZ 1 is projected to have an adequate supply of capacity resources to meet its PRMR requirements for the 2021/22 planning year, as well as the next several planning years.

## PJM – Indiana Michigan Power Company<sup>19</sup>

As previously stated, PJM has a mandatory forward capacity market for LSEs in its service territory. LSEs in the PJM service territory meet capacity obligations either through participation in PJM’s Reliability Pricing Model (RPM) Base Residual Auction (BRA) or through PJM’s Fixed Resource Requirement (FRR) plan. As a result of a 2016 complaint, FERC found that PJM’s capacity market was unjust and unreasonable due to the Minimum Offer Price Rule’s (MOPR) failure to mitigate out-of-market payments that threaten the competitiveness of the PJM’s capacity market. After several years and several rounds of proposals, in December 2019 FERC rejected most of the filed solutions in favor of an expanded MOPR and directed PJM to file a compliance filing by March 18, 2020.<sup>20</sup> In a May 21, 2020 order, FERC accepted PJM’s proposed replacement market design and directed further clarification on reserve market rules, which PJM provided. On November 12, 2020, FERC accepted PJM’s compliance filing and approved PJM’s treatment used to establish the minimum offer price.<sup>21</sup>

PJM announced an accelerated schedule for its next five annual capacity auctions following the FERC order to allow the regular cadence to resume. The first of these BRAs for the 2022/23 delivery

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<sup>17</sup>[2019 OMS-MISO Survey Results](#) released in June 2019 revised in August, 2019, accessed 03/17/2020.

<sup>18</sup> *Id.*

<sup>19</sup> Indiana Michigan Power Company is an electric operating company of American Electric Power Company, Inc. (AEP). I&M is a wholly owned subsidiary of AEP and is operated as a single utility in the American Electric Power System (AEP System).

<sup>20</sup> [FERC Directs PJM to Expand Minimum Offer Price Rule](#), December 19, 2019, accessed 03/22/2020.

<sup>21</sup> [FERC Order 2020-11-12](#), November 18, 2020, accessed 3/12/2021.

year opens May 19, 2021 and closes a week later. PJM expects results from that auction in early June of 2021.<sup>22</sup>

The capacity demonstration process and requirements approved by the Commission in Case No. U-20154<sup>23</sup> allow PJM LSEs to file an amended capacity demonstration two weeks after the completion of the PJM RPM BRA. Due to the multi-year FERC MOPR decision process, I&M was unable to update its capacity demonstration in prior years. Staff worked with the Company this year and last to allow I&M to submit a capacity demonstration based on its projection of owned-resources and capacity contracts for the 2023/2024 planning-year without an updated BRA.

I&M's most recent capacity demonstration filed in Case No. U-20886 indicates that the Company plans to continue with the PJM FRR plan that allows them to opt out of participation in the PJM competitive capacity market, barring any major FERC ordered changes. Based on this, I&M's capacity position should not be greatly affected by decisions resulting from FERC's November 12, 2020 order. Nevertheless, this delays the Company's ability to provide, with 100% certainty, an indication of where future planning year capacity will come from to make up small differences between owned-resources and short-term market purchases until the PJM BRA auction results are known in summer of 2021.

The Commission Order in Case No. U-16090 set I&M's customer choice cap amount to zero, and was subsequently reset to ten percent on February 1, 2019 pursuant to the Commission Order and MCL 460.10a(1)c. On February 1, 2019, I&M began enrolling customers in its choice program and is now fully subscribed at the cap. Currently, I&M is responsible for the capacity of its choice load in its FRR plan under the PJM RAA. If suppliers were to choose to self-supply capacity, then that capacity would also need to be included in I&M's FRR plan. Constellation NewEnergy Inc. is currently the only AES serving load in I&M's service territory.

Indiana Michigan Power Company's capacity demonstration indicates that it has already satisfied PJM's requirements for planning years 2021/22 through 2023/24 and that it expects to meet PJM's requirements for planning year 2024/25.

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<sup>22</sup> [PJM Reestablishes Capacity Auction Schedule](#), November 19, 2020, accessed 03/12/2021.

<sup>23</sup> [September 13, 2018 MPSC Order](#) in Case No. U-20154, accessed 03/14/2018.

**Figure 4: Indiana Michigan Power Company Capacity Demonstration Summary**

<b>Item</b>	<b>PY 2021/22</b>	<b>PY 2022/23</b>	<b>PY 2023/24</b>	<b>PY 2024/25</b>
Total Planning Reserve Margin (expected reserves), UCAP MW	4,325	4,386	4,386	4,386
Total Company Owned Generation, MW	3,993	4,034	3,400	3,400
Total Demand Response Resources (treated as capacity), UCAP MW	304	369	369	369
Total PPA, UCAP MW	223	280	618	618
Total Planning Resources, MW	4,520	4,683	4,387	4,387
UCAP Surplus / (Shortfall), MW	195	297	1	1

In addition to I&M’s capacity demonstration, Staff also reviewed information for approximately 231.9 MW of cooperative and municipal utility obligations in the Michigan portion of PJM’s territory for planning year 2024/25.

Based upon its review, Staff expects that the LSEs in the Michigan portion of PJM will continue to meet the PJM capacity obligations based on information included in individual capacity demonstrations and the current level of surplus capacity in the PJM market. With such an abundance of reserve resources, if I&M were to encounter an unanticipated shortfall in the immediate future, Staff expects that it could easily be accommodated through the procurement of some amount of these reserve resources through market purchases. As market conditions may change over time, Staff will continue to monitor the resource adequacy of the PJM region overall as well as the capacity plans of Michigan LSEs located within the PJM territory. Staff will continue to monitor I&M’s capacity plans and expects to work with the Company to update its capacity demonstration after PJM’s next BRA. As reaffirmed in the Company’s Integrated Resource Plan filed in Case No U-20591<sup>24</sup> Staff does not anticipate I&M to have any issues meeting capacity obligations.

## **LSE Capacity Demonstration Results (PY 2024/25)**

Staff appreciates the time and effort made by all Michigan LSEs to comply with the provisions of MCL 460.6w, as well as to comply with the questions, audits, contract reviews, and requests for additional information throughout this process. The LSE capacity demonstration results are reported for planning year 2023/24 because, following the initial capacity demonstration which covered four years, only the fourth year forward is required for compliance. As previously described in its September 15, 2017 Order in Case No. U-18197, the Commission requested a table be included in this report that identifies the capacity by type for each individual electric

<sup>24</sup> MPSC Case No. U-20591, Direct Testimony of John Torpey, p. 15.



provider without revealing the identity of any specific electric provider. The requested table with a breakdown for each electric provider that filed a capacity demonstration is included as Appendix A. In addition to the breakdown by individual supplier, Staff reports the following aggregate results in Figure 5 below.

**Figure 5: Resource Breakdown (%) by Supplier Type Planning Year 2024/25**

<b>Supplier Type</b>	<b>Owned</b>	<b>DR</b>	<b>Contract - PPA</b>	<b>Contract - ZRC</b>	<b>Auction</b>
Muni/Co-Op Aggregate	77.9%	0.1%	10.5%	7.9%	3.6%
AES Aggregate	3.0%	0.0%	8.2%	85.1%	3.7%
Utility Aggregate	77.8%	6.5%	15.6%	0.1%	0.0%

### Demand Response

As part of its analysis, Staff reviewed the LSEs’ DR programs as an optional source of capacity. When used, a reduction in demand through DR programs offsets a portion of an LSE’s capacity needs. LSEs can utilize interruptible DR during critical peak times to quickly respond to bulk electric system needs, which can delay future capital investment in new generation. Behavioral DR programs allow the utility to lower its peak demand forecast, thus mitigating the need for an equal of amount supply side resources.

Demand response played a prominent role in LSEs’ integrated resource plan filings, where DR is required to be considered along with traditional supply side resources for meeting capacity needs. MCL 460.6t directs Staff to complete a statewide study of DR potential in Michigan every five years, and the most current state of Michigan demand response potential study was issued on September 29, 2017.<sup>25</sup> Michigan is currently working with GuideHouse on conducting the next DR and Energy Waste Reduction potential study. In addition, the Commission approved Michigan Integrated Resource Planning Parameters on November 21, 2017 in Case No. U-18418 that include provisions regarding including DR options in future integrated resource plans.

By planning year 2024/25, Consumers Energy and DTE Electric are forecasting increased DR levels to support capacity through the expansion of existing programs. The DR levels assumed in both Consumers Energy’s and DTE Electric’s IRPs are reflected in their capacity demonstration filing. Consumers Energy forecasted growth in its Smart Thermostat program, which began last year, as well as its Commercial and Industrial Demand Response program. DTE Electric has a forecasted growth in its Programable Controllable Thermostat

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<sup>25</sup>[State of Michigan Demand Response Potential Study Technical Assessment](#), Applied Energy Group, September 29, 2017, accessed 03/22/2020.

DR program as well as other new DR pilots. Staff will continue to monitor these plans and the use of DR in Michigan for the foreseeable future.

## ZRC Contracts

In U-18441, Staff recommended that forward ZRC contracts to be utilized for capacity demonstration purposes specify delivery of the ZRCs in the MISO Module E Capacity Tracking (MECT) tool prior to the applicable PRA auction. All new forward ZRC contracts were audited by Staff this year, and all complied with Staff's requested delivery terms, allowing Staff to audit the ZRC transfers each year prior to the PRA.

An important thing to note is that ZRCs are defined in MISO's tariff and are created in the prompt year when UCAP for supply-side and demand-side resources are converted into ZRCs in the MISO MECT. ZRCs for any year further out than the prompt year are projected and do not become "real" ZRCs until the prompt year. ZRCs are fungible products that can be sold or transferred, and in some cases, sold more than once. The characteristics of ZRCs allow for them to be easily traded and tracked within the MISO MECT. MISO has a view into the source of ZRCs and transfers of those ZRCs that occur prior to the PRA in the prompt year, and those ZRC transfers can be audited by Staff as a secondary check on the ZRC contracts utilized in the capacity demonstrations.

At this point in time, the overall amount of ZRC contracts included in capacity demonstration filings do not impact Staff's ability to continue to make forward resource adequacy projections on a zonal basis. Staff will continue to monitor and audit ZRC contracts and ZRC transfers within the MECT going forward.

## AES Load Switching

For this year's report, there were no AESs that were required to file an amended or supplemental capacity demonstration. Like last year, Staff requested that any AES who experienced load switching during this time provide a signed affidavit confirming the increase or reduction in their load compared to the PLC data provided by the utility with their capacity demonstration that contained the amount of load switching for each planning year. Each supplier contracting for additional customer load provided a copy of its affidavit confirming this transaction to the supplier that was losing the load to be accounted for in both suppliers' demonstrations. For this filing year, all of the load switching had occurred prior to the filing date. Energy Harbor LLC f/k/a FirstEnergy Solutions also filed a confidential affidavit showing a load loss due to a business closure, which Staff reviewed and accepted.

## LSE Compliance with Capacity Demonstration Requirements

All LSEs that filed capacity demonstrations in Case No. U-20886 have met the requisite levels of planning resources for planning year 2024/25. Staff highlights a few issues that it will continue to monitor in the next section.

## Other Issues

### **FERC Order No. 2222<sup>26</sup>**

In addition to aggregation of DR, FERC has issued Order No. 2222. This rule enables Distributed Energy Resources (DER) to be aggregated and participate in regional wholesale markets in a similar manner to aggregated DR as a load modifying resource, but in contrast to DR, DERs may also participate as an energy resource and not just a capacity or ancillary market resource. The tariff will need to be designed and available to aggregated blocks of resources that do not exceed 100 kW but there are no minimum or maximum limits on individual DERs. This rule does not apply to smaller utilities whose electric output was 4 million MWh or less in the preceding year unless the relevant electric retail regulatory authority allows it. Currently compliance with this rule is due July 19, 2021, but MISO has requested a 9-month extension to April of 2022.

### **COVID-19 Crisis**

In March of 2020, Michigan experienced its first medical cases in the global novel coronavirus pandemic (COVID-19), which resulted in a partial lockdown to prevent the spread of the virus over the following year of which the MPSC was involved in.<sup>27</sup> The COVID-19 pandemic had wide-ranging social and economic impacts, which are difficult to reflect fully in long-term capacity positions. Some reported numbers may be affected in this case, including differences between residential and commercial/industrial loads, delays in facility construction, and flatter demand response trends. Staff does not expect these to impact the capacity position of Michigan over the evaluation period.

### **Polar Vortex 2021**

In the middle of February 2021, Texas was hit with several winter storms that left more than 4.5 million houses without power.<sup>28</sup> The Electric Reliability Council of Texas (ERCOT) determined that, at its worst point, nearly half of the power available to the grid went offline due to fuel supply shortages and/or freezing issues at various plants. The unfortunate situation in Texas should not have any direct impact on the Michigan grid, but it does serve as a lesson in reliability, resiliency, and energy diversification.

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<sup>26</sup> [FERC Order No. 2222](#), October 6, 2020, accessed on 03/16/2021.

<sup>27</sup> [MPSC COVID-19 Information Page](#), accessed 03/16/2021.

<sup>28</sup> [Millions Without Power in Texas](#), Time, February 17, 2021, accessed on 03/12/2021.

## Conclusion and Recommendations

All Michigan load serving entities required to file capacity demonstrations with the Michigan Public Service Commission for planning year 2024/25 pursuant to MCL 460.6w and the August 2020 Commission Order in Case No. U-20886 have filed. Staff has audited the filings, contracts, and other materials and finds that all Michigan LSEs have satisfied the capacity demonstration requirements and have procured appropriate levels of resources for planning year 2024/25.

Staff appreciates the cooperation of all Michigan LSEs with respect to this process and the willingness to provide sensitive data and answer questions necessary for Staff to complete its review. Staff opines that the process continues to become more efficient for both Staff and LSEs. To help accommodate further process efficiency improvements for future capacity demonstrations, Staff has the following comment as stated below.

Staff expects to continue monitoring the discussions taking place regarding changes to the MISO resource adequacy construct from annual to seasonal through the RASC. Once finalized, Staff expects it will work with the Commission and stakeholders to determine the most appropriate way to meet the requirements of MCL 460.6w(8) in light of these changes.

## Appendix A

**Figure 6: Planning Year 2024/25 Resource Breakdown (%) by Individual Supplier<sup>29</sup>**

LSE	Owned	DR	Contract - PPA	Contract - ZRC	Auction
Supplier 1	48%	52%	0%	0%	0%
Supplier 2	0%	0%	100%	0%	0%
Supplier 3	33%	0%	67%	0%	0%
Supplier 4	96%	0%	3%	1%	0%
Supplier 5	69%	0%	16%	7%	7%
Supplier 6	0%	0%	0%	100%	0%
Supplier 7	0%	0%	0%	100%	0%
Supplier 8	72%	0%	11%	11%	6%
Supplier 9	0%	0%	0%	100%	0%
Supplier 10	77%	0%	22%	0%	0%
Supplier 11	0%	0%	100%	0%	0%
Supplier 12	0%	0%	100%	0%	0%
Supplier 13	0%	0%	0%	100%	0%
Supplier 14	29%	37%	33%	0%	0%
Supplier 15	0%	0%	100%	0%	0%
Supplier 16	0%	0%	100%	0%	0%
Supplier 17	0%	0%	0%	100%	0%
Supplier 18	59%	0%	0%	41%	0%
Supplier 19	0%	0%	36%	0%	64%
Supplier 20	64%	8%	28%	0%	0%
Supplier 21	0%	0%	100%	0%	0%
Supplier 22	90%	8%	1%	0%	0%
Supplier 23	0%	0%	0%	100%	0%
Supplier 24	10%	7%	83%	0%	0%
Supplier 25	0%	0%	0%	100%	0%

<sup>29</sup> Suppliers (municipal and cooperative electric utilities) that combined their capacity resources are shown as one supplier in the above figure. The total number of suppliers may vary from year to year based on changes to which suppliers combine their capacity demonstrations as well as new suppliers or suppliers no longer serving load in Michigan.

<b>MPSC Case No.:</b>	U-20836
<b>Requestor:</b>	AG
<b>Question No.:</b>	AGDE-3.100a
<b>Respondent:</b>	J. Morren
	1 of 1

**Question:** Refer to page 39, lines 5-13 of Mr. Morren’s direct testimony. Please:  
a. Provide the forecasted cost per MMBtu of hydrogen generated from the hydrogen facility in each of the first three years of full operation based on a cost-of-service model reflecting what customers would pay in revenue requirement. Provide a copy of the analysis in Excel with formulas intact.

**Answer:** This analysis was not performed.

**Attachment:** None.

<b>MPSC Case No.:</b>	U-20836
<b>Requestor:</b>	AG
<b>Question No.:</b>	AGDE-5.128
<b>Respondent:</b>	S. Burgdorf
	1 of 1

**Question:** Refer to page 23, lines 11-25 of Mr. Burgdorf's direct testimony. Please confirm that the NPVRR for the Belle River Power Plant (BRPP) retirement analysis assumes that sufficient capacity will be available to replace the capacity of the retired plant at the assume prices.

If confirming, please provide a copy of any analysis performed by the Company or MISO that sufficient capacity would be available to replace the retired capacity under each of the four scenarios. If not confirming, explain what assumption you made on replacement capacity.

**Answer:** The capacity prices assumed in the NPVRR for Belle River Power Plant provide a range of possible outcomes in the future. It is assumed that replacement capacity would be procured at those prices for each scenario. No analysis has been performed on whether sufficient capacity would actually exist and able to be procured. If no capacity exists to be procured, then the price scenario of 100% CONE would apply.

**Attachment:** *None*

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

**SETTLEMENT AGREEMENT**

Pursuant to MCL 24.278 and Rule 431 of the Michigan Administrative Hearing System’s Rules of Practice and Procedure before the Michigan Public Service Commission (“MPSC” or the “Commission”), the undersigned parties agree as follows:

WHEREAS, on June 30, 2021 Consumers Energy Company (“Consumers Energy” or the “Company”) filed an Application requesting approval of the Company’s Integrated Resource Plan (“IRP”) pursuant to Section 6t of 2016 PA 341, MCL 460.6t, the Commission’s June 7, 2019 Order Approving Settlement Agreement in Case No. U-20165, and all other orders and applicable law. The Company filed testimony and exhibits in support of its positions concurrently with its Application.

WHEREAS, the initial prehearing conference was held on July 22, 2021 before Administrative Law Judge (“ALJ”) Sally L. Wallace. Beyond the Company, the parties to the IRP are: the MPSC Staff (“Staff”); the Attorney General; Hemlock Semiconductor Operations, LLC (“HSC”); the Biomass Merchant Plants (“BMPs”)<sup>1</sup>; Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club (“MNS”); Great Lakes Renewable Energy

<sup>1</sup> The BMPs consist of: Cadillac Renewable Energy, LLC, Genesee Power Partners Limited Partnership, Decker Energy-Grayling, LLC, Hillman Power Company, LLC, Tondu Corporation, National Energy of Lincoln, LLC, f/k/a Viking Energy of Lincoln, LP and National Energy of McBain, f/k/a Viking Energy of McBain, LLC.



Association (“GLREA”), Environmental Law and Policy Center, the Ecology Center, Vote Solar, and the Union of Concerned Scientists (collectively, the Clean Energy Organizations (“CEO”)); Residential Customer Group (“RCG”); Association of Businesses Advocating Tariff Equity (“ABATE”); Michigan Energy Innovation Business Council, Institute for Energy Innovation, and the Clean Grid Alliance (collectively, “Michigan EIBC/IEI/CGA”); Energy Michigan, Inc. (“Energy Michigan”); Midland Cogeneration Venture Limited Partnership (“MCV”); Michigan Electric Transmission Company, LLC (“METC”); Michigan Public Power Agency (“MPPA”); Wolverine Power Supply Cooperative (“Wolverine”); the Citizens Utility Board (“CUB”); the Mackinac Center for Public Policy (“Mackinac”); and the Urban Core Collective (“UCC”). 1 TR 11-12, 22.

WHEREAS, Consumers Energy filed testimony and exhibits requesting approval of the Company’s IRP Proposed Course of Action (“PCA”) in its entirety, as the most reasonable and prudent means of meeting the Company’s energy and capacity needs through 2040. The Company specifically requested the Commission to make the following determinations:

- (i.) Approve Consumers Energy’s PCA, which is inclusive of all proposals presented by the Company in this case, including the battery deployment program, as the most reasonable and prudent means of meeting the energy and capacity needs of the Company and its customers;
- (ii.) Approve the Company’s acquisition and proposed purchase costs for the New Covert Generating Facility (“Covert Plant”) and Dearborn Industrial Generation (“DIG Plant”), the Livingston Generating Station (“Livingston Plant”), and the Kalamazoo River Generating Station (“Kalamazoo Plant”), in the manner proposed by the Company, and proposed Energy Waste Reduction (“EWR”), Demand Response (“DR”), and Conservation Voltage Reduction (“CVR”) costs which will be commenced by the Company within three years following the Commission’s expected approval of the Company’s IRP;
- (iii.) Approval of the selection and proposed purchase of the DIG, Kalamazoo, and Livingston plants, by the Company from its affiliate, CMS Enterprises. The transaction was a result of a competitive solicitation and is compliant with the Commission’s Code of Conduct requirements. In the alternative, while complying with all other provisions of the Code of Conduct, the Company

requests a waiver of the asset transfer provision of the Code of Conduct, Mich Admin Code R 460.10108(4), for the acquisition of the DIG, Livingston, and Kalamazoo plants, from CMS Enterprises;

- (iv.) Approve the Company's proposal to recover the unrecovered book balances of D.E. Karn ("Karn") Units 3 and 4 and J.H. Campbell ("Campbell") Units 1, 2, and 3, including decommissioning costs, through regulatory asset treatment, with full return, over the design lives of those units;
- (v.) Approve the Company's proposals to: (i) defer employee retention costs related to the proposed accelerated retirements of Karn Units 3 and 4 and Campbell Units 1, 2, and 3, and (ii) defer retirement transition costs for future recovery;
- (vi.) Approve the Company's proposed modifications to its Public Utility Regulatory Policies Act of 1978 ("PURPA") construct and the Company's proposed competitive procurement process and the use of that competitive procurement process for: (i) determining PURPA avoided costs rates, and (ii) determining and addressing the Company's capacity position under PURPA;
- (vii.) Determine that the Company has no PURPA capacity need so long as the Company is implementing the PCA, with the competitive procurement process proposed by the Company; and
- (viii.) Approve the Company's proposed Financial Compensation Mechanism ("FCM") for any new, or newly amended, Power Purchase Agreements ("PPAs") entered into by the Company.

Staff and other intervening parties filed testimony and exhibits addressing various issues.

NOW THEREFORE, for purposes of settlement of Case No. U-21090, the undersigned parties agree as follows:

1. The parties agree that the Company's PCA, as modified in this Settlement Agreement, should be approved as the most reasonable and prudent means of meeting the Company's energy and capacity needs over the 5-year, 10-year, and 15-year time horizons. The parties agree that the Company will file its next IRP consistent with the requirements of MCL 460.6t.

2. The parties agree that the PCA shall include the Company's proposed purchase of the Covert Plant in 2023 but shall not include the ownership of the DIG, Kalamazoo, and

Livingston plants. The parties agree that the identified capital costs that the Company will incur for DR (\$23,751,000), CVR (\$9,736,315), and the purchase of the Covert Plant (\$815 million) in the next three years (June 2022 – June 2025) are reasonable and prudent and approved for cost recovery purposes and will be included in rates in a future Company rate case consistent with MCL 460.6t(11) and (17). The parties further agree to the approval of the projected capacity value provided by the Covert Plant and the DR (projected to achieve a total of 641 MW (657 Zonal Resource Credits (“ZRCs”)) by 2025), CVR (projected to achieve 136,351 MWh savings by 2025, 56.81 MW savings by 2025), and EWR (projected to achieve 545,305 MWh savings in 2025, 879 MW savings by 2025) resources included in the PCA during the next three years. The parties further agree that the Company shall continue to file an annual reporting template with the Commission addressing the implementation of the approved DR and CVR resources above.

3. The parties agree to the approval of the battery deployment program as proposed by Company witness Richard T. Blumenstock. The parties agree that the Company will conduct stakeholder outreach to solicit feedback regarding the battery deployment program prior to the issuance of the first battery deployment program competitive solicitation. The approval to recover the costs associated with the batteries acquired in the battery deployment program will be sought in future electric rate cases.

4. The parties agree that (i) Karn Units 3 and 4 will be retired on or before May 31, 2031, absent extraordinary circumstances that require prolonged operation, such as a System Support Resource designation by Midcontinent Independent System Operator, Inc. (“MISO”) or other emergent issues within the Company’s generation portfolio which require continued

operation of Karn Units 3 and 4 to maintain sufficient supply; and (ii) Campbell Units 1, 2, and 3 will be retired on or before May 31, 2025.

5. The parties agree that the Company will not file an application for a financing order for the unrecovered book balance and decommissioning costs of Campbell Units 1, 2, and 3. The parties agree that the Commission will permit Consumers Energy to recover the unrecovered book balance of Campbell Units 1, 2, and 3 through the Company's proposed regulatory asset treatment, with a return equal to the Company's weighted average cost of capital ("WACC") premised on the return on equity approved by the Commission in rate cases prior to the retirement date of those units and a 9.0% return on equity after the retirement date of those units, as part of the Company's electric rates over the current design lives of those units. The 9.0% return on equity will be used to modify the capital structure filed with each rate case and the return on equity will be the only modification to the capital structure used to calculate the return on the regulatory asset after the retirement date of the units. The parties further agree that the Company will be permitted to record a regulatory asset for actual decommissioning spending for Campbell Units 1, 2, and 3, with a return on the regulatory asset, with subsequent rate recovery in a rate case after a review of the reasonableness and prudence of the expenses. Recovery of the associated decommissioning and ash disposal costs will be treated as follows:

- a. The decommissioning costs, less salvage value, related to Campbell Units 1, 2, and 3 and the ash disposal costs related to Campbell Units 1, 2, and 3 will be recorded, as spent, to a regulatory asset; and
- b. The Company may request recovery in future base rate proceedings, and upon Commission determination that the Company has incurred those costs as the result of reasonable and prudent actions, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts.

6. The parties agree that subsequent to the Commission's order approving this Settlement Agreement, the Company shall issue a competitive solicitation ("the One-Time Solicitation") which will include the following parameters:

- a. The One-Time Solicitation will seek projects which will provide the Company with capacity credit in the MISO Zone 7 starting in the 2025 Planning Year;
- b. The One-Time Solicitation will include two all source tranches:
  - i. The first tranche will seek up to 500 ZRCs of capacity and associated energy and renewable energy credits ("RECs"), if applicable, from PPAs with terms up to 10 years. This tranche will seek dispatchable, non-intermittent generation capable of dispatching up or down in every hour of the year in response to wholesale energy market signals, providing capacity which meets the Local Clearing Requirement of MISO Zone 7; and
  - ii. The second tranche will seek up to 200 ZRCs of capacity and associated energy and RECs, if applicable, secured from unaffiliated third parties via PPAs or other third-party agreements that do not result in Company ownership with terms up to 25 years, at the discretion of the bidder. This tranche will seek intermittent resources and dispatchable, non-intermittent clean capacity resources (including battery storage resources), providing capacity which meets the Local Clearing Requirement of MISO Zone 7. This tranche will furthermore take into consideration the ability of the offered capacity to meet the Local Clearing Requirement of MISO Zone 7 for the duration of the contract length. Prior to the issuance of the second tranche portion of the One-Time Solicitation, the Company shall hold a stakeholder meeting including parties to this case and energy storage developers to discuss methods to improve RFPs and response to solicitations with respect to stand-alone storage projects and hybrid-storage projects.
- c. The Company's acquisition of the 700 ZRCs and associated energy and RECs, if applicable, sought in the One-Time Solicitation shall be considered incorporated into the PCA approved in Paragraph 1 of this Settlement Agreement. However, the actual selected bid(s) will be submitted in Case No. U-21090 for Commission approval subsequent to the completion of the One-Time Solicitation;
  - i. In that approval proceeding, the Commission shall: (i) confirm whether the solicitation process followed by the Company is consistent with the requirements of the Settlement Agreement; (ii) grant approval of the recovery of the costs associated with the selected project(s) pursuant to applicable law or make a preliminary finding that the costs associated

with the project(s) that prevail in the solicitation are reasonable and prudent; and (iii) grant any other approvals or findings necessary as required or provided by applicable law.

- d. The One-Time Solicitation will not be used to set the Company's avoided costs rates or capacity needs under PURPA.

7. The parties agree to the approval of the Company's proposed accounting request to defer expense related to the Campbell site severance and retention agreement, utilizing a regulatory asset to record the deferred amounts. The deferred amounts for 2022 will be capped at \$26 million. All amounts deferred for 2022 and beyond will be reviewed in future rate cases. This Settlement Agreement does not permit the Company to defer amounts related to the Campbell site severance and retention agreement outside of 2022.

- a. Consumers Energy will publicly file in Case No. U-21090 its community transition plan for Karn Units 1 through 4 within 150 days of all four Karn Units ceasing operation; and
- b. Consumers Energy will develop a draft community transition plan for the Campbell site. During the development of this draft community transition plan for the Campbell site, Consumers Energy will consult with community-based organizations and community members living in the area surrounding the retired assets on the community transition plan before finalizing and filing it for informational purposes in Case No. U-21090.

8. The parties agree to the extension of the annual competitive bidding process used to acquire the supply-side resource technologies specified in the PCA, as approved in Case No. U-20165 (collectively the "Annual Solicitations" and individually an "Annual Solicitation"), with certain modifications included below:

- a. Qualifying Facilities ("QFs") that the Company has a legal obligation to purchase from under PURPA (such facilities are referred to as "QFs" in this Settlement Agreement), may bid any technology into the Annual Solicitation but will be required to submit an offer consistent with the PPA terms sought in the Annual Solicitation;
- b. The competitive bid process shall be administered by an independent third party. The evaluation criteria and process is to be made available to all bidders submitting responses for the specific technology requested by the

Company, as part of the RFP, to ensure transparency. QFs may bid any technology that meets the requirements of PURPA. A ranking of proposals is to be used by the independent third party and provided to the Company for selection;

- c. In its September 9, 2021 Order in Case No. U-20852 the Commission adopted competitive bidding guidelines titled “Competitive Procurement Guidelines for Rate-Regulated Electric Utilities (Not for PUPRA Compliance) and “Competitive Procurement Guidelines For Rate-Regulated Electric Utilities for PURPA Avoided Cost and Capacity Determination.” The “Objective” of the adopted guidelines provides that when the guidelines are utilized by utilities, it is presumed that resulting projects and contracts are reasonable and prudent and in the event utilities diverge from the guidance provided in the guidelines, it is expected that the utility will provide sufficient justification in order to receive Commission approval and recovery. In the Annual Solicitation process, the Company will follow the Commission’s adopted guidelines, including the ability to diverge from the guidance as provided in the guidelines;
- d. The first competitive solicitation for the Company pursuant to this Settlement Agreement will be conducted no later than December 31, 2022. New full avoided cost rates stemming from each competitive solicitation will be filed with the Commission for review and approval within 30 days of the conclusion of each competitive solicitation;
- e. The Company will seek term lengths for competitively bid projects up to 25 years, at the discretion of the bidder;
- f. The Company will seek to acquire the target amount of capacity identified in the PCA for each Annual Solicitation period and may exceed that target amount depending on the amount of bids, the size of projects bid, cost and value, and variations in project commercial operation dates. Total newly acquired capacity will be reconciled against the amount of capacity projected in the PCA in the Company’s next IRP. (For example, if the Company acquired more capacity than planned, the proposed resource plan in the next IRP would incorporate that additional capacity with a potential reduction in the capacity needed going forward.);
- g. If the Company is unable to meet the target capacity amount identified in the PCA in any given Annual Solicitation, the remaining "open" capacity will not be offered to QFs. The remaining capacity would instead be addressed through the process described in Paragraph 8.f.;
- h. The parties agree and acknowledge that there are supply chain, energy security, labor, and environmental benefits associated with robust, local clean energy manufacturing capabilities. As part of the Company’s competitive bidding process, the parties agree that the Company will, to the extent

reasonably possible, incorporate clear, fair, and transparent criteria in the bid evaluation process to recognize value associated with clean energy supply chain diversification and sustainability, including intended use of Michigan manufactured components and low-carbon manufacturing as verifiable by life cycle assessment and/or disclosure using public, third-party verified environmental product declarations. The Company agrees to consult with parties to the settlement on the details of such bid evaluation criteria. Nothing in this settlement alters the opportunity for stakeholders and potential bidders to review and comment on any new proposed bidding criteria through the process as set forth in the MPSC's competitive bidding guidelines approved in MPSC Case No. U-20852 on September 9, 2021;

- i. The parties agree that the Annual Solicitation process does not restrict the Company's ability to make short-term capacity additions to address capacity shortfalls which cannot reasonably be addressed through the Annual Solicitation process; and
- j. The Company may pursue supply-side resource pilots for new and emerging technologies outside of an Annual Solicitation subject to cost and project approval in its future rate cases.

9. The parties agree that the new capacity that the Company intends to procure through the PCA, in each Annual Solicitation, shall be: (i) acquired through a competitive bidding process; and (ii) approximately 50% will be from PPAs and other third-party agreements that do not result in Company ownership and approximately 50% will be owned by the Company, as acquired through a competitive bidding process. The new capacity acquired from PPAs or other third-party agreements that do not result in Company ownership will not compete against the new capacity which will be owned by the Company. The Company will use commercially reasonable efforts to maintain the 50%/50% proportion for new IRP resources from 2022 through the Company's next IRP proceeding, and in no event shall any given annual solicitation result in the Company owning more than 60% of the new capacity acquired in such solicitation. The Company, in its sole discretion, may also choose to acquire more than 50% of its new capacity from third parties. The parties further agree that the Company's affiliates will



be prohibited from bidding on the portion of the Company's new capacity acquired from third parties.

10. The parties agree to the approval of the extension of the Company's FCM approved in Case No. U-20165 equal to the product of: (i) the annual PPA payment, and (ii) the Company's after-tax WACC based on its total capital structure, which is currently 5.62%, as updated from time to time by the MPSC in electric rate case final orders. The FCM will be applicable to all new PPAs, but will not apply to PPA amendments, PURPA PPAs, and Voluntary Green Pricing PPAs. The Company shall also not receive an FCM on any PPAs executed under the Company's Renewable Energy Plan. The FCM will be subject to the cap, as provided in Attachment A of the Settlement Agreement. The parties agree that nothing in this Settlement Agreement is intended to waive the requirements of MCL 460.6t(15).

11. The parties agree to the extension of the Company's PURPA avoided cost construct, as approved in Case No. U-20165 (based on the Company's Annual Solicitations), with certain modifications included below:

- a. The Company's PURPA avoided cost construct will be subject to review in the Company's future IRP filings, as opposed to separate biennial filings;
- b. QFs 150 kWac and below are eligible to receive full avoided cost rates regardless of the Company's capacity needs;
- c. Within 180 days subsequent to the Commission's approval of this Settlement Agreement, the Company shall initiate stakeholder outreach to develop a simplified agreement, tariff-based program, or other mechanism which will allow QFs 150 kWac and below to receive full avoided cost rates. Subsequent to the completion of the stakeholder outreach, at the earliest practicable date, the Company will file a proposal with the Commission for approval;
- d. When the Company does not have a PURPA capacity need, QFs above 150 kWac, that the Company has a legal obligation to purchase from under PURPA, are eligible to receive the Company's energy-only avoided cost rates. The Company's energy-only avoided cost rates shall be based on a forecast of LMPs for the first 5 years and actual LMPs for years 6 through 10. The

Company's energy-only avoided cost rates shall not include a payment for capacity;

- e. Current existing QFs, at or below the Company's PURPA must-purchase obligation MW threshold, with a PURPA-based PPA with the Company as of January 1, 2019 shall receive new PPAs, regardless of the Company's capacity need, upon the expiration of their current PPAs based on the Company's full avoided cost rates at the time of PPA expiration. QFs that entered a PPA with the Company prior to January 1, 2019 at an amount less than full avoided cost rates, such as reduced avoided cost rates based on the Planning Resource Auction ("PRA") rate and forecasted or actual LMPs and energy-only rates which only include an energy rate and do not provide a payment for capacity, shall not automatically receive a new PPA at the full avoided cost rate when their current PPA expires. QFs that have entered a PPA with the Company after January 1, 2019 are not eligible to receive a new full avoided cost rate PPA with the Company regardless of the Company's capacity need;
- f. QFs that the Company has a legal obligation to purchase from under PURPA, and which are eligible for full avoided cost rates, may select PPA terms up to 20 years; and
- g. QFs up to 5 MWac, that the Company has a legal obligation to purchase from under PURPA, are eligible for the Company's PURPA Standard Offer Tariff and Standard Offer Contract. The terms of the Standard Offer Contract will also be updated from using the MISO methodology for capacity accreditation at the time of PPA execution, to the average of the MISO methodologies at the time of PPA execution and delivery under the PPA. Within 30 days following the Commission's approval of this Settlement Agreement, the Company shall file revised Standard Offer tariff sheets and a revised Standard Offer contract, to reflect the Standard Offer construct and rates approved as part of this Settlement Agreement. Parties shall be given 14 calendar days subsequent to the Company's filing to provide comments to the Commission.

12. The Company has no PURPA capacity need so long as the Company is implementing the Commission-approved PCA, as provided in Paragraph 1, including the competitive Annual Solicitation process for future capacity needs.

13. The parties agree that the Company will donate \$5 million in 2022 to a low-income fund that provides bill assistance to Consumers Energy's electric customers. The Company will also donate \$2 million annually to the same low-income fund each year during the amortization period for the regulatory asset, provided in Paragraph 5 of this Settlement

Agreement, with each annual donation contingent on the Company filing and the Commission approving a Voluntary Revenue Refund (“VRR”). The donations described in this paragraph will not be recovered in rates and Consumers Energy will consult with the Attorney General and Staff on the low-income fund receiving the donations. The Company will provide an annual report to the Commission each year a donation is made. If known, the report will include the number of households served, the number of households over 150% of the federal poverty level (“FPL”), and number under 150% of the FPL. For those households 150% of FPL and under, the report will explain, if known, whether they are receiving the funds because they exhausted other benefits such as the Michigan Energy Assistance Program or State Emergency Relief.

14. In future IRPs, beginning with its next IRP, the Company will (i) collect the necessary data to compute marginal line losses and report these with average line losses and (ii) include marginal line losses and avoided transmission and distribution costs in its evaluation of all distributed resources, including residential DR potential.

15. Consumers Energy agrees to develop a distributed generation as a resource model approach that considers economic distribution connected solar to be modeled by bundling resources installed at the customer level to compare the total economic costs to the utility of distributed generation as a resource to other selectable supply-side resources, consistent with the methodology used for EWR. The Company will develop a model that accounts for all utility costs and/or incentives associated with participating and non-participating distributed generation customers. The Company agrees to present the model approach for stakeholder review and feedback prior to the next IRP. The model approach, including any incorporated stakeholder feedback, will be included into the Company’s next IRP.

16. The parties agree that Consumers Energy's IRP set forth a proposal to be Carbon Neutral by 2040 and retire all coal generation by 2025, 14 years ahead of the original timeline. These retirements include two substantial coal and gas units totaling approximately 2,000 MW. To replace the capacity, Consumers Energy has proposed adding existing natural gas-fired generation and plans to add about 8,000 MW of solar generation by 2040, to dramatically reduce the use of fossil fuel resources. The next IRP should consider transmission and how it can facilitate the mitigation of reliability and economic impacts to the electric system. The parties also agree that strategic investment in electric transmission needs continual assessment to understand the role of transmission in allowing for the most economic path to meeting the state's energy goals while complementing Michigan's Load Serving Entities' ("LSE") objectives. Michigan is transitioning its generation portfolio and must take the appropriate steps to increase system reliability, resiliency, flexibility, and affordability. Michigan will be better positioned by taking a forward-looking approach regarding resource adequacy. The state should continue to recognize and support the value of a multitude of resources such as Solar, Wind, DR, and Distributed Energy Resources which assist in an "all of the above" approach. Transmission is essential in delivering the reliability of these resources. The value of transmission can be even further realized by leveraging those transmission resources to better assist the Consumers Energy IRP. This will allow MISO LRZ 7 to access broader pools of generation resources, be better situated for future demands placed on the system, mitigate unnecessary risks, and increase performance of those "all of the above" resources to serve the demands of Michigan's customers reliably and economically.

17. The parties agree that the Company will include the following analysis in its next IRP:

- a. The Company will provide total emissions, in lbs or tons, and rate of emissions, in lbs or tons per MWh and per MMBtu, for each owned power plant unit, or units that that the Company has a power purchase agreement with, for the last 5 years of operation (for existing units) and projected for the next 5 years (for all units) for the following pollutants: carbon dioxide, nitrogen oxides, sulfur dioxide, volatile organic compounds (“VOCs”), and primary particulate matter (“PM2.5”);
- b. The Company will calculate the annual PM2.5-related health impacts associated with each power plant’s emissions. The modeling will include the impacts from primary PM2.5 emissions and PM2.5 precursors emissions (nitrogen oxides, sulfur dioxide, VOCs). The Company will use one model to evaluate the number and economic value of PM2.5-related health impacts of these emissions. The Company may use COBRA or BenMAP (which will require pollutant change inputs from another model such as InMAP) for these calculations, or models that are of equal or greater complexity and accuracy. The Company will report the total number and economic value of PM2.5-related health impacts across the US for the chosen model and spatially by Michigan county or at a higher resolution;
- c. The Company will use the MiEJScreen mapping and screening tool, or, if the MiEJScreen tool is not yet finalized, the EPA Environmental Justice Screening and Mapping Tool (“EJSCREEN”), to assess populations in a 1-mile and 3-mile buffer around each power plant location, including reporting total populations and any indicators and total index results above the 75th percentile;
- d. The Company will report projected low-income energy efficiency participation levels, low-income load-reduction data, and publicly available rooftop solar adoption rates. If available, information on rooftop solar adoption by low-income customers will be provided;
- e. The Company will include a narrative discussion of how the data obtained in a-d were considered by the utility; and
- f. To the extent that the Commission formally adopts revised Integrated Resource Plan Filing Requirements and/or revised Michigan Integrated Resource Planning Parameters that address environmental emissions, health impacts from emissions, or environmental justice, such filing requirements will supersede the terms of this Paragraph 17.

18. The parties agree that the Company will take the following steps to engage and gather input from the public prior to the filing of its next IRP with the Commission:

- a. Host meetings about the topic of the filing at a variety of times, during the daytime and the evening, with the Company providing equivalent content and equivalent and sufficient time for robust public response at each session;
- b. Host meetings about the topics in the filing with a roughly equal mix between (i) in-person meetings and (ii) virtual or hybrid meetings;
- c. For the duration of the proceedings before the MPSC, make available on its website recordings of (i) all virtual or hybrid meetings and (ii) to the extent feasible, any portion of an in-person meeting in which the Company is (a) addressing all participants in the meeting and/or (b) receiving public feedback and/or questions in a format intended to be heard by all participants in the meeting at the same time;
- d. When requested 10 business days prior to a meeting, provide translations of materials for the benefit of those communities whose first language is not English, based on the demographics of the community;
- e. When requested within 30 days subsequent to a meeting, the Company will use best efforts to provide a translation of recordings of the community meeting in a language specified by the person requesting the translation. Such translation recordings will be provided within 15 business days, subject to the Company's best efforts, after the request is received. If the Company is unable, after a good faith effort, to find or reasonably engage the services of a translator capable of translating the recording into the language requested, the Company will not be obligated to provide the translation;
- f. When requested at least 10 business days prior to an in-person meeting, the Company will use best efforts to include at least one live interpreter who can translate in the requested language. If the Company is unable, after a good faith effort, to find or reasonably engage the services of a translator capable of translating the meeting into the language requested, the Company will not be obligated to provide the translation;
- g. Coordinate with community-based organizations when organizing and promoting meetings about the filing. The Company will solicit input regarding the time, place, and manner of the meetings from the community organizations, in addition to any other meetings the Company wishes to hold of its own accord;
- h. Use best efforts to present the details of the integrated resource planning process in accessible, non-technical language that includes, but is not limited to, descriptions of the impacts of the Company's plans on communities, the environment, and public health;
- i. Include in its filings a concise general statement of the basis and purpose of the comments received by the Company and how the Company considered,

addressed, or rejected the issues raised in those comments in the IRP (as practicable); and

- j. Subsequent to the issuance of the Commission's order approving this Settlement Agreement, the Company agrees to meet with UCC to discuss potential stakeholder outreach prior to or subsequent to future electric rate case filings.

19. The parties agree that the Company will do the following with respect to combined heat and power ("CHP") resources:

- a. Within 180 days of the effective date of the Commission's order approving the settlement, the Company will initiate a voluntary survey among its commercial and industrial customers to gauge interest in CHP (the "CHP survey"), with survey responses intended to be used by the Company to support the evaluation of: (1) the types of CHP that customers prefer, with regard to size, technology and overall configuration, on both the demand side and supply side, including co-ownership arrangements and other potential partnerships with the Company, and: (2) non-confidential information regarding locations within the Consumers Energy territory that may be most appropriate for deployment of CHP. The CHP survey will be conditioned on respondent approval of the public release of all information provided by the respondent in response to the survey. Nothing in this section is intended to require the public release of any confidential and/or commercially sensitive customer or Company information;
- b. Within 360 days of the effective date of the Commission's order approving the settlement, the Company will share the results of the CHP survey in the Case No. U-21090 e-docket, including a summary of the types of CHP that customers prefer, with regard to size, technology, and overall configuration, on both the demand side and supply side, including co-ownership arrangements and other potential partnerships with the Company; and a summary of non-confidential information regarding locations within the Company's territory that may be most appropriate for deployment of CHP, according to the CHP survey results;
- c. In its next IRP proceeding, the Company will model behind-the-meter CHP representative of a demand-side resource based upon the results from the CHP survey as appropriate; and
- d. In its next IRP proceeding, the Company will model front-of-the-meter CHP configurations based upon the results from the CHP survey as appropriate.

20. This settlement is entered into for the sole and express purpose of reaching a compromise among the parties. All offers of settlement and discussions relating to this settlement are, and shall be considered, privileged under MRE 408. If the Commission approves this Settlement Agreement without modification, neither the parties to this Settlement Agreement nor the Commission shall make any reference to, or use, this Settlement Agreement or the order approving it, as a reason, authority, rationale, or example for taking any action or position or making any subsequent decision in any other case or proceeding; provided, however, such references may be made to enforce or implement the provisions of this Settlement Agreement and the order approving it.

21. This Settlement Agreement is based on the facts and circumstances of this case and is intended for the final disposition of Case No. U-21090. So long as the Commission approves this Settlement Agreement without any modification, the parties agree not to appeal, challenge, or otherwise contest the Commission order approving this Settlement Agreement. Except as otherwise set forth herein, the parties agree and understand that this Settlement Agreement does not limit any party's right to take new and/or different positions on similar issues in other administrative proceedings, or appeals related thereto.

22. This Settlement Agreement is not severable. Each provision of the Settlement Agreement is dependent upon all other provisions of this Settlement Agreement. Failure to comply with any provision of this Settlement Agreement constitutes failure to comply with the entire Settlement Agreement. If the Commission rejects or modifies this Settlement Agreement or any provision of the Settlement Agreement, this Settlement Agreement shall be deemed to be withdrawn, shall not constitute any part of the record in this proceeding or be used for any other purpose, and shall be without prejudice to the pre-negotiation positions of the parties.



23. The parties agree that approval of this Settlement Agreement by the Commission would be reasonable and in the public interest.

24. The parties agree to waive Section 81 of the Administrative Procedures Act of 1969 (MCL 24.281), as it applies to the issues resolved in this Settlement Agreement, if the Commission approves this Settlement Agreement without modification.

WHEREFORE, the undersigned parties respectfully request the Commission to approve this Settlement Agreement on an expeditious basis and to make it effective in accordance with its terms by final order.


MICHIGAN PUBLIC SERVICE COMMISSION STAFF

By: Spencer Sattler Digitally signed by Spencer  
Sattler  
Date: 2022.04.19 14:00:30 -04'00'

Date: April 19, 2022

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Assistant Attorneys General  
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Lansing, MI 48909

CONSUMERS ENERGY COMPANY

By:  Digitally signed by  
Robert W. Beach  
Date: 2022.04.19  
11:44:05 -04'00'

Date: April 19, 2022

Shaun M. Johnson (P69036)  
Bret A. Totoraitis (P72654)  
Robert W. Beach (P73112)  
Anne M. Uitvlugt (P71641)  
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Attorneys for Consumers Energy Company

ATTORNEY GENERAL, DANA NESSEL

By: **Celeste R. Gill** Digitally signed by  
Celeste R. Gill  
Date: 2022.04.19  
15:03:37 -04'00'

Date: \_\_\_\_\_

Celeste Gill, Esq.  
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GREAT LAKES RENEWABLE ENERGY ASSOCIATION

By: *Don L. Keskey*  
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Brian W. Coyer, Esq.  
Public Law Resource Center PLLC  
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East Lansing, MI 48823

Date: April 19, 2022


MICHIGAN ENVIRONMENTAL COUNCIL

By:  Digitally signed by  
Christopher M. Bzdok  
Date: 2022.04.19  
12:05:00 -04'00'

Date: April 19, 2022

Christopher M. Bzdok, Esq.  
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NATURAL RESOURCES DEFENSE COUNCIL

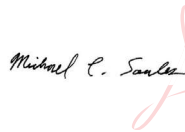
By:  Digitally signed by  
Christopher M. Bzdok  
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12:05:50 -04'00'

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Traverse City, MI 49686

Date: April 19, 2022

SIERRA CLUB

 Digitally signed by  
Michael C. Soules  
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12:08:37 -04'00'

By: \_\_\_\_\_


Michael C. Soules  
Earthjustice  
1001 G Street NW, Suite 1000  
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Date: April 19, 2022

Christopher M. Bzdok, Esq.  
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CITIZENS UTILITY BOARD OF MICHIGAN

 Digitally signed  
by Holly L. Hillyer  
Date: 2022.04.19  
12:29:05 -04'00'

By: \_\_\_\_\_

Abigail R. Hawley, Esq.  
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Traverse City, MI 49686

Date: April 19, 2022

MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL, INSTITUTE FOR ENERGY  
INNOVATION, AND CLEAN GRID ALLIANCE

By: **Laura A. Chappelle**  
Digitally signed by  
Laura A. Chappelle  
Date: 2022.04.19  
12:42:00 -04'00'

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Laura A. Chappelle, Esq.  
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Timothy J. Lundgren, Esq.  
Potomac Law Group  
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Lansing, MI 48933

Date: April 19, 2022

MICHIGAN ELECTRIC TRANSMISSION COMPANY, LLC

By: **Richard**  
**Aaron**  
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Dykema  
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Date: April 19, 2022

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ENVIRONMENTAL LAW & POLICY CENTER, VOTE SOLAR, ECOLOGY CENTER, AND  
UNION OF CONCERNED SCIENTISTS

By:   
Margrethe Kearney, Esq.  
Environmental Law & Policy Center  
146 Monroe Ctr St. NW, Ste 422  
Grand Rapids, Michigan 49503

Date: April 19, 2022

HEMLOCK SEMICONDUCTOR OPERATIONS LLC

By: **Jennifer Utter Heston**  Digitally signed by Jennifer Utter Heston  
Date: 2022.04.19 13:15:32 -04'00'

Date: April 19, 2022

Jennifer Utter Heston, Esq.  
Fraser Trebilcock Davis & Dunlap, P.C.  
124 West Allegan, Suite 1000  
Lansing, MI 48933

URBAN CORE COLLECTIVE



By:

\_\_\_\_\_  
Nicholas Leonard, Esq.  
Andrew Bashi, Esq.  
Great Lakes Environmental Law Center  
Local Counsel for Urban Core Collective  
4444 2nd Avenue  
Detroit, MI, 48201

19-April-2022

Date:

\_\_\_\_\_

Mark N. Templeton, Esq.  
Robert A. Weinstock, Esq.  
University of Chicago Law School –  
Abrams Environmental Law Clinic  
6020 South University Avenue  
Chicago, IL 60637

The following parties do not wish to be signatories to this Settlement Agreement; however they have agreed to sign below to indicate non-objection to the Settlement Agreement.


MICHIGAN PUBLIC POWER AGENCY

By: Nolan J. Moody Digitally signed by Nolan J. Moody  
Date: 2022.04.19 12:19:10 -04'00'

Date: April 19, 2022

Nolan J. Moody, Esq.  
Peter H. Ellsworth, Esq.  
Dickinson Wright PLLC  
123 W. Allegan Street, Suite 900  
Lansing, MI 48933

MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

By: **John Janiszewski**  
  
John A. Janiszewski, Esq.  
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201 Townsend Street, Suite 900  
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Digitally signed by: John Janiszewski  
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Date: 2022.04.20 09:49:53 -04'00'

Date: April 20, 2022



# ATTACHMENT A

## ATTACHMENT A

<b>Contract Year</b>	<b>Total Rate (\$/MWh)</b>
2019	\$ 55.54
2020	\$ 57.49
2021	\$ 59.38
2022	\$ 61.28
2023	\$ 63.25
2024	\$ 65.24
2025	\$ 67.24
2026	\$ 69.24
2027	\$ 71.23
2028	\$ 73.18
2029	\$ 75.08
2030	\$ 76.95

<b>MPSC Case No.:</b>	U-20836
<b>Requestor:</b>	GLREA
<b>Question No.:</b>	GLREADE-5.51c
<b>Respondent:</b>	J. Morren
	1 of 1

**Question:** Please refer to Witness Morren's direct at 35:  
c. If hydrogen were stored in Michigan in geological formations, how does DTEE envision it getting transported to the BWEC plant?

**Answer:** The Company has not evaluated the transport of hydrogen gas to and from underground storage facilities.

**Attachment:** None

<b>MPSC Case No.:</b>	U-20836
<b>Requestor:</b>	GLREA
<b>Question No.:</b>	GLREADE-5.51d
<b>Respondent:</b>	J. Morren
	1 of 1

**Question:** Please refer to Witness Morren's direct at 35:  
d. Where is the closest geological formation potentially suited to large quantity hydrogen storage to the BWEC power plant?

**Answer:** The Company is aware that natural gas is stored around BWEC. At this time, the Company has not identified specific locations of geological formations ideally suited to store large quantities of hydrogen.

**Attachment:** None

**MPSC Case No.:** U-20836  
**Requestor:** MNSC  
**Question No.:** MNSCDE-1.19ai  
**Respondent:** J. Morren  
**Page:** 1 of 1

**Question:** Refer to WP-JLM-BLRPP. For each of Belle River Units 1 and 2 and any common areas for the entire Belle River site:  
a. Please produce the most recent forecast of the unit's or common area's:  
i. non-environmental capital costs

**Answer:** Please see attachment labelled "U-20836 MNSCDE-1.19ai Belle River NPV Capital and OM Input".

**Attachments:** U-20836 MNSCDE-1.19ai Belle River NPV Capital and OM Input

MNSCDE-1.19ai Belle River NPV Capital and OM Input.xlsx

<b>Belle River</b>															
<b>May 2030 Retirement</b>															
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base O&M	52.8	54.4	55.5	56.7	58.1	59.4	60.8	62.3	47.8	6.5	6.7	6.8	7.0	7.2	—
Periodic O&M	10.3	9.6	—	7.1	7.3	—	3.8	—	—	—	—	—	—	—	—
Periodic Capital	54.7	46.6	—	33.1	12.2	—	3.7	—	—	—	—	—	—	—	—
BOP Capital	26.8	31.6	20.1	14.8	10.5	6.0	3.7	3.8	1.3	—	—	—	—	—	—
ELG Capital	8.0	25.0	22.0	—	—	—	—	—	—	—	—	—	—	—	—
<b>May 2028 Retirement</b>															
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base O&M	52.8	54.4	55.5	56.7	58.1	59.4	45.6	6.2	6.4	6.5	6.7	6.8	—	—	—
Periodic O&M	10.3	9.6	—	7.1	6.8	—	—	—	—	—	—	—	—	—	—
Periodic Capital	54.7	46.6	—	9.7	3.5	—	—	—	—	—	—	—	—	—	—
BOP Capital	26.8	31.6	14.5	5.7	3.5	3.6	1.2	—	—	—	—	—	—	—	—
ELG Capital	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
<b>May 2026 Retirement</b>															
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base O&M	52.8	54.4	55.5	56.7	43.5	5.9	6.1	6.2	6.4	6.5	—	—	—	—	—
Periodic O&M	10.3	9.6	—	3.5	—	—	—	—	—	—	—	—	—	—	—
Periodic Capital	54.5	31.8	—	2.3	—	—	—	—	—	—	—	—	—	—	—
BOP Capital	26.8	7.5	3.3	3.4	1.2	—	—	—	—	—	—	—	—	—	—
ELG Capital	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
<b>May 2023 Retirement</b>															
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Base O&M	52.8	40.8	5.6	5.7	5.8	5.9	6.1	—	—	—	—	—	—	—	—
Periodic O&M	10.3	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Periodic Capital	49.7	—	—	—	—	—	—	—	—	—	—	—	—	—	—
BOP Capital	13.5	3.5	—	—	—	—	—	—	—	—	—	—	—	—	—
ELG Capital	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—

## Belle River O&M and Capital Forecasts (fully-loaded, excluding inflation)

MNSCDE-1.19ai Belle River NPV Capital and OM Input.xlsx

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
<b>Base O&amp;M Spend (\$M)</b>															
Belle River Power Plant	\$43.1	(2020 Total less Periodic)													
	\$7.7	(Fully-loading 2020 Actual SC FS that will not be included in K&M for plant retiring)													
	(\$1.6)	(Covid known and measurable)													
	<u>\$0.6</u>	<u>(REF)</u>													
May 2030 Retirement	\$50	\$50	\$50	\$50	\$50	\$50	\$50	\$50	\$37	\$5	\$5	\$5	\$5	\$5	\$5
May 2028 Retirement	\$50	\$50	\$50	\$50	\$50	\$50	\$37	\$5	\$5	\$5	\$5	\$5			
May 2026 Retirement	\$50	\$50	\$50	\$50	\$37	\$5	\$5	\$5	\$5	\$5					
May 2023 Retirement	\$50	\$37	\$5	\$5	\$5	\$5	\$5								
<b>Periodic O&amp;M Spend (\$M)</b>															
May 2030 Retirement	\$ 10	\$ 9	\$ -	\$ 6	\$ 6	\$ -	\$ 3	\$ -	\$ -						
May 2028 Retirement	\$ 10	\$ 9	\$ -	\$ 6	\$ 6	\$ -	\$ -								
May 2026 Retirement	\$ 10	\$ 9	\$ -	\$ 3	\$ -										
May 2023 Retirement	\$ 10	\$ -													
<b>Periodic Capital Spend (\$M)</b>															
May 2030 Retirement	\$ 52	\$ 43	\$ -	\$ 29	\$ 11	\$ -	\$ 3	\$ -	\$ -						
May 2028 Retirement	\$ 52	\$ 43	\$ -	\$ 9	\$ 3	\$ -	\$ -								
May 2026 Retirement	\$ 51	\$ 29	\$ -	\$ 2	\$ -										
May 2023 Retirement	\$ 47	\$ -													
<b>Balance of Plant Capital Spend (\$M)</b>															
May 2030 Retirement	\$ 25	\$ 29	\$ 18	\$ 13	\$ 9	\$ 5	\$ 3	\$ 3	\$ 1						
May 2028 Retirement	\$ 25	\$ 29	\$ 13	\$ 5	\$ 3	\$ 3	\$ 1								
May 2026 Retirement	\$ 25	\$ 7	\$ 3	\$ 3	\$ 1										
May 2023 Retirement	\$ 13	\$ 3													

**Belle River O&M and Capital Forecasts (fully-loaded, including inflation)**

Cumulative Inflation Factor	1.06	1.09	1.11	1.14	1.17	1.19	1.22	1.25	1.28	1.31	1.34	1.37	1.40	1.44	1.47
Y/Y Change %	2.90%	2.90%	2.12%	2.23%	2.32%	2.34%	2.40%	2.36%	2.34%	2.32%	2.34%	2.33%	2.33%	2.33%	2.33%
Y/Y Change	1.03	1.03	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
<b>Base O&amp;M Spend (\$M)</b>															
May 2030 Retirement	\$53	\$54	\$56	\$57	\$58	\$59	\$61	\$62	\$48	\$7	\$7	\$7	\$7	\$7	\$0
May 2028 Retirement	\$53	\$54	\$56	\$57	\$58	\$59	\$46	\$6	\$6	\$7	\$7	\$7	\$0	\$0	\$0
May 2026 Retirement	\$53	\$54	\$56	\$57	\$44	\$6	\$6	\$6	\$6	\$7	\$0	\$0	\$0	\$0	\$0
May 2023 Retirement	\$53	\$41	\$6	\$6	\$6	\$6	\$6	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Periodic O&amp;M Spend (\$M)</b>															
May 2030 Retirement	\$10	\$10	\$0	\$7	\$7	\$0	\$4	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
May 2028 Retirement	\$10	\$10	\$0	\$7	\$7	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
May 2026 Retirement	\$10	\$10	\$0	\$4	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
May 2023 Retirement	\$10	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Periodic Capital Spend (\$M)</b>															
May 2030 Retirement	\$55	\$47	\$0	\$33	\$12	\$0	\$4	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
May 2028 Retirement	\$55	\$47	\$0	\$10	\$3	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
May 2026 Retirement	\$55	\$32	\$0	\$2	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
May 2023 Retirement	\$50	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Balance of Plant Capital Spend (\$M)</b>															
May 2030 Retirement	\$27	\$32	\$20	\$15	\$10	\$6	\$4	\$4	\$1	\$0	\$0	\$0	\$0	\$0	\$0
May 2028 Retirement	\$27	\$32	\$14	\$6	\$3	\$4	\$1	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
May 2026 Retirement	\$27	\$8	\$3	\$3	\$1	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
May 2023 Retirement	\$14	\$4	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0
<b>Environmental / Conversion Capital Spend (\$M)</b>															
May 2030 Retirement	\$8	\$25	\$22												
May 2028 Retirement															
May 2026 Retirement															
May 2023 Retirement															



MNSCDE-1.19ai Belle River NPV Capital and OM Input.xlsx

	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>	<u>2027</u>	<u>2028</u>	<u>2029</u>	<u>2030</u>	<u>2031</u>	<u>2032</u>	<u>2033</u>	<u>2034</u>	<u>2035</u>	<u>2036</u>
Yearly Factor	1	103.1%	106.1%	109.2%	111.5%	114.0%	116.6%	119.3%	122.2%	125.1%	128.0%	131.0%	134.0%	137.2%	140.4%	143.6%	147.0%
% Y/Y		3.1%	2.9%	2.9%	2.1%	2.2%	2.3%	2.3%	2.40%	2.36%	2.34%	2.32%	2.34%	2.33%	2.33%	2.33%	2.33%
	<b>2021 Rate Case</b>			Escalation based on deflator series													

<b>MPSC Case No.:</b>	U-20836
<b>Requestor:</b>	MNSC
<b>Question No.:</b>	MNSCDE-1.19cv
<b>Respondent:</b>	J. Morren
<b>Page:</b>	1 of 1

**Question:** Refer to WP-JLM-BLRPP. For each of Belle River Units 1 and 2 and any common areas for the entire Belle River site:

- c. Please identify each capital and major maintenance project with costs greater than \$1 million that was performed, is planned, or is under consideration for any of the years 2020 through 2028 that is being requested for rate recovery in this case. Please provide this information in a spreadsheet format, with any formulas intact, and include the following information:
- v. for projects that have expenditures in any of the years 2022-2028, please identify whether those expenditures would be avoidable under the 2023, 2026, 2028, and 2030 Belle River retirement scenarios (This includes projects that the Company is currently performing: if a project is already underway but would have been avoidable under any of the 2023, 2026, 2028, and 2030 retirement scenarios, please identify it.)

**Answer:** I consider none of the Belle River Unit 1 projects greater than \$1 million in this case avoidable.

I consider all Belle River Unit 2 projects greater than \$1 million in 2023 avoidable if the unit retires in May 2023.

I consider the majority of reliability-based (Unit 2 Waterwall Tubes, Unit 2 Primary Superheat Tubes, Unit 2 Expansion Joints, Fuel Supply DCS Consoles, Auxiliary Boiler Retube) projects greater than \$1 million in 2023 are avoidable if Belle River Unit 2 retires in 2026. Although these are likely avoidable, there would be reliability/PSCR/O&M impacts associated with not performing this work as scheduled.

I consider none of the \$1 million projects in this case avoidable if Belle River operates to 2028 or 2030.

**Attachments:** None.

**MPSC Case No.:** U-20836

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**Requestor:** MNSC

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**Question No.:** MNSCDE-1.22a

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**Respondent:** S. Manning

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**Page:** 1 of 1

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**Question:** Refer to page 17, line 5 through page 20, line 8 as well as page 24, line 23 through page 26, line 9 of the Direct Testimony of Justin L. Morren, which discusses the implications of recent changes to and DTE's plans to comply with the U.S. EPA's Steam Electric Effluent Limitation Guidelines (ELG) Rule.

a. Has the Company considered retiring any of the Monroe units instead of complying with any iteration of the ELG rule? If so, please produce analyses, reports, and other documents regarding this consideration.

**Answer:** DTE Electric objects to the request for the reason that the request is overly broad, seeks excessive detail, seeks confidential, proprietary research, or commercial information belonging to DTE Electric, the disclosure of which would cause DTE Electric and its customers competitive or commercial harm and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. DTE Electric also objects to this request to the extent the information requested consists of confidential and privileged attorney-client communications, information prepared in anticipation of litigation, or attorney work product related to the Company's preparation of its Integrated Resource Plan (IRP) to be filed later this year. Subject to this objection and without waiver thereof, the Company answers as follows: The Company considered retiring the Monroe units to comply with the ELG Rule. Please see the Monroe SPI analysis in Part III of this filing. Additionally, an analysis was prepared using new software that the Company acquired in late 2020 and was part of the process that the modeling team took to become familiar with the software. The models were not intended to provide a comprehensive analysis of any retirement scenario as is provided in an IRP. The modeling runs were intended as illustrative examples of potential sensitivities that could be evaluated in a future IRP while allowing the team to understand the capabilities of the software. See MNSCDE-1.6a and refer to case nos. 1, 2, 3, 4, 5, 6, 7, 8, 10 and 11. The confidential attachment provided in MNSCDE-1.6a is provided pursuant to the protective order in this case.

**Attachments:** None.

**Co-Respondent(s):** Legal

The Michigan Public Service Commission  
 DTE Electric Company  
 MNSCDE-1.5 WP SDB-2 Zone 7 Resource Forecast.xlsxZone 7 LCR Position Forecasts

Case No: U-20471  
 Witness: S. D. Burgdorf  
 Page 1 of 5

Line #	Description	PY 2020/21	PY 2021/22	PY 2022/23	PY 2025/26
1	Zone 7 Peak Demand <sup>1</sup>	20,963	20,296	20,752	20,399
2	LRR Unforced Capacity per-unit of Peak Demand <sup>2</sup>	119.5%	121.2%	119.4%	119.4%
3	Local Reliability Requirement (LRR = Line 1 x Line 2)	25,051	24,599	24,778	24,356
4	Capacity Import Limit (CIL)	3,200	4,888	3,749 <sup>3</sup>	3,200 - 4,888 <sup>4</sup>
5	Local Clearing Requirement (LCR = Line 3 - Line 4)	21,851	19,711	21,029	19,468 - 21,156
6	Zone 7 Resources	21,728	21,666	21,537 <sup>5</sup>	21,623 <sup>6</sup>
7	Anticipated LCR Position (Line 6 - Line 5)	(123)	1,956	508	466 - 2,154
8	Anticipated LCR Position without Belle River (Line 7 - 1,215 MW UCAP)				(748) - 940

PY 2022/23	PY 2025/26
20,752	20,399
119.4%	119.4%
24,778	24,356
3,749	3,200 - 4,888
21,029	19,468 - 21,156
21,537	21,623
508	466 - 2,154

PY 25/26 Analysis

	High	Low
LCR	21,156	19,468
LCR Position	466	2,154
LCR Position no BR	(749)	939

(1) Value based on 2020 MISO LOLE Report including known DTE peak load changes  
 (2) LRR is based on PY 2022/23 value in MISO's Planning Year 2022/23 Preliminary LOLE Study Report  
 (3) CIL is based on PY 2022/23 value in MISO's Planning Year 2022/23 Preliminary LOLE Study Report  
 (4) CIL is based on historic range of CIL values  
 (5) Value based on U-20886 MPSC Staff Report and Recommendations including known DTE resource changes  
 (6) Value based on U-20886 MPSC Staff Report and Recommendations including known DTE resource changes, risk of delays in DTE renewable build plan, and adjustments for Consumers IRP filed on June 30th, 2021

The Michigan Public Service Commission  
DTE Electric Company  
MNSCDE-1.5 WP SDB-2 Zone 7 Resource Forecast.xlsx Historical zone 7 Resources

Case No: U-20471  
Witness: S. D. Burgdorf  
Page 2 of 5

Description <sup>1</sup>	PY 2017/18	PY 2018/19	PY 2019/20	PY 2020/21	PY 2021/22
Zone 7 Resources	22,031	22,036	22,063	21,728	21,666

1) Data from actual MISO summaries of PRA results

The Michigan Public Service Commission  
 DTE Electric Company  
 MNSCDE-1.5 WP SDB-2 Zone 7 Resource Forecast.xlsx Historical zone 7 peak demand

Case No: U-20471  
 Witness: S. D. Burgdorf  
 Page 3 of 5

Description	PY 2017/18	PY 2018/19	PY 2019/20	PY 2020/21	PY 2021/22
Zone 7 Peak Demand <sup>1</sup>	21,410	21,174	21,350	20,963	20,296

1) PY 2017/18, PY 2018/19, PY 2019/20, PY 2020/21, PY 2021/22 data from preliminary PRA data published by MISO in corresponding years

line	<b>Forecasted Zone 7 Peak Demand using Capacity Demonstration Report with adjustments</b>	PY 22 23	PY 23 24	PY 24 25	PY 25 26	PY 26-27
1	Zone 7 2020 LOLE Peak	20562	20461	20360	20264	20167
2	DTE Capacity Dem. Peak	9,729	9,751	9,660	9,557	9,557
3	Zone 7 Capacity Dem. Peak Removing DTE Peak (line 1 - line 2)	10,343	10,295	10,242	10,192	10,143
4	DTE 20/21 PRA	10,219	10,166	10,118	10,071	10,024
6	DTE Rate Case Bundled Peak (includes PLD)	10,409	10,341	10,262	10,207	10,169
7	Capacity Demonstration Forecast of PY 2021/22 Zone 7 Peak with adjustments (line 3 + line 5 + line 6)	<b>20,752</b>	<b>20,635</b>	<b>20,504</b>	<b>20,399</b>	<b>20,312</b>

The Michigan Public Service Commission  
DTE Electric Company  
MNSCDE-1.5 WP SDB-2 Zone 7 Resource Forecast.xlsxLRR Actual vs Forecast

Case No: U-20471  
Witness: S. D. Burgdorf  
Page 4 of 5

Description	2017/18	2018/19	2019/20	2020/21	2021/22
<b>Zone 7 Per-Unit LRR<sup>1</sup></b>	114.1%	115.3%	117.2%	119.5%	121.2%

1) Source: MISO LOLE reports published for corresponding Planning Years

The Michigan Public Service Commission  
 DTE Electric Company  
 MNSCDE-1.5 WP SDB-2 Zone 7 Resource Forecast.xlsxZone 7 CapDem Resource Forecast

Case No: U-20471  
 Witness: S. D. Burgdorf  
 Page 5 of 5

	21/22	22/23	23/24	24/25	25/26
Staff Report (Demonstrated and Undemonstrated Zone 7 resources)	21,632	21,443	21,686	21,943	21,943
DTE Resource Changes	<u>(147)</u>	<u>94</u>	<u>74</u>	<u>517</u>	<u>850</u>
<b>Zone 7 Resources 2020 Capacity filing Demonstration (U-20886) with DTE known adjustments</b>	<b>21,485</b>	<b>21,537</b>	<b>21,760</b>	<b>22,460</b>	<b>22,793</b>

	21/22	22/23	23/24	24/25	25/26
Current DTE Resources	10,671	10,824	10,920	11,291	11,623
DTE Resources Cap Demo	10,818	10,730	10,846	10,774	10,774
DTE Resource Changes	(147)	94	74	517	850
Consumers Estimated Resource Change from PSCR Plan to IRP					<b>(923)</b>



The Michigan Public Service Commission  
 DTE Electric Company  
 MNSCDE-1.5 WP SDB-2 Zone 7 Resource Forecast.xlsxZone 7 CapDem Resource Forecast

Case No: U-20471  
 Witness: S. D. Burgdorf  
 Page 1 of 1

Cons 2021 PSCR Plan

**MICHIGAN PUBLIC SERVICE COMMISSION**  
Consumers Energy Company

Case No.: U-20802  
 Exhibit No.: A-10 (JWH-4)  
 Page: 1 of 1  
 Witness: JWHahn  
 Date: September 2020

**Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRCs)**

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		PY 2020-21	PY 2021-22	PY 2022-23	PY 2023-24	PY 2024-25	PY 2025-26
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW	7,956	7,864	7,956	7,950	8,006	7,981
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	749	811	857	905	982	1,114
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	7,207	7,053	7,099	7,045	7,024	6,867
4	Load Diversity Factor coincident to MISO, %	95.07%	95.07%	95.07%	95.07%	95.07%	95.07%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	6,852	6,705	6,749	6,698	6,677	6,529
6	Transmission Losses, %	3.70%	3.50%	3.50%	3.50%	3.50%	3.50%
7	Planning Reserve Margin % UCAP Basis	8.90%	9.40%	9.30%	9.30%	9.20%	9.00%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	7,737	7,593	7,635	7,577	7,547	7,365
9	Company Owned, In-State, Non-Intermittent, ZRC	4,749	4,594	4,853	4,533	4,659	4,661
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	17	17	17	17	17	17
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	71	121	196	306	431	556
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	11	12	12	12	12	12
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	4,848	4,743	5,077	4,867	5,118	5,245
18	Total Load Modifying Resources, Treated as Capacity, ZRC	499	599	649	682	772	861
19	PPA, In-State, Non-Intermittent, ZRC	2,363	2,351	1,566	1,566	1,566	1,478
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	34	34	28	28	28	24
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	60	60	135	260	385	510
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	4	4	3	2	2	2
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	2	18	25	26	26	30
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	0	38	233	301	301	301
29	Other Forward Capacity Contract, ZRC - In-State	20	-	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	2,483	2,504	1,989	2,182	2,307	2,344
32	Net Load Switching, ZRC	-	-	-	-	-	-
33	Planned Auction Purchases, ZRC	-	-	-	-	-	-
34	Total Planning Resources, ZRC (line 17 + line 18 + line 31 + line 32 + line 33)	7,831	7,847	7,715	7,731	8,196	8,450
35	UCAP Surplus/(Shortfall), ZRC (line 34 - line 8)	93	255	80	154	649	1,085

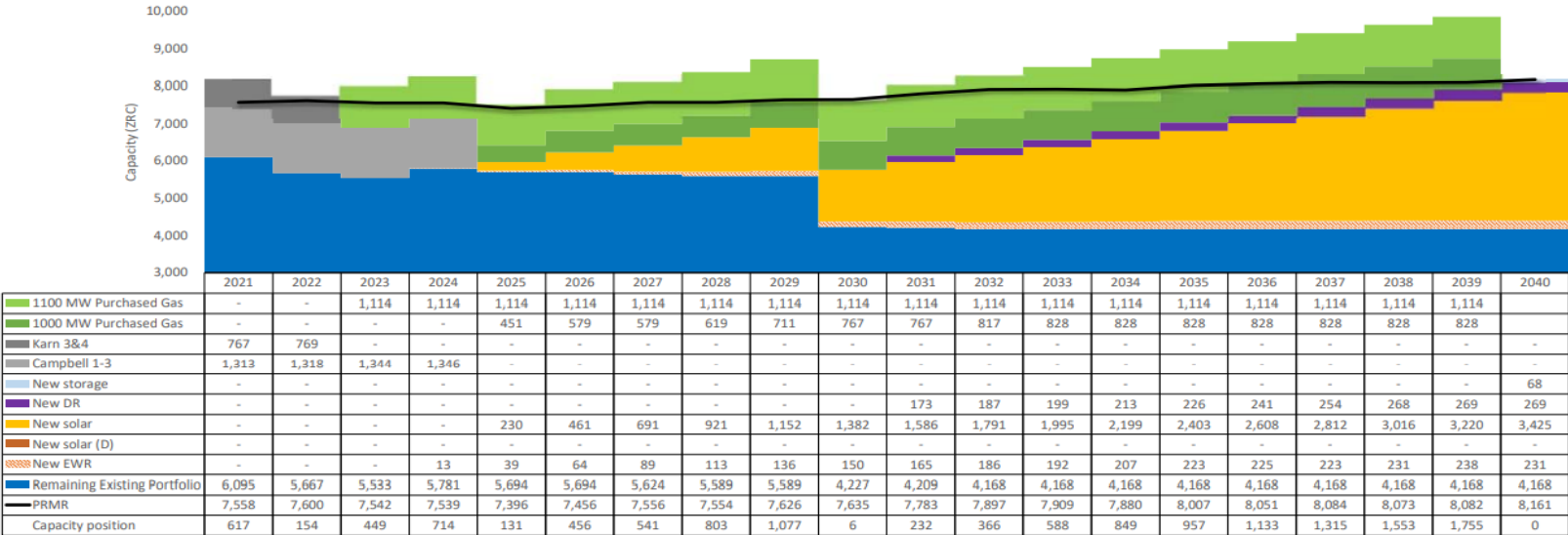
The Michigan Public Service Commission  
 DTE Electric Company  
 MNSCDE-1.5 WP SDB-2 Zone 7 Resource Forecast.xlsxZone 7 CapDem Resource Forecast

Case No: U-20471  
 Witness: S. D. Burgdorf  
 Page 1 of 1

CONS IRP

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

Case No.: U-21090  
 Exhibit No.: A-14 (STW-11)  
 Page: 5 of 10  
 Witness: STWalz  
 Date: June 2021



<b>MPSC Case No.:</b>	U-20836
<b>Requestor:</b>	MNSC
<b>Question No.:</b>	MNSCDE-1.6a
<b>Respondent:</b>	S. Manning
<b>Page:</b>	1 of 1

**Question:** Refer to Burgdorf direct testimony at pages 22-26 and Exhibit A-12, schedule B6.1-B6.3:

- a. Produce any and all comparisons, analyses, or evaluations of Belle River retirement scenarios that were undertaken but not presented in the exhibits.

**Answer:** DTE Electric objects to the request for the reason that the request is overly broad, seeks excessive detail, seeks confidential, proprietary research, or commercial information belonging to DTE Electric, the disclosure of which would cause DTE Electric and its customers competitive or commercial harm and is otherwise not reasonably calculated to lead to the discovery of admissible evidence. DTE Electric also objects to this request to the extent the information requested consists of confidential and privileged attorney-client communications, information prepared in anticipation of litigation, or attorney work product related to the Company's preparation of its Integrated Resource Plan (IRP) to be filed later this year. Subject to this objection and without waiver thereof, the Company answers as follows: Certain Belle River retirement scenarios were modeled with respect to ELG compliance. These analyses were prepared using new software that the Company acquired in late 2020 and were part of the process that the modeling team took to become familiar with the software. The models were not intended to provide a comprehensive analysis of any retirement scenario as is provided in an IRP. The modeling runs were intended as illustrative examples of potential sensitivities that could be evaluated in a future IRP while allowing the team to understand the capabilities of the software. See attachment labelled "NDA\_U-20836 MNSCDE-1.6a Practice Belle River and Monroe Analyses" and refer to case nos. 1, 2, 5, 6, 7, 8, 9, and 10 for Belle River retirement scenarios. This confidential attachment is provided pursuant to the protective order in this case.

**Attachments:** NDA\_U-20836 MNSCDE-1.6a Practice Belle River and Monroe Analyses

<b>MPSC Case No.:</b>	U-20836
<b>Requestor:</b>	MNSC
<b>Question No.:</b>	MNSCDE-5.3a
<b>Respondent:</b>	J. Morren
	1 of 1

**Question:** Refer to data response MNSCDE-1.22a and Exhibit A-12, Schedule B5.1.  
a. Does the Company consider any of the ELG or CCR costs at Monroe avoidable if any of the units retired by 2028?

**Answer:** Monroe Power Plant CCR-related closure costs projected in Exhibit A-12, Schedule B5.1 are unavoidable. The CCR Rule requires landfills and impoundments to be closed when they stop receiving waste, regardless of the power plant's retirement date. The Monroe Bottom Ash Basin has stopped receiving material and closure commenced in 2020 per the CCR Rule. The Monroe Fly Ash Basin is scheduled to stop receiving material in 2023 and the funding in this case is to prepare for that closure.

Monroe Power Plant Dry Fly Ash Conversion (ELG) projected costs in my exhibits are unavoidable because the deadline for compliance is no later than December 31, 2023. Furthermore, the majority of the funding for this project has already been spent.

Monroe Power Plant Bottom Ash Conversion (ELG) projected costs in my exhibits are unavoidable because the deadline for compliance is no later than December 31, 2025.

Monroe Power Plant FGD Wastewater (ELG) projected costs in my exhibits are unavoidable as the funding is related to study and pre-engineering costs for compliance alternatives.

**Attachment:** None.

**Co-Respondent(s):** R. Lee

**MPSC Case No.:** U-20836  
**Requestor:** MNSC  
**Question No.:** MNSCDE-5.9d  
**Respondent:** S. Burgdorf  
1 of 1

**Question:** Please provide the most recent forecast prepared by or for the Company of the following:  
d. MISO PRA capacity prices;

**Answer:** See table below for the MISO PRA capacity price forecast from the Company's 2022 PSCR Plan filing.

<b>Planning Year</b>	<b>Capacity (\$/kW-year)</b>
2021	1.83
2022	47.40
2023	1.83
2024	1.83
2025	1.83
2026	1.83

**Attachment:** None.

<b>MPSC Case No.:</b>	U-20836
<b>Requestor:</b>	MNSC
<b>Question No.:</b>	MNSCDE-8.1b
<b>Respondent:</b>	J. Morren
	1 of 1

**Question:** Refer to data response AGDE-3.96a.  
b. What share of total hydrogen burned at BWEC would 31,776 MMBtu represent? Please provide supporting documentation and/or analyses for this calculation.

**Answer:** 31,776 MMBTU of hydrogen represents 100% of the planned yearly hydrogen production of the hydrogen pilot project. Hydrogen is a 1/1 BTU replacement fuel when compared to natural gas.

**Attachment:** None.

<b>MPSC Case No.:</b>	U-20836
<b>Requestor:</b>	MNSC
<b>Question No.:</b>	MNSCDE-8.29b
<b>Respondent:</b>	S. Burgdorf
	1 of 1

**Question:** The following questions refer to discovery response attachment MNSCDE-1.5 WP SDB- 2 Zone 7 Resource Forecast:

b. With respect to the tab labeled “Zone 7 CapDem Resource Forecast,” provide the calculation of the (923) value for “Consumers Estimated Resource Change from PSCR Plan to IRP.”

**Answer:** The (923) value for “Consumers Estimated Resource Change from PSCR Plan to IRP” was calculated using the screenshots of Consumers 2021 PSCR Plan and 2021 IRP in the tab labeled “Zone 7 CapDem Resource Forecast”. The “Total Planning Resources, ZRC” line in the PSCR Plan indicated 8450 ZRCs for Planning Year 2025-26. The Consumers 2021 IRP shows a PRMR of 7396 and a capacity position of 131 ZRCs indicating total planning resources of 7527 ZRCs for planning year 2025-2026. The (923) value is equal to the decrease from 8450 ZRCs to 7527 ZRCs.

**Attachment:** None

<b>MPSC Case No.:</b>	U-20836
<b>Requestor:</b>	MNSC
<b>Question No.:</b>	MNSCDE-8.3a
<b>Respondent:</b>	J. Morren
	1 of 1

**Question:** Refer to discovery response AGDE-3.99.  
a. What share of the 5% blend of hydrogen burned at BWEC would be provided by the hydrogen project? Please provide supporting documentation and/or analyses used by the Company in determining this.

**Answer:** All of the hydrogen being consumed at BWEC will be provided by the Hydrogen Pilot. No other sources of hydrogen fuel are currently being considered for BWEC. Please refer to the Company's response to MNSCDE-8.2b and STDE-8.6a

**Attachment:** None.



<b>MPSC Case No.:</b>	U-20836
<b>Requestor:</b>	MNSC
<b>Question No.:</b>	MNSCDE-8.4b
<b>Respondent:</b>	J. Morren
	1 of 1

**Question:** Refer to the Direct Testimony of Justin Morren at page 39 lines 10-12 and data response AGDE-3.100b.

b. Please explain how the Company has determined when “curtailed renewable energy” would be available or unavailable to supply the project? Please include any supporting documentation or analyses used in making this determination.

**Answer:** DTE Electric is unaware of the exact reasons behind the curtailments of intermittent renewable energy (economic, reliability, testing, operational limitations) that have occurred, nor do we track all curtailments on an ongoing basis and cannot forecast future curtailments.

**Attachment:** None.

**Co-Respondent(s):** S. Burgdorf

<b>MPSC Case No.:</b>	U-20836
<b>Requestor:</b>	Staff
<b>Question No.:</b>	STDE-3.1a
<b>Respondent:</b>	J. Morren
<b>Page:</b>	1 of 1

**Question:** Please answer the following questions regarding the Bell River Fuel Conversion Engineering project, identified on line (2) of Exhibit A-12, Sch. B-5.1, p. 2:

a) When does the Company expect the conversion to occur?

**Answer:** There has been no decision to execute a Belle River fuel conversion project. If a conversion were to occur, the Company currently expects it would happen in conjunction with ceasing coal-fired operations by the end of 2028.

**Attachments:** None.

**MPSC Case No.:** U-20836

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**Requestor:** Staff

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**Question No.:** STDE-3.4a

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**Respondent:** J. Morren

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**Page:** 1 of 1

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**Question:** Please answer the following questions regarding the Monroe FGD Wastewater (ELG) project, identified on line (5) of Exhibit A-12, Sch. B-5.1, p. 2:

a) What is the deadline for compliance?

**Answer:** The deadline for Monroe FGD wastewater ELG compliance depends on the compliance technology selected. Power plants with FGD systems can comply with one set of limits by December 31, 2025 or comply with a set of more stringent limits by December 31, 2028 if the power plant plans to continue coal-fired operations past 2028.

**Attachments:** None.

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of  
CONSUMERS ENERGY COMPANY for approval Case No. U-21090  
of an Integrated Resource Plan under  
MCL 460.6t, certain accounting Volume 3  
approvals, and for other relief.

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CROSS-EXAMINATION

Proceedings held via Microsoft Teams in the  
above-entitled matter before Sally L. Wallace,  
Administrative Law Judge with MOAHR, for the Michigan  
Public Service Commission, Lansing, Michigan, on  
Wednesday, December 1, 2021, at 9:15 a.m.

APPEARANCES:

ROBERT W. BEACH, ESQ.  
BRET A. TOTORAITIS, ESQ.  
THERESA A.G. STALEY, ESQ.  
MICHAEL C. RAMPE, ESQ.  
GARY A. GENSCHE, JR., ESQ.  
ANNE M. UITVLUGT, ESQ.  
IAN F. BURGESS, ESQ.  
Consumers Energy Company  
One Energy Plaza, Room EP11-223  
Jackson, Michigan 49201

On behalf of Consumers Energy Company

(Continued)

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Cross-Examination by Mr. Waters	498
ROBERT J. LEE	
Direct Examination by Mr. Beach	510
Cross-Examination by Mr. Bzdok	537

SARA T. WALZ

REVISED DIRECT TESTIMONY

1 A-13 (STW-10). Instead, BTMG was a “locked in” resource in specific  
2 sensitivities to understand which resources would be “kicked out” of selection.  
3 Generally, the customer-owned solar programs tend to reduce the amount of  
4 transmission- or distribution-connected solar resources, or battery storage  
5 resources.

6 New Technology Resource Selections in Retirement Base Case Optimal Plans

7 **Q. The Company’s PCA includes accelerated retirement of Campbell Units 1-3 and**  
8 **Karn Units 3&4 and the addition of two existing natural gas assets. Please discuss**  
9 **the Aurora optimal plan resource selections corresponding to that sensitivity in the**  
10 **applicable scenarios.**

11 A. As discussed in Section VIII, the PCA, Portfolio 4, is a fixed resource plan. However,  
12 Portfolio 3, the optimal glide path portfolio was evaluated for the sensitivity considering  
13 retirement of the aforementioned resources. The specific build plan, Portfolio 3,  
14 corresponding to the accelerated retirement of Campbell Units 1 through 3 in 2025 and  
15 Karn Units 3 and 4 in 2023 and the addition of approximately 2,000 MW by 2025 of  
16 existing natural gas capacity under each scenario is presented in Exhibit A-14 (STW-11).  
17 This exhibit presents a graphical display of the resources selected as the optimal plan, with  
18 a summary table below the chart. The first eight pages of this exhibit shows the glide path  
19 optimal plan (Portfolio 3) for the retirement base case sensitivity under each of the eight  
20 scenarios; page 9 shows the same format of information for the final PCA, while page 10  
21 shows the alternate plan.

22 **Q. How were the results of the long-term capacity expansion runs, and the corresponding**  
23 **selection of resources by Aurora used to inform the decisions made regarding which**  
24 **resources to include in the PCA?**

25 A. Development of the PCA required the selection of capacity resources to fill the needs  
26 remaining after the addition of the existing natural gas unit capacity, as supported in the

## Comings Disallowance Exhibit

### Proposed Disallowances at Belle River

Unit	Project ID	2022 spending	2023 spending	Reason
Common	Fuel Conversion Engineering	\$2,441,000	-	DTE has not made decision on fuel conversion.
Common	Fuel Supply DCS Consoles	-	\$3,988,263	Avoidable with 2026 retirement, per DTE
Common	Auxiliary Boiler Retube	-	\$1,465,623	
Unit 2	Waterwall Tubes	-	\$1,342,239	
Unit 2	Primary Superheat Tubes	-	\$1,937,280	
Unit 2	Expansion Joints	-	\$4,041,600	
<b>TOTAL</b>		<b>\$2,441,000</b>	<b>\$12,775,004</b>	

### Proposed Disallowances at Monroe

Unit	Project ID	2022 spending	2023 spending	Reason
Common	Bottom Ash Conversion (ELG)	\$10,072,462	\$5,000,000	Avoidable with 2028 retirement
Common	FGD Wastewater (ELG)	\$1,000,000	\$833,333	
Common	Main Unit Transformer	\$5,984,509	\$2,636,607	IRR shows no net benefit unless plant runs until 2040
Unit 1	LPA & LPB Turbine Rotor & Blades	\$14,273,727	\$6,824,866	
Unit 1	Waterwall Tubes	\$1,499,173	\$16,500,075	
Unit 3	Waterwall Tubes	-	\$1,041,721	
<b>TOTAL</b>		<b>\$32,829,871</b>	<b>\$32,836,602</b>	

### Hydrogen Pilot

Unit	Project ID	2022 spending	2023 spending	Reason
Common	Project Cost	-	\$44,605,000	Resource decision that should be made in IRP, and has not been supported

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.

U-20836

**PUBLIC  
PROOF OF SERVICE**

On the date below, an electronic copy of the Public Version of the Direct Testimony of Tyler Comings on behalf of Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan and Exhibits MEC-53 through MEC-73 was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

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Date: May 19, 2022

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