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July 26, 2024

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

Re: **MPSC Case No. U-21534**

Dear Ms. Felice:

Attached for electronic filing in the above-referenced matter, please find the Direct Testimony and Exhibits of Alexander J. Zakem on behalf of Energy Michigan. Thank you for your assistance in this matter.

Very truly yours,

Tim Lundgren
Digitally signed by Tim Lundgren
Date: 2024.07.26 13:34:55 -04'00'

Tim Lundgren

TL/kd
Enclosure
c. All parties of record.

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	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

DIRECT TESTIMONY & EXHIBITS

OF

ALEXANDER J. ZAKEM

ON BEHALF OF

ENERGY MICHIGAN

Q. Please state your name and business address.

A. My name is Alexander J. Zakem, and my business address is 46180 Concord, Plymouth, Michigan 48170.

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

A. I am testifying on behalf of Energy Michigan.

Q. Please state your professional experience.

A. Since January of 2004, I have been an independent consultant providing services to various clients, including Energy Michigan and its members.

From March 2002 to December 2003, I was Vice President of Operations for Quest Energy, an alternative energy supplier in Michigan. My responsibilities included the overall direction and management of Quest's power supply to its retail customers. This included power supply planning, development of customized products, negotiation with suppliers, planning and acquiring transmission rights, and scheduling and delivery of power. It also included managing risk with respect to market price movements and variation of customer loads.

Prior to joining Quest, I was employed by Detroit Edison from 1977 to 2001, where from 1998 to 2001 I was the Director of Power Sourcing and Reliability, responsible for purchases and sales of power for mid-term and long-term periods, planning for generation

capacity and purchase power needs, strategy for and acquisition of transmission rights, and related support for regulatory proceedings.

Additional experience, qualifications, and publications are provided in Exhibit EM-1 (AJZ-1).

Q. Have you testified as an expert witness in prior proceedings?

A. Yes. I have testified as an expert witness in many proceedings before the Michigan Public Service Commission ("Commission") on topics such as standby rates, retail rates and regulations, recovery and allocation of costs and revenues, and the effects of rate restructuring. I have also testified before the Federal Energy Regulatory Commission ("FERC"). Case citations are provided in Exhibit EM-1 (AJZ-1). In addition, I have participated in various Commission-sponsored workshops and stakeholder working groups.

Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring the following exhibits:

- Exhibit EM-1 (AJZ-1): Qualifications
- Exhibit EM-2 (AJZ-2): Fuel Subtraction
- Exhibit EM-3 (AJZ-3): Other Energy Subtraction
- Exhibit EM-4 (AJZ-4): Fuel from 2024 PSCR Plan -- U-21425 Exh A-3
- Exhibit EM-5 (AJZ-5): Other Energy in Projected Fuel
- Exhibit EM-6 (AJZ-6): Adjustments to SRM

Q. What is the purpose of your testimony?

A. On behalf of Energy Michigan, I am addressing DTE's proposed State Reliability Mechanism ("SRM") Capacity Charge regarding two aspects:

1. The first is DTE's inclusion of non-fuel expenses erroneously categorized as fuel in setting the SRM Capacity Charge.

2. The second is the conflict between the SRM statute (MCL 460.6w) and the "Cost-of-Service" statute (MC 460.11(1)).

Q. Would you summarize your conclusions and your recommendations to the Commission?

A. First, in the calculation of the SRM capacity charge, DTE has included $260,787 (000) of imputed cost of energy from certain purchased power contracts by (a) labeling such costs as "fuel related" and then (b) using the costs as if they were actually fuel as specified in the SRM statute. These costs are not fuel, and so $260,787 (000) should be eliminated from the SRM calculation.

Second, in practical determination and operation, the SRM statute, MCL 460.6w, conflicts with the Cost-of-Service statute, MCL 460.11(1). The assumptions behind the SRM statute are obsolete and flawed, and in addition the Midcontinent Independent System Operator ("MISO") has, subsequent to the enactment of the SRM statute, changed its rules governing

resource adequacy and capacity obligations to seasonal rather than annual specifications, which may render the process specified in the SRM statute further obsolete and in conflict with the Cost-of-Service statute. Therefore, I recommend that the Commission determine the SRM capacity charge using actual costs of satisfying MISO's resource adequacy obligation, in a way explained later in my testimony.

I am not a lawyer, and Energy Michigan will address the legal issues involved in determining the SRM Capacity Charge while at the same time adhering to the Cost-of-Service statute in its brief. As an expert in the field of electric regulation, I can advise the Commission on the operational meaning of the plain words in the statutes and the implications of the new MISO rules.

I. Eliminate "Fuel-Related" Costs That Are Not Fuel.

I-A. SRM subtracts non-capacity costs and considers "offsets."

Q. How does the SRM statute specify the determination of the SRM Capacity Charge?

Section 6w of Public Act 341 of 2016 describes how the charge should be calculated and lists the factors to include or consider. The statute assigns to the Commission the responsibility to implement various aspects of the SRM statute.

The statute specifies defined subtractions of non-capacity costs in determining capacity costs that are to be included in the SRM Capacity Charge calculation, as follows:

> The commission shall do both of the following [. . .]:
>
> (a) For the applicable term of the capacity charge, include the capacity-related generation costs included in the utility's base rates, surcharges, and power supply cost recovery factors, regardless of whether those costs result from utility ownership of the capacity resources or the purchase or lease of the capacity resource from a third party.
>
> (b) For the applicable term of the capacity charge, subtract all non-capacity-related electric generation costs, including, but not limited to, costs previously set for recovery through net stranded cost recovery and securitization ***and*** the projected revenues, net of projected fuel costs, from all of the following:
>
> (i) all energy market sales.
> (ii) off-system energy sales.
> (iii) ancillary services sales.
> (iv) energy sales under unit-specific bilateral contracts.[1]

The projected revenues net of projected fuel costs listed in the SRM statute in (b) above are commonly referred to as "offsets" in discussions of SRM determinations.

Q. In its determination of the SRM Capacity Charge, has DTE included its capacity-related generation costs?

A. Yes. DTE's Exhibit A-16, Schedule F1.5, page 1 of 6 ("the SRM Exhibit") shows the calculation of the SRM Capacity Charge.[2] It begins with "Net Production Costs Rev. Req. on line 1, $3,213,177 (000), which comes from the Production cost of service study.

Q. Has DTE subtracted all non-capacity-related electric generation costs?

[1] MCL 460.6w(3)(a)&(b) (emphasis added).

[2] Exhibit A-16, Schedule F1.1, page 1 of 4, line 31, column (a). All citations to Exhibit A-16, Schedule F1.5 are to the revised version that DTE issued.

A. On the SRM Exhibit, non-capacity costs on lines 2, 3, 4, 5, and 6 are subtracted from Net Production Costs on line 1, resulting in a Subtotal of $1,957,094 (000) on line 7. The Subtotal represents capacity-related generation costs after the removal on non-capacity portions. I am not questioning the validity of these numbers, yet I will address the values and sources on two of the lines which are relevant to the exclusion of non-fuel values later in the calculation of energy market sales "offsets" required by the SRM statute.

I-B. DTE has correctly subtracted fuel from Production Costs

Q. Please explain the two values you are addressing.

A. The first value is line 2 on the SRM Exhibit, labeled "Less Fuel," with a value of $914,888 (000). This value comes from the Production cost of service study in this proceeding, the same exhibit that is the source of Net Production Costs Rev. Req. on line 2. I have prepared Exhibit EM-2 (AJZ-2) to provide an easy reference to the connection of fuel in the cost of service study and fuel in the SRM Exhibit. The "Less Fuel" label denotes a non-capacity cost that DTE subtracts from Production costs in the first part of the SRM Exhibit.

The second value is line 5 in the SRM Exhibit, labeled "Less Other Energy in PP," with a value of $260,787 (000). By subtracting this value from Production costs, DTE denotes it is a non-capacity cost, and so removes it from Production costs in the first part of the SRM Exhibit.

I-C. "Less Other Energy in PP" is not Fuel

Q. What is the source of the $260,787 (000) labeled "Less Other Energy in PP?

A. The value $260,787 on line 5 of the SRM Exhibit is the sum of two values: $2,925 from Exhibit A-26, Schedule P1, and $257,862 from Exhibit A-26, Schedule P2. I have prepared Exhibit EM-3 (AJZ-3) to provide an easy reference to how the sum of the two values connects to "Less Other Energy in PP" on the SRM Exhibit.

Q. How does DTE determine the two values that sum to $260,787?

A. On Exhibit A-26, Schedule P1, the value $2,925 appears in column (f) labeled "Total Fuel-Related Generation Cost," which footnote 1 on Schedule P1 identifies as:

> "Note 1: Fuel-Related Generation Cost based on difference of total projected PURPA PSCR Cost and the Capacity Related Generation Cost."

On Exhibit A-26, Schedule P2, the value $257,862 appears in column (j) labeled "Total Fuel-Related Generation Cost," which footnote 1 on Schedule P2 identifies as:

> "Note 1: Fuel-Related Generation Cost based on difference of total projected PA295 PSCR Cost and the Capacity Related Generation Cost."

The total of $2,925 plus $257,862 is $260,7872, which appears on line 5 of the SRM Exhibit.

Q. Does the caption "Total Fuel-Related Generation Cost" mean that $2,925 and $257,862 are in fact fuel costs?

A. No, not at all. These two numbers are simply the total costs of the PPA contracts that remain after backing out the portion of the total cost that DTE attributes to paying for capacity rights delivered under the contracts. DTE has identified such exactly in the footnotes on Schedules P1 and P2, cited above. The costs of $2,925 and $257,862 -- which total $260,787 -- are correctly non-capacity costs, but they are not actual fuel costs. [DTE has not demonstrated in its testimony that all non-capacity costs are, in fact, fuel costs.]

I-D. DTE erroneously includes $260,787 as fuel in the offset calculation.

Q. How does DTE determine the energy sales "offsets" as prescribed in the SRM statute?

A. DTE projects revenues for two categories of "offsets" -- Energy Market Sales and Regulation, Spinning, and Supplemental Ancillary Services Sales. These are shown on Exhibit A-26, Schedule P3, and total $2,184,379 (000) appearing on line 16. In direct testimony, DTE states that these projected revenues for year 2025 are taken from DTE's 2024 PSCR Plan (U-21425).

> The wholesale energy revenue forecasted for all Company assets (including PPAs) in the Company's 2024 PSCR Plan (U-21425) was calculated to be $2.180 billion shown on Exhibit A-26, Schedule P3, line 11.[3]

> The Company's 2024 PSCR Plan projected that Company's generation resources would generate $4.3 million of wholesale revenue associated with regulation, spinning, and supplemental reserves. The projected wholesale ancillary services revenues from the Company's generation resources in 2025 are shown on Exhibit A-26, Schedule P3, line 14.[4]

[3] Direct Testimony of Mr. S. D. Burgdorf, page 9, lines 7-10.

[4] Mr. Burgdorf, direct testimony, page 9, line 21 to page 10, line 1.

The total projected wholesale energy sales revenue including ancillary services in 2025 is $2.184 billion as shown on Exhibit A-26, Schedule P3, line 15. [5]

Q. What number does DTE use for "net of projected fuel costs" prescribed in the SRM statute?

A. DTE uses a fuel cost of $940,245 from its 2024 PSCR plan, and adds to it the $260,787 value of $260,787 that appears on line 5 of the SRM Exhibit in this proceeding, as discussed previously. The total of $940,245 plus $260,787 equals $1,201,032, and this total appears on lines 20 and 21 of Exhibit A-26, Schedule P3.

Exhibit EM-4 (AJZ-4) -- a copy of an exhibit from DTE's 2024 PSCR Plan, Case No. U-21425 -- shows the source of the $940,245 fuel value. I have prepared Exhibit EM-5 (AJZ-5) to provide an easy reference to how the sum of the two values -- $1,201,032 -- connects to line 20 and 21 on Schedule P3.

Q. How does DTE characterize the $1,201,032 number?

A. On Exhibit A-26, Schedule P3, line 20, DTE labels $1,201,032 as "Fuel," and on line 21 labels it as "Total Projected 2025 Fuel Generation Expense."

Q. Is the $1,201,032" projected "Fuel" expense entirely fuel?

[5] Mr. Burgdorf, direct testimony, page 10, lines 7-8. Note that the $2.184 billion number is on line 16 of the cited exhibit, rather than line 15.

A. No. From the evidence in DTE's testimony and exhibits, explained above, $940,425 represents the actual fuel portion of $1,201,032, and the remaining $260,787 represents the difference between total costs and capacity costs for specified power purchase agreements, as DTE notes on Exhibit A-26, Schedules P1 and P2, explained previously.

Q. How does DTE use the $1,201,032 projected "Fuel" expense in the calculation of the SRM Capacity Charge?

A. As cited previously, the SRM statute requires that capacity costs be offset by "projected revenues" (for four categories of sales) "net of projected fuel costs." On Exhibit A-26, Schedule P3, DTE shows the projections and the netting as follows:

Line	Label	Value
16	"Total Projected 2025 Energy Sales Revenue"	$2,184,379
21	"Total Projected 2025 Fuel Generation Expense"	$1,201,032
23	"Projected 2025 Energy Sales Revenue Net of Fuel Costs"	$983,347

The net of $983,347 is transferred to the SRM Exhibit A-16, Schedule F1.5, page 1 of 6, and becomes the offset shown on line 9 of that exhibit.

Q. Should the $260,787 be included in the offset calculation?

A. No. That expense may be a valid non-capacity expense to be subtracted on line 5 of the SRM exhibit, but it is not fuel. The description of the $260,787 expense evolves from a

non-capacity expense into imputed fuel in the course of DTE's exhibits, on the way to the calculation of the SRM Capacity Charge, as follows:

a. Difference between total projected PPA cost and Capacity Related Cost.
(Exh A-26, Sched P1 and P2, footnotes.)

b. "Fuel-Related Generation Cost"
(Exh A-26, Sched P1 and P2, column titles.0

c. Included in "Fuel"
(Exh A-26, Sched P3, line 20.)

d. Included in "Total Projected 2025 Fuel Generation Expense."
(Exh A-26, Sched P3, line 23.)

e. Included in the netting of fuel out of the projected sales revenue.
(SRM Exhibit, Exh A-16, Sched F1.5, page 1 of 6, line 9.)

The plain language of the SRM statute states "net of projected fuel costs." It does not say "net of projected imputed fuel costs," or "net of projected PPA costs less capacity costs," or "net of all variable costs," or "net of projected fuel-related costs," or "net of all costs required to make the sale," or any other netted cost except fuel. The SRM statutory language is clear. The SRM statute was a negotiated outcome, not a clean financial and operational solution to a defined problem, and there are flaws, which I will address later in my testimony. DTE may object to the reasonableness of the SRM statute, but this case U-21534 is not the forum to negotiate a change to MCL 460.6w(3), the SRM statute.

Q. Has the Commission approved the specific inclusion of imputed fuel costs of PPA in past determinations of the SRM Capacity Charge?

A. I have looked but cannot find any evidence that the Commission in the past has specifically addressed the imputed fuel costs in PPAs as part of "net of projected fuel" in determining offsets. The Commission has addressed other proposed inclusions in "net of projected fuel", such as emission and chemicals expense, and has removed such expenses from the SRM calculation in previous orders. An error that comes to light in this proceeding should be fixed here, whether or not it was present but unaddressed in past Commission proceedings.

I-E. The SRM Capacity Charge should be revised.

Q. How should the determination of the SRM Capacity Charge be revised if $260,787 of non-fuel cost is removed from the netting of fuel in the offsets to the SRM capacity cost?

A. I have prepared Exhibit EM-6 to show the adjustments to eliminate $260,787 from the projected fuel costs. Eliminating the $260,787 from fuel costs in the offset determination results in the offset on line 9 of the SRM Exhibit (A-16, Sched F1.5, page 1 of 6) changing from $983,747 to $1,243,954. The outcome is that DTE's proposed SRM Capacity Charge of $217.30 per MW-day would be changed to $159.21 per MW-day on line 17 of the SRM Exhibit.

If the Commission's final order in this proceeding results in changes to other values proposed by DTE -- such as a revision to Net Production Cost Revenue Requirement -- then those changes should be reflected in the SRM calculation also. In the absence of such

additional changes, I recommend that the Commission set DTE's SRM Capacity Charge at $159.21 per MW-day.

II. Follow the "Cost of Service" Statutory Requirements to Determine the SRM Capacity Charge.

Q. Is the determination of the SRM Capacity Charge affected by the Cost-of-Service statute, MCL 460.11(1)?

A. Yes. The SRM statute MCL 460.6w is not the only guide for the Commission in determining a just and reasonable SRM Capacity Charge. MCL 460.11(1), enacted in PA 286 in 2008, ("Cost-of-Service statute") which requires the Commission to set "electric rates equal to the cost of providing service to each customer class"[6] is also relevant. To the extent that application of Section 6w and Section 11(1) produce different results, the Commission has to decide how to reconcile competing statutory demands so as to determine and apply a SRM Capacity Charge that it is also in accordance with the Cost-of-

[6] MCL 460.11(1) "Except as otherwise provided in this subsection, the commission shall ensure the establishment of electric rates equal to the cost of providing service to each customer class. In establishing cost of service rates, the commission shall ensure that each class, or sub-class, is assessed for its fair and equitable use of the electric grid. If the commission determines that the impact of imposing cost of service rates on customers of an electric utility would have a material impact on customer rates, the commission may approve an order that implements those rates over a suitable number of years. The commission shall ensure that the cost of providing service to each customer class is based on the allocation of production-related costs based on using the 75-0-25 method of cost allocation and transmission costs based on using the 100% demand method of cost allocation. The commission may modify this method if it determines that this method of cost allocation does not ensure that rates are equal to the cost of service." *[Emphasis added.]*

Service statute, so that customers are assessed a just and reasonable rate for fair and equitable use of the electric grid.

The Commission has implemented the SRM Capacity Charge in several previous proceedings. However, since the enactment of the SRM statute, the Midcontinent Independent System Operator ("MISO") has changed its rules governing resource adequacy and capacity obligations, which may render the previous Section 6w process obsolete and in conflict with the Cost-of-Service statute.

Q. What should the Commission consider regarding the SRM Capacity Charge?

A. Since MISO capacity requirements and costs are now determined by season – four seasons with differing quantities and costs – the Commission could require that the SRM Capacity Charge also be determined by season, to reflect accurately the operational parameters in the Section 6w statute and to comply with the Cost-of-Service statute.

II-A. Meeting the capacity obligation to MISO.

Q. How does MISO quantify the capacity obligation for a Load Serving Entity ("LSE")?

A. The MISO tariff states how the capacity obligation, called the Planning Reserve Margin Requirement ("PRMR") for every Load Serving Entity ("LSE") in a retail choice area is to be determined. An LSE could be the local utility such as DTE Electric or an Alternative Energy Supplier ("AES").

If a customer has not been assigned to any LSE -- for example, a new customer to the service area -- the "provider of last resort" under the MISO tariff (here, DTE) will be assigned the responsibility to satisfy the capacity obligation attributed to that customer.[7]

Q. How does MISO impose the capacity obligation on LSEs?

A. MISO imposes the capacity obligation on LSEs by charging LSEs the MISO Auction Clearing Price ("ACP") (in dollars) multiplied by the PRMR (in MW) of the LSE.

Q. How does an LSE satisfy its capacity obligation to MISO?

A. MISO charges each LSE for necessary capacity using an amount based on its PRMR (MWs) multiplied by the ACP (dollars), and likewise pays owners of financial rights to capacity assets (known as Zonal Resource Credits or "ZRCs") the same ACP per MW. Consequently, an LSE satisfies its capacity obligation to MISO with payment of money.

II-B. MISO seasonal process affects the SRM Capacity Charge.

Q. What is the MISO seasonal resource adequacy process?

A. After about two years of development, MISO began a process on June 1, 2023, to plan for resource adequacy on a four-season basis, as opposed to the previous annual basis. Virtually every relevant factor – such as load forecasts, Planning Reserve Margin %, PRMR, Local Clearing Requirements, Auction Clearing Prices, accredited capacity values

[7] MISO Module E-1, section 69A.1.1.1.a.

of resources, etc. – are now evaluated and expressed by four seasonal values, not by one annual value. For example, the ACPs for Michigan Zone 7 for summer, fall, winter, and spring of the 2024-2025 Planning Year are $30, $15, $0.75, and $34.10 per MW-day, respectively.[8] These numbers can be compared to DTE's proposed single annual SRM Capacity Charge of $217.30 per MW-day as shown in DTE's SRM Exhibit A-16, Schedule F1.5, page 1 of 6, line 17.

Q. What is the effect of MISO's Seasonal Process on the SRM Capacity Charge?

A. MCL 460.6w(6) states:

> (6) A capacity charge shall not be assessed for any portion of capacity obligations for each planning year for which an alternative electric supplier can demonstrate that it can meet its capacity obligations through owned or contractual rights to any resource that the appropriate independent system operator allows to meet the capacity obligation of the electric provider. The preceding sentence shall not be applied in any way that conflicts with a federal resource adequacy tariff, when applicable. *[Emphasis added.]*

While Energy Michigan will address the legal implications of this section of the statute in its brief, the operational plain meaning is that MISO now allows an LSE to meet its capacity obligation by season, capacity resources (ZRCs) are qualified by season, the payments to MISO for PRMR are by season, the payments by MISO to holders of Zonal Resource Credits are by season. Therefore, the SRM Capacity Charge should be applied by season, not for all seasons in a year via one annual SRM Capacity Charge.

8 https://cdn.misoenergy.org/2024%20PRA%20Results%20Posting%2020240425632665.pdf. See page 2.

Q. What is the cost of satisfying MISO's seasonal capacity requirement?

A. The cost to an LSE of satisfying MISO's seasonal capacity requirement can be determined exactly: it is

- the LSE's PRMR (in MW)
- times the MISO Seasonal Auction Clearing Price (in $ per MW-day)
- times the number of days in the season.

For example, using current prices, if the LSE's obligation were 1 MW for the summer season (June-August), and the summer Auction Clearing Price were $30 per MW-day, then the cost -- MISO's charge to the LSE -- would be:

1 MW x $30 per MW-day x 92 days = $2,760.

Q. If an LSE is capacity deficient for 1 MW under the Commission's demonstration process, and the local utility has to satisfy such deficiency to MISO under Section 6w, what is the cost to the utility?

A. In the example above, if the utility were to pay the MISO bill, then the utility would pay MISO $2,760.

Q. Could the utility use its extra capacity, if any, to satisfy the LSE's deficiency, and if so, what would be the cost?

A. Under the present MISO tariff, the utility could not "use" extra capacity, but rather would offset the payment from MISO for that extra capacity. Prior to 2013, LSEs had to provide

MISO with owned or contracted capacity to satisfy their capacity obligations. Since the beginning of the MISO annual capacity Auction in 2013, LSEs simply pay the money. If an LSE owns qualified capacity in the form of Zonal Resource Credits, then MISO will pay the LSE the same Auction Clearing Price for the capacity credits as it charges the LSE for its PRMR.

Therefore, since under the MISO tariff all Zonal Resource Credits must be offered into the Auction, the utility would pay MISO the $2,760 to satisfy the LSE's capacity obligation. This payment would in effect offset the $2,760 it would receive for 1 MW of Zonal Resource Credits. Thus, the cost to the utility of providing the service of satisfying the deficient LSE's capacity obligation to MISO with "extra capacity" is still exactly $2,760, either way.

II-C. Determine the SRM Capacity Charge by season and set equal to the MISO seasonal Auction Clearing Price.

Q. Could an SRM Capacity Charge that is calculated annually be applied to a seasonal capacity deficiency?

A. An annual SRM Capacity Charge could not be applied and still match the cost of service, since the cost of service is determined by season. By simple arithmetic, it is true that if the utility were to calculate four seasonal SRM Capacity Charges from the same data used for the annual SRM Capacity Charge, then the average of those four seasonal charges (weighted by days in the season) would equal the annual charge, but the application of the

annual charge would equal the cost of four seasonal charges only if the LSE were deficient for all four of the seasons, which may be unlikely considering the Commission is requiring demonstration by season.

Q. If the annual SRM Capacity Charge proposed by DTE were implemented, what would the outcome be?

A. In the previous example for 1 MW of the summer season, where the MISO charge is $2,760, the outcome of the SRM Capacity Charge proposed by DTE would be:

1 MW x $217.30 per MW-day x 92 days = $19,991.60.

As a result, an LSE/customer paying this charge of $19,991.60 would not be paying the straightforward actual cost of the service it receives -- the service of satisfying a 1 MW capacity deficiency in capacity obligations to MISO -- which cost to the utility is exactly $2,760.

Q. How do you recommend the SRM Capacity Charge be determined such that it complies with the Cost-of-Service statute?

A. A workable and fair solution would be to set the SRM Capacity Charge at the MISO seasonal Auction Clearing Price and apply that charge to the MW value of the deficiency, for the days of the season that an LSE is deficient. This would comport exactly with the cost of providing the service -- the service of satisfying the MISO capacity obligation -- that the LSE/customer receives. This option is exactly consistent with the plain words of the Cost-of-Service statute.

Q. Would setting the SRM Capacity Charge at the MISO seasonal Auction price harm full-service customers?

A. Absolutely not. DTE would collect the exact cost of the service it provides to the LSE/customer. DTE would end up in the exact same financial position whether (a) it satisfied the LSE/Customer's capacity obligation to MISO and collected the defined SRM Capacity Charge or (b) did not satisfy the LSE/Customer's capacity obligation to MISO and did not collect the defined SRM Capacity Charge. Either way, full-service customers would not be harmed or even affected.

Q. Would setting the SRM Capacity Charge at the MISO seasonal Auction price be consistent with Section 6w?

A. Energy Michigan will address this further in its brief. Setting the SRM Capacity Charge at the MISO seasonal Auction price is obviously consistent with the Cost-of-Service statute. The plain wording of Section 6w does not appear to have envisioned anything other than an annual charge. Thus Section 6w may be impossible to follow on a seasonal basis in the same way the Commission interpreted it on an annual basis, and the Commission may have to use reasonable judgement in applying Section 6w in a way that harmonizes Section 6w with the Cost-of-Service statute and MISO's new process.

Q. Would setting the SRM Capacity Charge at the MISO seasonal Auction price create a subsidy to DTE's full service customers or to an AES's electric choice customers?

A. No. DTE expresses concerns about subsidies,[9] but there are no subsidies. Both DTE and the AES must satisfy the exact same reserve margin and PRMR obligations, pay the exact same price to MISO for capacity, pay the exact same price for transmission service, and their customers pay the exact same price for distribution service. How there can be a "subsidy" under the current grid rules and procedures, DTE does not specify.

If the SRM Capacity Charge were set at the MISO seasonal Auction price, as explained above, to satisfy a capacity obligation to MISO of $2,760 (quantified in section II-B previously), an AES would pay DTE $2,760 and DTE would pay MISO the same amount $2,760. There is no subsidy.

Under the current and DTE proposed SRM determination, to satisfy a capacity obligation to MISO of $2,760, an AES would pay DTE $19,991.60 (quantified in section II-C), and DTE would pay MISO the $2,760. The difference of $17,231.60 would go to DTE full service customers. That is a subsidy.

Q. Does DTE provide electric choice customers with "temporary capacity"?

A. No. Electric Choice customers do not obtain "temporary capacity" from the local utility — that ceased on April 1, 2005, when MISO began dispatching all the generation in the region to service all the load in the region. For the last 19 years, it has not been accurate

[9] See Mr. Burgdorf, direct testimony, page 11, lines 7-19.

to think that DTE's power plants serve DTE's customers or any other specified group of customers.

Market-based solutions to resource adequacy -- rather than physically tying specific facilities to specific customers -- have existed for the last couple of decades in most all regions. Ownership of generation provides a hedge against the volatility of market prices over time, and DTE is getting compensated for using that hedge to minimize price variation for its full service customers. DTE is not subsidizing anything.

II-D. Recommendation to meet both the SRM statute and the Cost-of-Service statute.

Q. What is your recommendation to the Commission?

A. I recommend that the Commission set the SRM Capacity Charge at the MISO seasonal Auction Clearing Price and apply that charge to the MW value of an LSE's seasonal capacity deficiency, adjusted by the number of days in the season. This determination:

a. follows the Cost-of-Service statute, MCL 460.11(1),

b. keeps the local utility neutral if it has to satisfy another LSE's capacity obligations under MCL 460.6w,

c. allows the Commission to maintain its capacity demonstration requirements by season, and

d. maintains the function of Section 6w that the local utility satisfy the capacity obligation to MISO for any LSE that is deficient of capacity under the demonstration process.

The LSE/customer would pay:

-- seasonal capacity deficiency (MW of seasonal capacity deficiency per the Commission's demonstration process)

-- x MISO seasonal Auction Clearing Price ($ per MW-day)

-- x number of days in the season.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

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	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

EXHIBITS OF

ALEXANDER J. ZAKEM

ON BEHALF OF

ENERGY MICHIGAN, INC.

ALEXANDER J. ZAKEM

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Plymouth, Michigan 48170
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CONSULTANT – MERCHANT ENERGY AND UTILITY REGULATION

Provides strategies and technical expertise on competitive market issues, transmission issues, state and federal regulatory issues involving the electricity business, and associated legal filings. Scope includes the Midwest ISO Energy Market and Resource Adequacy, FERC proceedings on transmission and market tariffs, state rules for competitive supply, and negotiation of settlements.

PRIOR POSITIONS: Quest Energy, LLC – a subsidiary of Integrys Energy Services

Vice President, Operations **March 2002 to December 2003**

Responsible for the planning, acquisition, scheduling, and delivery of annual power supply and transmission, to serve competitive retail electric customers.

- ***Power Planning*** -- Designed and negotiated customized long-term power contracts, to reduce power costs and exposure to spot energy prices.

- ***Transmission*** -- Revamped transmission strategy to reduce transmission costs.

- ***Load Forecasting*** -- Instituted formal short-term forecasting process, including weather normalization.

- ***Risk Management*** -- Developed summer supply strategy including call options to minimize physical supply risk at least cost. Instituted probabilistic assessment of forecast uncertainty to minimize transmission imbalance costs.

- ***Contract Management*** – Negotiated and recovered liquidated damages for power supply contracts. Included cost of transmission losses into customer contracts.

- ***Operations Capability*** -- Expanded the Operations staff. Oversaw daily activity in spot market purchases. Instituted back-up capability, including equipment and processes, enabling the company to schedule and deliver virtually all power during the August 2003 blackout in the Midwest.

PRIOR POSITONS : DTE Energy / Detroit Edison — 1977 to 2001

Director, Power Sourcing and Reliability **May 1998 to April 2001**

Director of group responsible for monthly, annual, and long-term purchases and sales of power for Detroit Edison, including procuring power for the summer peak season.

- ***Planning*** -- Planned summer power requirements for Detroit Edison, including mix of generation, option contracts, hub purchases, load management, and transmission, which balanced and optimized physical risk and financial risk.

- ***Contract Management*** – Established decision, review, and approval process for evaluation and execution of power transactions, including mark-to-market valuation.

- ***Execution*** -- Executed summer plans, contracting annually for purchased power and transmission services. Directed negotiations for customized structured contracts to provide the company with increased operating flexibility, dispatch price choices, and delivery reliability.

- ***Risk Management*** – Developed an optimizing algorithm using load shapes to minimize corporate exposure to volatile power prices. Developed a hedging strategy to fit power purchases to the corporation's risk tolerance level.

- ***Acquisitions*** -- Team leader for acquisition of new peakers.

- ***Settlements*** -- Negotiated and settled liquidated damages claims.

Relevant prior positions within Detroit Edison

Position ***Organization***

Director, Special Projects **Customer Energy Solutions**

Leader of several special projects involving the transformation of the corporation's merchant energy functions into competitive business units, including merger explorations and the start up of DTE Energy Trading (DTE's power marketing affiliate).

Directed filings to the Federal Energy Regulatory Commission to establish DTE Energy Trading as a power marketer and to gain authority for sales, brokering, and code of conduct. The FERC used DTE's flexible utility/affiliate code of conduct as precedent for rulings for other power marketers.

Director, Risk Management **Huron Energy (affiliate)**

Leader of team responsible for competitive pricing of wholesale structured contracts and for acquiring risk management hardware and software to support risk management policy. Prepared Board resolutions to implement risk management policy.

Director, Contract Development — **Customer Energy Solutions**

Leader of team that formulated a business strategy for the corporation in competitive power marketing. Team leader on project evaluating an existing steam and electricity contract, recommending and gaining Board approval for revamping the corporation's Thermal Energy business and strategy.

Project Director — **Executive Council Staff & Corporate Strategy Group**

Project leader for competitive studies, including business risk, generation pooling, and project financing in the merchant generation industry. Team member and/or team leader for analyses of merger and acquisition opportunities

Special Assignment — **Executive Council Staff**

Special assignment related to long-term industry strategies and mergers and acquisitions.

Pricing Analyst — **Marketing / Rate**

Developed, negotiated, and implemented an innovative standby service tariff. Testified as an expert witness in regulatory proceedings and in state legislative hearings.

Engineer — **Resource Planning**

Member of the company's electric load forecasting team, responsible for SE Michigan energy and peak demand forecasting, and for risk analysis. Developed the company's first residential end-use forecast model.

EDUCATION: M. A. in mathematics, University of Michigan
B. S. in mathematics, University of Michigan

MILITARY: U. S. Army, Viet Nam service. Honorably discharged.

PROFESSIONAL: Member, Engineering Society of Detroit

PUBLICATIONS & PAPERS:

- "Competition and Survival in the Electric Generation Market," published in *Public Utilities Fortnightly*, December 1, 1991.
- "Measuring and Pricing Standby Service," presented at the Electric Power Research Institute's "Innovations in Pricing and Planning" conference, May 3, 1990.
- "Assessing the Benefits of Interruptible Electric Service," presented at the 1989 Michigan Energy Conference, October 3, 1989.
- "Principles of Standby Service," published in *Public Utilities Fortnightly*, November 24, 1988.
- "Progress in Conservation," a satirical commentary published in *Public Utilities Fortnightly*, October 27, 1988.
- "Comparing Utility Rates," published in *Public Utilities Fortnightly*, November 13, 1986.
- "Uncertainty in Load Forecasting," with co-author John Sangregorio, published in *Approaches to Load Forecasting*, Electric Power Research Institute, July 1982.

PREVIOUS RECENT TESTIMONY :

- Michigan Public Service Commission, U-21389.
- Michigan Public Service Commission, U-21297.
- Michigan Public Service Commission, U-21224.
- Michigan Public Service Commission, U-21193.
- U.S. District Court, Eastern District of Michigan, Southern Division, Case No. 2:20-cv-12521.
- Michigan Public Service Commission, U-21090.
- Michigan Public Service Commission, U-20963.
- Michigan Public Service Commission, U-20836.
- Michigan Public Service Commission, U-20697.
- Michigan Public Service Commission, U-20561.
- Michigan Public Service Commission, U-20359.
- Michigan Public Service Commission, U-20471.
- Michigan Public Service Commission, U-20162.
- Michigan Public Service Commission, U-20134.
- Michigan Public Service Commission, U-18248.
- Michigan Public Service Commission, U-18239.

Fuel Subtraction

"Fuel" subtracted from Net Production Costs in the SRM calculation is the cost-of-service fuel expense in this case.

Line No.	(a) DTE Component	(b) Value ($000)	(c) Source	(d) Notes
1	"Fuel"	**$914,888**	**Cost of Service**, Exh A-16, Sch F1.1, line 6, col (a).	This is the fuel expense in this case, in the cost of service study.
2				
3	**"Less Fuel"**	**$914,888**	**SRM Calculation**, SRM exhibit, Exh A-16, Sch F1.5, page 1 of 6, line 2, col (a).	This is "Fuel" subtracted from Net Production Costs Rev Req, which is line 1 on the SRM exhibit.

"Other Energy" Subtraction

"Other Energy" subtracted from Net Production Costs in the SRM calculation is the difference between total PPA costs and imputed capacity-related generation cost. It is not fuel.

Line No.	(a) DTE Component	(b) Value ($000)	(c) Source	(d) Notes
1	"Total PURPA/PA2, Total Fuel-Related Generation Cost"	$2,925	Exh A-26, Sch P1, page 1, line 12, col (f).	DTE explained that "Fuel-Related Generation Cost" is the difference between total cost and imputed capacity cost. [See note A below.] It is not fuel.
2				
3	"Total PA295/PA342 Fuel-Related Generation Cost"	$257,862	Exh A-26, Sch P2, page 1, line 40, col (j).	DTE explained that "Fuel-Related Generation Cost" is the difference between total cost and imputed capacity cost. [See note B below.] It is not fuel.
4		----------		
5	*Total above*	***$260,787***		
6				
7	**"Less Other Energy in PP"**	**$260,787**	**SRM Calculation**, SRM exhibit, Exh A-16, Sch F1.5, page 1 of 6, line 4, col (a).	"Other Energy" expense subtracted from Net Production Costs Rev Req, which is line 1 on the SRM exhibit.
8				
9				
10	A. On Exh A-25, P1, DTE adds footnote 1:			
11	*"Note 1: Fuel Related Generation Cost based on the difference of total projected PURPA PSCR Cost and the Capacity Related Generation Cost."*			
12				
13	B. On Exh A-25, P2, DTE adds footnote 1:			
14	*"Note 1: Fuel Related Generation Cost based on the difference of total projected PA295 PSCR Cost and the Capacity Related Generation Cost."*			

Fuel from 2024 PSCR Plan

Michigan Public Service Commission
DTE Electric Company
Fuel Expense Forecast
Years 2024 - 2028

Case No.: U-21425
Exhibit: A-14
Witness: K. A. Maro
Page: 1 of 1

Line No.	(a) Description	(b) 2024	(c) 2025	(d) 2026	(e) 2027	(f) 2028
1	Coal*					
2	MBtu (000)	186,962	189,524	156,499	134,934	137,665
3	¢/MBtu	275	265	264	276	278
4	$ (000)	514,644	501,380	413,451	372,144	382,094
5						
6	No.2 Oil*					
7	MBtu (000)	486	498	391	285	289
8	¢/MBtu	2,039	1,913	1,812	1,795	1,748
9	$ (000)	9,912	9,519	7,080	5,120	5,059
10						
11	Natural Gas					
12	MBtu (000)	66,419	66,489	73,862	73,142	80,419
13	¢/MBtu	401	466	512	558	572
14	$ (000)	266,449	309,871	378,491	408,467	460,112
15						
16	Petroleum Coke					
17	MBtu (000)	20,450	20,981	20,167	21,151	21,454
18	¢/MBtu	273	296	306	304	300
19	$ (000)	55,919	62,005	61,664	64,261	64,383
20						
21	Total Fossil					
22	MBtu (000)	274,317	277,492	250,919	229,512	239,827
23	¢/MBtu	309	318	343	370	380
24	$ (000)	846,924	882,774	860,685	849,991	911,649
25						
26	Nuclear Fuel					
27	MBtu (000)	81,060	92,281	80,791	92,281	82,326
28	¢/MBtu	65	66	71	73	77
29	$ (000)	52,587	61,053	57,361	67,020	63,437
30						
31	All Fuels (including Steam)					
32	MBtu (000)	355,377	369,773	331,710	321,793	322,153
33	¢/MBtu	253	255	277	285	303
34	$ (000)	899,511	943,827	918,046	917,011	975,086
35						
36	Fuel Expense for Steam Sales					
37	$ (000)	(3,136)	(3,582)	(4,005)	(4,311)	(4,511)
38						
39	Electric Generation Fuel Expense (excluding Steam)					
40	$ (000)	896,375	940,245	914,041	912,700	970,575
41						
42	* - Excludes MPPA's portion of Belle River					

"Other Energy" in Projected Fuel

The "Other Energy" expense of $260,787 -- which is the difference between total PPA costs and imputed capacity-related generation cost -- is added to the fuel cost in DTE's 2024 PSCR Plan to get the "Fuel"/ "Total Projected 2025 Fuel Generation Expense" value for the SRM calculation in this case.

The Total, Projected 2025 Fuel Generation Expense, therefore, is more than simply "fuel."

Line No.	(a) DTE Component	(b) Value ($000)	(c) Source	(d) Notes
1	**"Less Other Energy in PP"**	**$260,787**	**SRM Calculation**, SRM exhibit, Exh A-16, Sch F1.5, page 1 of 6, line 4, col (a).	"Other Energy" expense subtracted from Net Production Costs Rev Req, which is line 1 on the SRM exhibit.
2				
3	"Generation & Fuel - $1,000	**$940,245**	**Case No. U-21425**, DTE 2024 PSCR Plan, Exh A-3, page 1 of 1, line 3, col (c), "2025".	This is the DTE projected fuel value for 2025 in its 2024 PSCR Plan, Case No. U-21425.
4		----------		
5	*Total of above*	***$1,201,032***		
6				
7	**"Fuel"**	**$1,201,032**	Exh A-26, Sch P3, page 1 of 1, line 20, col (b).	DTE "Fuel" is a combination of (a) an actual fuel value from the 2024 PSCR Plan case and (b) "Other Energy," which is the difference between total PPA costs and capacity-related generation costs.
8				
9	**"Total Projected 2025 Fuel Generation Expense"**	**$1,201,032**	Exh A-26, Sch P3, page 1 of 1, line 21, col (b).	Same value as line 7. The summation line in Exh A-26, P3. But only the $940,245 portion of this is actually fuel.

Adjustments to SRM

DTE Proposed vs. Energy MI Revisions

Line No.	(a)	(b)		(b) DTE Proposed A-16,F1.5, p1	(c) Energy MI Adjusted	(d) Comments
	CAPACITY COSTS DETERMINATION					
1	Net Production Costs Rev Req		$	3,213,177	3,213,177	No change. DTE proposed.
2	Less Fuel			(914,888)	(914,888)	No change. Fuel from C.O.S.
3	Less MER Rev Req			(6,463)	(6,463)	No change. Non-capacity
4	Less MISO Energy in PP			(40,376)	(40,376)	No change. Non-capacity.
5	Less Other Energy in PP			(260,787)	(260,787)	No change. Non-capacity.
6	Less Variable O&M			(33,569)	(33,569)	No change. Non-capacity.
7	Subtotal	= sum lines 1-6	$	1,957,094	1,957,094	No change.
8						
	9a Energy Sales Offset Breakdown:					
	9b Total Projected 2025 Energy Sales Rev		*$*	*(2,184,379)*	*(2,184,379)*	*No change.*
	9c Fuel from 20245 PSCR Plan			*940,245*	*940,245*	*No change. From 2024 PSCR Plan.*
	9d Imputed fuel-related gen PURPA/PA2			***2,925***	***0***	*- Not actual fuel. Delete.*
	9e Imputed fuel-related gen PA295/PA342			***257,862***	***0***	*- Not actual fuel. Delete.*
	9f Total fuel	*= lines 9c+9d+9e*		***1,201,032***	***940,245***	
9	Proj 2025 Energy Sales Rev Net of Fuel	= line 9b+line 9f		(983,347)	**(1,244,134)**	**Re-calculation.**
10						
11	Capacity Charge Revenue Requirement	= line 7+line 9	$	973,747	**712,960**	**Re-calculation.**
12						
13	SRM Capacity Charge Demand			12,277 MW	12,277	No change.
14						
15	SRM Capacity Charge per MW-Year	= line 11/ line 13	$	79,315	**58,073**	**Re-calculation.**
16						
17	SRM Capacity Charge per MW-Day	= line 15 / 365	$	217.30	**159.10**	**Re-calculation.**

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	)	Case No. U-21534
its rate schedules and rules governing the	)	
distribution and supply of electric energy, and	)	
for miscellaneous accounting authority.	)	

PROOF OF SERVICE

COMMONWEALTH OF VIRGINIA	)
	) ss.
COUNTY OF PRINCE WILLIAM	)

Keri D. Click, the undersigned, being first duly sworn, deposes and says that she is a Paralegal at Potomac Law Group PLLC and that on the 26th day of July, 2024 she served a copy of the Direct Testimony and Exhibits of Alexander J. Zakem on Behalf of Energy Michigan, via email, upon those individuals listed on the attached Service List.

Keri D. Click

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