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July 20, 2026

Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

RE: In the matter of the Application of **DTE ELECTRIC COMPANY** for Approval of Special Contracts and for other relief
MPSC Case No. U-22058

Dear Ms. Felice:

Attached for electronic filing in the above referenced matter is DTE Electric Company's Initial Brief (Public). Also Attached is the Proof of Service.

Very truly yours,

John A. Janiszewski

Digitally signed by John A. Janiszewski
Date: 2026.07.20 16:54:04 -04'00'

John A. Janiszewski

JAJ/erb
Encl.

cc: Service List

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
DTE ELECTRIC COMPANY	)	Case No. U-22058
for approval of special contracts and	)	
related relief	)	

DTE ELECTRIC COMPANY'S

PUBLIC

INITIAL BRIEF

Dated: July 20, 2026

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I. INTRODUCTION

DTE Electric Company ("DTE Electric" or the "Company") respectfully requests that the Michigan Public Service Commission ("MPSC" or the "Commission") approve the Company's Primary Supply Agreement ("PSA")[1] and Clean Capacity Accelerator Agreement ("CCAA")[2] (collectively, the "Special Contracts") with Google LLC (the "Customer"). Together, the Special Contracts provide a lawful, reasonable, and prudent framework for DTE Electric to provide service to the Customer and therefore should be approved.

DTE Electric and the Customer have structured the Special Contracts to hold other customers harmless. As the record demonstrates, the Special Contracts ensure that the costs of serving the Customer are not shifted to other customers and strengthen the Company's ability to fulfill its duty to serve a new, large-load customer without adverse impact to the existing customer base. Critically, the record establishes that the Special Contracts produce a benefit for DTE Electric's other customers, which the Company's analysis in this proceeding estimates at approximately $1.7 billion.

Additionally, the Special Contracts meaningfully advance Michigan's clean energy objectives, consistent with 2023 PA 235, MCL 460.1001 *et seq*., and Commission precedent, by developing up to 1,600 MW of new renewable energy projects and up to 480 MW of new energy storage projects at the Customer's expense, and reducing the Renewable Energy Credits ("RECs") the Company must otherwise procure in its forecast.

The public interest will be served by approval of the Special Contracts by contribution to the fixed costs that would otherwise be recovered by customers through both rate base and PSCR

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[1] *See* Exhibit A-16 and Exhibit A-22.

[2] *See* Exhibit A-18.

surcharges, creating the customer benefit, as well as through the construction of up to 1,600 MW of renewable energy projects and up to 480 MW of energy storage projects, fully funded by the Customer, that provide additional benefits to the broader electrical grid.

To the extent this Initial Brief responds to positions advanced by Staff and intervenors in their testimony, those responses are not intended to be exhaustive. The Company reserves the right to respond more fully to its arguments concerning any Staff or intervenor position in its Reply Brief, including after review of the arguments in the parties' Initial Briefs. The absence of a response to any particular position set forth in Staff and intervenor testimony should not be treated as agreement with that position; the Company maintains that the record as a whole supports approval of the Special Contracts as set forth herein.

II. HISTORY OF PROCEEDINGS

On March 17, 2026, DTE Electric filed its Application, with supporting testimony and exhibits, requesting that the Commission grant expedited approval of the Company's Special Contracts with the Customer on or before September 10, 2026, to satisfy conditions precedent.

On April 15, 2026, a prehearing conference was held before Administrative Law Judge Theresa A.G. Staley ("ALJ"). Commission Staff ("Staff") filed an appearance in this proceeding. Intervention was granted to the Michigan Attorney General ("AG"); the Association of Businesses Advocating Tariff Equity ("ABATE"); the Michigan Environmental Council, Natural Resource Defense Council, and Sierra Club (collectively, "MNS"); the Environmental Law & Policy Center, Ecology Center, Union of Concerned Scientists, Vote Solar (collectively, the Clean Energy Organizations ("CEO")), the Michigan Energy Innovation Business Council ("MEIBC"), and the Institute for Energy Innovation ("IEI") (collectively, "MEICEO"); and the Great Lakes Renewable Energy Association ("GLREA"). At the prehearing conference, the ALJ confirmed that the

Commission has elected to read the record in this proceeding without issuance of a proposal for decision. (1T 9; *see also* MCL 24.281(1)). On April 30, 2026, the ALJ entered a protective order.

DTE Electric sponsored the Direct Testimony and Exhibits of the following six Company Witnesses:

- Neal T. Foley, Director of Electric Marketing (Qualifications and Revised Direct Testimony at 3T 84-128);
- Kevin L. Bilyeu, Director of Renewable Energy Planning and Strategy (Qualifications and Direct Testimony at 3T 271-287);
- Shawn D. Burgdorf, Manager of Market Strategy and Settlements within Generation Operations (Qualifications and Direct Testimony at 3T 365-389);
- Aaron Willis, Director of Regulatory Affairs (Qualifications and Direct Testimony at 3T 404-415);
- Justin J.W. Brooks, Project Lead – PowerGEM (Qualifications and Direct Testimony at 3T 431-441); and
- Steven N. Benyard, Vice President of Distribution Operations Capital Delivery (Qualifications and Direct Testimony at 3T 444-451).

On June 5, 2026, Staff and intervenors filed their direct testimony and exhibits. Staff sponsored the Direct Testimony and Exhibits of Cody S. Matthews (3T 815-827), Naomi J. Simpson (3T 829-849), David W. Isakson (3T 851-883), and Katie J. Smith (3T 885-891). The AG sponsored the Direct Testimony and Exhibits of Sebastian Coppola (3T 461-515). ABATE sponsored the Direct Testimony and Exhibit of James R. Dauphinais (3T 520-555). MNS sponsored the Direct Testimony and Exhibits of Bryndis A. Woods (3T 613-653). MEICEO sponsored the Direct Testimony and Exhibits of William D. Kenworthy (3T 655-699), Chelsea

Hotaling (3T 701-728), Lee Shaver (3T 730-762), and Laura S. Sherman (3T 764-812). GLREA sponsored the Direct Testimony and Exhibits of John Richter (3T 558-610).

On June 17, 2026, DTE Electric filed the Rebuttal Testimony and Exhibits of Company Witnesses Neal T. Foley (3T 129-167), Kevin L. Bilyeu (3T 288-314), Shawn D. Burgdorf (3T 390-403), Aaron Willis (3T 416-429), and Steven N. Benyard (3T 452-457). On that same date, Staff filed the Rebuttal Testimony of Cody S. Matthews (3T 824-827) and Naomi J. Simpson (3T 847-849) to address certain recommendations in MEICEO witness Sherman's direct testimony. No other parties filed rebuttal testimony.

Evidentiary hearings were held before the ALJ on June 30, 2026, and July 1, 2026. DTE Electric's Initial Brief is being filed in accordance with the case schedule issued by the ALJ in this proceeding.

III. JURISDICTION AND STANDARD OF REVIEW

The Commission has jurisdiction over this matter pursuant to 1909 PA 106, as amended, MCL 460.51 *et seq*., and 1939 PA 3, as amended, MCL 460.1 *et seq*., including MCL 460.6 and MCL 460.10, and, as to the Voluntary Green Pricing ("VGP") Special Contract arising from the CCAA, pursuant to 2008 PA 295, as amended by 2023 PA 235, MCL 460.1001 *et seq*., including MCL 460.1061.

As a threshold matter, the approvals requested in DTE Electric's Application will not increase the cost of service to the Company's other customers. Therefore, the approvals sought by the Company "may be authorized and approved without notice or hearing." MCL 460.6a(3). Nevertheless, although the Company has not waived the foregoing right to seek *ex parte* treatment of special contracts, the Company filed its Application as a contested case. *See*, Application ¶ 16.

The Company has an obligation to serve customers who locate within its service territory. MCL 462.4(a); MCL 460.54. The Special Contracts implement that obligation to the Customer and are properly before the Commission for approval under the authorities cited above. The Commission's authority to approve special contracts, and the principle that the approval of a special contract does not itself constitute ratemaking, is well established. The Michigan Court of Appeals has squarely held that "merely approving and implementing a special contract is not sufficient, in and of itself, to cause any rate or cost of service increase to occur," and that any future rate or cost-of-service effects are properly addressed in a subsequent rate case in which all interested parties may participate. *Attorney General v Pub Serv Comm*, 227 Mich App 148, 154-155 (1997), *appeal den*, 459 Mich 910 (1998); *see also Attorney General v Pub Serv Comm*, 206 Mich App 290, 295-298 (1994).

The Commission's authority in this proceeding is defined, and bounded, by statute. The Commission is a creature of the Legislature possessing only express authority granted to it by statute, and it has no common-law or inherent powers. *Union Carbide Corp v Pub Serv Comm*, 431 Mich 135, 148-149; 428 NW2d 322 (1988); *see also Consumers Power Co v Pub Serv Comm*, 460 Mich 148, 155; 596 NW2d 126 (1999). The power to fix and regulate rates does not carry with it, either explicitly or by necessary implication, the power to make management decisions. *Union Carbide,* at 148-149. While the State may regulate with a view to enforcing reasonable rates and charges, "it is not the owner of the property of public utility companies and is not clothed with the general power of management incident to ownership." *Id*. Hence, the Commission's role with respect to the Special Contracts is accordingly to approve, or to decline to approve, the PSA and CCAA as presented. The Commission, however, possesses no statutory authority to reform, rewrite, or nullify the contracting parties' negotiated bargain, or to compel the Company and the

Customer to accept terms to which they did not agree. Where the Commission concludes that a special contract should not be approved as presented, its remedy is to decline approval — not to rewrite the contract or order it modified or rescinded. This limitation bears directly on several intervenor recommendations, which do not merely urge rejection but ask the Commission to rewrite specific, negotiated commercial terms of the Special Contracts. Such recommendations would require the Commission to impose a bargain the parties never struck, exceeding the Commission's authority. Notably, the Company's voluntary acceptance of certain reporting obligations does not enlarge that authority; it reflects the Company's acquiescence, not a Commission power to rewrite the Special Contracts over the contracting parties' objection.

As to the VGP Special Contract arising from the CCAA, the Commission's jurisdiction and approval authority derive from the Clean and Renewable Energy and Energy Waste Reduction Act, 2008 PA 295, as amended by 2023 PA 235, and in particular MCL 460.1061, which authorizes and governs the establishment and approval of VGP programs through which an electric provider procures renewable energy on behalf of a participating customer. Moreover, the VGP Special Contract is governed by the terms of the Commission-approved settlement agreements in Case Nos. U-20713 and U-20851, as well as Case No. U-21172 (collectively, the "VGP Settlement Agreements"). The VGP Special Contract is a customer-specific application of MCL 460.1061, as established in the VGP Settlement Agreements, and its approval is consistent with the Commission's recognition in Case No. U-21990 that VGP programs may be an appropriate vehicle for a large-load customer's renewable procurement. Case No. U-21990 Order dated December 18, 2025, p. 42 ("December 18 Order").

As to the related Rider 12 Demand Response ("DR") Agreement, the Customer's election of Rider 12 is not before the Commission for approval in this proceeding. Rider 12 is an existing, Commission-approved provision of the Company's Rate Book for Electric Service, and the Customer's election of Rider 12 is a standard tariff selection made pursuant to that approved tariff. Because Rider 12 is already an approved component of the Company's Rate Book, the Customer's election does not constitute a "special contract" requiring distinct approval in this proceeding, and does not "alter, change, or amend any rate or rate schedule" within the meaning of MCL 460.6a(1). The Rider 12 agreement is described in the record solely to provide context for the Company's overall service arrangement with the Customer and the DR commitments that support the Special Contracts. To the extent any party seeks to challenge, modify, or condition the terms of Rider 12 itself, such matters are outside the scope of this special contract proceeding and must be raised in an appropriate tariff or general rate case proceeding.

The December 18 Order provides applicable Commission precedent and an analytical framework for approving the Special Contracts.[3] There, the Commission conditionally approved DTE Electric's primary supply agreement and energy storage agreement to serve a different large load customer, resting its approval on a set of now-familiar elements, including: (i) a customer's contribution to fixed system costs through Rate D11 and the PSCR surcharge, producing a benefit to other customers; (ii) enhanced terms of service beyond standard Rate D11 — including an extended contract term, 80% minimum billing demand, termination payment, and credit and collateral requirements — that mitigate the risk of stranded costs and cost subsidization; (iii) the

[3] The Company recognizes that Case No. U-21990 was decided on an *ex parte* basis under MCL 460.6a(3), which authorizes approval "without notice or hearing" of an alteration or amendment in rates or rate schedules "that will not result in an increase in the cost of service to [the utility's] customers." The dispositive threshold question in U-21990 was therefore whether the special contracts qualified for *ex parte* treatment — a question the Commission properly answered in the affirmative. However, the procedural distinction between this contested case proceeding and Case No. U-21990 does not diminish proper application of the Commission's substantive findings in the latter. The reasonableness of the enhanced terms of service beyond Rate D11, the sufficiency of the credit and collateral package, the propriety of deferring cost allocation to future rate cases, and the public-interest benefits of a customer-funded resource commitment — do not depend on the *ex parte* posture and apply with equal force where, as here, those findings are supported by a contested record.

condition that a customer's obligations “will at least cover the costs to serve the Customer (including generation, transmission, distribution, or other costs)” so that those costs “are not covered by other customers”;[4] and (iv) the requirement that DTE Electric bear all risk associated with the sufficiency of collateral, such that "any unrecovered costs shall not be borne by ratepayers."[5]

The Commission presently considers each special contract on a case-by-case basis.[6] Nothing in this brief asks the Commission to treat Case No. U-21990 as compelling automatic approval; rather, the Company demonstrates that the record here independently satisfies, by a preponderance of the evidence, the same standards the Commission applied in U-21990 and demonstrates that the Special Contracts are reasonable, prudent, and in the public interest.[7]

The preponderance of evidence standard applies in this proceeding. *Aquilina v General Motors Corp*, 403 Mich 206, 210-211; 267 NW2d 923 (1978) (“The proof required in an administrative proceeding…is the same as that required in a civil judicial proceeding: a preponderance of the evidence.”). The preponderance of evidence standard is the lightest of all evidentiary standards when compared to the heightened “clear and convincing” standard[8] or the “beyond a reasonable doubt” standard that is only applicable to criminal proceedings.[9] The “preponderance of the evidence” standard is generally defined as follows:

> The greater weight of the evidence, not necessarily established by the greater number of witnesses testifying to a fact but by evidence that has the most

[4] December 18 Order, p. 43.

[5] *Id*. at 41.

[6] *Id*. at 39.

[7] The approval of special contracts “requires an evaluation of the public interest.” Case No. U-10646 Order dated March 23, 1995, p. 18, n. 8; *see also* December 18 Order, p. 32.

[8] *In re Moss*, 301 Mich App 76, 89-90; 836 NW2d 182 (2013).

[9] *Thangavelu v Dep’t of Licensing & Regulation*, 149 Mich App 546, 554-555; 386 NW2d 584 (1986).

> convincing force; superior evidentiary weight that, though not sufficient to free the mind wholly from all reasonable doubt, is still sufficient to incline a fair and impartial mind to one side of the issue rather than the other. [*Black's Law Dictionary* 1301 (9^{th} ed 2009).]

DTE Electric has the initial burden to prove its case by a preponderance of the evidence. "[O]nce a utility has satisfied its initial burden of proof, another party 'may challenge that evidence and present evidence of unreasonableness.' However, at that point, the other party has the burden to demonstrate its position is correct.'" October 25, 2017, Commission Order in Case No. U-18224, pp. 14-15, quoting January 11, 2010, Commission Opinion and Order in Case Nos. U-15768 and U-15751, p 38. This evidentiary standard also effectively bars last-minute criticisms of the Company's evidentiary presentation, as the Commission further explained:

> The Commission finds that a delicate balance must be maintained concerning the burden of proof. The company has the burden of going forward and demonstrating that it has proposed just and reasonable rates. In this instance, Detroit Edison made that showing. The Staff in response may challenge that evidence and present evidence of unreasonableness. At that point, however, the Staff has the burden to demonstrate its position is correct. The company may then rebut the Staff's criticisms of its case. The problem here is that the specific criticism that the company had not adequately explained itself came too late in the process for a fair determination on that issue, particularly given the evidence the company presented in support of its position. [January 11, 2010, Commission Opinion and Order in Case Nos. U-15768 and U-15751, pp 37-38.]

All Commission decisions must be authorized by law, and the Commission's findings must "be supported by competent, material and substantial evidence on the whole record." Const 1963, art 6, § 28; MCL 24.306. Substantial evidence is evidence "that a reasoning mind would accept as sufficient to support a conclusion." *Monroe v State Employees' Retirement Sys*, 293 Mich App 594, 607; 809 NW2d 453 (2011). Expert testimony is "substantial" only if it is offered by a qualified expert who has an informed and rational basis for his or her view, even if other experts disagree. *Great Lakes Steel v Pub Serv Comm*, 130 Mich App 470, 481; 334 NW2d 321 (1983).

This is a contested case proceeding conducted pursuant to the Michigan Administrative Procedures Act ("APA"), 1969 PA 306, as amended, MCL 24.201 *et seq.*, which precludes the Commission from making decisions based on non-record materials. MCL 24.276 provides: "Evidence in a contested case . . . shall be offered and made part of the record. Other factual information or evidence shall not be considered in determination of the case except as permitted under [MCL 24.277 concerning official notice of judicially cognizable facts and facts within the agency's specialized expertise]."[10] Noncompliance with the APA is reversible error. *In re Pub Serv Comm Guidelines for Transactions Between Affiliates*, 252 Mich App 254, 267; 652 NW2d 1 (2002).

In *Kar v Hogan*, 399 Mich 529, 539; 251 NW2d 77 (1976), the Michigan Supreme Court explained that "[t]he party alleging a fact to be true should suffer the consequences of a failure to prove the truth of that allegation." Thus, unproven allegations cannot stand in the place of evidence. Things not proven must be taken as not existing, since a decision cannot be based upon conjecture. *Star Steel v USF&G*, 186 Mich App 475, 481; 465 NW2d 17 (1990); see also, *Skinner v Square D Co*, 445 Mich 153; 516 NW2d 475 (1994).

IV. OVERVIEW OF THE SPECIAL CONTRACTS AND RELATED AGREEMENTS

The Customer (Google LLC) is a subsidiary of Alphabet Inc., a well-known technology company that is the third largest company in the United States by market capitalization. (Foley, 3T 92-93). The Customer plans to cause to be constructed and commission a data center facility in DTE Electric's service territory located at or near Van Buren Twp, Michigan (the "Facility"). The Facility's maximum load is approximately 1.0 gigawatt ("GW") and can begin taking service

[10] This standard is not satisfied with regard to contested issues. *See, e.g., Freed v Salas*, 286 Mich App 300, 341; 780 NW2d 844 (2009), where the Court of Appeals affirmed the trial court's refusal to take judicial notice of a speed limit.

as early as December 2027 with max load being achieved as early as December 2028. (Foley, 3T 93).

Following extensive negotiations between DTE Electric and the Customer, the parties executed the Special Contracts that will become effective upon Commission approval in this proceeding. The Special Contracts are included as Exhibit A-16 (PSA)[11] and Exhibit A-18 (CCAA) to Company Witness Foley's revised direct testimony.

The PSA, Exhibit A-16, stipulates that the Customer will receive electric service under the Company's Rate Schedule D11 ("D11"), including all associated surcharges, which is the Company's Primary Supply Rate. The PSA also establishes additional protections for the Company's other customers that are not included in D11. Importantly, the PSA ensures that the aggregate benefits of the Special Contracts, including revenues received from the Customer and avoided costs realized through the Special Contracts, outweigh the costs of serving the Customer's load. If aggregate benefits do not outweigh the costs, the Customer will pay the difference. (Foley, 3T 87-88).

The CCAA, Exhibit A-18, allows the Company to deploy a portfolio of up to 480 MW of energy storage projects and up to 1,600 MW of renewable energy projects, and recover from the Customer the full cost of these projects. Therefore, the costs of the energy storage and renewable energy projects developed to fulfill the CCAA with the Customer will not be passed on to the Company's other customers. In addition, the CCAA allows the Company to receive from the Customer 300 MW of Midcontinent Independent System Operator ("MISO") Zone 7 Zonal

[11] Exhibit A-22 reflects an amendment to Section 7.3(3) of the PSA that Company Witness Foley sponsors in his rebuttal testimony. Insofar as Section 7.3(3) of the PSA was amended, the term "Commencement Date" was replaced with "Load Ramp Completion Date" to correct a drafting error. (3T 136).

Resource Credits ("ZRCs") at no cost. (Foley, 3T 88). The ZRCs will be provided by the Customer from June 1, 2028, to May 31, 2033. (Foley, 3T 107).

The Customer will receive capacity and renewable generation credits for the projects that are deployed and the ZRCs that are received as part of the CCAA. As Company Witness Foley emphasizes, the credits received by the Customer for a given project or transferred ZRC cannot be greater than the incremental market revenues that are generated by that project or ZRC for a given billing period. This ensures that the Company's other customers do not bear any costs of CCAA resources. (Foley, 3T 88).

As Company Witness Foley explains, the PSA and CCAA do not displace the Company's standard D11; rather, they require the Customer to take service on D11 — including all associated surcharges — while layering on a series of additional, customer-protective terms that D11 does not otherwise provide. Company Witness Foley's Table 1 (Foley, 3T 89) compares each material term of the Special Contracts against the standard D11, which demonstrates that each deviation from standard D11 operates to the benefit of the Company's other customers.

Term-by-term, Company Witness Foley's Table 1 (Foley, 3T 89) confirms the following:

- **Contract Duration.** The Special Contracts bind the Customer for a 20-year term, as compared to the 5-year term of a standard D11 arrangement — a four-fold increase in the Customer's committed period of service.
- **Pricing and Ability to Change Rates.** The Customer pays D11 pricing under both, but the Special Contracts materially constrain the Customer's ability to switch rate schedules. Whereas standard D11 imposes only a 12-month restriction on rate changes, the PSA permits a rate-schedule change only if: (i) the Customer gives 24 months' advance notice; (ii) the change takes effect no earlier than 24 months after the Load Ramp Completion

Date; (iii) the new rate schedule was approved by the Commission after the PSA became effective; and (iv) the new rate schedule is not cross-subsidized by any other customer group. These limitations ensure any future rate change is vetted through a subsequent rate case and does not shift costs to other customers. (Foley, 3T 89, 96).

- **Minimum Billing Demand ("MBD").** The Special Contracts require an 80% MBD, materially higher than the 50-65% demand ratchets applicable under standard D11 — ensuring the Customer pays for a substantially larger share of its contracted capacity regardless of actual usage.
- **Contract Capacity Reductions.** Under the Special Contracts, the Customer cannot reduce its contract capacity, whereas standard D11 does not address capacity reductions beyond the initial term and ratchets.
- **Termination Payment.** The Special Contracts require a termination payment ensuring the Customer pays 15 years of MBD payments — a protection not addressed under standard D11.
- **Affordability Backstop.** The Special Contracts obligate the Customer to ensure that the aggregate benefits of the Special Contracts exceed their aggregate costs — a protection with no counterpart in standard D11.
- **Energy Waste Reduction.** The Customer commits to a self-directed Energy Waste Reduction ("EWR") plan, a commitment not addressed under standard D11.
- **Credit and Collateral Requirements.** The Special Contracts impose credit and collateral requirements, whereas standard D11 contains no specific requirement.

- **Direct Payment of Energy Storage.** Under the CCAA, the Customer directly funds up to 480 MW of energy storage, including up to 55 MW of long-duration storage — an obligation with no analog in standard D11.
- **Direct Payment of Renewable Energy.** Under the CCAA, the Customer directly funds up to 1,600 MW of renewable energy, which is likewise not addressed under standard D11.

In sum, Company Witness Foley's Table 1 confirms that the Special Contracts are more protective of the Company's other customers than standard Rate D11 in every respect in which they differ: they secure a longer commitment, a higher MBD, a robust termination payment, an affordability backstop, and customer-funded clean-energy resources — none of which a large-load customer, or any customer, taking standard Rate D11 service would be required to provide. These enhanced terms of service beyond Rate D11 are the core mechanism by which the Special Contracts hold other customers harmless while enabling the Company to serve the Customer pursuant to mutually agreed upon contractual terms and conditions.

The Rider 12 DR Agreement and Line Extension Agreement ("LEA") are two "Related Agreements," as defined in the PSA, that support the Company's provision of electric service to the Customer. However, the Rider 12 DR Agreement and LEA are standard contracts that the Company is not seeking Commission approval of in the instant case. (Foley, 3T 90). The Rider 12 agreement commits the Customer when called to reduce its electrical demand at its Facility to 650 MW between June 2027 through May 2033. *Id*. The LEA commits the Customer to pay for up to $50 million of distribution upgrades to serve their Facility. *Id*.

V. THE SPECIAL CONTRACTS ARE REASONABLE AND PRUDENT AND IN THE PUBLIC INTEREST.

The Special Contracts hold other customers harmless from any net cost of serving the Customer's load — through the 80% MBD, the termination payment, the credit and collateral requirements, the Company's acceptance of the U-21990 collateral-sufficiency condition, and the Affordability Backstop of PSA Section 5.1.3.

A. Primary Supply Agreement

The PSA, Exhibit A-16, governs the electric service the Company will provide to the Customer and is, at its foundation, an agreement to take service on the Company's existing, cost-based Rate D11, including all applicable surcharges, supplemented by a series of additional terms that Rate D11 does not otherwise require. (Foley, 3T 94). As Table 1 demonstrates in Company Witness Foley’s revised direct testimony, the additional terms operate to the benefit of the Company's other customers, including a longer contract commitment, tighter restrictions on rate switching, a higher minimum billing demand, load-ramp and contract-capacity protections, a substantial termination payment, an affordability backstop, a self-directed EWR commitment, and robust credit and collateral requirements. (Foley, 3T 88–89). None of these protections would apply to a large-load customer taking standard D11 service. As demonstrated in the subsections that follow, the PSA is lawful, reasonable, and in the public interest; it is consistent in every material respect with the Commission's precedent in Case Nos. U-21990 and U-21859;[12] and it should be approved as filed, subject only to the Exhibit A-22 correction to Section 7.3(3).

[12] *See* December 18 Order and Case No. U-21859 Order dated November 6, 2025 (“November 6 Order”).

1. 20-Year Contract Duration

The PSA commits the Customer to a 20-year term of service — a commitment four times longer than the standard arrangement for a new customer under Rate D11 over 1 MW of peak demand. As Company Witness Foley testifies, "[t]he PSA contract duration is 20 years, beginning at the time the Customer first receives electric service at its facility," and because the Customer can begin taking service in December 2027, the Company expects the term to extend through November 2047. (Foley, 3T 95). The PSA further automatically renews for up to two additional 5-year terms, and the Customer may opt out of those renewals only by providing notice to the Company at least 36 months before the beginning of a renewal period. *Id*.

The extended term directly benefits the Company's other customers. As Company Witness Foley testified, "[a] 20-year PSA contract duration represents a significant commitment on behalf of the Customer to the Company and its other customers," and "ensures that the Customer will make their proportionate contribution to the Company's system costs for a longer period than the Company normally requires of its customers under D11." (Foley, 3T 95–96). In other words, the longer the Customer is contractually bound to contribute to the recovery of the Company's fixed system costs, the greater the protection afforded to other customers against the risk that those costs would otherwise shift to them — the same principle that animates the aggregate net-benefit analysis and the termination-payment protection. The contract duration is therefore reasonable and in the public interest, and it is consistent with the extended-term commitments the Commission has approved for comparably situated large-load customers in Case Nos. U-21990 and U-21859.

No Staff or intervenor witness opposed the 20-year term of the PSA. The record thus presents the 20-year commitment as an uncontested, customer-protective feature of the Special Contracts.

2. Pricing and Restrictions on Rate Switching

Under the PSA, the Customer takes service at cost-based D11 pricing and pays all applicable surcharges (e.g., the PSCR Surcharge). (Foley, 3T 96). Because D11 is a cost-based rate, this pricing structure "ensure[s] that the Customer makes their proportionate contribution to the Company's fixed system costs," and the PSCR surcharge ensures the Customer also makes its proportionate contribution "both to the incremental fuel and purchased power costs that they are introducing, and to the fixed costs of renewable energy assets and transmission costs that are recovered through that mechanism." (Foley, 3T 96-97).

The PSA also materially constrains the Customer's ability to switch rate schedules, which D11 does not otherwise impose. Whereas a standard D11 customer is subject only to a 12-month restriction on rate changes, the PSA permits the Customer to change rate schedules only if all of the following four conditions are satisfied:

- *Advance notice*. "The Customer must request a rate schedule change 24 months in advance of the rate schedule change taking effect." (Foley, 3T 96).
- *Post–Load Ramp floor*. "The Customer cannot request a rate schedule change that would take effect prior to 24 months after their Load Ramp Completion Date." *Id*.
- *Newly-approved rate only*. "The Customer can only change to a rate schedule that is approved by the Commission after the PSA became effective." *Id*.
- *No cross-subsidization*. "The Customer can only change to a rate schedule that is not cross-subsidized by any other customer group." *Id*.

Each of these restrictions is reasonable and protects the Company's other customers. As Company Witness Foley explains, the notice period "ensures that any rate schedule change can be appropriately incorporated through a subsequent rate case," and the requirements that any new rate schedule be newly approved and not cross-subsidized “provide[] appropriate protections around the types of future rates that the Customer may be eligible for to ensure any potential future rate change would not negatively impact other customers.” (Foley, 3T 97). Together, these terms ensure that the Customer remains on a cost-based rate that recovers its proportionate share of system costs, and that any future change in the Customer's rate schedule is vetted through the Commission's ordinary ratemaking process and cannot be used to shift costs to other customers. The pricing and rate-switching provisions are therefore reasonable, prudent, and in the public interest.

No Staff or intervenor witness challenged the reasonableness of the PSA’s rate-switching restrictions. The record thus presents the rate-switching restrictions as uncontested, customer-protective features of the Special Contracts.

3. Minimum Billing Demand (80%)

The PSA reasonably and prudently establishes an MBD equal to 80% of the Customer's contract capacity for a given billing period — equal to 800 MW once the Customer reaches its full 1,000 MW contract capacity — which the Customer must pay regardless of whether its actual usage reaches that level. (Foley, 3T 97–99). Based on the D11 rates approved in Case No. U-21860, this MBD results in a Minimum Monthly Charge ("MMC") of approximately $13.8 million per month, or approximately $165.1 million per year. (Foley, 3T 99).

The 80% MBD is materially more protective of the Company's other customers than the terms applicable under the standard D11 tariff. As Company Witness Foley's Table 1 reflects, a standard D11 customer is subject to MBDs between 50–65%, whereas the PSA fixes the Customer's minimum billing obligation at 80%. (Foley, 3T 88–89). The higher MBD guarantees that the Customer will contribute to the recovery of the Company's fixed system costs based on the large capacity the Company has committed to serve, even if the Customer's actual consumption falls short — thereby reducing the risk that any portion of those fixed costs would shift to other customers. Indeed, Staff's minimum bill scenario analysis confirmed that the minimum bill alone is sufficient to cover the non-production costs of serving the Customer in every year of the contract term, with the lowest annual coverage being 116.64% in 2035. (Isakson, 3T 875). The 80% MBD therefore operates precisely as a customer-protective mechanism should, as it secures substantial cost recovery from the Customer irrespective of the Customer's usage.

The 80% MBD is not a novel figure; it is the level the Commission has twice endorsed for comparably situated large-load customers. The proposed 80% MBD is aligned with prior Commission determinations, because the Commission ordered the establishment of a Large Load Customer Provision for Consumers Energy that includes an 80% MBD in Case No. U-21859 and the Commission approved special contracts for the large load customer in Case No. U-21990 that also includes an 80% MBD.[13] (Foley, 3T 136). Specifically, the Commission has recognized that when combined with minimum contract terms, an 80% MBD reasonably balances utility and ratepayer interests in ensuring sufficient financial support for the necessary investments and large load customers' interests in flexibility and a fair assessment of the risk.[14]

- *Minimum Billing Demand (80%) – Staff and Intervenor Positions*

AG witness Coppola recommends that the Commission reject the 80% MBD and order the Company to set the threshold at no lower than 90%. (Coppola, 3T 468). AG witness Coppola argues that because of the 80% MBD, if the Customer uses less than 800 MW, then the Customer will be billed at 800 MW and "the Company must sell the 200 MW of excess capacity at a value

[13] November 6 Order, p. 109; December 18 Order, p. 33.

[14] November 6 Order, p. 109.

potentially lower than the cost of acquiring the capacity," such that "[t]he cost differential could negatively impact other customers." (Coppola, 3T 473). AG witness Coppola further contends that the 90% load-factor assumption used in the Company's modeling is "a reasonable level for the MBD." *Id*.

The Commission should reject AG witness Coppola's recommendation for four primary reasons. First, the 80% MBD is squarely consistent with Commission precedent,[15] while the 90% figure AG witness Coppola proposes is not. AG witness Coppola offers no persuasive basis for the Commission to depart from the very level it has twice approved for large load customers.

Second, AG witness Coppola's proposal conflates two distinct concepts — MBD and projected load factor. That the Company's modeling assumed a 90% load factor for the Customer does not mean the minimum billing obligation must be set at 90%. Load factor is based on actual energy usage (measured in kWh) as a portion of maximum potential energy usage given the Customer's contracted capacity (in this case, the energy required for 1,000 MW of demand 24/7), while MBD is based on peak demand (measured in kW). AG witness Coppola conflates these two distinct concepts when proposing a 90% MBD. The MBD is a floor that guarantees cost recovery regardless of usage; setting it below the expected load factor is how a minimum-bill mechanism is reasonably designed to function, and an 80% MBD already substantially exceeds the 50–65% ratchets applicable to standard D11 service. (Foley, 3T 88–89).

Third, AG witness Coppola's concern that other customers could be harmed if the Company resells unused capacity at a loss is not supported by the record. Staff's minimum bill scenario analysis demonstrated that the minimum bill covers the non-production costs of serving the Customer in every year — never falling below 116.64% coverage. (Isakson, 3T 875). The 80%

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[15] November 6 Order, p. 109; December 18 Order, p. 33.

MBD thus ensures substantial cost recovery from the Customer regardless of its actual usage. Moreover, to the extent the Customer consumes energy above its minimum bill, additional PSCR and energy-charge revenues flow to the benefit of other customers over and above the minimum bill. (Isakson, 3T 874-876). And to the extent that any cost exposure were nonetheless to arise during the term, it is addressed not by inflating the MBD but by the Affordability Backstop, which obligates the Customer to make up any Commission-determined shortfall. (Foley, 3T 103-104). The 80% MBD, viewed together with these during-term protections, is more than adequate to hold other customers harmless, which further demonstrates that the AG's proposed increase to a 90% MBD is unnecessary.

Fourth, to the extent that the AG asks the Commission to raise the negotiated 80% MBD to 90%, the AG seeks relief that cannot be lawfully granted. As set forth in Section III, the Commission lacks statutory authority to rewrite the PSA by raising the MBD over the parties' negotiated agreement. *Union Carbide*, at 148-149.

MNS witness Woods does not ask the Commission to increase the MBD like AG witness Coppola, but rather invokes the 80% MBD to argue that the Company's base sales benefit may be overstated. MNS witness Woods observes that the Company's base sales benefit calculation assumes that the Customer's underlying load is at full ramp of 1,000 MW and a 90% load factor, and contends that, because the PSA establishes an MBD of only 80% of contract capacity, "the Customer is under no obligation to reach a 90% load factor as assumed in the Company's benefit calculations." (Woods, 3T 627). From this, she reasons that "if the Customer's load factor is less than 90%, the Company's estimated Base Sales Benefit will be larger than the actual benefit," and urges the Commission not to predetermine the claimed benefit. (Woods, 3T 627–628).

MNS witness Woods' argument does not counsel against approval; if anything, it confirms why the PSA's structure is sound. The Commission should give it no weight in evaluating the 80% MBD, for four primary reasons.

First, MNS witness Woods misapprehends the function of the MBD. The 80% MBD is not a prediction of the Customer's load factor; it is a contractual floor that guarantees a minimum level of cost recovery regardless of the Customer's actual usage. That the Customer is obligated to pay for at least 80% of its contract capacity — whether or not it ever reaches a 90% load factor — is precisely the customer-protective feature the MBD is designed to provide. MNS witness Woods' observation that the Customer "is under no obligation to reach a 90% load factor" (Woods, 3T 627) is therefore not a criticism of the MBD; it is a description of how a minimum-bill mechanism works. The relevant question is not whether the Customer is guaranteed to run at a 90% load factor, but whether other customers are protected if it does not. They are — by the 80% MBD floor, which substantially exceeds the 50–65% ratchets applicable under standard D11 service. (Foley, 3T 88–89).

Second, the record affirmatively demonstrates that the 80% MBD floor is sufficient to protect other customers even if the Customer's load factor falls below 90%. Staff's minimum bill scenario analysis — which essentially tested the circumstance MNS witness Woods hypothesizes, where the Customer pays only its minimum bill — confirmed that the minimum bill covers the non-production costs of serving the Customer in every year of the contract term, with the lowest annual coverage being 116.64% in 2035. (Isakson, 3T 875). In other words, even at the 80% MBD floor, the Customer's payments more than cover the non-production costs it imposes. MNS witness Woods' concern that a sub-90% load factor would harm other customers is thus refuted by the record.

Third, Witness Woods' "do not predetermine" recommendation is not relief requested by the Company in this proceeding. MNS witness Woods' core recommendation is not that the MBD be changed, but that the Commission decline to "predetermine" that the Special Contracts will produce the projected benefit. (Woods, 3T 627–628). Notably, the Company does not ask the Commission to guarantee any specific benefit figure. In any event, her recommendation does not support rejecting or modifying the 80% MBD.

Fourth, to the extent MNS witness Woods' point goes to the magnitude of the base sales benefit rather than to the MBD itself, it fails for the reasons set forth in Section VI. Even under the more conservative sensitivities in the record — including Staff's removal of the revenue-escalation assumption, which still yielded a net benefit of $860.3 million — the analysis confirms a substantial positive net benefit to other customers. A lower-than-modeled load factor would reduce the size of the benefit; it would not convert the benefit into a cost, and it would not shift costs to other customers, who remain protected by the MBD floor and the Affordability Backstop.

In sum, the 80% MBD is reasonable and prudent, is directly aligned with the Commission's decisions in Case Nos. U-21859 and U-21990, and provides substantial protection to the Company's other customers. The Commission should approve it as filed and should reject AG witness Coppola's recommendation to increase it to 90%.

4. Termination Payment

The PSA includes a reasonable and prudent termination payment designed such that the Company will recover at least 15 years of Minimum Monthly Charges ("MMC") once the Customer achieves their max load. (Foley, 3T 102-103). If the PSA is terminated before the fifteenth anniversary of the Load Ramp Completion Date, the Customer owes a termination payment equal to the MMC multiplied by the greater of (1) the number of months from the early termination date to the fifteenth anniversary of the Load Ramp Completion Date, or (2) 24 months; and if the PSA is terminated after the fifteenth anniversary of the Load Ramp Completion Date, the Customer owes a termination payment equal to the lesser of 24 months of MMCs or the number of months remaining in the contract term. (Foley, 3T 102, 136; Exhibit A-22). Based on the D11 rate approved in Case No. U-21860, the termination payment at the Load Ramp Completion Date is approximately $2.48 billion. *Id*. This termination payment is associated with the PSA only; the CCAA contains a separate, incremental termination payment.[16] *Id*.

The termination-payment mechanics are transparent and formula-driven, as Company Witness Foley confirmed under cross-examination. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. The AG probed each of these mechanics on cross-examination and elicited nothing that undermines the reasonableness of the termination-payment formula; to the contrary, the cross-examination confirmed that the termination payment is a transparent, rate-based measure

[16] *See* Section V.B.2 for a separate discussion of the CCAA termination payment.

that adjusts to the Customer's then-current tariff obligations and secures at least fifteen years of the Customer's contribution to system costs.

The termination payment directly protects the Company's other customers by securing the Customer's long-term contribution to the recovery of system costs. As Witness Foley describes, "[t]he termination payment represents a long-term commitment by the Customer of at least 15 years to contribute to the Company's overall system costs, thereby reducing the cost responsibility of the Company's other customers." (Foley, 3T 103). Staff independently confirmed the adequacy of this protection. Staff witness Isakson's minimum bill scenario analysis established that the termination payment is sufficient to cover the non-production costs of serving the Customer over the contract term, observing that "the total non-production costs of $2.476B" is matched by "the termination payment beginning with the full ramp period in 2028, which is also $2.476B." (Isakson, 3T 875; *see also* Exhibit S-3.0).

The termination-payment structure is directly aligned with prior Commission approvals regarding large-load customers. In Case No. U-21859, the Commission ordered the establishment of a Large Load Customer Provision for Consumers Energy which included a termination payment (called an "Exit Fee") that starts based on 15 years of MBD and reduces over the term of the contract.[17] And in Case No. U-21990, the Commission approved special contracts for a large load customer which included a termination payment that starts based on 10 years of MBD and reduces over the term of the contract.[18] (Foley, 3T 136). The PSA's termination payment, which secures at least 15 years of MMCs, is therefore at or above the level of protection the Commission has twice endorsed. Staff agreed, characterizing the PSA's termination fee as "basically an extended

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[17] November 6 Order, pp. 109-110.

[18] December 18 Order, p. 33.

version of the exit fee" approved in the Consumers Energy Large Load Provision "due to the contract lasting longer than 15 years." (Isakson, 3T 870).

- *Termination Payment – Staff and Intervenor Positions*

AG witness Coppola characterizes the PSA termination payment as "based on the 80% Minimum Monthly Charge for the remaining years of the PSA with no further obligation by the Customer after 17 years." (Coppola, 3T 473). He argues that "the remaining 20% would be absorbed by other customers if the Company is not able to find a replacement customer to take the capacity," and concludes that the termination payment should instead be based on 100% of total demand for the full 20-year term of the PSA. (Coppola, 3T 473-474). The Commission should reject this recommendation as commercially unreasonable, inconsistent with previously approved termination payments, and unnecessary.

First, AG witness Coppola's premise that there is "no further obligation by the Customer after 17 years" is incorrect. As Company Witness Foley explains, under Section 7.3 of the PSA the Customer is responsible for a termination payment that provides 15 years of MMCs calculated on the Customer's full load ramp, and Section 7.3(3) additionally requires the Customer to pay a termination fee equal to the lesser of 24 months of MMCs or the number of months remaining in the contract term if the PSA is terminated after the thirteenth anniversary of the Load Ramp Completion Date. (Foley, 3T 136; Exhibits A-16 and A-22). AG witness Coppola's "three years short" critique — that Section 7.3 ends the payment obligation after the seventeenth anniversary of the Commencement Date — overlooks the additional Section 7.3(3) obligation, which requires the Customer to pay a further termination fee (the lesser of 24 months of MMCs or the months remaining in the term) if termination occurs after the thirteenth anniversary of the Load Ramp

Completion Date. *Id*. The PSA thus imposes a continuing termination obligation that AG witness Coppola's characterization overlooks.

Second, the 80% MBD basis for the termination payment is consistent with Commission precedent, whereas AG witness Coppola's proposed 100% full-term structure is not. As set forth above, the Commission approved termination payments keyed to MBD — not 100% of total demand — in both Case Nos. U-21859 and U-21990. (Foley, 3T 136). AG witness Coppola offers no valid basis to depart from that precedent, and Staff did not join his recommendation.

Third, AG witness Coppola's stated justifications for departing from Case Nos. U-21859 and U-21990 should be rejected. (3T 475-476). As applied to Case No. U-21859, he advocates for a change by arguing that no details regarding the impact of termination payments and collateral requirements were in that case; however, that assertion is unavailing since the Commission or parties could have estimated the impacts of various MBDs and termination payments for a hypothetical hyperscale data center. (Foley, 3T 137). As applied to Case No. U-21990, AG witness Coppola argues that it was an *ex parte* process (Coppola, 3T 476), but that does not withstand scrutiny. Even though Case No. U-21990 was resolved on an *ex parte* basis, the contract termination payment terms and financial impacts were presented in public testimony and exhibits[19] and the contracts were fully audited by the Commission and Staff.[20] (Foley, 3T 137). The substantive termination-payment terms that the Commission approved in the well-reasoned December 18 Order were therefore fully vetted, and the *ex parte* posture of that case supplies no

[19] Company Witness Foley's testimony in Case No. U-21990, pp. 9-11, publicly discussed, and provided a sample calculation of, that large load customer's 80% MBD. The termination payment in that matter was also publicly discussed in Witness Foley's testimony, p. 12, and presented in Exhibit E of the primary supply agreement in that matter (Exhibit A-1, p. 38). Thus, the financial impact of the proposed 80% MBD and termination payment in Case No. U-21990 were both publicly discussed and calculated.

[20] December 18 Order, p. 32.

reason to impose a more onerous structure here. In any event, this proceeding is not an appropriate forum to "re-evaluate" determinations made in Case Nos. U-21859 and U-21990, and the record before the Commission for decision fully supports the negotiated termination payment structure in the Special Contracts.

Fourth, AG witness Coppola's underlying concern — that other customers could bear costs if the Company cannot resell the Customer's capacity following an early exit — is already addressed by the PSA's layered protections. The termination payment secures at least 15 years of MMCs (plus the Section 7.3(3) tail), and Staff confirmed that this amount covers the non-production costs of serving the Customer. (Isakson, 3T 875). Inflating the termination payment to 100% of demand for the full term is therefore unreasonable and unnecessary to protect other customers.

In addition, AG witness Coppola's recommendation relies on confidential figures that, on examination, confirm rather than undermine the adequacy of the negotiated termination payment. AG witness Coppola calculates that the residual demand costs not captured by the 80% (rather than 100%) basis total approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] at contract inception in December 2027, declining thereafter, and on that basis contends the termination payment should increase from approximately [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] to as much as [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL]. (3T 908–909 (CONFIDENTIAL); Exhibit AG-1 (CONFIDENTIAL)). That recommendation should be rejected for the reasons explained above. The record confirms that the termination payment is designed to cover the non-production costs of serving the Customer in full (Isakson, 3T 875).

Lastly, to the extent that the AG asks the Commission to impose a termination payment based on 100% of total demand for the full 20-year term of the PSA, the AG seeks relief that cannot be lawfully granted. As set forth in Section III, the Commission lacks statutory authority to rewrite the PSA over the parties' negotiated agreement. *Union Carbide*, at 148-149.

ABATE witness Dauphinais recommends that approval of the Special Contracts be conditioned on modifying the Affordability Backstop (Section 5.1.3) "to allow an evaluation and modification of the termination payment by the Commission based on the facts and circumstances known or knowable at the time of termination of the PSA." (Dauphinais, 3T 543). This recommendation is seemingly based on the theory that the Affordability Backstop does not extend beyond termination of the PSA and does not provide for modification of the termination payment. (Dauphinais, 3T 542). The Commission should reject this recommendation as unnecessary.

First, with respect to the PSA, the termination payment "is based on the MBD and not on an assessment of specific costs or benefits of serving the Customer" — an approach that, as shown above, is consistent with previous Commission guidance in Case Nos. U-21859 and U-21990. (Foley, 3T 138-139). As Witness Foley observes, "Witness Dauphinais offers no argument for why the Commission's Orders in these cases were incorrect." (Foley, 3T 139).

Second, with respect to the CCAA, the termination payment "is set equal to the remaining revenue requirement of the energy storage and renewable energy projects deployed under that agreement that have not yet been recovered from the Customer," and therefore "automatically adjusts to account for the costs of those projects and ensures that the Customer will fully pay for each project's revenue requirement over the project's depreciable life." (Foley, 3T 138). No open-ended modification mechanism is needed because the CCAA termination payment already self-adjusts to actual unrecovered costs.

Third, ABATE witness Dauphinais' proposal is unnecessary because the termination payment is not static and is calculated at the time a termination occurs and is a function of the tariffs and rates that the Customer is subject to, which are determined in a rate case by Commission approval. (Foley, 3T 139). Because rates or tariffs may change and the Commission maintains oversight over these activities, it therefore maintains oversight over the rates that underpin the termination payment. *Id*. Any adjustment to those rates pursuant to Section 5.1.1, 5.1.2 or 5.1.3 of the PSA would be accounted for in the termination payment. Witness Dauphinais' suggestion also is not commercially reasonable and would prevent the Customer from being able to reasonably assess its potential future liabilities. *Id*.

In conclusion, the PSA's termination payment is reasonable and prudent, secures at least 15 years of the Customer's contribution to system costs, is confirmed by Staff to cover the non-production costs of serving the Customer, and is consistent with the Commission's decisions in Case Nos. U-21859 and U-21990. The Commission should approve the negotiated termination payment as filed, with the Exhibit A-22 correction to Section 7.3(3), and should reject both AG witness Coppola's proposed 100%, full-term structure and ABATE witness Dauphinais' proposed modification.

Staff witness Isakson recommended that the collateral amount and termination payment be re-examined within three years of the Load Ramp Completion Date. (Isakson, 3T 881). The Company does not oppose providing this information for review, however, any such review cannot extend to a future reformation of the negotiated terms of the Special Contracts in this proceeding. As explained in Section III, the Commission's authority here does not extend to unilaterally rewriting or reforming the Special Contracts. Any future adjustment to the collateral amount or termination payment would occur, if at all, through the mechanisms the Commission and the contracting parties' agreements already provide — including the credit-rating-driven collateral escalation built into the PSA and CCAA.

5. Credit and Collateral Requirements

The PSA includes reasonable and prudent credit and collateral requirements designed to protect the Company and its other customers in the event of Customer default. As Company Witness Foley explains, the PSA includes credit and collateral requirements through a Parent Guaranty ("PG") and, as necessary based on the parent's credit rating, a letter of credit designed to protect the Company and its customers in the event of Customer default. (Foley, 3T 105–106). This structure operates dynamically over the contract term. Once the PSA is approved, "the Customer will initially provide a PG to cover a portion of the Customer's financial obligations under the PSA." (Foley, 3T 106). Later in the contract term, the PG is reduced once the forecasted termination payment of the PSA drops below the initial PG and a larger PG becomes superfluous. *Id*. And "[i]f at any point the Customer's parent's credit rating drops below a pre-defined threshold, then the Customer will be required to post a Letter of Credit ('LoC') equal [to] the PG amount applicable at that time." *Id*. The collateral package thus tracks the Company's actual financial exposure over time and automatically strengthens — converting from a parent guaranty to a letter of credit — precisely when a decline in the parent's creditworthiness would otherwise increase risk to the Company and its other customers.

The proposed credit and collateral structure is directly aligned with prior Commission approvals for large-load customers. The structure is consistent with the December 18 Order, in which the Commission conditionally approved a primary supply agreement requiring the large-load customer to post a PG and, as necessary based on its parent's credit rating, a LoC based on its financial obligations under the PSA[21] — the same structure that is being proposed for the PSA in this instant case. It is likewise consistent with the November 6 Order, in which the Commission established a minimum termination payment starting at 15-years MMC (equal to the minimum length of a contract) backed by a 50% LoC or cash, which effectively establishes a minimum collateral requirement of 7.5-years of MMC, which the PSA in the instant case satisfies.[22] (Foley, 3T 106–107). The Company's proposed use of a parent guaranty is also expressly contemplated by the Commission's own guidance in the November 6 Order, p. 112, that it "remains open to considering the use of parent guarantees—either on their own or in concert with other collateral—on a case-by-case basis." Here, "given the creditworthiness of the Customer's parent, the Company is proposing the use of a PG." (Foley, 3T 107).

Staff independently confirmed that the PSA's collateral approach is permissible under the framework the Commission established in Case No. U-21859. As Staff witness Isakson testified, "DTE's request for approval of the PSA is a proposal for a different collateral requirement and form, which is allowable on the Consumers tariff established in U-21859," and the PSA "requires a letter of credit depending on the parent company's credit rating, so there is a mechanism by which a more secure form of collateral may be required if needed if the credit rating of the parent company changes following execution of the special contracts." (Isakson, 3T 871).

As Company Witness Foley confirms, DTE Electric has accepted that the risk of any collateral insufficiency falls on the Company, not on its other customers. (Foley, 3T 134-135). In the highly unlikely event of a Customer bankruptcy or other circumstances in which recovery from the Customer, its parent guarantor, and letters of credit is not sufficient, DTE Electric's position is

[21] December 18 Order, p. 41.

[22] November 6 Order, pp. 112-113.

that it would not seek to recover any remaining amounts due under PSA and CCAA from other customers.

- *Credit and Collateral Requirements – Staff and Intervenor Positions*

AG witness Coppola recommends that the Commission remove any limit on the PSA and CCAA collateral, arguing that "the parent company guaranty needs to be at the level that ensures full payment of the Customer's total obligations" and that "[t]he Company and other customers should not be at risk to absorb any shortfall in costs for which the Customer and its parent are responsible." (Coppola, 3T 475). The Commission should reject this recommendation as commercially unreasonable and unnecessary.

First, the premise of AG witness Coppola's recommendation — that other customers are "at risk to absorb any shortfall" — is incorrect. As set forth above, DTE Electric has accepted the risk of collateral insufficiency being borne by the Company, not by other customers. (Foley, 3T 134-135).

Second, the proposed collateral structure is consistent with Commission precedent, whereas AG witness Coppola's "full payment of total obligations" alternative is not. The Commission approved the identical PG-plus-conditional-LoC structure in Case No. U-21990 and expressly endorsed the case-by-case use of parent guarantees in Case No. U-21859. (Foley, 3T 106–107). Staff, which reviewed the same confidential collateral terms, did not join AG witness Coppola's recommendation, and instead opined that the PSA's collateral form and amount are permissible under the Case No. U-21859 framework. (Isakson, 3T 871).

Third, the credit and collateral structure already escalates to address the very credit risk AG witness Coppola identifies. Because the PG converts to a letter of credit if the parent's credit rating falls below the defined threshold, the structure provides a more secure form of collateral automatically, precisely when it is needed, without imposing the commercially unreasonable requirement that the Customer post collateral equal to 100% of its total obligations for the entire term. (Foley, 3T 106).

Fourth, to the extent that AG witness Coppola asks the Commission to remove any limit on the PSA and CCAA collateral, the AG seeks relief that cannot be lawfully granted. As set forth in Section III, the Commission lacks statutory authority to rewrite the PSA and CCAA over the contracting parties' negotiated agreement. *Union Carbide*, at 148-149.

ABATE witness Dauphinais asserts that "DTE is unwilling to commit to not seeking recovery from its other customers for any amount owed by Google to DTE under the PSA and CCAA." (Dauphinais, 3T 524–525). That assertion — based on the Company's discovery responses — has been overtaken by Company Witness Foley's rebuttal, which states the Company's commitment expressly: DTE will not seek to recover amounts owed by Google under the PSA and CCAA, including any costs the Commission may have determined exceeded the benefits of serving the Customer. (Foley, 3T 134–135). Because the Company has accepted the very condition Witness Dauphinais seeks, there is no genuine dispute on this point. His recommendation provides no basis to reject the PSA or to alter its negotiated collateral amounts or structure; it goes only to the allocation of residual risk, which the layered protections in the record — the parent guaranty and conditional letter of credit, the Company's acceptance of the U-21990 collateral-risk condition, and the Affordability Backstop — already resolve in other customers' favor.

In sum, the PSA's credit and collateral requirements are reasonable and prudent, escalate automatically to protect the Company and its other customers in the event of a decline in the parent's creditworthiness, and are consistent with the structures the Commission approved in Case

Nos. U-21990 and U-21859. The Commission should approve them as filed and should reject AG witness Coppola's and ABATE witness Dauphinais' recommendations.

6. Affordability Backstop (PSA Section 5.1.3)

Section 5.1.3 of the PSA is the contractual mechanism that guarantees, on a going-forward basis, that if the Commission ever determines that the aggregate costs to serve the Customer exceed aggregate benefits, the Customer bears that net shortfall. Section 5.1.3 of the PSA provides, in relevant part, that a "goal of this Agreement and the Related Agreements is to protect other customers, other customer classes and Company from funding the costs to serve Customer," and that if, at any time during the term of the PSA, the Commission "issues a ruling or order determining that the costs to serve Customer exceed the combined revenues paid or payable to the Company under this Agreement and the applicable Related Agreements," or "disallows Company's recovery of costs to the extent attributable to serving Customer," then the "Customer agrees to comply with any such ruling or order … and, as applicable, Customer shall reimburse Company for any unrecovered costs, plus interest." (Foley, 3T 103–104, quoting PSA Section 5.1.3). As Company Witness Foley testifies, the PSA "ensures that the aggregate benefits, including revenues received from the Customer and avoided costs realized through the Contracts, outweigh the costs of serving the Customer's load." (Foley, 3T 103). The Affordability Backstop thus allocates the risk of any Commission-determined cost-benefit shortfall to the Customer — not to other customers.

The Affordability Backstop operates by comparing, in the aggregate, the costs of serving the Customer's load against the revenues and avoided costs attributable to the Customer over the life of the Special Contracts. As Company Witness Foley explains, "[t]he Company believes it is critically important that the Commission take an aggregate view of the benefits and costs of serving the Customer's load over the life of the contract." (Foley, 3T 104). With respect to the components of that assessment, the "costs of serving the Customer's load" include any incremental expense or resource revenue requirement caused by serving the Customer. For example, the revenue requirement of energy storage and renewable energy projects deployed under the CCAA; the revenue requirement of renewable energy projects deployed to meet the Company's RPS obligations not covered by the CCAA; the revenue requirement of other resources identified in the IRP as caused by the Customer's load; increased fuel and purchased power costs; and the revenue requirement of transmission investments. (Foley, 3T 143-144). Against those costs, the assessment credits revenues received and avoided costs realized through the Special Contracts, including the revenue requirement of resources the Company was able to avoid deploying by virtue of serving the Customer's load. (Foley, 3T 143-144).

Company Witness Foley's cross-examination further described how these categories will be determined in practice. The resources "caused by" the Customer's load are identified through a with-and-without comparison in the upcoming IRP. The resources selected in an IRP scenario that includes the Customer's load are compared against the resources selected in a scenario without it, and the difference between the two scenarios— the incremental resources added to serve the Customer's load and the resources avoided by virtue of serving it — is reflected in the presentment of aggregate costs and benefits in support of the Affordability Backstop assessment, with incremental additions accounted for as costs and the avoided resources accounted for as offsetting benefits. (Foley Cross, 3T 244–245). Company Witness Foley was careful to qualify, however, that this with-and-without comparison identifies resources associated with the Customer's load only in the aggregate; it does not assign any specific resource to the Customer. As he testified, the resources identified through the comparison "are part of a portfolio of resources" that the Company deploys to serve its total load, and "those assets are not specifically assigned to the Customer for its service." (Foley Cross, 3T 246). The Affordability Backstop thus operates at the aggregate level — comparing total costs to serve the Customer against total revenues and avoided costs.

With respect to transmission, Company Witness Foley confirmed that the Company will include the incremental transmission charge that ITC allocates to DTE Electric (associated with the approximately $308 million in ITC upgrades), rather than the full project revenue requirement. (Foley Cross, 3T 249–250). With respect to distribution, the Company confirmed that no distribution costs are expected to enter the assessment because the Customer funds up to $50 million of distribution upgrades, and any recoverable distribution costs would be included only if they exceed $50 million — which the Company does not expect. (Foley Cross, 3T 251–252).

On the question of "when" the Commission would test for a benefit, Section 5.1.3 states that costs and benefits "should be considered in regulatory proceedings applicable to Company's cost to serve Customer." In particular, the Company envisions combined revenues and avoided costs will be presented in general rate case filings and PSCR filings, both of which are contested proceedings. In these proceedings, the Company will present an accounting of the aggregate benefits and costs of serving the Customer's load. (Foley, 3T 144). Because rate cases and PSCR proceedings are themselves contested proceedings, Staff and intervenors will have a full and fair opportunity to test the Company's aggregate cost-and-benefit presentation as actual costs and revenues become known, rather than litigating hypothetical figures in this special contract proceeding.

Separate and apart from the presentation of aggregate cost and benefits in PSCR and rate cases, the Company proposes to file an annual report, by April 15 of each year, presenting information on the realization of the benefit, together with the aggregate cost-and-benefit accounting presented in the applicable contested proceedings, and to provide the underlying supporting documentation. (3T 152-153). The Company does not take a view in this Initial Brief on the appropriate docket for the annual report, but notes that Customer information is considered confidential and will need to be protected as such. (3T 152). As Company Witness Foley describes, the annual report will include the Customer's load profile for the previous year; the Customer's maximum demand for the previous year (by month) compared to the expected contract capacity and MBD; the total MW of energy storage projects deployed under the CCAA that have achieved their commercial operation date ("COD") by the end of the previous year; the total MW of renewable energy projects deployed under the CCAA that have achieved their COD by the end of the previous year; any changes to the Customer's or its parent's credit rating. The report will also include a presentation of the aggregate costs and benefits of serving the Customer as of the end of the previous year (similar to the presentation that will be provided in PSCR and rate cases). (3T 153). This framework ensures the Commission and stakeholders can monitor the Affordability Backstop's operation on a recurring basis over the life of the Special Contracts. Then, consistent with Section 5.1.3 of the PSA, during future rate cases and PSCR proceedings, the Company will present aggregate costs and benefits of serving the Customer such that the Commission can determine if benefits exceed aggregate costs. *Id*.

- *Affordability Backstop (PSA Section 5.1.3) – Staff and Intervenor Positions*

Several intervenors contend that Section 5.1.3 must be supplemented with additional metrics, triggers, true-up procedures, and/or reporting obligations. The Commission should decline these proposals, because the negotiated Affordability Backstop as written — together with the reporting framework above — already provides the protection the intervenors seek.

MEICEO witness Kenworthy recommends that the Affordability Backstop be revised to include “measurable triggers,” such as 45Q credit realization or the Customer's ZRC obligation, and a defined true-up and reporting cadence tied to the IRP. (Kenworthy, 3T 693-696). Although the Company agrees with MEICEO witness Kenworthy that certain reporting obligations will be required for the application of Section 5.1.3 of the PSA, to the extent that he suggests that the negotiated Section 5.1.3 of the PSA should be modified, the Company disagrees. (Foley, 3T 143). Section 5.1.3 already includes broad acknowledgements and commitments to effectuate the Affordability Backstop. *Id*. As Company Witness Foley highlighted, it is unclear how MEICEO witness Kenworthy’s “triggers” would work in practice or how they fit into the contractual language of Section 5.1.3. (Foley, 3T 144). The Affordability Backstop, as negotiated by DTE Electric and the Customer, operates on the comprehensive aggregate cost-and-benefit approach described above; layering discrete, single-variable triggers onto that aggregated approach, as advocated by MEICEO witness Kenworthy, would introduce complexity and potential inconsistency without enhancing the core protection already memorialized in the PSA, which is the Customer's obligation to reimburse any Commission-determined shortfall. Moreover, to the extent that MEICEO witness Kenworthy asks the Commission to rewrite Section 5.1.3 of the PSA to add terms the parties did not agree to, he seeks relief that cannot be lawfully granted. As set forth in Section III, the Commission lacks statutory authority to rewrite the PSA and CCAA over the contracting parties’ negotiated agreement. *Union Carbide*, at 148-149.

MEICEO witness Kenworthy suggests the Commission should consider an annual “no-cost-shift” requirement. (Kenworthy, 3T 677). He observed that, within the Company's 20-year modeling of the $1.7 billion benefit, "there are four years out of the twenty years that the Company is modeling a cost increase to customers" — specifically, 2035 through 2038 — and argues that the Commission should determine whether its no-cost-shift requirement must be satisfied on an annual basis or over the life of the contract. (Kenworthy, 3T 677). That the annual profile shows modeled net costs in four interim years does not establish a cost shift, because the governing standard measures the benefit in the aggregate over the life of the Special Contracts. The Commission should apply the aggregate, over-the-life standard, for the below reasons.

First, the governing standard measures the benefit in the aggregate over the full term of the Special Contracts, not year-by-year. The customer benefit analysis and the Affordability Backstop both operate over the life of the Contracts because this proceeding approves 20-year contracts and any assessment of costs and benefits must match the same period. (Foley, 3T 146). Looking narrowly at individual years could lead to making suboptimal decisions. *Id*. This aggregate framing is not a litigating position devised for briefing; it is embedded in the Special Contracts. PSA Section 5.1.3 tests whether "the costs to serve Customer exceed the combined revenues paid or payable to the Company" over the term, and the Company confirms that the aggregate cost-and-benefit accounting will be presented in future rate-case and PSCR proceedings. (Foley, 3T 103–104; 143–144).

Second, the four interim-cost years are an artifact of the timing of the proxy resource, not evidence that other customers subsidize the Customer. The modeled net costs in 2035–2038 reflect the assumed 2033 in-service date of the proxy CCGT with CCS, whose revenue requirement is counted against the benefit beginning when the resource is placed in service, before the offsetting benefits of the associated resources and sales are fully realized over the balance of the term. (Foley, 3T 146; Exhibit A-19). The annual pattern therefore reflects the ordinary timing mismatch between when a capacity resource's costs begin and when its cumulative benefits accrue — not a structural shifting of costs to other customers. Indeed, the same proxy resource whose in-service timing produces the interim-cost years is itself a conservative construct whose full cost is charged against the benefit, as explained above.

Third, the aggregate benefit remains substantial and positive notwithstanding the four interim-cost years under the Company's analysis and other sensitivities in the record. The four modeled cost years are already fully embedded in the $1.7 billion net figure; they are not additive to it. Staff, who examined the same annual profile, independently confirmed that the net benefit remains positive even after removing the Company's revenue-escalation assumption, calculating a conservative lower-bound net benefit of $860.3 million. (Isakson, 3T 858). And even on ABATE's present-value recalculations, the benefit remains positive by approximately $1.0 billion. (Dauphinais, 3T 540). No party's analysis, however the interim years are treated, produced a net cost to other customers over the life of the Special Contracts.

Fourth, an annual no-cost-shift test would be both unworkable and inconsistent with how the Commission approved the analogous special contracts in U-21990. Requiring that the Special Contracts produce a net benefit in every individual year would effectively prohibit the Company from ever deploying new resources because any such resources necessarily impose their revenue requirement in a discrete year while their benefits accrue over decades. That is not the standard the Commission applied in Case No. U-21990, which assessed the aggregate benefit over the contract term, and it is not the standard Section 5.1.3 of the PSA embodies. The appropriate response to the interim-year timing is the aggregate assessment the Affordability Backstop already requires, not a year-by-year test that "could lead to making suboptimal decisions." (Foley, 3T 146).

Next, Staff witness Simpson and GLREA witness Richter recommend quarterly reporting modeled on Case No. U-21990, with Staff recommending a first report by June 30, 2027. (Simpson, 3T 844; Richter, 3T 609). The Company's proposed annual reporting framework will already provide transparent, recurring information, and the presence of Section 5.1.3 of the PSA in this case introduces new tracking and reporting requirements that did not exist in Case No. U-21990, such that "simply replicating what was done in Case No. U-21990 will not satisfy Section 5.1.3 of the PSA." (Foley, 3T 152). A quarterly cadence is unwarranted, however, particularly once the Customer's full ramp is achieved and the reported information is not expected to change meaningfully from one report to the next. Additionally, with respect to the presentation of aggregate benefits under Section 5.1.3, given the regular cadence of the rate case, PSCR, IRP, and REP proceedings in which the aggregate assessment is actually presented a quarterly presentation is not necessary. Staff and intervenors identify no benefit to other customers from more frequent reporting that the annual report and those contested proceedings do not already provide. Importantly, the Company's response to these proposals is not that ongoing oversight is unnecessary, but that Section 5.1.3 and the annual reporting framework already supply it. The no-cost-shift test is properly applied over the full 20-year life of the Special Contracts — consistent with the aggregate standard the Affordability Backstop embodies — rather than on the annual or single-year basis certain intervenors propose.

With respect to transmission expense cost-tracking, MEICEO witness Kenworthy contends the record does not show how much of the $91 million increase in 2029 transmission expense reflects ITC capital recovery through MISO Schedule 9 versus load-driven increases across other MISO schedules, and asserts that Company Witness Burgdorf did not describe the methodology used to derive the allocation change. (Kenworthy, 3T 685). That contention was answered directly in rebuttal. As Company Witness Burgdorf explains, "[t]he $91 million difference in 2029 transmission expense between the 'base case' and the 'Customer datacenter case' is attributable to two factors: (1) $49.2 million in estimated ITC network upgrade costs charged through Schedule

9; and (2) \$41.8 million in estimated load-driven increases across all transmission schedules." (Burgdorf, 3T 396). Company Witness Burgdorf provides a schedule-by-schedule breakdown (Schedules 1, 9, 10, 10-FERC, 26, 26-A, and 26-C) in tabular form. *Id*. Each transmission schedule is derived by multiplying a forecasted rate by either the peak demand or the total system usage depending on the schedule. If the \$308 million ITC network upgrade costs are removed from the analysis, the forecasted 2029 Schedule 9 expense is \$518.0 million, leaving approximately \$4.2 million of the Schedule 9 difference associated with the Customer's load and approximately \$49.2 million associated with the ITC network upgrade costs." (Burgdorf, 3T 396–398). The record therefore contains precisely the breakdown and methodology MEICEO witness Kenworthy claimed were absent.

AG Witness Coppola separately recommended that the Commission direct the Company to implement cost-accounting procedures to track and report all transmission-related incremental costs for each data center. (Coppola, 3T 485–486). The Company partially agrees and partially disagrees. The Company agrees that the incremental transmission cost attributable to serving the Customer's load is a proper input to in the presentment of aggregate costs and benefits in support of the Affordability Backstop assessment, and it will present that cost in the applicable contested proceedings and proposed annual reporting. As Company Witness Foley confirms, the Company will include the incremental transmission charge that ITC allocates to DTE Electric, associated with the approximately \$308 million in ITC upgrades, in the presentment of aggregate costs and benefits in support of the Affordability Backstop assessment. (Foley, 3T 249–250; *see also* Burgdorf, 3T 396–398). The Company disagrees, however, to the extent AG witness Coppola seeks an implied, project-by-project transmission cost-tracking regime imposed as a condition of approval. The Company is not billed by ITC on a project-specific basis for ratemaking purposes;

instead ITC allocates a share of its costs to DTE Electric through MISO Schedule 9. Because of this, the Company must use best available information, including actual project capital costs for network upgrades that would otherwise impact DTE Electric's customers and modeled transmission expense impacts associated with the Customer's load. This provides a reasonable estimate for transmission-related costs associated with serving the Customer's load, but the Company may not be able to provide the precise project-by-project billing traceability implied by some intervenor recommendations. (Foley, 3T 146).

To the extent MEICEO witness Kenworthy and AG witness Coppola recommend more granular, project-by-project tracking of transmission costs, the Company agrees to the extent described above. However, requiring project-by-project traceability is not possible nor is it supported through ITC's billing to the Company. It would add unnecessary complexity and speculation without meaningfully improving the accuracy of the aggregate costs and benefits assessment, and other customers are protected in all events by the aggregate no-cost-shift standard Section 5.1.3 embodies.

Next, Staff witness Simpson recommended that, in DTE Electric's upcoming IRP, Clean Energy Plan, or Amended Renewable Energy Plan filing, the Company analyze its large-load customers collectively rather than performing customer-specific analyses. Specifically, witness Simpson recommended that the Commission require future analyses to include both of the Company's large-load customers rather than performing a separate analysis for each large-load customer. (Simpson, 3T 839).

The Commission should decline to adopt Staff witness Simpson's aggregated modeling recommendation. As Company Witness Neal Foley explains, Section 5.1.3 of the PSA relies on a presentation of the aggregate costs and benefits of serving the Customer's load, so that the

Commission can determine whether the aggregate benefits of the Customer exceed the aggregate costs. (Foley, 3T 149-150). One component of that analysis is the revenue requirement associated with resources identified in the IRP as being caused by the Customer's load and not otherwise recovered through the CCAA. (Foley, 3T 149-150). Thus, each large-load customer's load must be considered individually in the IRP such that resource planning changes under each load sensitivity can be identified; however, combining the large-load customers would make such identification impossible. *Id*.

Staff witness Simpson's recommendation is also inconsistent with prior Commission guidance. The December 18 Order, p. 42, requires annual reporting regarding the realization of the projected affordability benefit for the large-load customer approved in that matter (Oracle America Cloud Services or "OACS"). The Company can provide such customer-specific reporting only if it can identify, through IRP modeling, the resource-planning impacts caused by OACS. Accordingly, large load customers must be considered individually, and not in the aggregate. (Foley, 3T 150).

The Company's commitment to individualized analysis does not mean that the Customer is modeled in isolation, as though OACS does not exist. OACS was already under contract at the time the Special Contracts in the instant case were executed and should be reflected in the Company's IRP load forecast as such. The Company will therefore model each large-load customer individually in sequence in the upcoming IRP—assessing OACS's impact first and then assessing the Customer incrementally to the Case No. U-21990 large-load customer—rather than modeling the two customers together in a single, undifferentiated block as recommended by Staff witness Simpson.

Importantly, sequential modeling is "individual" modeling; it simply reflects the order in which the respective special contracts were approved and the reality that OACS's load is part of the baseline against which the Customer's incremental impact must be measured. This sequential, incremental modeling approach comports to the customer-specific requirements that Staff's own recommendations invoke, because (i) it satisfies PSA Section 5.1.3 by measuring the Customer's incremental resource-planning impacts on top of OACS's baseline, allowing the Company to isolate the costs and benefits attributable to the Customer's load; and (ii) it satisfies the December 18 Order's directive to report annually on the "realization of the projected affordability benefit" for the special contracts approved in that matter. In contrast, the aggregated modeling that Staff witness Simpson recommended would collapse the two large-load customers into a single load block, defeating the customer-specific analyses the PSA and December 18 Order require.

In sum, the Commission should confirm that the Company's sequential, customer-specific modeling —OACS first, then Google incremental to the OACS—satisfies both PSA Section 5.1.3 and the Commission's prior directives, and should decline to adopt Staff witness Simpson's recommendation to aggregate the Company's large-load customers in future IRP analyses. (Foley, 3T 150).

Next, AG witness Coppola recommended that the Company establish a regulatory liability account to capture the affordability benefit and ensure its annual pass-through to customers. (Coppola, 3T 486). The Commission should reject this proposal as unnecessary and counterproductive. As Company Witness Foley explains, a regulatory liability account to capture annual financial benefits is unnecessary because the benefits already flow to customers through existing ratemaking mechanisms. (Foley, 3T 148). Specifically, "benefits flowing through the PSCR will be realized through a lower PSCR factor than would have otherwise been applied," and "base rate benefits arising from increased sales will support a lower revenue requirement for other customers by offsetting a greater portion of the Company's investments in the grid and the transition to new generation sources." (Foley, 3T 148; Exhibit A-20). The two principal categories of benefit thus reach customers routinely: the PSCR-related benefits through the annual PSCR plan and reconciliation process, and the base-rate benefits through the Company's general rate cases, in which the increased sales attributable to the Customer's load reduce the revenue requirement borne by other customers.

AG witness Coppola's proposed mechanism would also delay, not accelerate, the realization of those benefits. In fact, such a mechanism could delay the realization of benefits for the Company's other customers, because the recording of AG witness Coppola's proposed regulatory liability would need to happen after the Customer's usage occurs and then would need to be addressed in a general rate case or separate accounting application before the benefit could be passed to the Company's customers. (Foley, 3T 148-149). By contrast, allowing the benefit to flow through existing processes allows customers to realize the benefit faster, potentially in 'real time' through, for example, the annual PSCR plan process and establishment of the PSCR factor. *Id*. AG witness Coppola's proposed regulatory liability account would therefore insert an additional layer of regulatory process — a deferral entry followed by a rate case or accounting application — between the Customer's payments and the customers who are to benefit from them, slowing the very pass-through it purports to maintain.

In sum, Section 5.1.3 is operational, enforceable, and sufficient. It obligates the Customer — not other customers — to reimburse any costs the Commission determines during the term of the PSA exceed the combined revenues and avoided costs attributable to the Customer, applies through the Company's ordinary contested proceedings as actual costs become known, and is made transparent through the Company's proposed annual reporting. The Commission should approve Section 5.1.3 of the PSA as written and should decline the intervenors' proposals to supplement it with additional triggers, true-up mechanisms, or a quarterly reporting cadence.

7. Load Ramp Flexibility

The PSA permits the Customer to temporarily delay its load ramp by up to 18 months in the aggregate — a term the standard D11 tariff does not address. (Foley, 3T 88–89). Because the PSA allows the Customer to begin its load ramp in December 2027 and reach its maximum load by December 2028, the option to delay could push the Customer's Load Ramp Completion Date as late as mid-2030. (Foley, 3T 99–100). This provision reasonably accommodates the practical realities of constructing and commissioning the Facility while preserving the Customer's underlying commitments. As explained in Section V.A.4, the termination payment is calculated from the Load Ramp Completion Date, so any delay in the ramp correspondingly shifts — but does not diminish — the Customer's minimum-bill and termination obligations.

While the PSA affords the Customer limited timing flexibility during the ramp period, it does not permit the Customer to reduce the contract capacity the Company has committed to serve— again, a protection absent from standard D11 service. (Foley, 3T 88–89). This distinction is important, as the Customer may adjust when it reaches full load but it cannot unilaterally shrink the 1,000 MW contract capacity upon which its 80% MBD, termination payment, and collateral obligations are based. The Customer's core financial commitments to the Company — and thus the protections those commitments afford other customers — are therefore preserved regardless of the ramp timing.

The PSA also provides the Company with corresponding protection. Under Section 2 of the PSA, if circumstances arise in which the Company is unable to achieve or maintain the

Customer's load ramp or maximum load, the Company and the Customer will seek a mutually agreeable solution. If the Company and the Customer cannot agree on a solution, the Company can unilaterally propose an adjustment to the Customer's load ramp or max load, which the Customer can accept or terminate the agreement and pay all applicable termination payments. (Foley, 3T 101). As Company Witness Foley testifies, this adjustment right "provides protection for the Company's generation and distribution systems and for the reliability of its other customers," and "mitigates any risk that the Company's other customers would be impacted if the Company does not have sufficient resources to serve the Customer's load." *Id*. In other words, Section 2 of the PSA ensures that the Company is not forced to over-commit its system to serve the Customer at the expense of its obligations to other customers.

- *Load Ramp Flexibility – Intervenor Positions*

ABATE witness Dauphinais recommended that the Company be required to commit "to fully utilize the discretion given to it under Section 2 of the PSA." (Dauphinais, 3T 547). The Commission should decline to impose ABATE's proposed condition because it is unclear and unnecessary. Witness Dauphinais provides no detail on what he means for the Company to "fully utilize" the discretion given to it in his recommendation versus exercising the "reasonable discretion" that he acknowledges Section 2 already provides to the Company. Section 2 of the PSA already vests the Company with the discretion to adjust the Customer's load ramp or maximum load when needed to protect its system and its other customers, and the Company will exercise that discretion reasonably in light of the circumstances then present. (Foley, 3T 140). A blanket commitment to "fully utilize" that discretion in every instance would be both unnecessary and potentially counterproductive, because the appropriate exercise of the Section 2 right depends on facts — system conditions, resource availability, and reliability considerations — that cannot be known in advance. Further, ABATE witness Dauphinais provides no detail as to what is intended by the suggestion that the Company "fully utilize that provision to protect resource adequacy." In addition to Section 2 of the PSA, once approved by the Commission, the Customer will be subject to the amended Emergency Electric Procedures in the Company's Rate Book, which will require firm load shedding prior to other customers. (Foley, 3T 140-141).

In conclusion, the PSA's load-ramp flexibility reasonably and prudently accommodates the construction of the Facility without diminishing the Customer's commitments; the contract-capacity protections preserve the financial obligations on which other-customer protections depend; and the Company's Section 2 adjustment right protects the reliability of service to other customers. These provisions are reasonable and in the public interest, and the Commission should approve them as filed.

8. Energy Waste Reduction

The PSA includes a commitment by the Customer to participate in EWR that supports the State of Michigan's statutory EWR objectives — a commitment the standard D11 tariff does not require. In the PSA, the Customer is committing to participate and comply with the self-directed EWR plan requirements as set forth in MCL 460.1093. (Foley, 3T 103). Because of the magnitude of the Customer's load, the Customer's expected annual peak load will qualify it to self-direct an EWR plan in accordance with the Commission's Order in Case No. U-21627, and the savings identified in the Customer's self-directed EWR plan will be counted toward the Company's statutory goals and thus support the State of Michigan's EWR objectives. *Id*. The Customer's EWR commitment therefore not only satisfies the Customer's own statutory obligations but also contributes to the Company's achievement of its EWR targets under 2008 PA 295, as amended.

- *Energy Waste Reduction – Staff Positions*

Staff does not oppose the Customer's election to self-direct its EWR plan. As Staff witness Smith testified, although “the Company [is not] requesting anything related to EWR for this case,” the Customer “is planning to self-direct its legislative EWR goals," and the Customer's self-direction commitment is governed by Section 9.4 of the PSA, under which the Customer “agrees to reasonably cooperate with Company to pursue the energy waste reduction standards set forth in Michigan Public Act 295 of 2008, MCL 460.1001 et seq. and to participate in and comply with the self-directed energy waste reduction plan requirements set forth in MCL 460.1093.” (Smith, 3T 889–890). Staff confirmed that the Customer “will still be required to pay a surcharge based on [its] obligation to the low-income programs of the Company’s EWR plan” even if it self-directs, ensuring that the Customer continues to support the Company’s low-income EWR programs. (Smith, 3T 889).

Staff makes recommendations regarding the Customer's EWR self-direction that the DTE Electric does not oppose because the Company expects to meet Staff’s recommendations through its normal course of business. Staff recommended that the Commission direct the Company to work with the Customer to establish a self-directed EWR plan consistent with the forms, instructions, and first-year targets set forth in the Commission's Order in Case No. U-21627; to make the Customer aware of the reporting requirements of Section 93(9) of Act 295; and to communicate to the Customer the expectations of self-directing an EWR plan, including that a self-directed plan must be multi-year in duration and is subject to a financial penalty if the Customer does not meet its goals with newly implemented EWR measures annually. (Smith, 3T 889–891).

The EWR provision of the PSA is reasonable, prudent, and in the public interest. It secures the Customer's compliance with Michigan's self-directed EWR requirements, preserves the

Customer's contribution to the Company's low-income EWR programs, and advances the State's EWR objectives. Thus, the Commission should approve it as filed.

B. Clean Capacity Acceleration Agreement

The CCAA enables the Company to deploy up to 480 MW of energy storage and up to 1,600 MW of renewable energy, and to receive 300 MW of ZRCs, with the Customer paying the full cost of all projects and providing the ZRCs at no cost — such that no CCAA costs are shifted to other customers. The VGP Special Contract arising from the CCAA is authorized under MCL 460.1061 and the VGP Settlement Agreements. Approval is sought for the CCAA and two related accounting authorizations (the CCAA Regulatory Liability and the ZRC financial adder).

1. VGP Special Contract

Although the CCAA is a single agreement, its renewable-energy component is, in substance and effect, a customer-requested VGP Special Contract, and it is presented for approval under MCL 460.1061 and the VGP Settlement Agreements. As Company Witness Foley testifies, the CCAA terms governing the deployment of renewable energy comply with the VGP Settlement Agreements discussed in Company Witness Bilyeu's testimony, and "[t]herefore, the renewable energy resources included in the CCAA are considered part of a customer-requested VGP special contract and treated as such for RPS purposes." (Bilyeu, 3T 110-111). Rather than entering into a standalone VGP special contract for the customer-requested renewable projects, DTE Electric and the Customer reasonably incorporated the VGP Special Contract terms into the CCAA.

The statutory basis for the VGP Special Contract is MCL 460.1061, which authorizes and governs VGP programs through which an electric provider procures renewable energy on behalf of a participating customer. In its June 9, 2021 Order in Case Nos. U-20713 and U-20851, the

Commission approved a partial settlement agreement that established a customer-requested offering within the Company's VGP program. As Company Witness Bilyeu explains, this offering “supports unique, customer driven renewable energy projects that fall outside the standard Rider 17 options,” under which "the Company designs and constructs dedicated renewable energy projects that support each participating customer's specific sustainability goals." (Bilyeu, 3T 278). The Commission expressly anticipated in the December 18 Order, p. 42, that voluntary green pricing (VGP) programs may provide a vehicle for applicable customers to comply with the requirements necessary to qualify for the sales and use tax exemptions,[23] and indicated that the Commission would consider the approval of such VGP programs in future proceedings.

The VGP Special Contract fits squarely within the Company’s existing, Commission-approved VGP framework. The Customer has elected to enroll 40% of its load in the VGP Special Contract. (Bilyeu, 3T 279). The Customer has requested that the Company build up to 1.6 GW of renewable energy projects through such a VGP Special Contract, and the contractual terms governing the deployment of that renewable energy comply with the VGP Settlement Agreements. (Bilyeu, 3T 296).

Consistent with the defining feature of every VGP special contract, the Customer pays the full cost of the renewable resources procured on its behalf. As Company Witness Bilyeu confirms, all costs associated with the development of the renewable energy project(s) to supply VGP special contracts are fully recovered through the subscription fees … that are featured in the VGP special contracts and are billed to the subscriber, and any early termination or default of the contract from the subscriber's actions or inactions results in a termination fee, designed to ensure all costs of participation and termination are borne by subscribers and that no costs are subsidized by non-

[23] *See*, MCL 205.54ee(10)(e)(ix)(C); MCL 205.94cc(10)(e)(ix)(D).

subscribers. (Bilyeu, 3T 278-279). Hence, the VGP Special Contract embodies the same "hold harmless" principle that governs the Special Contracts as a whole.

The VGP Special Contract remains subject to ongoing Commission oversight. As Company Witness Foley confirms, renewable energy projects deployed under the CCAA will be selected consistent with the VGP Settlement Agreements, with the details of the competitive process being agreed upon with the Customer, and "the Company will submit each project to the Commission for review and approval prior to construction." (Foley, 3T 110.) The VGP Special Contract therefore advances Michigan's clean-energy objectives — consistent with 2023 PA 235 and the Commission's VGP precedent — while ensuring that the Company's other customers bear none of its costs and that each project returns to the Commission for approval.

- *VGP Special Contract – Staff and Intervenor Positions*

MEICEO witness Sherman contends that the Company's use of a customer-requested VGP Special Contract (which she refers to as the "CRO") is inappropriate, arguing that if the Customer instead procured renewable service through Rider 17, the resource procurement would follow the ownership split established in the Company's IRP settlement, and that the VGP Special Contract structure allows the Company to avoid that third-party-ownership split. She further contends that the VGP Special Contract lacks a sufficiently standardized competitive-procurement structure, and recommended that the renewable resources be procured using a 50% third-party / 50% Company-owned split. (Sherman, 3T 774). The Commission should reject these recommendations for several compelling reasons.

First, the customer-requested VGP offering is the correct, Commission-approved vehicle, as opposed to the inapplicable IRP settlement. As Company Witness Bilyeu explains, “[t]he customer-requested offering was established in Case Nos. U-20713/U-20851 to provide a customer-specific procurement framework for large customers with unique requirements," and "is not a substitute for Rider 17; it is a distinct offering developed to accommodate the scale and complexity of large-load customer contracts, such as the VGP Special Contract." (Bilyeu, 3T 306). The Customer's requirement for up to 1,600 MW of renewable energy "is precisely the type of arrangement the customer-requested offering VGP settlement provision was designed to address." *Id*. As applied to the proposed VGP Special Contract, the appropriate focus in this proceeding is on whether the procurement framework is tailored to produce resources that are reasonable for the Customer's VGP participation, preserve flexibility, and remain consistent with the Commission-approved framework arising from the VGP Settlement Agreements. Consistent with prior VGP special contracts and the VGP Settlement Agreements, the bespoke procurement framework under the Customer's VGP Special Contract was developed collaboratively between DTE Electric and the Customer and is reasonably tailored to the Customer's specific objectives and requirements. (Bilyeu, 3T 304-305).

Second, no ownership split is needed to protect other customers, because the Customer bears the full cost. As Witness Bilyeu testified, "the Customer is responsible for the full revenue requirement associated with the renewable resources procured to serve its VGP enrollment," and "[g]iven that the Customer bears these costs in full, a Commission-imposed ownership split is not needed to protect other ratepayers from the renewable resource revenue requirement." (Bilyeu, 3T 304).

Third, MEICEO witness Sherman's "capital bias" assertion neglects the applicable VGP special contract context and is not supported by current market data. The VGP Special Contract is the direct result of negotiated terms and conditions between the Company and the Customer that reflect the bespoke procurement framework required to serve the Customer's unique and complex needs. (Bilyeu, 3T 306-307). MEICEO witness Sherman's "capital bias" assertion also ignores the risk and accountability that DTE Electric has accepted under the proposed Special Contracts. As emphasized in Company Witness Foley's rebuttal testimony, DTE Electric has accepted customer-protection obligations under the Power Supply Agreement, CCAA, and related agreements, including the position that the Company would not seek to recover from other customers costs that the Commission ultimately determines are in excess of the combined revenues payable to the Company under those agreements. Given that risk allocation, it is reasonable for DTE Electric to maintain sufficient control over the development, procurement, timing, and integration of resources needed to satisfy the Customer specific VGP Special Contract. Third-party suppliers do not assume the same obligations to the Customer, the Commission, or DTE Electric's other customers under the Special Contracts. (Bilyeu, 3T 307).

Fourth, MEICEO witness Sherman's claim that third-party resources are cheaper is unfounded and entitled to no weight. It is telling that, to support a 50% third-party mandate in this limited special contract proceeding, she must reach back to a more than six-year-old solicitation from a different utility rather than address DTE Electric's own current RFP data — data that shows third-party ownership is the *more* expensive option. Company witness Bilyeu pointed out that in DTE Electric's 2024 All-Source Renewable RFP, Company-owned projects averaged approximately $75 per MWh, while third-party-owned projects averaged approximately $92 per MWh, and that Witness Sherman's reliance on Consumers Energy's 2019 solicitation is unreliable and outdated given materially changed market conditions. (Bilyeu, 3T 307–308). Accordingly, mandating higher levels of third-party ownership could increase costs rather than reduce them. (Bilyeu, 3T 308).

Fifth, a rigid 50/50 ownership split mandate would harm, not promote, competition. As Company Witness Bilyeu explains, "mandating a predetermined ownership split could reduce procurement flexibility and could diminish competitive pressure," and "[b]y requiring a specific ownership outcome in advance, the Commission would limit DTE Electric's ability to select the most advantageous projects and could inadvertently increase costs." (Bilyeu, 3T 309). Staff agrees, having "consistently opposed a 50% ownership split in all cases on the simple premise that if the Competitive Procurement Guidelines are met, the most economic projects should be selected." (Simpson, 3T 848). Relatedly, the self-build portion of the VGP portfolio serves a different function than third-party ownership; namely, it allows the Company to maintain direct development accountability, schedule control, and integration with the Customer-specific VGP Special Contract obligations. Because the Customer is responsible for the costs of the renewable resources procured under the VGP Special Contract, the question is whether the procurement framework is reasonable (consistent with the Commission approved VGP Settlement Agreements) and produces resources suited to the Customer's VGP participation, not whether the Commission should replace that framework with a new ownership mandate in this special contract proceeding. (Bilyeu, 3T 310).

MEICEO witness Sherman also relies on paragraph 7 of the Case No. U-21172 settlement to tenuously argue that, upon termination, the VGP renewables would be reallocated to other customers, exposing them to cost — and that greater third-party ownership is therefore warranted. However, that reliance is misplaced because the cited settlement provision does not override the Customer-specific termination-payment and cost-recovery provisions of the CCAA, under which the Customer cannot voluntarily terminate the CCAA, and, upon a default termination, the Customer is obligated to pay a termination payment designed to collect the unrecovered portion of each project's costs over its depreciable life. (Bilyeu, 3T 311–312). As Company Witness Bilyeu concludes, a third-party ownership mandate would not change the CCAA termination payment obligation, as the key protection is the Customer's payment obligations under the CCAA itself, not the ownership form of the renewable resource. (Bilyeu, 3T 312).

To the extent that MEICEO witness Sherman asks the Commission to impose a 50/50 ownership split, she seeks relief that cannot be lawfully granted. As set forth in Section III, the Commission lacks statutory authority to rewrite the PSA and CCAA over the parties' negotiated agreement and cannot lawfully impose a 50/50 ownership split that does not expressly and affirmatively derive from statute. *Union Carbide*, at 148-149; *see also Consumers Power Co*, 460 Mich 148.

It should also be noted that to the extent that MEICEO witness Sherman suggests that a mandatory 50% third-party BTA requirement already applies is incorrect. As Company Witness Bilyeu explains, the Case No. U-21172 settlement provides that the Company will target acquisition of a minimum of 50% of the required capacity through build-transfer agreements, but "establishes a procurement process, not a mandatory RFP outcome," and does not require the Company to continue issuing RFPs indefinitely if solicitations do not yield contracted projects. (Bilyeu, 3T 305–306).

To the extent Staff witness Simpson recommended that the Competitive Procurement Guidelines govern the VGP renewables, Company Witness Bilyeu clarifies the distinction between the two CCAA resource categories. While the Company will apply the Competitive Procurement Guidelines to the 2026 Energy Storage RFP, the renewable resources under the VGP Special Contract will be selected consistent with the Commission-approved settlement agreements in Case Nos. U-20713/U-20851 and U-21172, because procurement for VGP special contracts is governed by the VGP Settlement Agreements that establish the applicable competitive procurement framework for customer-requested special contracts. (Bilyeu, 3T 296–297). As Witness Bilyeu concludes, "this proceeding is not the appropriate forum to revisit or modify the previously approved VGP Settlement Agreements or impose additional procurement requirements that would alter the negotiated VGP Special Contract framework." (Bilyeu, 3T 297).

2. The CCAA Does Not Shift Costs to Other Customers

The defining feature of the CCAA — like the PSA — is that it holds the Company's other customers harmless through layered contractual and regulatory protections. The Customer pays the full cost of every resource deployed under the CCAA and provides the 300 MW of ZRCs at no cost, and the credits the Customer receives are capped so that other customers can never bear a CCAA cost and, in fact, share in the upside. As Company Witness Foley summarized, the CCAA "pricing and associated reconciliation processes ensure that the Customer fully pays for the actual costs of the energy storage and renewable energy projects." (Foley, 3T 115). In this way, the CCAA prevents cross-subsidization of the projects and mitigates the risk of stranded assets. *Id*. The primary features of the CCAA that establish this protection are discussed below.

First, the Customer pays the full cost of every CCAA project. Under the CCAA, the Customer will pay the full cost (i.e., revenue requirement) of the projects over each project's depreciable life. (Foley, 3T 107). For each Company-owned project, the Company calculates an annual revenue requirement "in the same manner that a revenue requirement is calculated in a general rate case for energy storage projects or a Renewable Energy Plan … for renewable energy projects," including AFUDC, depreciation, the Company's authorized rate of return, amortization of Investment Tax Credits, O&M, property tax, and insurance; for third-party tolling agreements or power purchase agreements, the revenue requirement equals the annual cost of the TA or PPA plus any authorized financial incentive under MCL 460.1028. (Foley, 3T 111–112). Because the Customer bears the entire revenue requirement of each project over its depreciable life, the costs of the energy storage and renewable energy projects developed to fulfill the CCAA with the Customer will not be passed on to the Company's other customers. (Foley, 3T 88).

Second, annual reconciliation will ensure that the Customer pays actual costs. The Customer's payments are not fixed estimates, and they will be trued up to actual costs each year. As Company Witness Foley stated, "[a]fter each calendar year, the Company will perform a cost reconciliation for each project deployed under the CCAA," comparing the amount charged to the Customer to the actual costs of the project, with "[a]ny over recovery or under recovery … incorporated into the subsequent year's Customer charges." (Foley, 3T 114). The costs of the projects and the associated Customer charges will be presented in the Company's future general rate cases (for energy storage) and annual REP reconciliation cases (for renewables), where the Commission and stakeholders can review them. *Id*.

Third, Customer credits are capped at market revenues, protecting and benefiting other customers. The capacity and renewable generation credits the Customer receives for CCAA resources are strictly capped so that other customers bear no cost. For each project and billing period, the Company provides the Customer the lower of 1) the calculated capacity credit, or 2) the capacity market revenues, and the same lower-of methodology applies to Renewable Generation Credits (the lower of the calculated credit or the energy market revenues). (Foley, 3T 120–123). This cap protects other customers in both directions. When market revenues exceed the calculated credit, the Customer receives only the calculated credit, and the difference (i.e., market revenues less calculated capacity credit) is a benefit to the Company's other customers that will be realized through the PSCR mechanism. (Foley, 3T 118). On the other hand, when market revenues are less than the calculated credit, the Customer receives only the market revenues, so the Company's other customers are protected because the credits being provided to the Customer will never be more than the market revenues generated by that project. (Foley, 3T 119, 123). The credit structure therefore not only insulates other customers from CCAA costs but affirmatively delivers to them, through the PSCR, any market revenues that exceed the Customer's calculated credits.

Fourth, no CCAA project is deployed without Commission review. As Company Witness Foley confirms, for both energy storage and renewable energy projects, "the Company will submit each project to the Commission for review and approval prior to construction." (Foley, 3T 110). The Commission thus retains the ability to review the prudence of each CCAA project before it is built, providing a further safeguard against any cost shift to other customers.

Fifth, accelerated recovery and the CCAA Regulatory Liability prevent any post-term cost shift. Because certain CCAA projects will have depreciable lives extending beyond the 20-year CCAA term (23 years for solar, 26 [24]years for wind), it is expected that a portion of each CCAA project's depreciable life will extend beyond the term of the CCAA. (Foley, 3T 113). Thus, the CCAA is structured to ensure the Customer fully pays for each project even where its life extends past the term. The Company calculates the revenue requirement that would be incurred beyond the term and collects it from the Customer during the term, recording the excess recovery as a CCAA Regulatory Liability that will grow throughout the term of the CCAA and can then be used beyond the term of the CCAA to offset the remaining costs of the projects. (Foley, 3T 113–114). As Company Witness Foley testifies, "[t]his approach ensures that the Company's other customers

24 The Company notes that it inadvertently listed the depreciable life of wind energy assets as 27-years. The currently approved depreciable life of wind energy assets is 26-years. This does not affect the Company's modeling in this case.

will not be responsible for the costs of the renewable projects during their depreciable lives." (Foley, 3T 114). The Company's request for authorization to record this Regulatory Liability (to Account 254) is addressed in Section V.B.3 below.

Sixth, the CCAA includes a termination payment that operates differently from — and independently of — the PSA termination payment, and it is structured to fully protect the Company's other customers against stranded-asset risk. As a threshold matter, the Customer cannot voluntarily terminate the CCAA; a termination payment is triggered only upon a Customer default. (Foley, 3T 124). If the CCAA is terminated through Customer default, "the termination payment is set equal to the unrecovered portion of each project's costs (i.e., revenue requirement) over its respective depreciable life" — that is, "the remaining amount that the Company would have collected had the agreement not been terminated." *Id*.

Because the CCAA termination payment is keyed to the unrecovered revenue requirement of the deployed energy storage and renewable energy projects, it is inherently self-adjusting (i.e., it automatically reflects the actual costs of the projects deployed and the amounts already recovered from the Customer as of the termination date). As Company Witness Foley explains, the termination payment is designed to collect whatever amounts would have otherwise been collected had the CCAA not been terminated; as such, the costs of all CCAA projects would be fully recovered from the Customer, mitigating the risk of stranded assets for these projects. *Id*. The termination payment thus works in tandem with the CCAA's project-pricing and regulatory-liability mechanics to ensure the Customer bears the full cost of every project deployed under the CCAA, whether the agreement runs its full term or is terminated early upon default.

Lastly, the CCAA includes credit and collateral requirements that protect the Company and its other customers in the event of Customer default. The CCAA provides for these protections through a parent guaranty and, if necessary based on the parent's credit rating, a letter of credit designed to protect the Company and its customers in the event of Customer default. (Foley, 3T 124). The structure operates dynamically over the contract term. As Witness Foley explains, once the CCAA is approved the Customer will initially provide a PG to cover a portion of the Customer's financial obligations under the CCAA. Later in the contract term, the PG is reduced once the forecasted termination payment of the CCAA drops below the initial PG and a larger PG becomes superfluous. (Foley, 3T 125). And if at any point the parent's credit rating drops below a pre-defined threshold, then the Customer will be required to post a LoC equal to the PG amount applicable at that time. *Id*. Hence, the collateral package therefore tracks the Company's declining financial exposure over time and automatically strengthens — converting from a parent guaranty to a letter of credit — precisely when a decline in the parent's creditworthiness would otherwise increase risk to the Company and its other customers. As with the PSA, the Company has accepted that the risk of any collateral shortfall under the CCAA falls on the Company. (Foley, 3T 133-134).

- *The CCAA Does Not Shift Costs to Other Customers – Intervenor Positions*

To the extent that ABATE witness Dauphinais recommended that approval of the Special Contracts be conditioned on modifying the Affordability Backstop (Section 5.1.3 of the PSA) "to allow an evaluation and modification of the termination payment by the Commission based on the facts and circumstances known or knowable at the time of termination" (Dauphinais, 3T 543), the CCAA termination payment's self-adjusting design inherently addresses ABATE's concern. Thus, witness Dauphinais' recommendation is unnecessary specifically because the CCAA termination payment is set equal to the remaining revenue requirement of the energy storage and renewable energy projects deployed under that agreement that have not yet been recovered from the Customer and automatically adjusts to account for the costs of those projects. (Foley 3T, 138). Please see Section V.A.4 for the Company's further response to ABATE witness Dauphinais' termination payment modification recommendation, which is incorporated herein.

AG witness Coppola recommended the Commission remove any limit on the PSA and CCAA collateral, arguing that the parent company guaranty needs to be at the level that ensures full payment of the Customer's total obligations. Please see Section V.A.5 for the Company's further response to AG witness Coppola's collateral recommendation, which is incorporated herein. DTE Electric adds in response to AG witness Coppola's recommendation that, as applied to the CCAA, the CCAA guaranty is deliberately calibrated to the Company's declining exposure. The guaranty declines over time to track the declining termination payment, because a larger guaranty becomes superfluous as the Customer pays down the projects' revenue requirement. (Foley, 3T 125). Requiring a static guaranty equal to the peak potential obligation for the entire term, as AG witness Coppola seemingly proposes, would impose a commercially unreasonable requirement untethered from the Company's actual, declining risk. Moreover, the guaranty escalates automatically to address the credit risk AG witness Coppola discusses. Because the guaranty converts to a letter of credit if the parent's credit rating falls below the defined threshold, the structure provides a more secure form of collateral precisely when it is needed.

Because the Customer pays the full, reconciled cost of every CCAA project, receives credits capped at market revenues, funds any post-term revenue requirement through the CCAA Regulatory Liability, remains obligated upon any default to pay a termination payment equal to the unrecovered revenue requirement of the deployed projects, and secures its obligations through a parent guaranty and, as necessary, a letter of credit, the CCAA does not shift any costs to the

Company's other customers. Thus, it should be approved as reasonable, prudent, and in the public interest.

3. CCAA Regulatory Liability

The Commission should authorize DTE Electric to record a regulatory liability to Account 254 to effectuate the accelerated cost recovery mechanism of the CCAA. This mechanism is a core customer-protection feature to ensure that the Customer pays the full revenue requirement of each energy storage and renewable energy project over its entire depreciable life, even where that life extends beyond the 20-year CCAA term. No Staff or intervenor has opposed this request in testimony.

The CCAA Regulatory Liability prevents cost-shifting to other customers. Under the CCAA, the Customer pays the full cost (i.e., the revenue requirement) of each energy storage and renewable energy project over the project's respective depreciable life. (Foley, 3T 111). The current depreciable lives of solar (23 years) and wind (27 years) assets, however, extend beyond the CCAA's 20-year term, and a portion of an energy storage project's depreciable life may as well, depending on its commercial operation date. (Foley, 3T 111, 113). Absent an accelerating mechanism, the post-term portion of each project's revenue requirement would fall to the Company's other customers—precisely the outcome the Special Contracts are structured to avoid.

To close the gap, the CCAA allows the Company to accelerate recovery of a project's costs. (Foley, 3T 113). The Company calculates the revenue requirement that will be incurred beyond the CCAA term and collects those costs from the Customer during the term by dividing them evenly across the applicable billing periods. *Id*. As a result, Google pays more than the annual revenue requirement during the term. *Id*. The Company records this excess recovery—the Customer charge less the project's revenue requirement—as a Regulatory Liability. *Id*. That liability grows throughout the term of the CCAA and is then applied beyond the term to offset the projects' remaining revenue requirement. (Foley, 3T 113–114). This approach ensures that the Company's other customers will not be responsible for the costs of the renewable projects during their depreciable lives." (Foley, 3T 114).

Consistent with the foregoing, the Company requests Commission authorization to record the CCAA Regulatory Liability to Account 254 during the term of the CCAA related to the accelerated recovery (i.e., customer collections above revenue requirement) of energy storage and renewable energy projects deployed under the CCAA. (Foley, 3T 127–128).

4. ZRC Transfer and Financial Adder

Under the CCAA, the Customer commits to transfer 300 MW of MISO Zone 7 ZRCs to the Company at no cost, which the Company can then use to meet its capacity needs. As Company Witness Foley clarifies, the Customer commits to transfer 300 MW of ZRCs to the Company which the Company can then utilize to meet its capacity needs, and the ZRCs will be provided by the Customer for each MISO season from June 1, 2028 to May 31, 2033. (Foley, 3T 115). The transfer of 300 MW of capacity to the Company at no cost is a direct benefit to the Company's other customers, contributing to the Company's resource adequacy without any associated cost to other customers.

In addition to transferring the ZRCs at no cost, the Customer has agreed to pay the Company a financial adder. As Company Witness Foley explains, "the Customer will pay the Company an amount equal to the ZRCs transferred to the Company multiplied by MISO Cost of New Entry ('CONE') multiplied by the Company's pre-tax weighted average cost of permanent capital ('financial adder')." (Foley, 3T 116). The Company is proposing that it be allowed to record this amount as non-refundable income, like it does with Financial Compensation

Mechanisms ("FCM"). *Id*. The financial adder is conceptually similar to an FCM in that it accounts for the opportunity cost of the Company foregoing the development of a Company-owned resource. Because it is similar in concept and objective, the Company proposes that it receive the same accounting treatment. (Foley, 3T 155).

- *ZRC Transfer and Financial Adder – Staff and Intervenor Positions*

Staff witness Simpson, ABATE witness Dauphinais, MEICEO witness Sherman, and GLREA witness Richter each contend that the Company should not be permitted to record the financial adder as pre-tax net income, and that the adder should instead either be rejected or treated as ordinary revenue used to offset the Company's future revenue deficiencies. (Simpson, 3T 843-844, Dauphinais, 3T 550, Sherman, 3T 808-811 Richter, 3T 587). Staff witness Simpson, for example, recommended that the Commission deny the request on the ground that the transaction is not a power purchase agreement, as there is no actual purchase of power, and that the FCM revenue instead be used to benefit all customers and be recorded as revenue that will offset the Company's future revenue deficiencies. (Simpson, 3T 843-844). The Commission should reject these recommendations for four primary reasons.

First, Staff and intervenors' principal objection — that the financial adder cannot be treated like an FCM because there is no power purchase agreement with the Customer — misconstrues the basis for the Company's request. The Company is not suggesting that the accounting treatment be granted pursuant to MCL 460.1028. (Foley, 3T 155-156). The financial adder is part of a special contract, which by its nature may contain special terms and conditions, and is indeed not tied to the statutory FCM. *Id*. The absence of a statutory PPA is therefore beside the point; the financial adder is a negotiated term of a special contract, and the intervenors identify no factual or legal basis to deny the accounting treatment requested by the Company beyond the inapposite observation that there is no PPA. *Id*.

Second, Staff and intervenors' position works an inequitable allocation of risks and benefits. As Company Witness Foley pointed out, “all four intervenors that took a position on the accounting treatment of the financial adder variously argued that the Company should bear the risk of the Customer not fully covering their financial obligations,” yet “all four also argued that the Company should not be allowed to offset that risk by capturing the benefit of the financial adder that the Customer has agreed to pay.” (Foley, 3T 156). Hence, requiring the Company to accept the downside risk of serving the Customer while denying it a modest negotiated benefit works to establish an unfair and inequitable sharing of risks and benefits. *Id*.

Third, granting the requested treatment does not harm other customers, but interferes with the Company’s right to negotiate contract terms. As Company Witness Foley emphasizes, "the financial adder is not offsetting a cost to the Company that it would otherwise recover from its other customers." *Id*. The Company's customers will be held harmless if the Commission were to grant the Company's requested accounting treatment. *Id*. Because the financial adder is an amount the Customer has agreed to pay over and above the full cost of the ZRC-related resources — and is not a cost that would otherwise fall on other customers — Staff and intervenors' concern that ratepayers are somehow disadvantaged is unfounded.

Fourth, to the extent that Staff and intervenors ask the Commission to override a negotiated payment term’s treatment, they seek relief that cannot be lawfully granted. As set forth in Section III, the Commission lacks statutory authority to rewrite the PSA and CCAA over the parties’ negotiated agreement. *Union Carbide*, at 148-149.

ABATE witness Dauphinais alternatively recommended that, even if the Commission approves the accounting treatment, it should condition approval on DTE Electric "agreeing that the Commission's approval of Google's agreement to provide a financial incentive to the ZRC transfer does not set any precedent with respect to whether DTE is entitled to mandate the receipt of such a financial incentive from its customers on customer self-supplied capacity and energy." (Dauphinais, 3T 550). The Company does not object to ABATE's alternative recommendation (Foley, 3T 156), as it does not view the Commission's approval of the adder as precedent to impose financial adders on other customers in future cases.

To the extent MEICEO witness Sherman recommended that a portion of the 300 MW ZRC obligation be met through Company-administered programs such as an expanded Smart Savers program or a new Virtual Power Plant ("VPP") program, her recommendation should be rejected as unreasonable and inconsistent with the ZRC contract structure under which the Customer provides the ZRCs at no cost and at its own discretion as to source. Specifically, witness Sherman recommended (i) that the Company expand enrollment in its Smart Savers program by 100 MW to partially offset the 300 MW of ZRCs that the Customer has agreed to transfer to the Company, potentially through an additional enrollment pathway for smart-thermostat manufacturers and Customer subsidies for residential thermostats; and (ii) that the Company establish a VPP program to provide some portion of the needed 300 ZRCs. (Sherman, 3T 791-807).

First, MEICEO witness Sherman's recommendations reflect a fundamental misunderstanding of the ZRC product and negotiated contract terms regarding same. As Company Witness Foley explains, "[t]he Company is not involved in the Customer's procurement of ZRCs that will be transferred to the Company as part of the CCAA." (Foley, 3T 165). The obligation to provide the ZRCs is the Customer's, and the source of those ZRCs is at their discretion. Because the Company is not party to the Customer's procurement of those ZRCs and the source of the ZRCs is not at issue, MEICEO witness Sherman's recommendation to partially meet the ZRCs through utility programs is wholly out of context in this case. (Foley, 3T 165–166).

Second, substituting Company-administered programs for a portion of the ZRC obligation would introduce reliability risk to other customers. Section 2.4 of the PSA provides protections in the event the Customer does not provide the ZRCs, including a potential reduction in their load ramp. (Foley, 3T 166). As Company Witness Foley explains, restructuring the CCAA "such that the Customer is only required to provide 200 MWs (with the other 100 MW provided through Company programs) could introduce reliability risk to the Company's other customers since the Company could not invoke Section 2.4 if it, for example, failed to achieve the Smart Saver enrollment targets recommended by witness Sherman." *Id*. In other words, MEICEO witness Sherman's proposal would transfer to the Company — and ultimately to its other customers — a performance risk that the CCAA presently places squarely on the Customer. This is unreasonable and must be rejected.

Third, the proposal would disrupt the no-cost nature of the ZRC transfer. The Customer is providing the ZRCs "at no cost to the Company," and, as Company Witness Foley emphasizes, "[i]t would be unreasonable to change such an arrangement to the extent that it introduces any costs to the Company or its customers." (Foley, 3T 166). MEICEO witness Sherman's proposal — which contemplates Company-administered Smart Savers expansion and a new VPP program, potentially with up-front incentives — would necessarily introduce program costs that do not exist under the negotiated CCAA, in which the Customer bears the entire ZRC obligation at no cost to ratepayers.

Fourth, this special contract proceeding is not the appropriate forum to mandate new Company resource programs. The Commission's review in this proceeding should be limited to whether the PSA and CCAA negotiated between DTE Electric and the Customer are reasonable and should be approved, and should not be misused as a vehicle to mandate new Company-administered resource programs or a different resource portfolio that was not proposed by the Company and not negotiated with the Customer. (Foley, 3T 166). The Company does not dispute that future resources such as demand response or VPPs may have a role to play; but the role of future resources should be considered in the Company's IRP, and those future planning questions do not provide a basis to replace or reduce the Customer's negotiated obligation to provide ZRCs under the CCAA in this special-contract proceeding. (Foley, 3T 167).

Fifth, to the extent that MEICEO witness Sherman asks the Commission to restructure how the negotiated 300 MW ZRC obligation is met, she seeks relief that cannot be lawfully granted. As set forth in Section III, the Commission lacks statutory authority to rewrite the PSA and CCAA over the contracting parties' negotiated agreement. *Union Carbide*, at 148-149.

Next, ABATE witness Dauphinais and MEICEO witness Hotaling recommended that both the ZRC transfer under the CCAA and the Rider 12 DR Agreement[25] be extended beyond their negotiated May 31, 2033 end dates. (Dauphinais, 3T 547-548; Hotaling, 3T 717). ABATE witness Dauphinais asks the Commission to modify the CCAA and the Rider 12 DR Agreement to require extension to the extent DTE Electric has been unable to bring 550 MW of ZRCs of new capacity online in MISO Zone 7 to replace the ZRCs provided by the Customer, reasoning that the sunset of these commitments is likely the principal contributor to the Company's projected need for 677 MW of perfect capacity in 2033. (Dauphinais, 3T 547-548). MEICEO witness Hotaling similarly

[25] *See*, Section V.D for detailed discussion of the Rider 12 DR Agreement.

suggests that an extension could be conditioned upon whether the extension of these resources could address incremental need identified as a result of the Customer in the next IRP. (Hotaling, 3T 717). The Commission should reject these recommendations for the below reasons.

First, the ZRC transfer is a voluntary, negotiated term of the CCAA that the Commission cannot unilaterally extend through this proceeding. The 300 MW ZRC transfer is an obligation the Customer voluntarily agreed to provide, at no cost, from June 1, 2028 through May 31, 2033, as part of the broader bargain captured in the Special Contracts. (Foley, 3T 163). The intervenors do not merely urge the Commission to decline that term; they ask the Commission to rewrite the CCAA's negotiated end date and compel the Customer to provide ZRCs for additional years it never agreed to. Therefore, to the extent that the intervenors ask the Commission to extend voluntary, negotiated commitments the Customer did not agree to, they seek relief that cannot be lawfully granted. As set forth in Section III, the Commission lacks statutory authority to rewrite the PSA and CCAA over the parties' negotiated agreement. *Union Carbide*, at 148-149.

Second, ABATE and MEICEO's recommendations rest on unverified assumptions and concern a future resource-planning question reserved for the IRP. Their recommendations rely on an assumption that (1) the resources will be available beyond May 31, 2033, and (2) the Customer is willing to provide these resources beyond May 31, 2033; however, neither of these threshold assumptions has been assessed or verified. (Foley, 3T 163). The underlying concern that the projected need for capacity in 2033 following the sunset of the ZRC and Rider 12 DR commitments is undoubtedly a resource adequacy question that the Company will address in its 2026 IRP, which is the proper forum for determining how to meet any 2033 capacity need. It is not a basis to rewrite the negotiated end date of a standard tariff DR arrangement in this special contract proceeding.

In sum, the 300 MW ZRC transfer provides capacity to the Company at no cost, and the financial adder is a negotiated CCAA term that the Company appropriately proposes to record as non-refundable income. Staff and intervenors identify no cost to other customers and no legal barrier to the requested treatment; their position would inequitably deny the Company the benefit of a negotiated term the Customer agreed to pay while leaving the Company to bear the associated risk. The Commission should approve the requested accounting treatment for the financial adder, subject to ABATE's non-precedent condition the Company has accepted.

5. System Benefits and Reduction in RECs Needed in the Forecast

Beyond holding other customers harmless, the CCAA — and in particular its VGP Special Contract component — affirmatively benefits the Company's other customers and advances Michigan's clean-energy objectives. It does so principally by reducing the RECs the Company must otherwise procure in its forecast, while ensuring the Customer funds the associated renewable resources and continues to contribute to system renewable costs.

The Customer has elected to enroll 40% of its load in the VGP Special Contract. (Bilyeu, 3T 279). Under 2023 PA 235, load enrolled in a VGP program is removed from the Company's total retail sales for purposes of the Renewable Portfolio Standard ("RPS") compliance calculation, thereby reducing the RPS target. (Bilyeu, 3T 283; *see also* 3T 326-327). As a result, although the addition of the Customer's load increases the Company's RPS target, the Customer's 40% VGP enrollment materially mitigates that increase — the net effect being an approximately 10.8% increase in the RPS target rather than the larger increase that would result absent VGP enrollment. (Bilyeu, 3T 283). By allocating 1.6 GW to the VGP Special Contract, the Customer is positioned to claim 100% renewable energy usage once the Company reaches its 60% RPS target. (Bilyeu, 3T 279–280).

The renewable resources supporting the VGP enrollment are funded entirely by the Customer, yet the Customer also continues to contribute to the Company's system renewable costs through the PSCR. Because the Customer is subject to the PSCR, it will contribute to the Company's existing and future renewable and transmission costs, which ensures any incremental renewable generation for RPS compliance associated with the Customer's load is appropriately offset. (Bilyeu, 3T 284). As Company Witness Bilyeu explained on cross-examination, the combined effect is that the Customer "*effectively [pays] for 140 percent of renewables*" — funding 100% of its load through the PSCR while simultaneously reducing the RPS target for other customers through its VGP enrollment — which he aptly described as "a great benefit to customers." (Bilyeu Cross, 3T 346).

The Company's analysis demonstrates that, with the 1.6 GW enrolled in the VGP Special Contract, the Company can maintain a positive REC balance and meet the RPS requirements under PA 235. (Bilyeu, 3T 284). The Company has substantial experience developing and integrating renewable resources, with over 2,600 megawatts of renewable energy currently online, and maintains a robust development pipeline, competitive RFP processes, and acquisition capabilities sufficient to meet the renewable build associated with the VGP Special Contract. (Bilyeu, 3T 298-300). The detailed renewable build strategy will be further developed and reviewed in the Company's forthcoming 2026 IRP and Amended REP, to be filed concurrently later this year. (Bilyeu, 3T 300).

MNS witness Woods raised two challenges to the Company's REC forecast, neither of which withstands scrutiny. MNS witness Woods first contends that the Company's forecasted REC surplus is not aligned with historical trends and therefore may be unreasonable. (Woods, 3T 644). However, as Company Witness Bilyeu testifies, “[h]istorical REC surplus trends are not particularly relevant to evaluating DTE Electric's forecast because the regulatory and resource planning environment reflected in the forecast is fundamentally different from the historical period on which Witness Woods relies." (Bilyeu, 3T 302). Because Michigan's RPS remains at 15% through 2029 while the Company is simultaneously building new renewable generation in preparation for substantially higher renewable energy requirements of 50% in 2030 and 60% in 2035, the forecast reflects accelerated build-out ahead of higher future standards, driven by statutory requirements and planned additions, not past REC trends. (Bilyeu, 3T 302). MNS witness Woods, in effect, "criticizes a forecast that reflects prudent planning for higher statutory renewable energy requirements." (Bilyeu, 3T 302).

MNS witness Woods also asserts that a calculation error in the REC market-purchase assumption would reduce the Company's forecasted REC position and could produce a REC shortfall in 2032. However, even under MNS witness Woods' adjusted calculation, the forecasted REC position does not demonstrate noncompliance, because the Company's compliance position reflects both banked REC surpluses from prior years and planned resource additions, and a single-year adjustment to the market purchase assumption does not account for the cumulative REC balance or the additional renewable resources that will be brought online through the VGP Special Contract and IRP processes. (Bilyeu, 3T 303). The Company will update these assumptions comprehensively in its forthcoming IRP and Amended REP, which are the appropriate forums for such exercises. (Bilyeu, 3T 303–304).

GLREA witness Richter contends that data-center load could make it more challenging for the Company to meet its renewable energy requirements, and recommended that the Commission issue a warning regarding future RPS compliance. (Richter, 3T 600). This concern is misplaced, as the up to 1,600 MW of renewable energy to be fully funded by the Customer and developed under the VGP Special Contract will contribute substantially to the Company's renewable energy portfolio and support its RPS compliance position. (Bilyeu, 3T 314). The Company's upcoming IRP and Amended REP will thoroughly evaluate RPS compliance, including the effects of large-load customers, as well as identify any additional resources needed to maintain compliance. (Bilyeu, 3T 314). Because the Company remains committed to meeting its obligations under the RPS statutory framework, Company Witness Bilyeu concluded — and the Company submits — that the Commission should not adopt GLREA witness Richter's recommendation to issue a warning on future RPS compliance in this special contract proceeding, as such a warning is not warranted and this is not the appropriate forum. (Bilyeu, 3T 314).

Staff witness Simpson recommended that the Commission "not approve a VGP program that does not require RECs be retired prior to being removed from the RPS compliance calculation," and, more specifically, that the RECs generated by the CCAA renewable resources "be retired in the year that the Company is subtracting those VGP sales from its renewable portfolio requirement calculation." (Simpson, 3T 842, 845). Staff's underlying concern is the prevention of double-counting — ensuring that the same renewable attribute is not counted both for the Customer's VGP participation and for the Company's RPS compliance. The Company shares that objective. But Staff's recommendation errs in insisting that DTE Electric's mandatory retirement is the only acceptable means of achieving it. The Commission should decline to impose that condition.

First, the Company agrees with the anti-double-counting principle — it simply disagrees that mandatory utility retirement is the exclusive means of honoring it. As Company Witness Bilyeu testifies, "[w]hile I agree that mechanisms must exist to prevent double counting of renewable attributes, I disagree that DTE Electric must be the entity responsible for the retirement of RECs in order for VGP sales to be removed from the RPS compliance calculation." (Bilyeu, 3T 290). The critical compliance safeguard is that RECs associated with the Customer's VGP participation must not also be used by DTE Electric to satisfy its RPS compliance obligation for non-VGP retail sales, and once those RECs are transferred to the Customer or retired on the Customer's behalf, they are not available for DTE Electric to count toward its RPS compliance. (Bilyeu, 3T 292–293). That objective can be fully achieved through appropriate REC ownership, tracking, assignment, transfer, and reporting, as it comes down to a tracking and verification issue, not a requirement that DTE Electric be the entity that retires every REC associated with VGP sales. (Bilyeu, 3T 292, 295).

Second, neither MCL 460.1061 nor Commission precedent require utility retirement as the exclusive means of demonstrating that renewable energy is attributable to a VGP customer. (Bilyeu, 3T 291-292). The statute requires that participating customers be able to specify the amount of electricity attributable to them that will be renewable energy, but does not require that DTE Electric retire the RECs on the customer's behalf. *Id*. Had the Legislature intended to require retirement in all circumstances, it would have expressly stated so.[26] Indeed, the very order Staff cites — the Commission's July 12, 2017 Order in Case No. U-18349 at page 8 — points the other way: the Commission recognized that "for some large commercial and industrial participants, it may be advantageous to provide an option for the customer to own and retire any RECs generated under the [VGP] program." As Company Witness Bilyeu explains, that "own and retire" language arises in the context of large C&I customers being given the option to own and retire any RECs

[26] *See Consumers Energy Co v Storm*, 509 Mich 195, 200; 983 NW2d 397 (2022); *see also, Empire Iron Mining Partnership v Orhanen*, 455 Mich 410, 424; 565 NW2d 844 (1997) ("We avoid inserting words in statutes unless necessary to give intelligible meaning or to prevent absurdity); *Omne Fin, Inc v Shacks, Inc*, 460 Mich 305, 311; 596 NW2d 591 (1999) ("Courts may not speculate regarding legislative intent beyond the words expressed in a statute. Hence, nothing may be read into a statute that is not within the manifest intent of the Legislature as derived from the act itself").

generated under the program, and that option "has been preserved here, as the VGP Special Contract likewise allows for customer ownership and retirement of RECs." (Bilyeu, 3T 294). Staff's position therefore effectively adds a requirement that does not appear in the statute. (Bilyeu, 3T 292). The Commission should decline Staff's invitation to read into the statute a restriction that the Legislature did not enact.

Third, the transfer of a REC does not diminish the renewable nature of the underlying energy or create any deficiency. (Bilyeu, 3T 291). A REC represents the renewable attribute associated with one megawatt-hour of renewable generation, and transferring a REC does not eliminate or invalidate the renewable nature of the underlying energy — it simply transfers ownership of the renewable attribute from one party to another. *Id*. Thus, a REC transferred to the Customer "remains a valid REC representing renewable energy," and the transfer "does not convert renewable energy into non-renewable energy, nor does it create any deficiency in renewable generation." *Id*.

Fourth, the Customer's role as the funder of the renewable resources makes REC-treatment flexibility particularly appropriate here. Unlike a customer simply purchasing renewable energy from an existing program, the Customer has agreed to support the development of up to 1,600 MW of renewable energy resources through a VGP Special Contract and will bear the associated costs of those resources. (Bilyeu, 3T 293). As a result, the Customer has a direct economic interest in both the renewable energy produced by the projects and the associated renewable attributes, and a customer that is funding renewable development should have flexibility regarding how those attributes are managed, provided appropriate safeguards exist to prevent double counting. Requiring that all RECs be retired by the utility would deprive the Customer of a fundamental and valuable component of the product it is purchasing. *Id*.

Fifth, Staff witness Simpson's recommendation carries adverse implications for the Company's other large VGP customers. As Company Witness Bilyeu testifies, the Company "has historically offered participating customers flexibility regarding the treatment of RECs, including the option for DTE Electric to retire the RECs on its behalf or to transfer the RECs to the customer." (Bilyeu, 3T 295). Other VGP special contract customers, such as Ford, Stellantis, and University of Michigan, are also offered the same flexibility provided for in Case No. U-18349. *Id*. Because these are sophisticated energy consumers with substantial renewable energy objectives who often manage their own REC portfolios, a rigid utility-retirement mandate could harm results and undermine the continued attractiveness of VGP for large customers interested in supporting renewable energy development. *Id*.

Finally, the Company acknowledges, and commits to satisfy, the legitimate compliance safeguard Staff identifies. Witness Simpson correctly observes that “RPS compliance and Clean Energy Plan ('CEP') compliance must align to ensure that RECs are only used once.” (Simpson, 3T 843). DTE Electric agrees and commits that “[t]he Company will maintain appropriate REC records to ensure that RECs associated with the Customer's VGP participation are not also used by the Company for RPS compliance in a manner that would result in double counting.” (Bilyeu, 3T 295–296). Whether those RECs are retired by DTE Electric on behalf of the customer or transferred to the customer, however, does not alter the renewable nature of the generation, does not create double counting, and does not conflict with MCL 460.1061. *Id*.

Accordingly, the Commission should reject Staff witness Simpson's recommendation to require DTE Electric's mandatory REC retirement as a precondition to removing VGP sales from the RPS compliance calculation. The anti-double-counting objective Staff identifies is fully satisfied through appropriate REC tracking, verification, and reporting — which the Company commits to maintain — and does not require the Commission to override the REC-ownership flexibility that is a core, Commission-approved feature of the Company's VGP program.

6. Procurement and Deployment of CCAA Resources

The CCAA's deployment and procurement provisions are reasonable, prudent, and in the public interest. Staff and certain intervenors challenge the manner in which the CCAA provides for procuring and deploying the energy storage and renewable energy resources: MNS witness Woods argues the "up to" quantities should be converted to mandatory floors; MEICEO witness Hotaling argues the caps should be raised or removed; and Staff witness Simpson argues the Competitive Procurement Guidelines should govern all CCAA resources. None of these challenges warrants modifying the negotiated CCAA, and each should be rejected.

MNS witness Woods recommended that the Commission "condition its approval of the Special Contracts on the requirement that the Company deploy (and the Customer pay for) the full 1,600 MW [renewable energy] and 480 MW [energy storage] goals and treat the goals as floors, not ceilings," arguing that the "up to" language "all but ensures" the Company will deploy less than those amounts. (Woods, 3T 621). The Commission should reject this recommendation.

First and foremost, the Company intends to deploy the full contemplated amounts. As Company Witness Foley confirms, the Company's modeling assumes that only 450 MW of energy storage projects (of the maximum 480 MW) are deployed, with the 30 MW difference providing flexibility to develop an energy storage portfolio of at least 450 MW while accounting for potential variability in the size of projects that are bid into its energy storage RFP — and "the Company intends to deploy at least 450 MW and up to 480 MW of energy storage." (Foley, 3T 158). With respect to renewables, "the Company intends to deploy the full 1,600 MW of renewable energy projects." *Id.*

Second, the “up to” language is a commercially reasonable provision, not a contrivance to under-deliver. The language reflects the fact that renewable and energy storage projects are developed in discrete project sizes and are subject to procurement, permitting, interconnection, cost, and commercial-operation timing considerations, and the contract should not be converted into a commercially unreasonable requirement that would force the Customer to accept resources that exceed the negotiated quantity or otherwise fall outside the agreed commercial framework or force the Company into default if it cannot meet the precise minimum. (Foley, 3T 159). MNS witness Woods, moreover, offers no reasoning for why it is necessary to deploy the full 480 MW of energy storage. (Foley, 3T 158).

Third, other customers are protected regardless of the amount deployed. Regardless of the specific amount of energy storage and renewable energy projects that are deployed, the Affordability Backstop will still be in effect, ensuring the Company's other customers are protected. (Foley, 3T 159). And if the Company is unable to fully deploy the contemplated resources, Section 2.4 of the PSA provides a mechanism for the Company and the Customer to jointly identify an alternative solution, or to reduce the Customer's load ramp accordingly. *Id*. Converting the negotiated "up to" quantities into mandatory floors is therefore unnecessary to protect other customers.

Fourth, to the extent that MNS witness Woods asks the Commission to convert negotiated “up to” quantities into a mandatory floor or uncapped obligation (i.e., force the Customer to accept terms beyond the bargain), she seeks relief that cannot be lawfully granted. As set forth in Section III, the Commission lacks statutory authority to rewrite the PSA and CCAA over the contracting parties’ negotiated agreement. *Union Carbide*, at 148-149.

Next, although MNS witness Woods agrees that specific resources should be reviewed and selected in the Company's upcoming IRP — not in this case — she simultaneously urges the Commission to impose IRP-style “best practice” procurement, feasibility-study, DER, and mitigation-plan requirements here and now. (Woods, 3T 631-632). That request is internally inconsistent with her own testimony characterizing the Company’s committed approach of comparing resource needs with and without the Customer’s load and selecting an optimized, least-cost portfolio in the upcoming IRP as “best practice.” (Woods, 3T 620, 631). If adopted, MNS witness Woods’ recommendation would improperly convert this special contract proceeding into a resource-planning and procurement matter. The Company already maintains the planning processes, development pipeline, and competitive-procurement mechanisms that MNS witness Woods' "best practices" describe, and the appropriate forum for the detailed resource-planning review she seeks is the Company's upcoming IRP and Amended REP. The Commission should decline to impose these conditions.

As Company Witness Bilyeu explains, MNS’ recommendations would effectively turn this special contract approval case into a resource planning and procurement proceeding." (Bilyeu, 3T 301). The forthcoming IRP and Amended REP to be filed concurrently later this year are specifically designed to evaluate resource planning decisions, projected load growth, renewable resource needs, project portfolios, timing considerations, and long-term resource development strategies, and provide the appropriate forum for detailed review of DTE Electric's renewable development plans than the instant case. (Bilyeu, 3T 300-301). Imposing prescriptive procurement requirements now could constrain flexibility or lead to uneconomic outcomes before the relevant resource selection record is established. *Id*.

MNS witness Woods' underlying premise — that the Company may be unable to meet the Customer's future renewable needs — is unfounded on this record. DTE Electric maintains an active and ongoing renewable development pipeline consisting of projects at various stages of evaluation, development, permitting, contracting, and construction and standard planning practice that provides flexibility to respond to evolving customer needs, changing load forecasts, project timing considerations, and market conditions. (Bilyeu, 3T 299-301). The Company has substantial experience developing, acquiring, and integrating renewable resources with over 2,600 megawatts of renewable energy currently online. *Id*. In addition to its pipeline, DTE Electric conducts competitive RFPs to identify additional renewable resources, which are a well-established component of DTE Electric's resource planning process. *Id*. Upon approval of the Special Contracts, the actual renewable energy resources capable of serving the Customer's needs will be identified through future planning and procurement processes, with project-specific feasibility, timing, and procurement detail incorporated into its Amended REP, which the Company expects to file later this year. Requiring the Company to identify today the specific projects that may ultimately serve future load growth would be inconsistent with prudent planning and would unnecessarily constrain DTE Electric's ability to optimize project selection as circumstances evolve. *Id*.

In sum, MNS witness Woods agrees the IRP is the proper venue for resource selection and least-cost optimization, and the Company agrees. The Commission should hold witness Woods to that shared premise and decline to import IRP-style procurement, feasibility-study, DER, and mitigation-plan requirements into this special contract proceeding. The Company already maintains the planning processes, pipeline, and competitive-procurement tools that her "best practices" describe; and the detailed resource-planning review she seeks will occur in the upcoming IRP and Amended REP.

Next, MEICEO witness Hotaling argues that DTE Electric's energy-storage accreditation assumption “may introduce risk that the energy storage in the CCAA is not sufficient” and that capping storage at 480 MW “does not leave any flexibility for consideration of how the accreditation of those resources might evolve over time.” (Hotaling, 3T 722). She therefore recommended that the Commission consider directing the Company to increase the cap on energy storage and renewable energy projects. (Hotaling, 3T 722-723). The Commission should reject this recommendation.

MEICEO witness Hotaling's recommendation to raise or remove the CCAA deployment caps misapprehends the function of the CCAA, which allows the Company to deploy up to a specified nameplate capacity but is not designed to match the Customer's individual capacity needs. As Company Witness Foley explains, the Company does not deploy any single resource type to serve an individual customer; it deploys a portfolio of resources to serve its total load reliably and economically, and it ensures system resource adequacy through its IRP proceedings. MEICEO witness Hotaling's proposal thus runs counter to both the structure of the CCAA and the way the Company plans and deploys resources. (Foley, 3T 160). The proposal is also commercially unreasonable since removing the caps would force the Customer to accept uncapped liabilities and prevent it from reasonably assessing its potential future obligations. *Id*. Finally, the accreditation concern underlying the recommendation belongs in the Company's IRP, where its full resource-adequacy outlook will be studied, not in tracking the accreditation of individual CCAA resources — which would not reveal what resources are attributable to the Customer's load.

In any event, the Affordability Backstop in PSA Section 5.1.3 protects other customers regardless of how much storage or renewable capacity is ultimately deployed. *Id*.

Staff witness Simpson recommended that the Commission direct the Company to prioritize resources for meeting the Company's IRP and those resources necessary to serve all customers first, so that the Customer is not paying less for resources contracted under the CCAA as compared to the same technology types contracted at a similar time for IRP, Amended REP, or CEP purposes. (Simpson, 3T 840). The Company shares Staff's underlying objective but respectfully submits that the recommended condition is both unnecessary and unworkable, for four reasons.

First, the Company agrees with the general principle that the CCAA should not cause other customers to subsidize the Customer's renewable resources. (Bilyeu, 3T 297). Thus, there is no dispute between the Company and Staff on the objective; the disagreement is only as to whether a new procurement-priority condition is needed to achieve it.

As Company Witness Bilyeu emphasizes, procurement for customer-requested VGP special contracts is already governed by Commission-approved settlement provisions in Case Nos. U-20713/U-20851 and U-21172, and Staff's recommendation "would effectively add a new procurement-priority condition to that approved framework, which is not necessary or appropriate in this proceeding. (Bilyeu, 3T 297). Imposing a resource-sequencing mandate on the VGP renewables in this special contract proceeding would modify the previously negotiated and approved VGP Settlement Agreements outside the forum in which those agreements were adopted.

Staff witness Simpson's proposed same-technology, same-timeframe price comparison is not analytically sound for purposes of creating a rigid procurement requirement. The proposed comparison between resources contracted under the CCAA and resources procured for the IRP, Amended REP, or CEP is not as straightforward as comparing technology type and timing.

(Bilyeu, 3T 298). As Company Witness Bilyeu explains, "[w]hether resources are comparable depends on the specific procurement framework and project attributes, and the customer-specific obligations the resource is intended to satisfy," and "[a] resource procured for a customer-specific VGP special contract may be subject to different commercial requirements, eligibility criteria, risk allocations, or customer-requested attributes than a resource procured for general system needs." *Id*. Accordingly, a price difference between resources of the same technology type and similar contractual timeframe would not, by itself, demonstrate that the Customer is receiving preferential treatment or that other customers are paying more for certain resources. *Id*. A price-comparison condition that rests on a flawed apples-to-oranges premise would generate disputes without protecting other customers.

For these reasons, while the Company agrees that the Special Contracts must not shift costs to other customers, the Commission should decline to impose Staff witness Simpson's proposed procurement-priority condition. The no-subsidization objective Staff identifies is already achieved through the CCAA's full-cost-recovery and market-revenue-cap mechanics and through the Commission-approved VGP procurement framework, and Staff's proposed price comparison does not provide a sound basis for the additional condition.

C. Cost Allocation and Rate Design are Reserved for Future Proceedings

DTE Electric seeks approval of the Special Contracts as reasonable, prudent, and in the public interest in this case — not approval of any particular allocation of costs among customer classes, any rate design, or any methodology for recovering costs from other customers. That distinction is fundamental, and it defines the limited scope of the cost-related questions properly before the Commission here. As demonstrated above, including Sections V and VI, the Company has shown by a preponderance of the evidence that the Special Contracts hold other customers harmless and do not shift costs to them. The separate question of *how* any costs ultimately attributable to serving the Customer's load would be allocated among rate classes, or recovered in rates, is not one this proceeding decides — and it is not one the Commission must, or should, resolve in order to approve the Special Contracts.

This is not merely the Company's litigating position; it is the framework the Commission itself established. As the Commission held in the December 18 Order, pp. 37-38, the approval of a special contract "does not guarantee any particular ratemaking treatment," and no cost allocation or cost recovery methods are approved as a result of such an order. Ratemaking instead "may still take place in the appropriate forum wherein all parties may contest the ratemaking proposals of the utility and the other parties." December 18 Order, p. 38. The Michigan Court of Appeals has confirmed the same principle: "merely approving and implementing" a special contract "is not sufficient, in and of itself, to cause any rate or cost of service increase to occur," and any future rate or cost-of-service effects are properly addressed in a subsequent rate case in which all interested parties may participate. *Attorney General v Pub Serv Comm*, 227 Mich App 148, 154–155 (1997), *appeal den*, 459 Mich 910 (1998).

Staff agrees that "[c]ost allocation issues associated with the Customer are more appropriately addressed in the Company's general rate cases along with all other utility costs and revenues." (Isakson, 3T 864). Likewise, Company Witness Willis confirms that cost allocation and rate design "are a matter for general rate cases in the context of the Company's full costs and revenues, and not a matter for proceedings to approve special contracts." (Willis, 3T 419). The Company and Staff are therefore aligned on the dispositive point that the proper forum for cost allocation and rate design is a general rate case, not this special contract proceeding.

The Company's position on the specific cost-related recommendations advanced by Staff and the intervenors follows directly from that principle. Where a recommendation is consistent with the deferral of cost allocation to future rate cases, the Company does not oppose it — and indeed, the Company affirmatively commits to provide the six cost-of-service and rate-design studies the Commission directed in the December 18 Order, and to track costs attributable to the Customer, in its future rate cases. Where, however, a recommendation would have the Commission decide cost allocation, create a new rate class, or apply prospective contribution-in-aid-of-construction ("CIAC") policy in this proceeding — as the recommendations of ABATE witness Dauphinais, MNS witness Woods, and, in part, Staff witness Isakson would do — the Company respectfully submits that the recommendation asks the Commission to decide, in the wrong forum and on an incomplete record, questions that the December 18 Order, Commission precedent, and Staff's own testimony all reserve for future rate cases. As set forth below, each such recommendation should be deferred to the appropriate proceeding, and none provides a basis to reject or condition the Special Contracts.

The Company and Staff largely agree on the six cost-of-service and rate-design studies. In the December 18 Order, pp. 39-40, the Commission directed the Company to provide six specified cost-of-service and rate-design studies for large-load customers, and Staff witness Isakson recommended that the Commission require those studies here. (Willis, 3T 420). The Company does not oppose providing the six studies — indeed, it has already done so. In the Company's pending general rate case, Case No. U-22046, the Company developed and submitted the original six studies as required by the December 18 Order. (Willis, 3T 420-421). Company Witness Willis further confirms that "[t]hese six studies include both Oracle load and the Customer load at issue in this case assuming their full load ramp is online." (Willis, 3T 420–421). The very studies Staff seeks are therefore already before the Commission in the appropriate forum — a pending rate case — and reflect both large-load customers at full ramp.

The Company's agreement extends to the substance of Staff's proposed change to Study #6. Staff witness Isakson recommended that the sixth study directly assign costs to each large-load customer individually, rather than to a large-load customer class. *Id*. As Company Witness Willis confirms, "the studies currently available in Case No. U-22046 align with Witness Isakson's proposed change to Study #6 and directly allocate costs to individual large load customers." (Willis, 3T 421). There is thus no substantive dispute between the Company and Staff regarding either the substance of the six studies or the refinement to Study #6.

DTE Electric's disagreement with Staff regarding the six studies is relatively narrow and concerns forum and cadence. To the extent Staff witness Isakson recommended that the Commission, in this special contract proceeding, impose an ongoing requirement that the Company provide the six studies annually or in every future case involving a large-load customer, that recommendation should be addressed in a general rate case rather than here. (Willis, 3T 421–422). This special contract proceeding is not the correct forum to establish a longer term study requirement that is generic to all large load customers. (Willis, 3T 421). Two considerations further support deferring the cadence question to a rate case.

First, the pending rate case should be permitted to resolve before any generic, ongoing study requirement is established. Discussion of the currently available studies in Case No. U-22046 should be completed before determining any future study requirements, because it may be that following the conclusion of Case No. U-22046 there are targeted or specific areas of continued exploration and investigation the Commission finds important. (Willis, 3T 421). Just as Staff witness Isakson correctly observes that cost of service should be addressed in rate cases and not in special contract cases, "so too should the cost-of-service discussion in the pending rate case be allowed to resolve before determining what, if any, next steps are appropriate." (Willis, 3T 421).

Second, imposing a standing requirement to produce these voluminous studies is a matter better weighed against the burden it imposes, which is a rate case determination. As Company Witness Willis explains, the Commission has recognized "the ever-growing size and complexity of rate cases," and the six studies "represent a substantial additional burden of work for all parties to the case." (Willis, 3T 421–422). In Case No. U-22046, the six studies gave rise to voluminous direct testimony and comprised more than 500 pages of direct exhibits, a volume certain to grow when intervenor testimony and exhibits, rebuttal testimony and exhibits, and briefs are included. *Id*. Whether to require the ongoing submission of such studies "would be best weighed in a rate case, and not in this more narrow proceeding." (Willis, 3T 422).

In sum, the Company commits to providing the six cost-of-service and rate-design studies, including the direct-assignment refinement to Study #6 that Staff recommended, and has already submitted them, incorporating both large-load customers at full ramp, in its pending rate case. As applied to the six studies, the Commission should decline only Staff's request to establish, in this proceeding, a generic and ongoing study requirement applicable to all large-load customers; that cadence question is properly determined in a rate case, and the pending Case No. U-22046 should be permitted to resolve first.

While the Company and Staff agree that cost allocation belongs in a general rate case rather than in this special contract proceeding, the Company disagrees with Staff witness Isakson's suggestion that the IRP is a proper venue for deciding how the costs of resources associated with the Customer's load should be allocated. The distinction is important, and the Company's position draws a clean line between what the IRP does and what a rate case does.

Staff witness Isakson introduces the concept that the IRP is a viable venue for discussion of the allocation of incremental resources, testifying that “[i]n the Company's next and subsequent IRPs, the Commission should consider how to eventually assign production costs to the Customer, or to the Customers' rate class if it is separated, so that any marginal cost of new capacity resources will not be passed on to other customers unfairly.” (Isakson, 3T 880). As a threshold matter, the Company agrees with Staff's broader point that “cost allocation and rate design issues are a matter for general rate cases in the context of the Company's full costs and revenues, and not a matter for proceedings to approve special contracts, such as this case.” (Willis, 3T 419). That agreement is consistent with the December 18 Order. *Id*.

The Company parts ways with Staff, however, on whether cost allocation can be decided in an IRP because such issues cannot be fully addressed in an IRP. (Willis, 3T 419). Company Witness Willis explains the proper — and limited — role of the IRP: "[t]he IRP will serve as the basis for understanding the change in resource mix as a result of serving the Customer's load, however the IRP is not the appropriate venue to determine how to recover those costs." (Willis, 3T 419–420). In other words, the IRP is where the Company will identify the resources caused by the addition of the Customer's load, but it is not where the Commission decides how, or from whom, the costs of those resources are recovered.

Notably, this limitation is one Staff witness Isakson himself acknowledged in testimony: “Costs are not allocated nor is revenue collected via IRP proceedings.” (Isakson, 3T 880). The Company fully agrees. (Willis, 3T 420). Company Witness Willis explains that this is not merely a matter of convention but of function: “[t]here is simply not the right information in an IRP, nor is it the purpose of the IRP, to facilitate that assessment.” (Willis, 3T 420). An IRP evaluates resource planning on a system-wide basis; it is not designed to allocate costs among rate classes or to establish cost-recovery mechanisms, which require the full presentation of the Company's costs and revenues that occurs only in a general rate case.

Accordingly, the Company recommends that "any exploration of cost allocation or cost assignment be addressed in a rate case and not in an IRP." (Willis, 3T 420). This position harmonizes the two distinct statutory proceedings rather than pitting them against each other: the IRP will inform the record by identifying the changes in the Company's resource mix attributable to serving the Customer's load, and the subsequent general rate case will use that information — together with the full complement of the Company's costs and revenues — to make any cost-allocation and cost-recovery determinations, with the participation of all interested parties. To the extent Staff witness Isakson's recommendation would have the Commission decide, or commit to deciding, cost allocation in an IRP, the Commission should decline it and confirm that cost allocation and recovery remain matters for a future general rate case.

Next, ABATE witness Dauphinais recommended that the Commission modify the PSA to place the Customer into its own customer class — separate from the Rate D11 class, but initially charged the same rates as D11. (Dauphinais, 3T 548-549). His premise is that placing the Customer (and the large load customer from Case No. U-21990) into the D11 customer class will overwhelm the current load characteristics of the traditional commercial and industrial customers of that class, which he asserts "is highly likely to cause large subsidies between the members of the class." *Id*. Witness Dauphinais claimed there is a "significant possibility" that data-center-specific costs will be allocated to D11 at some point in the future. (Dauphinais, 3T 549). From this, ABATE proposes that a new rate class can be readily established for the Customer and other large data center loads that initially utilizes the same rates as the Rate D11 class. *Id*. He contends this new rate class "would produce the same outcome as initially placing these loads on Rate D11 at the outset of service without introducing any risk of intra-class subsidies to the existing members of the Rate D11 class." *Id*. The Commission should reject this recommendation.

First, rate-class design is a rate-case question, not a special-contract question — as the Commission and Staff both recognize. This case is not the appropriate venue for a substantive discussion of, or changes to, cost of service and rate design. (Willis, 3T 426–427). The Commission addressed this precise venue question in the December 18 Order, p. 38, holding that "should it be shown in a future rate case that any particular rate class does not benefit from a reduction to the cost of service, it is the rate case that is the proper forum for ratemaking." Staff witness Isakson agrees, testifying that "[c]ost allocation issues associated with the Customer are more appropriately addressed in the Company's general rate cases along with all other utility costs and revenues." (Isakson, 3T 864). Creating a new rate class is a quintessential rate-design determination, and the venue for it is a general rate case.

Second, the concern ABATE identified is already being addressed in the proper forum. The Company's currently pending general rate case includes several cost of service and rate design studies intended to facilitate discussion of this very question. (Willis, 3T 427). As set forth above, the six cost-of-service and rate-design studies now before the Commission in Case No. U-22046 include a study directly assigning costs to individual large-load customers and a study evaluating a new large-load customer rate class. Hence, the intra-class-subsidy question Witness Dauphinais raises is already teed up for resolution in the forum designed to resolve it, on a complete record of the Company's costs and revenues and with the participation of all parties. There is no need, and no sound basis, to prejudge that question here.

Third, ABATE's proposal is unnecessary to protect other customers. Witness Dauphinais concedes that his proposed new class would initially utilize the same rates as the Rate D11 class and produce the same outcome as initially placing these loads on Rate D11. (Willis, 3T 426). The proposal thus changes nothing about the rates the Customer pays at the outset; it seeks only to guard against a speculative future allocation of costs to D11 — precisely the contingency the Commission reserved for, and the pending Case No. U-22046 studies are designed to inform. The layered protections in the Special Contracts, together with the Company's commitment that cost allocation will be addressed in future rate cases, already ensure that other D11 customers are protected; a preemptive rate-class restructuring in this proceeding is neither necessary nor appropriate.

Accordingly, ABATE witness Dauphinais' separate-rate-class recommendation should be rejected. The Company recommends that the Commission find, consistent with the December 18 Order, that discussion of, or changes to, cost of service or rate design is appropriately addressed in a general rate case and not in a special contract proceeding.

D. Other Issues

1. Rider 12 Demand Response Agreement

With respect to the Rider 12 DR Agreement, Company Witness Burgdorf describes the major terms and conditions of the Rider 12 DR Agreement in his testimony solely to complete the description of how the Company will serve the Customer's load, not to seek approval of those terms. (Burgdorf, 3T 387-389). DTE Electric's Rider 12 allows for flexible demand response arrangements with its customers. The Customer's Rider 12 DR Agreement accounts for the risks of the large load addition, ensures other customers remain financially unharmed, and accounts for current MISO Rules and future tariff revisions as they relate to Load Modifying Resources ("LMR"). The agreement is for a reduction in load to a Firm Service Level ("FSL") of 65% of the customer committed capacity ramp during the load ramp period as well as when the Customer is at full load (65% of the full 1000 MW). The agreement is one of the additional resources needed to meet the MISO resource adequacy requirements for the increase in load from the Customer discussed by Company Witnesses Burgdorf and Brooks. Specifically, the Rider 12 DR Agreement is for an amount of approximately 250 MWs of DR with the corresponding accredited ZRCs for MISO's resource adequacy construct. (Burgdorf, 3T 387). The agreement begins on June 1, 2027, and ends on May 31, 2033, and requires a firm service level of 650 MW. As demonstrated in the record, the Rider 12 DR Agreement meets the current MISO requirements and those expected to be in place beginning with the 2028/29 MISO Planning Year. (Burgdorf, 3T 387-388). The Rider 12 DR Agreement is structured to recover damages for non-performance to ensure full recovery of any lost revenues from the Planning Resource Auction.

Because the Rider 12 DR Agreement is not before the Commission for approval, any Staff or intervenor request that the Commission alter its terms in this proceeding is beyond the scope of the case. As set forth in Section III, the Commission's review in this special contract proceeding is properly limited to whether the PSA and the CCAA are reasonable and should be approved; it is not a vehicle to modify the Company's existing tariffs or the Customer's elections under them. To the extent any party's recommendation would require the Commission to rewrite, extend, or attach conditions to the Rider 12 DR Agreement, the Commission should decline to do so and should address such matters, if at all, in the appropriate tariff or resource-planning docket.

Nevertheless, the Company must respond to certain intervenor arguments regarding the Rider 12 DR Agreement that have been injected into this proceeding. AG witness Coppola raises a concern that penalties for the Customer's non-performance under the Rider 12 DR Agreement should be separately accounted for and credited to other customers. (Coppola, 3T 483-484). This concern does not support any modification of the Rider 12 DR Agreement in this proceeding. The

Rider 12 DR Agreement is designed so that damages for the Customer's non-performance cover the associated MISO penalties and lost revenues, and any such amounts are assessed to the Customer and reconciled through the PSCR mechanism — the same mechanism through which DR performance is ordinarily addressed. (Burgdorf, 3T 387-389). Penalties assessed by the Company for future lost accreditation will also be shown as a reduction in power supply costs. The Company agrees with AG witness Coppola that the penalties, if any, should be credited to other customers. (Burgdorf, 3T 399). However, because the Rider 12 DR Agreement is a standard tariff arrangement and non-performance amounts are handled through the existing PSCR process, no special condition is necessary or appropriate, and the matter is in any event outside the scope of the Special Contracts submitted for approval.

ABATE witness Dauphinais and MEICEO witness Hotaling recommended that both the ZRC transfer[27] and the Rider 12 DR Agreement be extended beyond their negotiated May 31, 2033 end date. (Dauphinais, 3T 547-548; Hotaling, 3T 717). For the reasons stated in Section V.B.4 and the additional points made below, the Commission should reject these recommendations.

First, the Rider 12 DR commitment is a voluntary, negotiated Customer obligation that the Commission cannot unilaterally extend through this proceeding. The Rider 12 DR Agreement is a Customer obligation that the Customer has voluntarily agreed to as part of a broader negotiated agreement captured through the Special Contracts. (Foley, 3T 163). Requiring the Customer to extend this commitment would override the negotiated bargain. Moreover, as to DR specifically, "[r]equiring that the Customer (or any customer) participate in DR would run counter to the voluntary nature of DR programs." (Foley, 3T 163). This concern is especially acute for the Rider 12 DR Agreement, which — unlike the PSA and CCAA — is not even a contract submitted for

[27] *See*, Section V.B.4 for detailed discussion of the ZRC Transfer and Financial Adder.

approval in this proceeding. The Commission cannot compel an extension of a standard-tariff DR election that is not before it for approval.

Second, ABATE and MEICEO's recommendations rest on unverified assumptions and concern a future resource-planning question reserved for the IRP. The underlying concern that the projected need for capacity in 2033 following the sunset of the ZRC and Rider 12 DR commitments is undoubtedly a resource adequacy question that the Company will address in its 2026 IRP, which is the proper forum for determining how to meet any 2033 capacity need. It is not a basis to rewrite the negotiated end date of a standard tariff DR arrangement in this special contract proceeding.

In sum, the Rider 12 Capacity Release Agreement is a standard contract under the Company's existing, Commission-approved Rider 12, is not submitted for approval in this proceeding, and is described only to provide a complete picture of how the Company will serve the Customer. The Commission should confirm that the Rider 12 Capacity Release Agreement is not before it for approval, and should reject the recommendations to extend or condition that agreement as both outside the scope of this proceeding and, in the case of the proposed 2033 extension, contrary to its voluntary and negotiated nature.

2. Line Extension Agreement and CIAC

The Line Extension Agreement ("LEA") is not before the Commission for approval in this proceeding. As Company Witness Foley explains, the LEA — like the Rider 12 Demand Response Agreement — is a standard contract that the Company is not seeking Commission approval of in the instant case and is described only to provide a complete description of how the Company intends to serve the Customer. (Foley, 3T 90). The Company's relief requested in this special contract proceeding is limited to approval of the PSA and CCAA and the two related accounting items (the CCAA Regulatory Liability and the ZRC financial adder). Nor does this proceeding present any question about the Company's contribution-in-aid-of-construction ("CIAC") policy, as the Company "is not proposing to change the current CIAC policy." (Benyard, 3T 451).

The record demonstrates that the LEA nonetheless benefits DTE Electric's other customers. Under DTE Electric's current CIAC policy, the Customer's allowance would be approximately $550 million — more than ten times the Company's $29.1–$44.3 million estimate for the distribution upgrades — so absent the Special Contracts, those costs would be added to rate base and recovered from other customers. (Benyard, 3T 456-457; Willis, 3T 423-424). By committing the Customer to fund the first $50 million of Customer-caused distribution costs, and to build and own its own substation, the LEA shifts to the Customer costs that other customers would otherwise bear. (Willis, 3T 424–425).

Staff and certain intervenors have nonetheless raised arguments directed at the LEA and CIAC. As set forth below, these arguments are outside the scope of this proceeding and, in any event, fail on the merits.

MNS witness Woods recommended that the Commission condition any approval of the Special Contracts on the Customer paying all electric infrastructure costs required to connect its Facility without any cap and prohibit DTE Electric from recovering any of these costs from non-data center customers. (Woods, 3T 651). Her sole stated justification is a concern that, because the LEA commits the Customer to pay up to $50 million toward infrastructure upgrades while the Company's current cost estimate for those upgrades is $29.1 million to $44.3 million, "there is only $5.7 million of headroom between the top of the range and the Company's own cap on infrastructure costs: the point past which other customers will start to foot the bill." (Woods, 3T 628). The Commission should reject this recommendation for the below reasons.

As a threshold matter, the relief MNS witness Woods seeks is outside the scope of this proceeding. As discussed above, the LEA is a standard contract that the Company is not asking the Commission to approve, and it is described only to provide a complete picture of how the Company will serve the Customer. (Foley, 3T 90). In addition, to the extent MNS witness Woods' recommendation would rewrite the negotiated LEA to strip its cap and impose uncapped liability on the Customer, it also seeks relief the Commission lacks authority to grant in this special contract proceeding, for the reasons set forth in Section III. *Union Carbide*, at 148-149. Thus, the recommendation should be rejected on these grounds alone.

Even if the Commission reaches the merits, MNS witness Woods' recommendations fails for four independent reasons. First, MNS witness Woods' recommendation conflicts with the Company's currently approved CIAC policy, and she offers no justification for changing that policy in this special contract proceeding. (Willis, 3T 424). Under the current CIAC policy, "the Customer would not be directly responsible for any distribution upgrade costs since their CIAC Allowance would be greater than the cost of the upgrades." (Willis, 3T 424). The Customer's CIAC allowance under current tariffs would be approximately \$550 million — more than ten times the Company's cost estimate for the Customer's distribution infrastructure. (Benyard, 3T 457). Witness Woods' recommendation would thus override the Company's approved CIAC policy without any record justification for doing so.

Second, the LEA's \$50 million commitment is an incremental *benefit* to other customers, not a cost exposure. MNS' premise has the effect of the LEA backward. Absent the Special Contracts, the Customer's distribution upgrade costs would be added to the Company's rate base and recovered through base rates — because the Customer's ~\$550 million CIAC allowance far exceeds the ~\$29.1–44.3 million cost of the upgrades. (Willis, 3T 424; Benyard, 3T 457). "Said differently, the Customer agreeing to pay up to $50 million toward infrastructure upgrade costs represents an incremental benefit to the Company's other customers that they would not otherwise realize under current CIAC policy." (Willis, 3T 424–425). Far from exposing other customers to cost, the LEA shifts to the Customer costs that other customers would otherwise bear.

Third, the cost-escalation concern underlying MNS witness Woods' recommendation is unfounded, because the Customer bears cost-escalation and site-condition risk. Company Witness Benyard confirms that the risk of cost escalation MNS identified "was accounted for within the estimate range of $29.1–$44.3 million," which "accounted for potential 4% inflation, varying design complexity, and a 50% accuracy range." (Benyard, 3T 456). Given the Company's estimated cost of associated distribution work has accounted for a broad range of uncertainty, the expectation is that all distribution costs caused by the Customer will be paid for by the Customer. *Id*. And the Customer has agreed in the LEA to be responsible for the costs of any unexpected site conditions or events. *Id*. Thus, the Customer's obligations under the LEA already address the very cost-overrun scenario that animates MNS witness Woods' recommendation.

Fourth, *prospective* large-load CIAC policy is being appropriately addressed in pending Case No. U-22061. (Willis, 3T 425). To the extent MNS seeks a broader change to how CIAC applies to large-load customers, that policy question belongs in the pending large-load tariff proceeding, not in this special contract proceeding.

Next, Staff witness Isakson recommended that, "if the Commission approves the proposed tariff in Case U-22061 with a CIAC provision, then that same standard should be applied to the Customer for costs beyond the $50M identified in the line extension agreement." (Isakson, 3T 869). Under his recommendation, if infrastructure costs exceed $50M by less than 2-years of distribution revenue then those costs should be included for recovery in future rate cases, but the

Customer should be responsible for any costs over the CIAC allowance approved for the large load provision, and Staff calculated the resulting CIAC allowance under the Case No. U-22061 proposal at approximately $30 million. *Id*. The recommendation should be rejected, for two primary reasons.

First, the Customer has already agreed to fund distribution investments beyond what the Company's approved Rate Book requires. As Company Witness Willis confirms, under the currently approved DTE Electric Rate Book for Electric Service the CIAC allowance for a D11 customer of the Customer's size is approximately $550 million. (Willis, 3T 423). The Customer, however, has agreed to fund the first $50 million of Customer-caused distribution costs in addition to building and owning their own substation. *Id*. Because the Company's estimated cost of associated distribution work is less than $50 million, the expectation is that all Customer-caused distribution costs will be paid for by the Customer. *Id*. The Customer has thus already committed to bear distribution costs that, under the current Rate Book's $550 million CIAC allowance, other customers would otherwise fund — a commitment that far exceeds what current tariffs require and that already accomplishes the customer-protection objective Staff's recommendation seeks.

Second, it is inappropriate to apply a tariff provision from a pending, unresolved proceeding retroactively to a contract that has already been executed. Case No. U-22061 remains a pending proposal that the Commission has not approved and is slated for decision months after the instant case. It would not be appropriate to retroactively apply tariffs to prior contracts or requests. (Willis, 3T 423). That principle is fundamental to how tariffs function, as explained by Company Witness Willis: "[t]ariffs function to describe the responsibilities of customers and the Company in the provision of electric service on a prospective basis; neither party can make informed decisions if the basic framework of the transaction is subject to retroactive changes."

(Willis, 3T 424). For example, the Commission's elimination of new master-metered multi-unit residential dwellings was a change made on a prospective basis but without retroactive application, even though concerns about then-existing master metered buildings gave rise to the Commission order. *Id*., citing Case No. U-5502 Order dated September 28, 1978. Retroactive tariff application would open current and future customers to future risk, responsibility, or, as in the case of CIAC allowances, financial liability. *Id*. Because the Special Contracts were negotiated and executed against the backdrop of the currently approved Rate Book, it is inappropriate to change CIAC policy for this customer on a retroactive basis and the Commission should reject the proposal. *Id*.

Lastly, the Company notes that Staff's recommendation is contingent on the Commission's approval of the CIAC provision pending Case No. U-22061. There is thus no CIAC standard arising from that case presently in effect to apply to the Customer, and the premature adoption of a not-yet-existent standard is not a basis to condition approval of the Special Contracts. Whatever CIAC standard the Commission ultimately adopts for prospective large-load customers in Case No. U-22061 can be applied prospectively, in that proceeding and in future rate cases, to customers who take service under that framework. There is no need — and, for the reasons above, no sound basis — to graft that pending standard retroactively onto the already-executed Special Contracts in this proceeding. Accordingly, the Commission should reject Staff witness Isakson's recommendation to apply the pending Case No. U-22061 CIAC standard retroactively to the Customer.

3. GLREA Scarcity Fee

GLREA does not oppose approval of the Special Contracts. GLREA witness Richter acknowledges that the Customer "has demonstrated a very concerted effort to prevent this data center from impacting other DTE Electric customers, at considerable cost to themselves."

(Richter, 3T 580). He further acknowledges "the adequacy of provisions set forth in the PSA and CCAA" (Richter, 3T 580–582), including the contested case review, renewable and EWR commitments, termination payment, transmission-cost payment, load commitment off-ramp, and the Affordability Backstop.

Despite extolling the Customer's efforts to prevent the Facility from impacting other customers and the protections set forth in the Special Contracts, GLREA witness Richter recommended that "the Commission should be open to imposing temporary 'scarcity cost' fees on service to data center customers, until the scarcity of supplies is resolved by market adjustments." (Richter, 3T 607). The premise of GLREA witness Richter's recommendation is that data centers, as a category, are driving up the prices of power equipment and MISO energy and capacity, such that their proliferation contributes to supply "scarcity" that raises costs for the system generally. (Richter, 3T 606–607). Witness Richter frames this concern economy-wide and at the industry level rather than as a cost caused by the Special Contracts, acknowledging that the risk he identifies is "not particular to this data center, but appl[ies] to all hyperscale data centers." (Richter, 3T 586–587). He does not, however, propose a specific fee mechanism, methodology, or amount for the Commission to consider. For the reasons below, the Commission should reject GLREA's recommendation.

GLREA witness Richter's scarcity fee recommendation collapses under its own cost-causation logic. He expressly concedes that any potential price increases attributable to data centers as a group are "indirect costs." (Richter, 3T 607). He draws the distinction himself, testifying that "[t]he cost impact of data centers as a group is different than the cost impact of any particular data center" (Richter, 3T 606); that "[d]emand across the country, and the world, has caused these price increases" (Richter, 3T 606); and that the risks his proposal addresses is "not particular to this data center, but apply to all hyperscale data centers." (Richter, 3T 586–587).

This is fatal to the recommendation in a special-contract proceeding governed by cost-causation principles. As Company Witness Burgdorf explains, by confirming the costs as indirect, witness Richter has made no attempt to identify the requisite causal relationship between the Customer and the alleged indirect costs and offers no evidence that the Company's agreements with the Customer have or will increase prices of power equipment or MISO energy and capacity. (Burgdorf, 3T 401). GLREA cannot have it both ways. Witness Richter himself invokes the Case No. U-21859 framework as the benchmark for how data center costs should be assigned — pointing to that order's direction that cost allocation be resolved through cost-of-service study in the next rate case (Richter, 3T 583–584) — yet his scarcity-fee proposal would surcharge the Customer for admittedly "indirect" costs that he concedes are "not particular to this data center" and were "caused" by economy-wide demand, not these Special Contracts. (Richter, 3T 606–607). Thus, the same cost-causation logic embedded in the Case No. U-21859 framework he endorses defeats his proposed surcharge.

Moreover, GLREA witness Richter commends the customer protections set forth in the Special Contracts while simultaneously urging an additional "scarcity cost" fee, yet offers no explanation for why an additional "scarcity cost" fee is warranted notwithstanding the very protections he commends. (Burgdorf, 3T 400-402). He also makes "no actual proposal for the Commission to evaluate and offer[s] only general commentary which is neither specific to the

Company nor the issues before the Commission in this proceeding."[28] (Burgdorf, 3T 402). There is accordingly "nothing substantive for the Commission to evaluate." *Id*.

Based on the foregoing, the Commission reject GLREA's "scarcity cost" fee recommendation.

VI. THE CUSTOMER BENEFIT ANALYSIS AND AFFORDABILITY BACKSTOP DEMONSTRATE THAT THE SPECIAL CONTRACTS BENEFIT, AND DO NOT SHIFT COSTS TO, OTHER CUSTOMERS.

The record establishes that the Special Contracts hold other customers harmless and are projected to produce a substantial benefit of approximately $1.7 billion to the Company's other customers over the 2028–2047 contract term. The benefit was quantified through a rigorous, transparent with-and-without modeling analysis, was independently replicated by Staff, and remained positive under the sensitivities presented by the other parties. Notably, no party placed an analysis in the record showing a net cost to other customers over the life of the Special Contracts.

The Special Contracts ensure that the Customer will pay the full costs of serving its own load, such that no costs are shifted to other customers and other customers are held harmless from the addition of the Customer's load. The December 18 Order, p. 32-33, indicated that a large-load customer should fully pay the costs to serve it, not be cross-subsidized by other customers, and demonstrate that its service will not impose costs on the Company's other customers. The

[28] There is no requirement for the Commission to attempt to unravel and consider such non-conforming arguments. Courts have repeatedly recognized, for example: "It is not sufficient for a party 'simply to announce a position or assert a claim of error and then leave it up to this Court to discover and rationalize the basis for his claims, or unravel and elaborate for him his arguments, and then search for authority to sustain or reject his position." *Wilson v Taylor*, 457 Mich 232, 243; 577 NW2d 100 (1998), quoting *Mitcham v Detroit*, 355 Mich 182, 203; 94 NW2d 388 (1959). *See also, Gross v General Motors Corp*, 448 Mich 147, 161-62, n 8; 528 NW2d 707 (1995).

Company’s customer benefit analysis presented in this record demonstrates that the Special Contracts are projected to satisfy this standard.

The Special Contracts are structured, first and foremost, to hold other customers harmless. Company Witness Foley confirms that, at their core, the Special Contracts ensure that the aggregate benefits, including revenues received from the Customer and avoided costs realized through the Special Contracts, outweigh the costs of serving the Customer's load, and that if aggregate benefits do not outweigh the costs, the Customer will pay the difference. (Foley, 3T 87–88; *see also* Foley, 3T 94). This hold-harmless commitment operates on both the PSA and the CCAA. As to the CCAA, Company Witness Foley further confirms that the Company recovers from the Customer the full cost of the energy storage and renewable energy projects, “[t]herefore, the costs of the energy storage and renewable energy projects developed to fulfill the CCAA with the Customer will not be passed on to the Company's other customers,” and that the capacity and renewable generation credits the Customer receives “cannot be greater than the incremental market revenues" generated by each project or ZRC, which "ensures that the Company's other customers do not bear any costs of CCAA resources.” (Foley, 3T 88).

As to the PSA, Section 5.1.3 of the PSA (the “Affordability Backstop”) provides that a “goal of this Agreement and the Related Agreements is to protect other customers, other customer classes and Company from funding the costs to serve Customer,” and obligates the Customer, in the event the Commission “issues a ruling or order determining that the costs to serve Customer exceed the combined revenues paid or payable to the Company,” to “reimburse Company for any unrecovered costs.” (Foley, 3T 103–104). As Company Witness Foley summarized, “the Customer agrees to comply with any Commission order ensuring that they are fully covering their costs.” (Foley, 3T 104).

The customer benefit analysis and the Affordability Backstop are complementary, but serve distinct functions. The customer benefit analysis demonstrates, on the present record, that the Special Contracts are projected to produce a substantial net benefit and not shift costs to other customers. The Affordability Backstop provides that if the Commission ever determines that the costs to serve the Customer exceed the benefits in a ruling or order, the Customer bears the shortfall. Together, they establish both that other customers are expected to benefit and that, in all events, other customers will be held harmless from any net cost of serving the Customer's load.

The Company's customer benefit analysis, as presented by Company Witness Willis, quantifies a net benefit of approximately $1.7 billion to other customers from 2028 through the conclusion of the contract in 2047. (Willis, 3T 408-411; Exhibit A-19). Because the Special Contracts are a single, integrated, 20-year commitment, the proper measure of whether other customers are held harmless is the aggregate benefit realized across that full term (Foley, 3T 105; Willis, 3T 404), not on a year-by-year basis, which is consistent with the framework the Commission applied in Case No. U-21990.

Company Witness Willis presents the detailed build-up of this benefit in Exhibit A-19 (Customer Benefit) and the underlying base sales benefit in Exhibit A-20 (Base Sales Benefit). The total net benefit to other customers is measured over the full term of the Contracts from 2028 through their conclusion in 2047. (Willis, 3T 404). As set forth in Company Witness Willis' direct testimony (Willis, 3T 411), that net figure is the product of several distinct benefit and cost components, each of which is separately quantified in Exhibit A-19 on column (v) lines 2-12 and which build up to the total as follows:

- Base Sales Benefit $4.85B benefit

- PSCR[29] $2.31B benefit
- Other Non-F&PP O&M $0.02B cost
- Proxy CCGT $4.17B cost
- CCS direct cost $2.43B cost
- Storage Pull Ahead $1.16B benefit
- **Total** **$1.70B benefit**

As the build-up reflects, the $1.7 billion benefit is driven principally by three sources. First is the Base Sales Benefit of approximately $4.85 billion — the contribution the Customer's load makes toward the Company's fixed system costs through its payments under D11, which reduces the fixed-cost responsibility that would otherwise fall on the Company's other customers. (Exhibit A-19; Willis, 3T 411-413). Second is the PSCR benefit of approximately $2.31 billion, reflecting the net reduction in power supply costs borne by other customers as a result of serving the Customer's load and deploying the associated resources. (Exhibit A-19; *see also* Exhibits A-11 through A-13). Third is the Storage Pull-Ahead benefit of approximately $1.16 billion, reflecting the value of accelerating cost-effective energy storage onto the system. (Exhibit A-19). These benefits are partially offset by the modeled costs of the proxy generation resource used in the analysis — a combined-cycle gas turbine with carbon capture and sequestration ("CCGT with CCS") — and a modest increment of other non-fuel O&M. (Exhibits A-5 and A-19). Even after netting the three benefit components (approximately $4.85 billion, $2.31 billion, and $1.16 billion) against the three cost components (approximately $4.17 billion, $2.43 billion, and $0.02 billion), the analysis yields a substantial positive benefit of approximately $1.7 billion to the Company's other customers.

[29] As indicated by Company Witness Willis, this includes the avoided cost benefit of reducing renewable compliance build by 250 MW as described by Company Witnesses Bilyeu and Burgdorf.

The approximately $1.7 billion benefit was not derived in the abstract. It is the output of a rigorous, transparent "with-and-without" modeling analysis sponsored by Company Witness Burgdorf (Burgdorf, 3T 373-381; Exhibits A-5 through A-13), who discusses changes in the capacity resource mix and the power supply cost impacts from the addition of the Customer's load, with the resulting customer-impact quantification presented by Company Witness Willis. (Willis, 3T 409-415; Exhibits A-19 and A-20). The methodology, the two scenarios compared, and the key inputs are described below.

The core of the customer benefit analysis is a comparison of two scenarios modeled over the 2028–2047 period by Company Witness Burgdorf: a Base Case, which reflects the Company's system without the Customer's load and the associated Special Contract resources; and a Customer Datacenter Case, which reflects the same system with the Customer's load and the resources deployed to serve it. (Burgdorf, 3T 373-381; Exhibits A-7 through A-13). The benefit is rooted in the difference between these two scenarios — that is, the net effect on the Company's other customers of adding the Customer's load together with the Special Contract resources.

The Base Case reflects the Company's existing resource plan, including the scheduled retirement of the Monroe units and the renewable and storage additions already planned through the Company's Amended Renewable Energy Plan ("REP") and its previously special contracts in Case No. U-21990. The Customer Datacenter Case adds the Customer's approximately 1,000 MW of load and the resources committed to serve it — including up to 1,600 MW of renewable energy, approximately 450 MW of CCAA energy storage, the 300 MW of transferred ZRCs, and the 250 MW Rider 12 demand response commitment — as well as a proxy 727 MW CCGT with CCS added in 2033[30] to reflect the incremental capacity resource associated with serving the load. (Burgdorf, 3T 373-381; Exhibits A-5, A-9, A-10, A-12).

The two scenarios were modeled using EnCompass, an industry-standard capacity expansion and production cost model that the Company also uses in its integrated resource planning ("IRP"). (Burgdorf, 3T 371). The model optimizes the Company's resource portfolio and simulates production costs, fuel and purchased power expense, and market sales across the study horizon, producing the projected PSCR expense figures reflected in Exhibits A-7 through A-13 for each scenario. (Exhibits A-7 through A-13). Importantly, the Company has been clear about the analytical role of this modeling: it is a reasonable planning tool developed to quantify the customer benefit of the Special Contracts, and it is not a substitute for, or a prejudgment of, the Company's forthcoming 2026 IRP, in which the Company's actual going-forward resource mix will be determined. (Burgdorf, 3T 372).

The reasonableness of the analysis is reinforced by the sourcing and conservatism of its principal inputs. Because the actual capacity resource will be reviewed and selected, as applicable, in the forthcoming IRP, the Company reasonably used a proxy 727 MW CCGT with CCS to represent the incremental capacity addition in the Customer Datacenter Case, with capital and fixed-cost inputs drawn from Wood Mackenzie. (Burgdorf, 3T 375-380; Exhibit A-5). The full cost to build and operate this proxy resource was counted against the benefit in the analysis, which represents conservative treatment that reduces the net benefit figure. (Exhibit A-19). This is counted against the benefit in the analysis, which represents conservative treatment that reduces the net benefit figure. (Exhibit A-19).

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[30] The addition of a proxy capacity resource in 2033 corresponds to the "perfect capacity" need Company Witness Brooks identified for that year through the Company's SERVM-based resource adequacy analysis, which found that additional capacity was required to maintain an adequate loss-of-load expectation ("LOLE") once the Customer's load is added. (Burgdorf, 3T 375, Brooks, 3T 440-441; Exhibit A-4).

Because the proxy CCGT with CCS has a useful life extending beyond the 2047 contract term, the Company accounted for the proxy resource's remaining net revenue requirement after 2047 — approximately $1.0 billion on a net-present-value basis, with roughly 74% of the resource paid off by the end of the contract term — as reflected in Exhibit A-15. (Burgdorf, 3T 379). This treatment ensures the benefit calculation does not overstate the value attributable to the Special Contracts by assigning the Customer credit for value that accrues after the contract term.

Non-fuel variable and O&M cost inputs for storage were reasonably based on the National Renewable Energy Laboratory's Annual Technology Baseline ("NREL ATB"). (Burgdorf, 3T 378; Exhibit A-6). The analysis conservatively assumes deployment of only 450 MW of the up-to-480 MW CCAA storage portfolio, such that any incremental storage deployment would generate additional, unmodeled customer benefits. (Exhibit A-19, n.2.)

Taken together, these scenarios, model, and inputs produce the component build-up presented by Company Witness Willis and yield a benefit of approximately $1.7 billion to the Company's other customers over the life of the Contracts. (Exhibit A-19). As Section VI describes, Staff independently audited and replicated the core of this analysis and confirmed a positive net benefit.

Company Witness Willis also performed a base sales benefits analysis that utilizes the Company’s cost-of-service study ("COSS"), as approved in Case No. U-21534 and updated for additional sales from Case No. U-21990, that independently confirms serving the Customer's load does not shift costs to the Company's other customers. (Willis, 3T 412-414; Exhibit A-20.) The customer benefit analysis and the COSS are complementary rather than duplicative: the customer benefit analysis measures the net dollar benefit to other customers over the life of the Special Contracts, while the COSS tests whether, holding the Company's revenue requirement constant, the addition of the Customer's load reallocates cost responsibility away from — rather than toward — the existing customer base.

Company Witness Willis' base sales benefits analysis compares the allocation of the Company's cost of service between a case that excludes the Customer's load and a case that includes it. Because the Customer takes service on the cost-based D11 and contributes to the recovery of the Company's fixed system costs, the study demonstrates that the addition of the Customer's load reduces the revenue requirement borne by the Company's other rate classes. In particular, the base sales benefits analysis shows a reduction in the residential class revenue requirement attributable to the addition of the Customer's load. (Willis, 3T 413; Exhibit A-20). This result is confirmation that rather than subsidizing the Customer, the Company's other customers — including residential customers — are projected to bear less cost responsibility with the Customer's load on the system than without it.

Taken together with the customer benefit analysis, the base sales benefits analysis provides the Commission with two independent, mutually reinforcing analyses — one measuring the estimated net dollar benefit and the other testing the reallocation of cost responsibility — each of which supports the same conclusion: the Special Contracts hold the Company's other customers harmless and do not shift costs to them. The Company respectfully submits that this dual showing satisfies, by a preponderance of the evidence, that no-cost-shift will occur as a result of the Special Contracts.

The Company's customer benefit analysis does not stand alone. Notably, it was independently audited, tested, and — in its core respects — replicated by Staff, whose review confirmed a substantial positive net benefit to the Company's other customers. Staff witness Isakson conducted Staff's analysis of the Company's proposed Special Contracts, including the customer benefit showing, and sponsored a series of supporting exhibits: Staff Exhibit S-3.0 (Staff Customer Benefit), Staff Exhibit S-3.1 (Staff Cost of Service Study Analysis), Staff Exhibit S-3.2 (Staff Customer Choice Assumption Comparison), and Staff Exhibit S-3.3 (Staff Scenario Analysis).

Staff audited the Company's revenue calculation and confirmed its integrity, finding that Staff Exhibit S-3.0 "largely matches Company Exhibit A-19" and that Staff's independent recreation of the sales benefit "matches the Company's finding on Exhibit A-20." (Isakson, 3T 857, 863). Critically, Staff confirmed that the net benefit remains substantially positive even after removing the Company's 1.5% revenue-escalation assumption, calculating a net benefit of $860.3 million (compared to the Company's $1.7 billion) that Staff expressly characterized as a conservative "lower-bound." (Isakson, 3T 858). Staff witness Isakson's review reflected conditional support for approval of the Special Contracts, not opposition — agreeing that cost allocation belongs in future rate cases and recommending adoption of the collateral-sufficiency condition from Case No. U-21990 (Isakson, 3T 864, 871). This independent audit and replication by Staff provides strong corroboration that the Special Contracts hold other customers harmless and that no-cost-shift will occur.

Neither Staff nor any intervenor produced a quantitative analysis showing that serving the Customer under the Special Contracts would leave the Company's other customers worse off over the contract term. That is the dispositive point. The Company's demonstration that other customers are held harmless is therefore not seriously in dispute on this record; what the intervenors therefore contest is the magnitude of a benefit that every quantitative analysis in the record confirms is positive. Indeed, MEICEO witness Kenworthy — the intervenor witness who scrutinized the customer benefit calculation most extensively — acknowledged that the $1.7

billion figure "is built on DTE's own legitimate modeling tools, and the basic structure of the calculation is reasonable." (Kenworthy, 3T 691). DTE Electric addresses each of the intervenors' specific critiques of the Company's customer benefit analysis below and demonstrates that none undermines the reasonableness and prudence of the Special Contracts. And critically, whatever the ultimate magnitude of the realized benefit, the Affordability Backstop guarantees that any Commission-determined shortfall is borne by the Customer, not by other customers.

MEICEO witness Kenworthy and ABATE witness Dauphinais both contend that the $1.7 billion figure is overstated because it is presented as a nominal, 20-year arithmetic sum rather than a discounted present value. (Kenworthy, 3T 676; Dauphinais, 3T 540). This critique does not undermine the reasonableness and prudence of the Special Contracts, for three primary reasons.

First, the nominal presentation is transparent and was never mischaracterized. MEICEO witness Kenworthy himself acknowledges that "the DTE witnesses do not characterize the $1.7 billion as a net present value." (Kenworthy, 3T 676). Indeed, the figure is exactly what the Company represented it to be — the aggregate benefit during the term of the Special Contracts — and the Company confirms here that the $1.7 billion is a nominal sum, aggregated across the 2028–2047 term. There is no concealment for the intervenors to expose, as the annual, undiscounted values are set forth line-by-line in Exhibit A-19, which is why both intervenors were able to recompute them.

Second, a nominal presentation is reasonable and appropriate for the customer benefit analysis. The benefit measures the actual revenues and avoided costs that reduce other customers' cost responsibility, year by year, as those dollars are collected and applied — not a capital-investment return for which discounting is the conventional metric. The principal driver of the benefit, the Base Sales Benefit, reflects the Customer's actual D11 revenue contribution, escalated at 1.5% per year — a rate the Company derived from the "average D11 full service rate increase across Case Nos. U-20836, U-21297, and U-21534." (Exhibit AB-1, p. 19; *see also* Willis, 3T 413–414). Presenting those real, nominal revenue flows on a nominal basis is a reasonable way to show the Commission the magnitude of the dollars that will actually pass to and from customers over the contract term.

Third, and dispositively, the benefit remains substantial and positive even under the intervenors' own present-value recalculations. ABATE witness Dauphinais calculated that, "on a net present value basis with a discount rate of 7.05%, DTE's net benefit value drops from approximately $1.7 billion to approximately $1.0 billion." (Dauphinais, 3T 540). MEICEO witness Kenworthy performed the parallel calculation and derived a present-value equivalent of "approximately $984 million" at a 7% discount rate. (Kenworthy Direct, 3T 678). In other words, the two opposing experts who pressed the present-value critique independently confirmed that, even on their own preferred basis, the Special Contracts deliver approximately $1 billion in net benefit to the Company's other customers.

Next, MNS witness Woods and MEICEO witness Kenworthy criticize the customer benefit analysis because of the reliance on the hypothetical 727 MW CCGT with CCS assumed online in 2033. (Kenworthy, 3T 679; Woods, 3T 630-633). MNS witness Woods goes so far as to urge the Commission to "disregard all information DTE has provided regarding the various benefits of the CCGT plus CCS proxy resource . . . ." (Woods, 3T 633). MEICEO witness Kenworthy contends the proxy "does double duty," driving approximately $6.6 billion of cost in the analysis while also supplying the resource-adequacy justification, and that the Commission is being "asked to approve special contracts here on the basis of a resource decision it will make later, in the IRP." (Kenworthy Direct, 3T 679–680). These criticisms should be rejected.

First, the Commission is not being asked to approve the proxy resource, nor is such approval a prerequisite for approving special contracts before the Commission. The proxy CCGT with CCS is exactly that — a proxy for purposes of use in the customer benefit analysis. As Company Witness Burgdorf emphasizes, the Company's upcoming IRP will determine the optimal resource mix to address reliability needs on a system-wide basis, and the proxy CCGT with CCS used in this proceeding is a reasonable assumption for purposes of quantifying the benefit, which stands on its own merits in this case independent of future IRP outcomes. (Burgdorf, 3T 394). As the Company further confirmed in discovery, "[t]he 727 MW of CCGT is a proxy used for resource adequacy analysis and is not an identified or proposed specific generation project," but rather "a placeholder representing potential future 'perfect capacity' … needs identified through modeling, rather than a determination that the Company will construct or acquire a specific CCGT resource." (Exhibit MEC-44, p. 1).

Not only is MEICEO witness Kenworthy's suggestion that approval of the Special Contracts here predetermines an IRP resource decision incorrect, but its implicit inverse that the Commission cannot approve the Special Contracts until the resources to serve the Customer are approved in an IRP is contrary to law. Special contract approval under MCL 460.6a and IRP resource approval under MCL 460.6t are distinct statutory processes that give rise to distinct proceedings. Nothing requires that the resources to serve a special contract customer be preapproved in an IRP before a special contract itself may be approved. The Commission confirmed as much in Case No. U-21990, where it approved the special contracts in that matter and directed the Company to file its resource plan afterward.[31] Moreover, the Commission can

[31] The Commission placed specific requirements on IRP planning scenarios in order to ensure that the appropriate information is obtained for evaluating the impact of the special contracts. *See*, December 18 order, pp. 35-36.

approve the Special Contracts without awaiting the 2026 IRP because the customer-protective structure of the Special Contracts holds regardless of which resource(s) the IRP ultimately selects. The Customer pays the full cost of CCAA resources, the D11 revenue and 80% MBD cover the cost to serve, and the Affordability Backstop places any Commission-determined shortfall on the Customer, not other customers. The proxy resource is thus a reasonable estimate used to quantify the benefit, not a precondition to approval; and the actual resource(s), if any, will be reviewed and selected in the 2026 IRP without any prejudgment from this proceeding.

Second, the proxy's use is a reasonable and standard modeling approach, and the record supports its inputs. The proxy was not a matter of guesswork. The Company used a third-party forecast from Wood Mackenzie for the plant's capital cost, CCS capital cost, and non-fuel O&M assumptions for a new 727 MW CCGT with CCS, and the model calculated the annual revenue requirement incorporating depreciation, non-fuel O&M, property tax, allowed return, and the federal production tax credits associated with a CCS system. (Burgdorf, 3T 375–376). Because this is a special contract proceeding and not an IRP, the Company appropriately modeled a single reasonable capacity resource to quantify the benefit rather than conducting a full resource optimization exercise reserved for the IRP.

Third, the proxy's treatment is conservative, so its hypothetical nature works in favor of other customers, not against them. The revenue requirement of the proxy is counted as a cost against the benefit in Exhibit A-19. (*See also*, Willis, 3T 410). The representative resource type was chosen based on being the economic resource selection in the Base Case modeling results. The Company believes this is a conservative approach, as the benefit would likely be greater than those shown in Exhibit A-15 under other scenarios where different types of resources are displaced. (Burgdorf, 3T 395).

Fourth, the proxy resolves a perfect capacity need in 2033 that the Company's SERVM modeling identified, which confirms, rather than undermines, the integrity of the analysis. As Company Witness Burgdorf explains, in 2033 “additional ‘perfect capacity’ is needed to ensure resource adequacy,” and the proxy CCGT with CCS “was modeled to address this need.” (Burgdorf, 3T 375). Because it serves as a proxy to estimate the cost of an incremental resource in the customer benefit analysis (Burgdorf, 3T 375), the proxy is tied to a modeled perfect capacity need identified through Company Witness Brooks' analysis (Brooks, 3T 440; Exhibit A-4), not an arbitrary cost line. The Company was careful not to overstate that requirement. While the expiration of the ZRC and DR commitments is factored into the 2033 analysis, those expirations do not define the 2033 system reliability requirements, which are set by the combination of all load and resource changes on the system. (Burgdorf, 3T 399). That the same proxy both addresses the modeled 2033 reliability need and carries the associated cost is not "double duty" in any improper sense, as MEICEO witness Kenworthy suggests (Kenworthy, 3T 679). To the contrary, it is the natural consequence of modeling a single resource to meet a modeled need and then charging its full cost against the benefit in Exhibit A-19.

Fifth, the intervenors' concern that IRP modeling may ultimately differ is neutralized by the Affordability Backstop. The Company does not dispute that certain cost and benefit categories may change with updated IRP modeling over a longer horizon; that is inherent in any forward-looking analysis. But the appropriate response is not to disregard a reasonable planning analysis — it is the Affordability Backstop, which measures the aggregate benefit over the life of the Special Contracts and obligates the Customer to reimburse any shortfall the Commission ultimately determines. (Foley, 3T 103–104.) The proxy resource's role in the customer benefit analysis therefore provides no basis to reject or condition the Special Contracts.

Based on the foregoing, MNS witness Woods' recommendation that the Commission "disregard all information DTE has provided regarding the various purported benefits of the CCGT plus CCS proxy resource" (Woods, 3T 651), and MEICEO witness Kenworthy's suggestion that the analysis improperly predetermines an IRP resource decision (Kenworthy, 3T 679–680), should both be rejected.

Next, MEICEO witness Kenworthy contends that the CCS cost line in Exhibit A-19 is shown net of the federal 45Q carbon-capture tax credit, pointing to the increase in the CCS revenue requirement as reflecting the end of the 12-year 45Q window. He argues that if the credit "is reduced, repealed, or the project does not qualify, the CCS cost to ratepayers rises and the net benefit shrinks." (Kenworthy, 3T 680–681.). The Commission should not give this criticism weight, for four primary reasons.

First, incorporating the 45Q credit is standard, correct revenue-requirement modeling, not a thumb on the scale. As Company Witness Burgdorf explained, the annual revenue requirement for the proxy resource "was an output of the model which incorporated various components such as depreciation expense, non-fuel O&M, property tax, allowed return, and federal production tax credits associated with the CCS system." (Burgdorf, 3T 377). A revenue-requirement calculation that reflects the tax credits available to a resource under current law is the accurate way to model that resource's cost, as ignoring an available federal credit would have overstated the resource's cost and understated the benefit. Hence, MEICEO witness Kenworthy identifies no error in the calculation, he identifies only a risk that federal law or project eligibility could change in the future.

Second, the 45Q risk is a risk of the proxy, not of the Special Contracts, and the Commission is not being asked to approve the former. As explained above, the CCGT with CCS is a modeling proxy, and actual resources will be reviewed and selected in the Company's upcoming IRP. (Burgdorf, 3T 393). MEICEO witness Kenworthy's concern that a "hypothetical plant the Commission has not approved" may carry tax-credit uncertainty (Kenworthy, 3T 681) is therefore not a reason to reject the Special Contracts.

Third, even if MEICEO witness Kenworthy's own figures are accepted, the net benefit remains substantial and positive. He quantifies the assumed 45Q credit at "approximately $75 million per year . . . on the order of $0.9 billion or more over the credit window." (Kenworthy, 3T 681.) Even if that entire assumed credit were disregarded — an extreme assumption, given that 45Q is current federal law — the projected $1.7 billion benefit would remain positive by a wide margin.

Fourth, any residual 45Q risk is addressed by the Affordability Backstop on an aggregate basis and without assigning any resources outside of the CCAA exclusively to the Customer. To the extent MEICEO witness Kenworthy's concern is that actual costs could differ from those modeled if the credit is later reduced, that contingency is resolved by the Affordability Backstop, which does not turn on the cost of any single resource. Because the Affordability Backstop operates at the aggregate level, other customers are protected from any net cost regardless of how the 45Q assumption ultimately bears on any particular resource. Critically, nothing in this proceeding, and nothing in the Affordability Backstop, determines that the proxy CCGT with CCS, or any future resource, is caused by or will be assigned to the Customer. As Company Witness Foley explained, the Company's with-and-without modeling identifies resources caused by the Customer's load as part of a portfolio of resources and those assets are not specifically assigned to the Customer for its service. (Foley, 3T 246). The identification of any resource caused by the Customer's load, and the allocation of its costs, are matters reserved for the Company's future IRP and general rate cases — not this special contract proceeding. MEICEO witness Kenworthy's alternative recommendation that 45Q realization be built-in as a discrete backstop “trigger” is therefore both unnecessary and inconsistent with the aggregate design of Section 5.1.3, as the Company explains in Section V.A.6.

In sum, the Company's 45Q assumption reflects a correct application of current law to a modeling proxy that the Commission is not being asked to approve; its elimination would not convert the substantial benefit into a net cost to other customers; and, in all events, the Affordability Backstop ensures that other customers are held harmless from any net cost of serving the Customer's load, on an aggregate basis and without assigning any specific resource to the Customer.

Next, MNS witness Woods observes that the Company's Base Sales Benefit calculation assumes that the Customer's underlying load is at full ramp of 1,000 MW and a 90% load factor, and contends that this level of utilization is "exceptionally efficient" relative to a 2025 E3 study of existing data centers. (Woods, 3T 626). She notes that because the PSA establishes an 80% minimum billing demand, “the Customer is under no obligation to reach a 90% load factor as assumed in the Company's benefit calculations.” *Id*. From this, she concludes only that “if the Customer's load factor is less than 90%, the Company's estimated Base Sales Benefit will be larger than the actual benefit,” and urges the Commission “not to predetermine” the $1.7 billion benefit. *Id*. MNS Witness Woods' observation does not counsel against approval; if anything, it confirms why the PSA's structure protects other customers.

First, MNS witness Woods' “do not predetermine” recommendation is not tied to any relief requested by the Company in this proceeding. MNS witness Woods' core recommendation is that the Commission decline to "predetermine" that the Special Contracts will produce the projected benefit. (Woods, 3T 627–628). Notably, the Company does not ask the Commission to predetermine or otherwise guarantee any specific benefit figure. In any event, her recommendation does not support rejecting the benefit analysis.

MNS witness Woods identifies, at most, a point about the magnitude of the benefit, not a cost shift. Her testimony narrowly asserts that a load factor below 90% would make the estimated benefit "larger than the actual benefit." (Woods, 3T 626). She does not testify that a lower load factor would produce a net cost to other customers. A reduction in the size of a large, positive benefit is not a cost shift, and it provides no basis to reject or condition the Special Contracts.

Second, the 80% MBD floor — the very term Witness Woods cites — is what protects other customers if the Customer's load factor is lower than modeled. The MBD is not a prediction of the Customer's load factor; it is a contractual floor guaranteeing a minimum level of cost recovery regardless of the Customer's actual usage. That the Customer "is under no obligation to reach a 90% load factor" (Woods, 3T 626) is precisely the point. Whatever the Customer's realized utilization, it must pay for at least 80% of its contract capacity. Staff's independent minimum bill scenario analysis confirmed that this floor is more than sufficient, as the MBD covers the non-production costs of serving the Customer in every year of the term, with the lowest annual coverage being 116.64% in 2035. (Isakson, 3T 874). In other words, even in a scenario in which the Customer never exceeds its minimum bill, other customers are fully protected.

Third, to the extent the Customer does consume energy above the MBD, that generates additional benefits, not costs. As Staff witness Isakson explained, "[i]f the Customer pays its minimum billing demand but also uses any amount of energy, then the additional revenues that would flow through the PSCR and other energy charges would also provide additional customer benefit." (Isakson, 3T 876). Therefore, the 90%-versus-80% question bears only on how large the benefit is, bounded on the downside by the 80% MBD floor and increasing to the extent actual usage is higher — with other customers protected across the entire range.

Fourth, Staff independently audited and confirmed the Base Sales Benefit that incorporates the 90% assumption. Staff audited the billing determinants and rates used by the Company to calculate the annual revenue generated by the Customer, finding that Staff's recreation "largely matches Company Exhibit A-19" and "matches the Company's finding on Exhibit A-20." (Isakson, 3T 857, 863). The record thus contains no quantitative analysis, from MNS witness Woods or any other party, showing that a lower load factor would eliminate the net benefit, let alone impose a net cost on other customers.

In sum, MNS witness Woods' load-factor observation goes only to the magnitude of a benefit that remains positive across the full range of realized load factors; the 80% MBD floor and the Affordability Backstop protect other customers regardless of the Customer's actual utilization; and Staff's independent audit confirms the Base Sales Benefit. Her observation provides no basis to reject or condition the Special Contracts, and her "do not predetermine" recommendation is out of context in this proceeding.

Next, ABATE witness Dauphinais recalculates the Company's post-2047 remaining-value analysis (Exhibit A-15) by assuming 0% growth in capacity and energy prices across the entire 2048–2067 period, and on that basis converts the Company's projected $75.01 million net present-value benefit for the post-contract life of the proxy resource into a projected $129.55 million net present-value cost. (Dauphinais, 3T 539–540; Exhibit AB-2.) The Commission should give this sensitivity no weight, for four reasons.

First, the zero-growth assumption is unreasonable on its face. ABATE witness Dauphinais performed a single sensitivity assuming 0% growth in energy and capacity prices throughout the entire 2048–2067 period to arrive at a net cost of the remaining assets of $129.55 million. As Company Witness Burgdorf testifies, "[t]his assumption is neither reasonable nor consistent with inflationary price impacts that consistently rise over time." (Burgdorf, 3T 393). Assuming that capacity and energy prices remain frozen at a single year's level for two full decades is contrary to ordinary price behavior, and ABATE witness Dauphinais offered no reasoned basis for it.

Second, the Company's underlying post-2047 analysis was itself deliberately conservative, making the realistic result more favorable, not less. As Witness Burgdorf explains, the Company's presentation of post-contract benefits was developed using a representative capacity resource (i.e., storage) displaced by the proxy CCGT with CCS, and that resource type was chosen based on being the economic resource selection in the Base Case modeling results. (Burgdorf, 3T 393–394). Because the Company modeled the proxy displacing one of the lowest-cost capacity resources, "the net customer benefits would likely be greater than those shown in Exhibit A-15 under other scenarios where other types of resources are displaced." (Burgdorf, 3T 394.) Witness Dauphinais' sensitivity thus takes an already conservative analysis and layers an unrealistic zero-growth assumption on top of it.

Third, even accepting ABATE witness Dauphinais' sensitivity, it does not change the outcome of this case. Even under ABATE witness Dauphinais' sensitivity, there is no material change to the Company's expectation of customer benefits. (Burgdorf, 3T 393). That is because the post-2047 analysis addresses only the remaining value of the proxy resource after the contract term; it is separate from, and dwarfed by, the net benefit realized during the 20-year term. The swing ABATE witness Dauphinais posits from a $75.01 million benefit to a $129.55 million cost is immaterial against the in-term net affordability benefit, which remains approximately $1.0

billion even on ABATE witness Dauphinais' own present-value basis (Dauphinais, 3T 540) and approximately $1.7 billion in Exhibit A-19.

Fourth, the post-2047 analysis is a conservative addition to the Company's showing and is not necessary to the benefit conclusion. The Company presented the Exhibit A-15 remaining-value analysis to give the Commission a complete picture, demonstrating that the proxy resource — approximately 74% of whose cost is paid off by the end of the contract term on a net-present-value basis — continues to provide value to customers beyond 2047 with an estimated $647 million in market value offsetting its approximately $1.0 billion remaining revenue requirement. (Burgdorf, 3T 379; Exhibit A-15). And the Company reasonably declined to perform an exhaustive sensitivity analysis for the post-contract period because this is not an IRP filing and performing resource-type sensitivities over that horizon (two to four decades into the future) would require speculative assumptions about resource availability, technology costs, and market structures that cannot be reliably forecasted today. (Burgdorf, 3T 394).

In sum, ABATE witness Dauphinais' zero-growth sensitivity rests on an assumption the record shows to be unreasonable, applies it to an already-conservative analysis, and in any event does not alter the Company's showing that the Special Contracts produce a substantial net affordability benefit and hold other customers harmless over the life of the Special Contracts.

Next, MEICEO witness Kenworthy does not dispute that the $1.16 billion storage pull-ahead is properly calculated or that the customer-funded storage is correctly excluded from other customers' costs; indeed, he concedes the "customer-funded storage is correctly off DTE's ratepayer books." (Kenworthy, 3T 682). He argues only that the benefit may be overstated if the displaced Company storage is deferred beyond the 2047 window rather than permanently avoided, such that "the true benefit may be closer to the time value of deferral than to the full $1.16 billion avoided revenue requirement." *Id*. He further opined, borrowing from MEICEO witness Hotaling, that a portion of the avoided cost “reflects a planning assumption rather than a true avoidance.” (Kenworthy, 3T 682.) Neither point undermines the benefit or supports rejecting the Special Contracts.

First, the storage pull-ahead reflects a real, modeled avoided cost to other customers. As Company Witness Willis explains, because the Customer directly funds the CCAA energy storage, “the storage assets were removed from the base build plan, generating an avoided cost benefit to existing customers," reflected on Line 12 of Exhibit A-19. (Willis, 3T 411). The benefit is not a theoretical construct — it is the revenue requirement of storage that the Company's EnCompass modeling shows other customers would otherwise have funded, but no longer must, because the Customer pays for that storage under the CCAA. MEICEO witness Kenworthy identifies no error in that calculation.

Second, MEICEO witness Kenworthy's “deferral versus avoidance” argument is speculative and unquantified. He does not testify that the displaced storage will be deferred rather than avoided, merely offering that the benefit “may be” closer to the time value of deferral “if” the storage is deferred beyond 2047. (Kenworthy, 3T 682). He performed no calculation of what that alternative value would be and offered no record basis to conclude that deferral, rather than avoidance, is the likely outcome. An unquantified “may be” does not rebut the Company's quantified, modeled result.

Third, and dispositively, the net benefit remains substantial and positive even if the storage pull-ahead is removed entirely. MEICEO witness Kenworthy's own analysis establishes that removing the storage pull-ahead benefit reduces the present value of the benefit only "to approximately $531 million" — a figure that remains a positive net benefit to other customers.

(Kenworthy, 3T 678). In other words, even under the most extreme version of Witness Kenworthy's own critique, disregarding the entire $1.16 billion storage pull-ahead and discounting the remainder to present value, the Special Contracts still produce a net benefit of over half a billion dollars to the Company's other customers. That is more than sufficient to satisfy the no-cost-shift standard, and it confirms that the storage-pull-ahead debate goes only to the magnitude of a benefit that remains positive under every treatment in the record.

In sum, MEICEO witness Kenworthy concedes the Customer-funded storage is correctly off other customers' books, identifies no error in the calculation, and quantifies his own most-aggressive sensitivity at a still-positive ~$531 million. The storage pull-ahead is a real, modeled avoided cost benefit, and any residual timing uncertainty is captured by the Affordability Backstop.

Next, MEICEO witness Kenworthy argues that the Commission's reasonableness inquiry should include whether the proposed contracts represent the most cost-effective approach to serving the Customer's load, and that the $1.7 billion affordability benefit does not demonstrate DTE Electric's proposals are cost effective. (Kenworthy, 3T 688-689). MEICEO witness Kenworthy goes on to argue that as a condition of approving the Special Contracts, the Commission should order DTE Electric to evaluate and pursue more cost-effective options, which he claims MEICEO witness Sherman identified, and require an "ex post demonstration" that those opportunities have been considered and pursued where cost-effective. *Id*. The Commission should reject MEICEO's arguments, as MEICEO witness Kenworthy's proposed "most cost-effective approach" standard finds no support in Michigan law governing special contracts and would improperly graft an IRP-style resource-optimization test onto a proceeding whose limited question is whether the negotiated Special Contracts are reasonable, in the public interest, and free of cost-shifting — a standard the contracts amply satisfy by an estimated $1.7 billion.

First, MEICEO witness Kenworthy's recommendations are both legally unfounded and analytically confused. As a legal matter, no provision of MCL 460.6a, MCL 460.10, or the Commission's special-contract precedent conditions approval of a special contract on a finding that it is the single least-cost alternative among all hypothetical resource portfolios; the governing standard is whether the contract is lawful, reasonable, in the public interest, and does not shift costs to other customers. MEICEO's proposed "cost-effective" standard would rewrite that governing standard, importing a resource-optimization inquiry that the Legislature and the Commission have reserved for IRPs under MCL 460.6t. As a factual matter, MEICEO's proposed "most cost-effective approach" standard also confuses the record. The customer benefit analysis does not purport to identify an optimized system-wide resource portfolio — a task expressly reserved for the 2026 IRP — but instead demonstrates that the negotiated contracts, as presented for approval, hold other customers harmless and are projected to produce a substantial net benefit. MEICEO witness Kenworthy's insistence on a "most cost-effective" showing thus asks the Commission to answer a question that is not before it, under a legal standard that does not exist, and to disregard the actual showing the record makes — that the Special Contracts create a substantial benefit for other customers by an estimated $1.7 billion.

As Company Witness Burgdorf made clear, "[t]he purpose of this proceeding is not to conduct a full resource-planning optimization or to select the Company's future resource portfolio." (Burgdorf, 3T 395). That evaluation will occur in the Company's upcoming IRP, which is the appropriate forum for determining the optimal resource mix on a system-wide basis, and "[t]he IRP — not a special contract approval proceeding — is the appropriate forum for optimizing resource procurement." *Id*. Whether a hypothetical alternative portfolio advocated by MEICEO witness Sherman could cost less has no bearing on the issues before the Commission for decision.

In essence, MEICEO witness Kenworthy's "most cost-effective approach" standard would improperly convert this special contract proceeding into a resource-planning optimization that self-servingly mandates focusing on MEICEO witness Sherman's preferred resources[32] and that unquestionably belongs in the IRP. Tellingly, the optimization MEICEO seeks is not resource neutral. When MEICEO witness Kenworthy's cost-effectiveness framing is read together with MEICEO witness Sherman's recommendation (Kenworthy, 3T 688-689), MEICEO's objective is simply to impose mandatory ownership splits and favor witness Sherman's preferred resources. But an ownership split would not lead to the most cost-effective projects. As Company Witness Bilyeu testifies, DTE's 2024 All-Source Renewable RFP showed Company-owned projects averaging approximately $75 per MWh against approximately $92 per MWh for third-party-owned projects, such that "mandating higher levels of third-party ownership could increase costs rather than reduce them." (Bilyeu, 3T 307–308). Staff agrees, opposing a 50/50 split "in all cases on the simple premise that if the Competitive Procurement Guidelines are met, the most economic projects should be selected." (Simpson, 3T 848). MEICEO thus invokes "cost-effectiveness" while advocating a structural preference for third-party-owned resources that the record shows would raise costs. Regardless of the merits of that ownership-policy debate, it is a system-wide procurement policy question reserved for the IRP and does not serve as a basis to reject or re-engineer the negotiated Special Contracts in this proceeding.

Moreover, MEICEO witness Kenworthy's proposed "ex post demonstration" condition, requiring DTE Electric to prove, after the fact, that it considered and pursued the specific "cost-effective options" (namely, those identified by MEICEO witness Sherman), has no legal

[32] See Section V.B.1 for discussion on the unreasonableness of MEICEO witness Sherman's proposals, including a failure to demonstrate that her preferred resource types are cheaper.

foundation, rises no higher than the defective "most cost-effective" standard to which it is tethered, and would improperly commandeer resource-procurement and portfolio-optimization decisions that Michigan law reserves to the IRP and competitive-procurement processes. MEICEO's "ex post demonstration" condition is not merely unsupported, it is affirmatively contrary to the applicable statutory decision-making scheme. Determining which resources to pursue, in what quantities, from which owners, and at what cost is the precise function of the IRP process under MCL 460.6t and the Commission's Competitive Procurement Guidelines and the VGP Settlement Agreements that govern procurement of resources under the VGP Special Contract. MEICEO witness Kenworthy's "ex post demonstration" mandate would extract those decisions from the forums the Legislature and the Commission established for them and displace them into an open-ended compliance obligation appended to a special contract — and, worse, would tilt that obligation toward a particular procurement outcome, namely the third-party-owned resources MEICEO witness Sherman advocates, which the record shows would tend to raise costs rather than lower them.

In any event, the Company's customer benefit analysis affirmatively demonstrates that the Special Contracts are beneficial to other customers. Contrary to MEICEO witness Kenworthy's contention, the customer benefit analysis shows that the inclusion of the Customer (i.e., PSA, CCAA and Rider 12 DR Agreement), plus the proxy CCGT with CCS, is beneficial for other customers by an estimated $1.7 billion. (Burgdorf, 3T 395-396). The customer benefit analysis thus does not simply decline to perform an optimization — it demonstrates a substantial, quantified benefit to other customers from the contracts as negotiated. MEICEO witness Kenworthy's premise that the $1.7 billion figure says nothing about "cost-effectiveness" is therefore incorrect on the face of the record, regardless of the confusion he creates.

For the foregoing reasons, the Commission should reject MEICEO's "most cost-effective approach" standard and the "ex post demonstration" condition tethered to it. Neither has any foundation in MCL 460.6a, MCL 460.10, or the Commission's special-contract precedent, and both would improperly convert this special contract proceeding into a system-wide resource-optimization exercise that Michigan law reserves to IRPs.

In sum, the customer benefit analysis demonstrates, on the present record, that the Special Contracts are projected to produce a substantial net benefit and not shift costs to the Company's other customers. The Affordability Backstop in Section 5.1.3 of the PSA then converts that projected result into a durable, enforceable protection. Under Section 5.1.3, if the Commission ever determines that the costs to serve the Customer exceed the benefits, the Customer — and not the Company's other customers — is obligated to reimburse the shortfall. (Foley, 3T 103–104).

VII. REQUEST FOR RELIEF

Based on the foregoing, DTE Electric Company respectfully requests that the Michigan Public Service Commission issue a final order on an expedited basis:

1. Approving the Company’s Special Contracts with Google LLC as reasonable, prudent, and in the public interest;
2. Approving the Company’s request to record regulatory liabilities to Account 254 for the accelerated recovery of costs for storage and renewable energy projects under the CCAA;
3. Approving the Company’s request to record to income the financial adder to be paid by the Customer for the ZRC transfer under the CCAA; and
4. Granting such other lawful relief that the Commission deems reasonable and appropriate.

Respectfully submitted,

DTE ELECTRIC COMPANY
Legal Department

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Dated: July 20, 2026

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	Case No. U-22058
for Approval of Special Contracts	)	
and for other relief	)	

PROOF OF SERVICE

ESTELLA R. BRANSON states that on July 20, 2026, she served a copy of the DTE Electric Company's Initial Brief (Public), via electronic mail upon the persons listed on the attached service list.

Estella R. Branson

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