

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

QUALIFICATIONS
AND
PUBLIC
DIRECT TESTIMONY
OF
NEAL T. FOLEY

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF NEAL T. FOLEY

Line
No.

1 **Q1. What is your name, business address and by whom are you employed?**

2 A1. My name is Neal Foley. My business address is: One Energy Plaza, Detroit,
3 Michigan 48226. I am employed by DTE Electric Company (“DTE Electric” or
4 “Company”).

5

6 **Q2. On whose behalf are you testifying?**

7 A2. I am testifying on behalf of DTE Electric.

8

9 **Q3. What is your educational background?**

10 A3. I received a Bachelor of Science in Aerospace Engineering and a Bachelor of
11 Science in Mechanical Engineering from the University of Michigan. I also
12 received a Master of Science in Systems Engineering from Johns Hopkins
13 University and a Master of Business Administration from Georgetown University.

14

15 **Q4. Please summarize your professional experience.**

16 A4. In 2007, I was employed by Lockheed Martin Corporation as a Satellite Operations
17 Engineer. In 2008, I was hired by Booz Allen Hamilton as an Associate Consultant
18 in its Federal consulting practice. In 2012, I was hired by Deloitte as a Manager of
19 Financial Analysis in its Federal consulting practice. In 2014, I was hired by
20 McKinsey & Company as an Associate Consultant, ultimately being promoted to
21 Engagement Manager before my departure in 2017. In 2017, I was hired by DTE
22 Energy Company as Manager of Corporate Strategy. In this role, I was broadly
23 responsible for tracking and assessing utility industry trends, executing analyses to
24 better understand the economic impacts of emerging technologies and business
25 models, and leading strategic initiatives for the Company. In December 2020, I was

Line
No.

1 promoted to Director of Regulatory Affairs where I was responsible for the
2 management of regulatory activities related to DTE Electric’s Load Research,
3 Tariffs, Pricing, and Rate Design. In December 2024, I started my current role as
4 Director of Electric Marketing for DTE Electric.

5

6 **Q5. Have you previously sponsored testimony before the Michigan Public Service**
7 **Commission (“MPSC” or “Commission”)?**

8 A5. Yes. I have sponsored testimony and exhibits before the MPSC in the following
9 DTE Electric cases:

10	<u>Case No.</u>	<u>Description</u>
11	U-20836	DTE 2022 Electric Rate Case
12	U-21376	DTE 2023 Distributed Generation Tariff Options
13	U-21297	DTE 2023 Electric Rate Case
14	U-21534	DTE 2024 Electric Rate Case
15	U-21860	DTE 2025 Electric Rate Case
16	U-21990	DTE 2025 Data Center Special Contracts

Line
No.

1 **Purpose of Testimony**

2 **Q6. What Commission action is the Company seeking through the instant case?**

3 A6. The Company is seeking the Commission's approval of two special contracts and
4 other related relief that will govern how the Company serves a new, large load
5 customer. Specifically, the Company is seeking approval of the following special
6 contracts that have been executed between the Company and Google LLC ("the
7 Customer").

- 8 • Primary Supply Agreement ("PSA")
- 9 • Clean Capacity Accelerator Agreement ("CCAA")

10 Taken together, the PSA and CCAA are referred to as the "the Contracts"
11 throughout my testimony.

12

13 The Company is requesting Commission review of the Contracts by September 10,
14 2026.

15

16 **Q7. Why is the Company requesting a Commission order by September 10, 2026?**

17 A7. The September 10th date will satisfy the conditions precedent set forth in the
18 Contracts which require Commission approval by September 10, 2026.

19

20 **Q8. Can you summarize the Contracts that are being proposed for approval?**

21 A8. Yes. The PSA stipulates that the Customer will receive electric service under the
22 Company's Rate Schedule D11 ("D11") which is the Company's Primary Supply
23 Rate. The PSA also establishes additional protections for the Company's other
24 customers that are not included in Rate Schedule D11. Importantly, the PSA
25 ensures that the aggregate benefits of the Contracts, including revenues received

Line
No.

1 from the Customer and avoided costs realized through the Contracts, outweigh the
2 costs of serving the Customer's load. If aggregate benefits do not outweigh the
3 costs, the Customer will pay the difference.

4

5 The CCAA allows the Company to deploy a portfolio of up to 480 MW of energy
6 storage projects and up to 1,600 MW of renewable energy projects, and recover
7 from the Customer the full cost of these projects. Therefore, the costs of the energy
8 storage and renewable energy projects developed to fulfill the CCAA with the
9 Customer will not be passed on to the Company's other customers. In addition, the
10 CCAA allows the Company to receive from the Customer 300 MW of
11 Midcontinent Independent System Operator ("MISO") Zone 7 Zonal Resource
12 Credits ("ZRCs") at no cost.

13

14 The Customer will receive capacity and renewable generation credits for the
15 projects that are deployed and the ZRCs that are received as part of the CCAA.
16 Importantly, the credits received by the Customer for a given project or transferred
17 ZRC cannot be greater than the incremental market revenues that are generated by
18 that project or ZRC for a given billing period. This ensures that the Company's
19 other customers do not bear any costs of CCAA resources.

20

21 Table 1 below summarizes these terms and compares them to the Company's
22 standard D11 rate.

Line
No.

1

Table 1: Comparison of PSA/CCAA contract terms to D11 rate

2

Term	PSA/CCAA	Standard D11
Contract duration	20-years	5-years
Pricing and ability to change rates	D11 pricing; 24-month and other restrictions on rate switching	D11 pricing; 12-month restriction on rate changes
Minimum Billing Demand (MBD)	80%	50-65% (demand ratchets)
Load Ramp Flexibility	Customer can temporarily delay load ramp by up to [REDACTED]	Not addressed
Contract Capacity Reductions	Customer cannot reduce contract capacity	Not addressed beyond initial term and ratchets
Termination Payment	Customer ensures 15-years of MBD payments	Not addressed
Affordability backstop	Customer ensures aggregate benefits of the Contracts are greater than aggregate costs	Not addressed
Energy Waste Reduction	Customer commits to self-directed EWR plan	Not addressed
Credit and collateral requirements	Credit and collateral requirements	No specific requirement
Direct payment of energy storage	Up to 480 MW, including up to 55 MW of long-duration storage	Not addressed
Direct payment of renewable energy	Up to 1,600 MW	Not addressed

Line
No.

1 **Q9. Are there any other agreements between the Company and the Customer to**
2 **support providing electric service?**

3 A9. Yes, there are two additional agreements that support the Company providing
4 electric service to the Customer:

- 5 • Rider 12 Demand Response ("DR") Agreement which commits the
6 Customer when called to reduce its electrical demand at its facility to 650
7 MW between June 2027 through May 2033¹; in his testimony, Witness
8 Burgdorf describes the Rider 12 DR Agreement
- 9 • Line Extension Agreement ("LEA") which commits the Customer to pay
10 for up to \$50 million of distribution upgrades to serve their facility; in his
11 testimony, Witness Benyard describes how the Company expects total
12 distribution upgrades to cost less than \$50 million

13

14 The Rider 12 DR Agreement and LEA are standard contracts that the Company is
15 not seeking Commission approval of in the instant case. They are being discussed
16 as part of the Company's filing to provide a complete description of how the
17 Company intends to serve the Customer.

18

19 **Q10. What is the purpose of your testimony?**

20 A10. The purpose of my testimony is to first introduce the Company's witnesses and
21 describe the scope of their testimonies. I then generally describe and support the
22 structure and provisions of the Contracts and how the Contracts mitigate the risk of
23 stranded assets.

¹ During load ramp period, Customer is required to reduce load to 65% of applicable contract capacity at the time of the event which could be less than 650 MW

Line
No.

1 **Q11. How is your testimony organized?**

2 A11. My testimony includes the following sections:

- 3 1. Introduction of Company witnesses
- 4 2. Overview of the Customer
- 5 3. Proposed PSA
- 6 4. Proposed CCAA
- 7 5. Regulatory treatment
- 8 6. Summary of requested Commission action

9

10 **Q12. Are you sponsoring any exhibits in this proceeding?**

11 A12. Yes. I am sponsoring the following exhibits:

12	<u>Exhibit</u>	<u>Description</u>
13	A-16	Primary Supply Agreement - Confidential
14	A-18	Clean Capacity Accelerator Agreement - Confidential

15

16 **Q13. What was your involvement in the preparation of the Contracts?**

17 A13. I was involved in the development of the key terms included in the Contracts, as
18 discussed throughout my testimony.

19

20 **Introduction of Company Witnesses**

21 **Q14. How will the Company present evidence in support of its proposals in this**
22 **case?**

23 A14. The Company will present its case through six witnesses, including myself, as
24 described below.

Line
No.

- 1) Mr. Kevin L. Bilyeu discusses the impact that the Customer’s load will have on the Company’s Renewable Portfolio Standard (“RPS”) obligations, describes the Company’s Voluntary Green Pricing (“VGP”) program as it relates to special contracts, and how the deployment of renewable energy under the CCAA will help offset those impacts.
- 2) Mr. Steven N. Benyard discusses the projects that are required to provide safe and reliable service to the Customer; in addition, he discusses the cost estimate for the distribution and transmission upgrades needed to support the Customer’s connection to the electric grid.
- 3) Mr. Shawn D. Burgdorf discusses changes in the capacity resource mix and the Power Supply Cost impacts from the addition of the Customer’s load. He also describes the Company’s Rider 12 demand response contract with the Customer.
- 4) Mr. Justin J. W. Brooks explains the results of the resource adequacy analysis performed at the Company’s request in years 2029 and 2033 to support the addition of the Customer’s load to the DTE Electric system.
- 5) Mr. Aaron Willis discusses the Company’s customer impact modeling which demonstrates how the Company expects its other customers to realize a benefit of approximately \$1.7 billion during the term of the Contracts.

Overview of the Customer

Q15. Can you describe the Customer?

A15. Yes. 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

Line
No.

1 market capitalization. The Customer intends to build a data center that will be
2 engaged in the management, storage, processing, and distribution of data.

3

4 **Q16. Where will the data center be located?**

5 A16. The data center will be located in Van Buren Township, Michigan, within the
6 Company's service territory. It will be developed on roughly 280 acres.

7

8 **Q17. What is the planned Customer load at the facility and when will the load
9 materialize?**

10 A17. The maximum load at the facility is 1,000 MW ("max load" or "contract capacity").
11 The Customer's load is planned to begin materializing in December 2027², with
12 max load being achieved by December 2028 ("load ramp" or "load ramp period")
13 and held constant thereafter. Later in my testimony, I describe the Customer's
14 ability to adjust the timing of the load ramp and the date by which they achieve
15 their max load ("Load Ramp Completion Date").

16

17 **Q18. Will the Company's other customers benefit from the Contracts?**

18 A18. Yes. In his testimony Witness Willis describes how the Contracts are expected to
19 deliver a \$1.7 billion benefit to the Company's other customers.

20

21 **Q19. Will serving the Customer's load have an impact on the Company's Energy
22 Waste Reductions ("EWR") targets?**

23 A19. Yes. Later in my testimony I describe the Customer's commitment to achieving
24 EWR targets contained within the PSA.

² Load to support construction of the site could materialize before December 2027.

Line
No.

1 **Primary Supply Agreement - Overview**

2 **Q20. Can you provide an overview of the PSA?**

3 A20. Yes. The PSA, Exhibit A-16, governs the obligations of the Company and the
4 Customer as it relates to the electric service that the Customer will receive.

5

6 At a high level, the PSA requires that the Customer take service on D11, including
7 all associated surcharges, and includes additional terms that are not currently
8 included in Rate Schedule D11. Of critical importance, the PSA ensures that the
9 aggregate benefits of the Contracts, including revenues received from the Customer
10 and avoided costs realized through the Contracts, outweigh the costs of serving the
11 Customer's load.

12

13 **Q21. What are the terms of the PSA between the Company and the Customer that**
14 **differ between a standard contract under the Company's D11 rate?**

15 A21. The terms of the PSA that differ from the D11 rate are the following:

- 16
- 17 • Contract duration
 - 18 • Pricing and ability to change rates
 - 19 • Minimum Billing Demand (MBD)
 - 20 • Customer load ramp flexibility
 - 21 • Contract capacity reductions
 - 22 • Termination payment
 - 23 • Affordability backstop
 - 24 • Energy Waste Reduction
 - Credit and collateral requirements

Line
No.

1 I will describe each of these elements in the following sections of my testimony.

2

3 **Primary Supply Agreement – Contract Duration**

4 **Q22. What is the contract duration of the PSA?**

5 A22. The PSA contract duration is 20 years, beginning at the time the Customer first
6 receives electric service at its facility. As the Customer is expected to begin taking
7 service in December 2027, the Company expects the PSA contract duration to
8 extend through November 2047.

9

10 Later in my testimony I describe the Customer’s ability to temporarily delay their
11 load ramp, including when they begin receiving electric service at the data center
12 facility.

13

14 The PSA will automatically renew for up to two additional 5-year terms. The
15 Customer can opt-out of these automatic renewals by providing notice to the
16 Company at least 36-months prior to the beginning of a renewal period.

17

18 **Q23. Is the PSA contract duration beneficial to the Company’s other customers?**

19 A23. Yes. The PSA contract duration is much longer than the Company typically requires
20 for large industrial customers. For comparison, the standard agreement for a new
21 customer under D11 over 1 MW of peak demand is five years.

22

23 A 20-year PSA contract duration represents a significant commitment on behalf of
24 the Customer to the Company and its other customers. It ensures that the Customer

Line
No.

1 will make their proportionate contribution to the Company's system costs for a
2 longer period than the Company normally requires of its customers under D11.

3

4 **Primary Supply Agreement – Pricing and Ability to Change Rates**

5 **Q24. How is electric service pricing structured under the PSA?**

6 A24. Under the PSA, the Customer agrees to take service on D11 and pay all applicable
7 surcharges (e.g., the Power Supply Cost Recovery ("PSCR") Surcharge).

8

9 **Q25. Can the Customer change rate schedules under the PSA?**

10 A25. Under the PSA, the Customer can only change rate schedules under the following
11 conditions:

- 12 • The Customer must request a rate schedule change 24 months in advance of
13 the rate schedule change taking effect;
- 14 • The Customer cannot request a rate schedule change that would take effect
15 prior to 24 months after their Load Ramp Completion Date;
- 16 • The Customer can only change to a rate schedule that is approved by the
17 Commission after the PSA became effective; and
- 18 • The Customer can only change to a rate schedule that is not cross-subsidized
19 by any other customer group.

20

21 **Q26. Are the PSA pricing and ability to change rate schedule terms reasonable?**

22 A26. Yes. D11 is a cost-based rate that will ensure that the Customer makes their
23 proportionate contribution to the Company's fixed system costs. Being subject to
24 the PSCR surcharge ensures that the Customer makes their proportionate
25 contribution both to the incremental fuel and purchased power costs that they are

Line
No.

1 introducing, and to the fixed costs of renewable energy assets and transmission
2 costs that are recovered through that mechanism.

3
4 The limitations on rate schedule switching in the PSA are also reasonable. The
5 notice period ensures that any rate schedule change can be appropriately
6 incorporated through a subsequent rate case. The limitation that the rate schedule
7 be newly approved and not cross-subsidized provides appropriate protections
8 around the types of future rates that the Customer may be eligible for to ensure any
9 potential future rate change would not negatively impact other customers.

10

11 **Primary Supply Agreement – Minimum Billing Demand**

12 **Q27. How is Minimum Billing Demand (“MBD”) structured under the PSA?**

13 A27. Under the PSA, the Customer agrees that the minimum demand for a given billing
14 period will be 80% of the contract capacity applicable for that billing period. In
15 practice, this means the Customer’s Minimum Monthly Charge (“MMC”) for a
16 given billing period will be calculated using an 80% MBD as applied to the
17 customer’s contracted capacity during the specific billing period. The MBD will
18 increase during the Customer’s load ramp and then will be held constant at the
19 contract capacity once the max load is achieved.

20

21 Given that the Customer’s max load is 1,000 MW, the MBD will be 800 MW (i.e.,
22 80% of 1,000 MW) once the Load Ramp Completion Date is reached.

23

24 **Q28. How will the MBD be applied?**

25 A28. On D11, the Customer is subject to three demand charges:

Line
No.

- 1 • Power Supply Capacity Demand Charge
- 2 • Power Supply Non-Capacity Demand Charge
- 3 • Distribution Demand Charge

4

5 The first two demand charges (Power Supply Capacity and Power Supply Non-
6 Capacity) are typically calculated based on the billing period's monthly on-peak
7 billing demand as defined in D11. Under D11 these charges would also typically
8 be subject to a 65% ratchet³; however, this term is superseded by the 80% MBD
9 agreed to in the PSA.

10

11 The third demand charge (Distribution) is typically calculated based on the
12 maximum demand measured during the previous 12 months as defined in Rate
13 Schedule D11. Under D11 this charge would also typically be subject to the greater
14 of actual maximum demand or 50% of contract capacity; however, this term is
15 superseded by the 80% MBD agreed to in the PSA.

16

17 Under the PSA, the Company will calculate all three demand charges using the
18 greater of:

- 19 • 80% of the contract capacity applicable for the billing period; or
- 20 • The customer's actual billing demand if greater than 80% of the contract
21 capacity applicable for the billing period.

³ The D11 ratchet mechanism is defined as "[t]he monthly on-peak billing demand will not be less than 65% of the highest monthly on-peak metered billing demand during the billing months of June, July, August, September, and October of the preceding eleven billing months, nor less than 50 kilowatts."

Line
No.

1 Based on the D11 rates approved in Case No. U-21860, the Customer's MMC will
2 be \$13.8 million per month, or \$165.1 million per year⁴.

3

4 **Q29. Is the MMC impacted if the Customer's load does not fully materialize?**

5 A29. No. Even if the customer's actual usage never reaches the contract capacity (i.e.,
6 1,000 MW) agreed to in the PSA, the MMC will be calculated based on that contract
7 capacity. While the timing of the Customer's load ramp can be temporarily delayed,
8 the Customer cannot reduce their contract capacity during the term of the PSA once
9 the load ramp is reached.

10

11 **Q30. Does the MBD provide adequate protection for the Company's other
12 customers?**

13 A30. Yes. The MBD term ensures that the Company will collect from the Customer a
14 minimum amount of revenue regardless of the Customer's actual demand. Through
15 the PSA the Company is committing to make available the max load to the
16 Customer for the life of the contract. The MBD likewise commits the Customer to
17 pay for that capacity through D11 demand charges. As described above, the MBD
18 provision in the PSA is higher than the standard term included in the Company's
19 D11 rate.

20

21 **Primary Supply Agreement – Customer load ramp flexibility**

22 **Q31. Can the Customer adjust the timing of when their load will materialize or
23 when they must achieve max load?**

⁴ See WP NTF-1 for calculation

Line
No.

1 A31. Yes. The Customer can temporarily delay their load ramp or any increase in the
2 scheduled ramp by up to [REDACTED] in the aggregate. The Customer cannot modify
3 the contract capacity that the Company has committed to serve. In practice, this
4 means that the Load Ramp Completion Date could occur as late as [REDACTED] if the
5 Customer elects to delay by the maximum [REDACTED] allowed in the PSA.

6

7 Figure 1 demonstrates the Customer's slowest and fastest ramps allowable under
8 the PSA.

9

10

11

12 **Primary Supply Agreement – Contract Capacity Reductions**

13 **Q32. Can the Customer's contract capacity be reduced during the term of the PSA?**

14 A32. Yes. In summary, the PSA addresses a situation where the Company cannot meet
15 the Customer's load ramp or max load due to any of the following conditions:

16

- The CCAA or Rider 12 DR Agreement is terminated;

Line
No.

- 1 • The Company is unable to achieve or maintain the Customer's load ramp
- 2 or max load due to reasons not attributable to the Company;
- 3 • The Company is unable to achieve or maintain the Customer's load ramp
- 4 or max load due to the Customer's underperformance or nonperformance
- 5 under any agreement with the Company; and/or
- 6 • The Company determines that the energy storage portfolio being deployed
- 7 under the CCAA is not feasible.

8

9 If any of the above conditions are true, the Company and the Customer will meet
10 to negotiate a solution that could include, for example, an adjustment to the
11 resources being deployed under the CCAA, an adjustment to the Customer's load
12 ramp or max load, and/or a pass-through mechanism whereby the cost of
13 incremental MISO market purchases needed to meet the Customer's load ramp or
14 max load are passed directly to the Customer.

15

16 If the Company and the Customer cannot agree on a solution, the Company can
17 unilaterally propose an adjustment to the Customer's load ramp or max load. The
18 Customer can accept the proposed adjustment or terminate the agreement and pay
19 all applicable termination payments.

20

21 **Q33. Does the ability of the Company to reduce the Customer's load ramp or max**
22 **load adequately protect the Company's other customers?**

23 A33. Yes. The ability of the Company to reduce the Customer's contract capacity under
24 certain conditions provides protection for the Company's generation and
25 distribution systems and for the reliability of its other customers. This mitigates any

Line
No.

1 risk that the Company's other customers would be impacted if the Company does
2 not have sufficient resources to serve the Customer's load.

3

4 **Primary Supply Agreement – Termination Payment**

5 **Q34. Can you explain the termination payment under the PSA?**

6 A34. Yes. The termination payment was designed such that the Company will recover at
7 least 15 years of Minimum Monthly Charges once the Customer achieves their max
8 load. If the PSA is terminated before the fifteenth anniversary of the Load Ramp
9 Completion Date, the Customer will be subject to a termination payment based on
10 the MMC multiplied by the greater of 1) the number of months from the early
11 termination date to the fifteenth anniversary of the Load Ramp Completion Date,
12 or 2) 24 months. If the PSA is terminated after the fifteenth anniversary of the Load
13 Ramp Completion Date, the customer is subject to a termination payment equal to
14 24 months of Minimum Monthly Charges.

15

16 Under this mechanism and based on the D11 rate approved in Case No. U-21860,
17 the termination payment at the Load Ramp Completion Date is \$2.48 billion⁵.

18

19 The Company notes that this termination payment is only associated with the PSA.
20 The CCAA has separate, incremental termination payment that I discuss later in my
21 testimony.

22

23 **Q35. Does the termination payment benefit the Company's other customers?**

⁵ See WP NTF-2 for calculation of the termination payment.

Line
No.

1 A35. Yes. The termination payment represents a long-term commitment by the Customer
2 of at least 15 years to contribute to the Company's overall system costs, thereby
3 reducing the cost responsibility of the Company's other customers.
4

5 **Primary Supply Agreement – Energy Waste Reduction**

6 **Q36. What commitment is the Customer making in the PSA to support the State of**
7 **Michigan's EWR objectives?**

8 A36. In the PSA, the Customer is committing to participate and comply with the self-
9 directed EWR plan requirements as set forth in MCL 460.1093. In accordance with
10 the Commission Order in Case No. U-21627, the Customer's expected annual peak
11 load will qualify them to self-direct an EWR plan. The savings identified in the
12 Customer's self-directed EWR plan will be counted toward the Company's
13 statutory goals and thus support the State of Michigan's EWR objectives
14

15 **Primary Supply Agreement – Affordability Backstop**

16 **Q37. Does the PSA ensure that the rates paid by the Company's other customers**
17 **will not be negatively impacted by the contracts?**

18 A37. Yes. The PSA ensures that the aggregate benefits, including revenues received from
19 the Customer and avoided costs realized through the Contracts, outweigh the costs
20 of serving the Customer's load.
21

22 Specifically, the PSA (Exhibit A-16) states:
23

24 "The Parties acknowledge that a goal of this Agreement and the Related
25 Agreements is to protect other customers, other customer classes and Company

Line
No.

1 from funding the costs to serve Customer. The Parties also acknowledge that
2 the combined revenues received by the Company under this Agreement and the
3 applicable Related Agreements along with any avoided costs attributable to
4 Google should be considered in regulatory proceedings applicable to
5 Company's cost to serve Customer, and the Parties shall act in good faith to
6 ensure such combined revenues and avoided costs are presented in such
7 proceedings to the extent applicable. If, at any time during the Term, the
8 Commission (a) issues a ruling or order determining that the costs to serve
9 Customer exceed the combined revenues paid or payable to the Company under
10 this Agreement and the applicable Related Agreements, or (b) disallows
11 Company's recovery of costs to the extent attributable to serving Customer,
12 then, in either case, Customer agrees to comply with any such ruling or order
13 to ensure that Customer pays all costs associated with its service from
14 Company, and, as applicable, Customer shall reimburse Company for any
15 unrecovered costs, plus interest accrued on such amount at the Interest Rate
16 within ninety (90) days of any such order; provided, however, that
17 notwithstanding the foregoing, Customer shall not be required to reimburse
18 Company for unrecovered costs incurred due to the gross negligence or willful
19 misconduct of Company." (Section 5.1.3)

20

21 In summary, the Customer agrees to comply with any Commission order ensuring
22 that they are fully covering their costs. In addition, the Customer agrees to
23 reimburse the Company for any unrecovered costs caused by a Commission
24 disallowance attributable to the Customer's load.

Line
No.

1 **Q38. Why has the Company agreed to “act in good faith to ensure such combined**
2 **revenues and avoided costs are presented in such proceedings to the extent**
3 **applicable”?**

4 A38. The Company believes it is critically important that the Commission take an
5 aggregate view of the benefits and costs of serving the Customer’s load over the
6 life of the contract. The individual aspects of the agreements will be addressed in
7 different regulatory proceedings. For example, the benefit to base rates of serving
8 the Customer’s load will be addressed in rate cases, while the costs of incremental
9 transmission investments will be addressed in PSCR plan and reconciliation cases.
10 Long term generation needs will be addressed through IRP cases, while approval
11 of renewable generation plans will be requested through REP cases.

12

13 Taking a narrow view of benefits and costs, for example by only considering the
14 costs and benefits of the specific items being directly addressed in each case, may
15 result in decisions that are not well-aligned with the broader provision of service to
16 large-load customers such as the Customer.

17

18 As such, the Company agreed to present an aggregate view of serving the Customer
19 as applicable in future regulatory proceedings.

20

21 **Primary Supply Agreement – Credit and Collateral Requirements**

22 **Q39. Does the PSA include credit and collateral requirements?**

23 A39. Yes. The PSA includes credit and collateral requirements through a Parent
24 Guaranty (“PG”) and as necessary based on the parent’s credit rating, a letter of

Line
No.

1 credit designed to protect the Company and its customers in the event of Customer
2 default.

3

4

5

6

7

8

9

10

11

12

13

14

15

16

17

18

19

20

21

22

23

24

25

- The Commission’s November 6, 2025, Order in Case No. U-21859 in which it approved amendments to Consumers Energy’s General Primary Demand Rate (“Rate GPD”) applicable to large load customers. In that order, the Commission established a minimum termination payment starting at 15-

Line
No.

1 years MMC (equal to the minimum length of a contract) backed by a 50%
2 LoC or cash. This effectively establishes a minimum collateral requirement
3 of 7.5-years of MMC, [REDACTED]

4
5 Notably, the Commission also stated that it “remains open to considering
6 the use of parent guarantees—either on their own or in concert with other
7 collateral—on a case-by-case basis” (page 112). [REDACTED]

8 [REDACTED]
9 [REDACTED]

10

11 **Clean Capacity Accelerator Agreement (CCAA) - Overview**

12 **Q41. Can you provide an overview of the CCAA between the Company and the**
13 **Customer?**

14 A41. Yes. The CCAA, Exhibit A-18, governs the obligations of the Company and the
15 Customer related to the deployment and cost recovery of up to 480 MW of energy
16 storage projects and up to 1,600 MW of renewable energy projects. The Customer
17 will pay the full cost (i.e., revenue requirement) of the projects over each project’s
18 depreciable life.

19

20 In addition, the CCAA commits the Customer to transfer 300 MW of ZRCs to the
21 Company which the Company can then utilize to meet its capacity needs. The ZRCs
22 will be provided by the Customer from June 1, 2028 to May 31, 2033.

Line
No.

1 The Customer will receive capacity and/or renewable generation credits for the
2 energy storage projects, renewable energy projects, and ZRCs that are paid for or
3 provided by the Customer under the CCAA.

4

5 **Q42. What are the key terms of the CCAA between the Company and the**
6 **Customer?**

7 A42. The key terms of the CCAA are the following:

- 8 • Contract duration
- 9 • Energy storage portfolio
- 10 • Renewable energy portfolio
- 11 • Project pricing
- 12 • ZRC transfer
- 13 • Capacity credits
- 14 • Renewable generation credits
- 15 • Termination and termination payment
- 16 • Credit and collateral requirements

17

18 **Clean Capacity Accelerator Agreement – Contract Duration**

19 **Q43. What is the contract duration of the CCAA?**

20 A43. The CCAA contract duration is set such that the CCAA ends at the same time as
21 the initial term of the PSA. Like the PSA, the CCAA ends 20 years after the
22 Customer first receives electric service at the data center facility.

23

24 **Q44. Does the CCAA contract length offer adequate protection against stranded**
25 **asset risk to the Company's other customers?**

Line
No.

1 A44. Yes. As I describe later in my testimony, the full cost of projects deployed under
2 the CCAA will be recovered during the CCAA contract term. The CCAA is
3 designed such that any risk of stranded asset risk associated with CCAA projects is
4 mitigated.

5

6 **Clean Capacity Accelerator Agreement – Energy Storage Portfolio**

7 **Q45. What obligations does the Company have related to the deployment of energy**
8 **storage projects under the CCAA?**

9 A45. Under the CCAA, the Company can deploy a portfolio of energy storage projects
10 of up to 480 MW through a combination of self-build projects, Build Transfer
11 Agreements (“BTAs”), and third-party Tolling Agreements (“TAs”).

12

13 Included within the 480 MW of energy storage is up to 425 MW of 4-hour lithium-
14 ion energy storage, and up to 55 MW of long duration storage (i.e., at least 8-hour
15 duration). The long duration storage can be lithium-ion or a different technology.

16

17 **Q46. How will energy storage projects be selected for development under the**
18 **CCAA?**

19 A46. The Company intends to issue an Energy Storage Request for Proposal (“RFP”) to
20 identify energy storage projects to be deployed under the CCAA. The RFP will be
21 conducted under a competitive procurement process that follows the MPSC’s
22 Competitive Procurement Guidelines for Rate-Regulated Electric Utilities and the
23 terms of the Company’s 2022 Integrated Resource Plan (“IRP”) Settlement
24 Agreement dated July 26, 2023 (“IRP Settlement Agreement”) in Case No. U-
25 21193.

Line
No.

1 **Q47. Will the energy storage projects deployed under the CCAA be Company**
2 **owned, third party owned, or a combination of both?**

3 A47. The energy storage projects deployed under the CCAA will be a combination of
4 Company owned and third party owned. The IRP Settlement Agreement stipulated
5 that additional energy storage projects should be allocated consistent with the
6 allocation for the PCA build between Company owned and third party owned
7 projects⁶. The Company intends to select projects that are consistent with this
8 ownership split identified in the IRP Settlement Agreement.

9

10 **Q48. Will the Company submit energy storage projects deployed under the CCAA**
11 **to the Commission for review and approval?**

12 A48. Yes. The Company will submit each project to the Commission for review and
13 approval prior to construction.

14

15 **Clean Capacity Accelerator Agreement – Renewable Energy Portfolio**

16 **Q49. What obligations does the Company have related to the deployment of**
17 **renewable energy projects under the CCAA?**

18 A49. Under the CCAA, the Company can deploy a portfolio of renewable energy projects
19 up to 1,600 MW.

20

21 **Q50. How will the deployment of renewable energy under the CCAA be treated with**
22 **respect to the Company’s Renewable Portfolio Standard (“RPS”) obligations?**

23 A50. As Witness Bilyeu describes in his testimony, the CCAA terms governing the
24 deployment of renewable energy comply with the Section 61 Settlement Agreement

⁶ Section 13 of IRP Settlement (<https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000008puPjAAI>)

Line
No.

1 discussed in his testimony. Therefore, the renewable energy resources included in
2 the CCAA are considered part of a customer-requested VGP special contract and
3 treated as such for RPS purposes.

4

5 **Q51. How will renewable energy projects be selected for development under the**
6 **CCAA?**

7 A51. Renewable energy projects will be selected consistent with the Section 61
8 Settlement Agreement, with the details of the competitive process being agreed
9 upon with the Customer. See Witness Bilyeu's testimony for additional details.

10

11 **Q52. Will the Company submit renewable energy projects deployed under the**
12 **CCAA to the Commission for review and approval?**

13 A52. Yes. As described by Witness Bilyeu, the Company will submit each project to the
14 Commission for review and approval prior to construction.

15

16 **Clean Capacity Accelerator Agreement – Project Pricing**

17 **Q53. What is the Customer pricing structure for energy storage and renewable**
18 **energy projects deployed under the CCAA?**

19 A53. For both energy storage and renewable energy projects, the Customer will pay the
20 full cost of each project during its respective depreciable life⁷. For each Company
21 owned project in the portfolio, the Company will calculate an annual revenue
22 requirement for the depreciable life of the project in the same manner that a revenue
23 requirement is calculated in a general rate case for energy storage projects or a

⁷ Currently approved depreciable life is 15-years for energy storage, 23-years for solar energy assets, and 27-years for wind energy assets

Line
No.

1 Renewable Energy Plan (“REP”) for renewable energy projects. The revenue
2 requirement will include, for example:

- 3 • Allowance for Funds Used During Construction (“AFUDC”) accumulated
4 during the construction of the project
- 5 • Depreciation
- 6 • The Company’s prevailing authorized rate of return
- 7 • Amortization of Investment Tax Credits (“ITC”) generated by the
8 construction of the site
- 9 • O&M
- 10 • Property Tax
- 11 • Insurance

12

13 For third party TAs or Power Purchase Agreements (“PPA”), the revenue
14 requirement will be equal to the annual cost of the TA or PPA plus any authorized
15 financial incentive under MCL 460.1028.

16

17 For billing purposes, the annual project revenue requirement of each project will be
18 evenly divided into the number of billing periods applicable to that year to
19 determine the billing period project charge⁸. The summation of individual project
20 billing period charges will be invoiced to the customer.

21

22 **Q54. When will the revenue requirement be determined for an individual energy**
23 **storage or renewable energy project for the purposes of billing the Customer?**

⁸ In general, the applicable billing periods during a year will be 12, although could vary in the first and final calendar years of the depreciable life since project CODs could happen mid-year.

Line
No.

1 A54. For the purposes of billing the Customer, the revenue requirement for Company
2 owned projects will first be calculated around the time the project achieves its
3 Commercial Operation Date (“COD”). At that time the Company will provide the
4 Customer with a projection of the annual revenue requirement for the project for
5 each year of the project’s depreciable life. This projection will be based on actual
6 construction costs and a forecast of ongoing lifetime costs.

7

8 For third party TAs or PPAs, the cost will first be calculated when the Company
9 enters into the TA or PPA.

10

11 **Q55. Is the Customer still responsible for the costs of a project if its depreciable life**
12 **extends beyond the term of the CCAA?**

13 A55. Yes. Given that the current depreciable life of solar and wind assets is 23 and 27-
14 years respectively it is expected that a portion of each renewable energy project’s
15 depreciable life will extend beyond the term of the CCAA. In addition, it is possible
16 that a portion of an energy storage project’s depreciable life could extend beyond
17 the term of the CCAA depending on its COD. To ensure that the Customer fully
18 pays for each project over its depreciable life, the CCAA allows the Company to
19 accelerate recovery of a project’s costs.

20

21 More specifically, the Company will calculate the costs (i.e., revenue requirement)
22 during each project’s depreciable life that will be incurred beyond the term of the
23 CCAA. These costs will be collected from the Customer during the term of the
24 CCAA by evenly dividing these costs by the number of billing periods that will
25 occur during the term of the CCAA for such a project. The result will be added to

Line
No.

1 the Customer's invoice for each billing period of the CCAA applicable to the
2 project. In this way, the Customer will fully pay for each project even if the
3 project's depreciable life extends beyond the term of the CCAA.

4

5 In practice, this means that the Customer will be paying more than the revenue
6 requirement for a project during the term of the CCAA. The Company is proposing
7 to record this excess recovery (i.e., customer charge less revenue requirement of
8 the project) as a Regulatory Liability. This liability will grow throughout the term
9 of the CCAA and can then be used beyond the term of the CCAA to offset the
10 remaining costs (i.e., revenue requirement) of the projects. This approach ensures
11 that the Company's other customers will not be responsible for the costs of the
12 renewable projects during their depreciable lives.

13

14 **Q56. Is the revenue requirement for an energy storage or renewable energy project**
15 **fixed once it is initially calculated?**

16 A56. No. After each calendar year, the Company will perform a cost reconciliation for
17 each project deployed under the CCAA. That reconciliation will compare the
18 amount charged to the Customer during the previous calendar year for a given
19 project to the actual costs of that project. Any over recovery or under recovery will
20 be incorporated into the subsequent year's Customer charges.

21

22 Under this approach, the Customer pays the actual costs of each project deployed
23 under the CCAA.

Line
No.

1 **Q57. Will the Commission and other stakeholders have an opportunity to review**
2 **the reconciliation?**

3 A57. The reconciliation process is between the Customer and the Company. However,
4 the costs of energy storage projects and the associated Customer charges will be
5 provided in the Company's future general rate cases. The costs of renewable energy
6 projects and the associated Customer charges will be provided in the Company's
7 future annual REP reconciliation cases. At those times, the Commission and other
8 stakeholders will have the opportunity to review the costs and Customer revenues
9 associated with the energy storage and renewable energy projects deployed under
10 the CCAA.

11

12 **Q58. Does the CCAA pricing and annual reconciliation provide adequate protection**
13 **for the Company's other customers?**

14 A58. Yes. The CCAA pricing and associated reconciliation processes ensure that the
15 Customer fully pays for the actual costs of the energy storage and renewable energy
16 projects. In this way, the CCAA prevents cross-subsidization of the projects and
17 mitigates the risk of stranded assets.

18

19 **Clean Capacity Accelerator Agreement – ZRC transfer**

20 **Q59. What are the key terms governing the transfer of ZRCs from the Customer to**
21 **the Company?**

22 A59. Under the CCAA, the Customer commits to transfer 300 MW of ZRCs to the
23 Company which the Company can then utilize to meet its capacity needs. The ZRCs
24 will be provided by the Customer for each MISO season from June 1, 2028 to May
25 31, 2033.

Line
No.

1 In addition, the Customer has agreed to pay the Company an amount based on the
2 Financial Compensation Mechanism (“FCM”) that the Company is authorized to
3 receive for PPAs it enters into associated with clean energy projects. More
4 specifically, the Customer will pay the Company an amount equal to the ZRCs
5 transferred to the Company multiplied by MISO Cost of New Entry (“CONE”)
6 multiplied by the Company’s pre-tax weighted average cost of permanent capital
7 (“financial adder”). The Company is proposing that it be allowed to record this
8 amount as non-refundable income, like it does with the FCM.

9

10 **Clean Capacity Accelerator Agreement – Capacity Credits**

11 **Q60. What types of CCAA resources will receive capacity credits?**

12 A60. All resources addressed under the CCAA (i.e., energy storage projects, renewable
13 energy projects, and ZRCs transferred from the Customer) will receive capacity
14 credits. In the CCAA, capacity credits associated with energy storage projects and
15 ZRCs transferred from the Customer are referred to as “Clean Capacity Credits”
16 while capacity credits associated with renewable energy projects are referred to as
17 “Renewable Capacity Credits.”

18

19 **Q61. How are capacity credits calculated?**

20 A61. The Customer will receive capacity credits that vary based on the accredited
21 capacity of the resource (i.e., energy storage projects, renewable energy projects,
22 and ZRCs). As this is a capacity-based credit, the amount of the credit will be based
23 on the capacity portion of the D11 rate.

Line
No.

1 Capacity credits will be calculated separately for each CCAA resource and
2 separately for each billing period during the term of the CCAA. For a given billing
3 period and a given resource, the capacity credit is determined using the following
4 equation:

5

$$\text{Capacity Credit} = \text{Accredited Capacity} \times \left(\frac{\text{Adjusted Capacity}}{\text{Credit Rate}} \times \left(\frac{\text{Peak Demand}}{\text{Contract Capacity}} \right) + \frac{\text{MISO Net}}{\text{CONE}} \times \left(1 - \frac{\text{Peak Demand}}{\text{Contract Capacity}} \right) \right)$$

6

7

where:

8

- “Accredited Capacity” means:

9

- For an energy storage project, the number of ZRCs assigned to that project in the MISO Planning Resource Auction (“PRA”) for Zone 7

10

11

12

- For a renewable energy project or ZRCs transferred from the Customer, the number of ZRCs assigned to that project in the MISO PRA for the applicable zone

13

14

15

- “Adjusted Capacity Credit Rate” is determined using the following equation:

16

17

$$\frac{\text{Adjusted Capacity}}{\text{Credit Rate}} = \left(\frac{\text{D11 Capacity Rate}}{1 + \text{PRM}} \right)$$

18

where:

19

- “D11 Capacity Rate” is defined by the Capacity Demand Charge contained within the D11 rate applicable for the billing period

20

21

- “PRM” is the Planning Reserve Margin that the Company is subject to for the given billing period

22

Line
No.

- 1 • “Peak Demand” is the Customer’s measured on-peak demand during the
- 2 given billing period
- 3 • “Contract Capacity” is the contract capacity applicable during the given
- 4 billing period (i.e., 1,000 MW once the Load Ramp Completion Date is
- 5 achieved)
- 6 • “MISO Net CONE” is the value established by MISO for the given billing
- 7 period and applicable zone

8

9 Once the capacity credit has been calculated for a given project and a given billing
10 period, the Company will compare that amount to the MISO capacity market
11 revenues generated by that project during the billing period. The Company will then
12 provide to the Customer as a capacity credit for each project the lower of 1) the
13 calculated capacity credit, or 2) the capacity market revenues.

14

15 **Q62. How will the Company determine the amount of capacity market revenues**
16 **generated by each CCAA project or ZRC during a billing period?**

17 A62. The Company will utilize the MISO settlements process to determine the amount
18 of capacity market revenues generated by each project or ZRC during a billing
19 period. The MISO settlements process allows for market revenues and charges to
20 be identified by their source. As such, the Company will be able to determine the
21 specific market revenues and charges that were generated by each project or ZRC.

22

23 **Q63. What happens if the capacity market revenues generated by a project exceed**
24 **the calculated capacity credit for that project during a billing period?**

Line
No.

1 A63. As described above, if capacity market revenues generated by a project for a billing
2 period exceed the calculated capacity credit for that project, the Company will
3 provide to the Customer the calculated capacity credit. The difference (i.e., capacity
4 market revenues less calculated capacity credit) is a benefit to the Company's other
5 customers that will be realized through the PSCR mechanism.

6

7 **Q64. What happens if the calculated capacity credit for a project exceeds the**
8 **capacity market revenues generated by that project during a billing period?**

9 A64. As described above, if capacity market revenues generated by a project for a billing
10 period are less than the calculated capacity credit for that project, the Company will
11 provide to the Customer the capacity market revenues. In this way, the Company's
12 other customers are protected because the credits being provided to the Customer
13 for a billing period will never be more than the capacity market revenues generated
14 by that project.

15

16 **Q65. Who will manage the operations of the projects deployed under the CCAA and**
17 **their participation in the MISO capacity market?**

18 A65. The Company will operate and manage the CCAA projects and transferred ZRCs,
19 including their participation in the MISO wholesale markets as the MISO Market
20 Participant. The projects deployed under the CCAA will be operated in a manner
21 similar to other Company resources.

22

23 **Q66. How will the capacity credits be provided to the Customer?**

24 A66. The capacity credits will be provided to the Customer through their monthly
25 invoice.

Line
No.

1 **Q67. Will the Company recover from the Customer the incremental costs of**
2 **Company activities associated with being the MISO Market Participant for**
3 **the CCAA resources in the wholesale capacity market?**

4 A67. Yes. The Company will recover its incremental costs related to the management of
5 the CCAA projects and ZRCs in the MISO wholesale capacity markets through an
6 administrative fee applied to the Customer's monthly invoice. This fee is consistent
7 with resource specific special contracts, including other VGP special contracts, that
8 have been approved for other customers.

9

10 **Clean Capacity Accelerator Agreement – Renewable Generation Credits**

11 **Q68. What type of CCAA projects will receive Renewable Generation Credits?**

12 A68. Only renewable energy projects deployed under the CCAA will receive Renewable
13 Generation Credits.

14

15 **Q69. How are the Renewable Generation Credits calculated?**

16 A69. The Customer will receive Renewable Generation Credits based on the generation
17 of the renewable energy projects that have been deployed under CCAA. As this is
18 an energy-based credit, the amount of the credit will be based on the energy portion
19 of the D11 rate.

20

21 Renewable Generation Credits will be calculated separately for each renewable
22 energy project and separately for each billing period during the term of the CCAA.
23 For a given billing period and a given renewable energy project, the Renewable
24 Generation Credit is determined using the following equation:

Line
No.

1

Renewable Generation Credit =

$$\text{Project Generation} \times \left(\frac{(\text{D11 On-Peak Rate} \times \text{On-Peak Hours}) + (\text{D11 Off-Peak Rate} \times \text{Off-Peak Hours})}{\text{Total Hours}} \right)$$

2

3

Where:

4

- “Project Generation” is the actual generation of the renewable energy project during the billing period

5

6

- “D11 On-Peak Rate” and “D11 Off-Peak Rate” are defined by the Non-Capacity Energy Charge portion of the D11 rate applicable to the billing period

7

8

9

- “On-Peak Hours” is the number of on-peak hours during the billing period as defined by the D11 rate

10

11

- “Off-Peak Hours” is the number of off-peak hours during the billing period as defined by the D11 rate

12

13

- “Total Hours” is the total hours during the billing period

14

15

Once the Renewable Generation Credit has been calculated for a given project and a given billing period, the Company will compare that amount to the revenues generated by that project during the billing period in the MISO energy and operating reserve markets. Similar to the capacity credit, the Company will then provide to the Customer as a Renewable Generation Credit for each project the lower of 1) the calculated Renewable Generation Credit, or 2) the energy market revenues.

16

17

18

19

20

21

Line
No.

1 **Q70. How will the Company determine the amount of energy market revenue**
2 **generated by each renewable energy project during a billing period?**

3 A70. The Company will utilize the MISO settlements process to determine the amount
4 of energy market revenues generated by each renewable energy project during a
5 billing period. The MISO settlements process allows for market revenues and
6 charges to be identified by their source. As such, the Company will be able to
7 determine the specific energy market revenues that were generated by each
8 renewable energy project.

9
10 **Q71. What happens if the energy market revenues generated by a project exceed**
11 **the calculated Renewable Generation Credit for that project during a billing**
12 **period?**

13 A71. As described above, if energy market revenues generated by a project for a billing
14 period exceed the calculated Renewable Generation Credit for that project, the
15 Company will provide to the Customer the calculated Renewable Generation
16 Credit. The difference (i.e., energy market revenues less calculated Renewable
17 Generation Credit) is a benefit to the Company's other customers that will be
18 realized through the PSCR mechanism.

19
20 **Q72. What happens if the calculated Renewable Generation Credit for a project**
21 **exceeds the renewable generation market revenues generated by that project**
22 **during a billing period?**

23 A72. As described above, if energy market revenues generated by a project for a billing
24 period are less than the calculated Renewable Generation Credit for that project,
25 the Company will provide to the Customer the energy market revenues. In this way,

Line
No.

1 the Company's other customers are protected because the credits being provided to
2 the Customer for a billing period can never be more than the energy market
3 revenues generated by that project.

4

5 **Q73. Who will manage the operations of the renewable energy projects deployed**
6 **under the CCAA and their participation in the MISO energy market?**

7 A73. The Company will operate and manage renewable energy projects deployed under
8 the CCAA, including managing their participation in the MISO wholesale markets
9 as the MISO Market Participant. The projects deployed under the CCAA will be
10 operated in a manner similar to other Company resources.

11

12 **Q74. How will the Renewable Generation Credits be provided to the Customer?**

13 A74. The Renewable Generation Credits will be provided to the Customer through their
14 monthly invoice.

15

16 **Q75. Will the Company recover from the Customer the incremental costs of**
17 **Company activities associated with being the MISO Market Participant for**
18 **the renewable energy projects in the wholesale energy markets?**

19 A75. Yes. The Company will recover its incremental costs related to the management of
20 the renewable energy projects in the MISO wholesale energy markets through an
21 administrative fee applied to the Customer's monthly invoice. This fee is consistent
22 with resource specific special contracts, including other VGP special contracts, that
23 have been approved for other customers.

Line
No.

1 **Clean Capacity Accelerator Agreement – Termination and Termination Payment**

2 **Q76. Can the Customer voluntarily terminate the CCAA?**

3 A76. No. The Customer cannot voluntarily terminate the CCAA. If the CCAA is
4 terminated through a customer default, the Customer is obligated to pay the
5 Company a termination payment.

6
7 **Q77. How is the termination payment calculated?**

8 A77. The termination payment is set equal to the unrecovered portion of each project's
9 costs (i.e., revenue requirement) over its respective depreciable life. In other words,
10 the termination equals the remaining amount that the Company would have
11 collected had the agreement not been terminated.

12
13 **Q78. How does the termination payment protect the Company's other customers?**

14 A78. The termination payment is designed to collect whatever amounts would have
15 otherwise been collected had the CCAA not been terminated. As such, the costs of
16 all CCAA projects would be fully recovered from the Customer, mitigating the risk
17 of stranded assets for these projects.

18
19 **Clean Capacity Accelerator Agreement – Credit and Collateral Requirements**

20 **Q79. Does the CCAA include credit and collateral requirements?**

21 A79. Yes. The CCAA includes credit and collateral requirements through a parent
22 guaranty and, if necessary based on the parent's credit rating, a letter of credit
23 designed to protect the Company and its customers in the event of Customer
24 default.

Line
No.

1 [REDACTED]
2 [REDACTED]
3 [REDACTED]
4 [REDACTED]
5 [REDACTED]
6 [REDACTED]
7 [REDACTED]

8

9 **Regulatory Treatment**

10 **Q80. Would Commission approval of the Contracts increase the Company's cost of**
11 **service or customer rates?**

12 A80. No. Commission approval of the proposed Contracts does not increase the
13 Company's cost of service or customer rates. Instead, the proposed Contracts
14 govern how the Customer's future load will be served and how a portfolio of
15 projects will be deployed under the CCAA. Moreover, as discussed by Witness
16 Willis, the aggregate benefits of the Contracts, including both revenues received
17 from the Customer and avoided costs realized through the Contracts, will more than
18 offset any potential future cost of service increases and result in a customer benefit
19 of \$1.7 billion over the life of the contract. Importantly, the PSA establishes that if
20 in the future the aggregate benefits do not outweigh the costs, the Customer will
21 pay the difference.

22

23 **Q81. Will the Contracts be reflected in future regulatory filings?**

24 A81. Yes. If approved, the Contracts would be reflected in future general rate cases,
25 PSCR (plan and reconciliation) cases, and REP (plan and reconciliation) cases.

Line
No.

1 **Q82. How will the PSA and CCAA be incorporated into future rate cases?**

2 A82. The Contracts will be incorporated into future general rate cases in several ways,
3 including:

4 • The Customer's expected load will be incorporated into the Company's load
5 forecast that is used, for example, to determine present revenues, determine
6 cost allocations, and calculate rates;

7 • The Company owned energy storage projects deployed under the CCAA
8 will be proposed to be added to the Company's rate base as those projects
9 will be owned by the Company; and

10 • The amounts collected from the Customer through the CCAA for energy
11 storage projects will be incorporated to offset the additional rate base costs
12 from those energy storage projects.

13

14 The energy storage portfolio project costs that are added to the Company's rate base
15 will be fully offset by the amounts collected from the Customer through the CCAA.

16

17 **Q83. How will the PSA and CCAA be incorporated into future PSCR plans and
18 reconciliation cases?**

19 A83. As described above, the portfolio of energy storage projects, renewable energy
20 projects, and ZRCs deployed by the Company under the CCAA will be managed
21 by the Company as the MISO Market Participant. As such, these projects and ZRCs
22 will generate MISO revenues that would be reflected in future PSCR plan and
23 reconciliation filings.

Line
No.

1 Capacity credits and Renewable Generation Credits paid to the Customer will also
2 be reflected in PSCR cases. This credit is similar to how VGP credits are reflected
3 in PSCR cases for the Company's MIGreenPower and VGP Special Contracts.

4

5 **Q84. How will the PSA and CCAA be incorporated into future REP plans and**
6 **reconciliation cases?**

7 A84. In accordance with the order in Case No. U-21990, the Company will file its next
8 Amended REP alongside its IRP later this year. As part of the IRP process, the
9 Company will assess potential incremental additions to its renewable portfolio and
10 develop an optimized strategy to support RPS compliance. As described by Witness
11 Bilyeu, the 2026 IRP will detail DTE Electric's approach to maintaining RPS
12 compliance. The 2026 Amended REP will further define these plans, detailing DTE
13 Electric's renewable energy credit acquisition strategy and further ensuring
14 compliance with RPS targets.

15

16 **Summary of Requested Commission Action**

17 **Q85. Can you summarize the Commission action that the Company is seeking**
18 **through the instant case?**

19 A85. Yes. The Company is seeking the Commission's approval of the following:

- 20
- 21 • PSA
 - 22 • CCAA
 - 23 • Ability of the Company to record Regulatory Liabilities during the term of
24 the CCAA related to the accelerated recovery (i.e., customer collections
above revenue requirement) of energy storage and renewable energy

Line
No.

1 projects deployed under the CCAA; the Regulatory Liability would be
2 recorded to Account 254

3 • Ability to record the financial adder related to the transferred ZRCs
4 addressed in the CCAA as non-refundable income

5

6 **Q86. Does this complete your direct testimony?**

7 A86. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

EXHIBITS
OF
NEAL T. FOLEY

AMENDED AND RESTATED SCHEDULE DESIGNATION D11 PRIMARY SUPPLY AGREEMENT

This Amended and Restated Schedule Designation D11 Primary Supply Agreement (this “**Agreement**”) is entered into on this 12th day of March, 2026 (“**Contract Date**”), by and between:

- (1) **DTE Electric Company**, a corporation organized under the Laws of the State of Michigan with an address of One Energy Plaza, Detroit, Michigan 48226 (“**Company**”); and
- (2) **Google LLC**, a Delaware limited liability company with an address of [REDACTED] (“**Customer**”).

Company and Customer are referred to herein collectively as the “**Parties**” and each individually as a “**Party**”. Capitalized terms shall have the meaning set forth in Exhibit A.

RECITALS

WHEREAS:

- (A) Company and Customer entered into that certain Primary Supply Agreement, dated as of December 17, 2025 (the “**Original PSA**”) pursuant to which Company, a regulated electric utility that provides retail electric service within the State of Michigan, and Customer agreed that: (a) Company shall, through itself or one or more Affiliates, design, engineer, procure, construct, upgrade, extend, commission, operate and maintain certain generation and distribution electric facilities (the “**Electric Facilities**”) necessary to provide electric capacity and energy for the Facility (the “**Electric Service**”) at the Data Center Location, (b) Customer and Company will enter into the Line Extension Agreement, pursuant to which Company will construct certain distribution system upgrades, and Customer will construct, operate and maintain a substation, each as necessary to provide service to the Facility; (c) to facilitate Company’s development, procurement and utilization of one or more new generation projects, storage projects, renewable projects, and/or capacity resources to serve the electric capacity and energy needs of the Facility, Customer and Company will enter into the Clean Capacity Accelerator Agreement, (d) Customer will receive and take Electric Service from Company in a monthly maximum electrical demand in accordance with the commitments set forth in Exhibit B-1 thereto (the “**Customer Committed Capacity Ramp**”) to serve the Facility at the Data Center Location, and (e) Company will (i) provide such Electric Service to the Data Center Location in accordance with the terms of this Agreement and Company’s Rate Book, (ii) develop, procure and/or otherwise utilize resources on behalf of Customer in accordance with the Clean Capacity Accelerator Agreement, and (iii) construct and operate the applicable distribution system upgrades on behalf of Customer in accordance with the Line Extension Agreement;
- (B) The Parties wish to amend and restate the Original PSA in its entirety in accordance with the terms and conditions set forth herein; and
- (C) To the extent Company agrees to terms for the provision of Electric Service that differ from Company’s Rate Book, this Agreement must be approved by the Michigan Public Service Commission, or its successor (the “**Commission**”).

NOW, THEREFORE, the Parties enter into this Agreement subject to the terms and conditions as set forth herein, and in consideration of the mutual covenants and promises contained herein and intending to be legally bound, do hereby agree as follows:

1. **Provision of Electric Service.** Except as otherwise provided herein, Company shall provide Electric Service and Customer will receive Electric Service at the Facility at the Data Center Location in accordance with Company's Rate Book for Electric Service ("**Company's Rate Book**"), and under the Rate Schedule, as such Rate Schedule may be (a) amended, or (b) changed in accordance with Section 5.1. Except with respect to Section 5.3.3, to the extent there is any conflict or inconsistencies between Company's Rate Book, this Agreement, the Clean Capacity Accelerator Agreement, the Demand Response Agreement, any Supplemental Agreements, and/or the Rate Schedule, any conflict or inconsistency shall be resolved in the following order of precedence: (i) this Agreement, (ii) the Clean Capacity Accelerator Agreement, (iii) the Demand Response Agreement, (iv) any Supplemental Agreements, (v) Company's Rate Book, and (vi) the Rate Schedule. All energy and capacity purchased by Customer will be used solely for the energy needs of the Facility. Resale of energy and/or capacity purchased by Customer under this Agreement is prohibited.
2. **Customer Electric Demand Requirements**
 - 2.1. **Customer Committed Capacity Ramp.** Company agrees to provide the Electric Service within the Customer Committed Capacity Ramp set forth in Exhibit B-1 to Customer by the dates set forth in Exhibit B-1 to serve the Facility at the Data Center Location; provided that: (a) the dates by which each phase of the Customer Committed Capacity Ramp shall be achieved shall be adjusted equitably to account for the time required for the Parties to negotiate and reach mutual agreement on amendments to this Agreement, in accordance with Sections 4.4.1, 4.4.2 and 4.5, if applicable, and to the extent applicable, the Clean Capacity Accelerator Agreement, (b) subject to Section 2.4, Company shall have the right in its reasonable discretion to adjust such dates and/or the Customer Committed Capacity Ramp if the electric capacity achieved at any time through Project Agreements is insufficient to meet the Customer Committed Capacity Ramp by the dates set forth in Exhibit B-1, including due to the termination or expiration of any Project Agreement, the failure to perform, or the action or inaction of any Project Party (excluding Company or any Affiliates of Company), (c) Customer shall have the right on sixty (60) calendar days' prior Notice to Company prior to the implementation of any increase in the Customer Committed Capacity Ramp, to delay the implementation of any increase in the Customer Committed Capacity Ramp with such delays to the Customer Committed Capacity Ramp totaling no more than [REDACTED] in the aggregate ("**Ramp Grace Period**"), (d) pursuant to the Clean Capacity Accelerator Agreement, Company may revise the Customer Committed Capacity Ramp to reflect the removal of any "Clean Capacity Project" (as that term is defined in the Clean Capacity Accelerator Agreement) from Customer's "Clean Capacity Project Portfolio" (as that term is defined in the Clean Capacity Accelerator Agreement), and (e) Company shall have the right in its reasonable discretion to adjust the dates set forth in Exhibit B-1 and/or the Customer Committed Capacity Ramp if Company is delayed in providing Electric Service; provided that (x) any of the Conditions Precedent are not satisfied, and (y) neither Party exercises its right to terminate the Agreement in accordance with Section 4.2.3; and in each of (a), (b), (c), (d), and (e), the Customer Committed Capacity Ramp set forth on Exhibit B-1 as of the date hereof shall no longer be in effect and the revised Customer Committed Capacity Ramp shall become the Customer Committed Capacity Ramp for purposes of this Agreement.
 - 2.2. **Energization.** Company agrees to provide Electric Service as of the Commencement Date in accordance with the terms of the Energization Schedule set forth in Exhibit B-2.

2.3. Failure to Deliver. Company shall not have any liability for (a) failure to provide Electric Service to Customer under this Agreement, or (b) failure to achieve the Customer Committed Capacity Ramp, in each case, if such failure is: (i) due to a Customer breach of any obligation Customer (or any Affiliate of Customer or other party under the control of Customer) owes to Company under this Agreement or any Related Agreement (including, but not limited to, Customer's failure to deliver ZRC Product under and in accordance with the terms of the Clean Capacity Accelerator Agreement and Customer's obligation to curtail its load in accordance with the requirements of the Demand Response Agreement) or any delay caused by Customer (or any Affiliate of Customer or other party under the control of Customer); (ii) due to a Force Majeure Event or Change in Law as set forth in Section 17; (iii) delays or other impacts to Company's ability to perform hereunder arising from the actions or inactions of any Project Party (excluding Company or any Affiliate of Company), the Transmission Owner (including delays in completing the Underground Cable Work), MISO, the Commission, or other regulatory body governing the generation or transmission of electric capacity or energy; or (iv) otherwise excused pursuant to Company's Rate Book (each (i)-(iv), an "**Excusable Event**").

2.4. Clean Capacity Accelerator Agreement Project Availability.

2.4.1. If at any time after the Effective Date and before the end of the Term: (a) the Clean Capacity Accelerator Agreement, the Demand Response Agreement, and/or any Supplemental Agreement is terminated, (b) Company is unable to achieve or maintain the Customer Committed Capacity Ramp due to reasons not attributable to the breach or default of Company, including, but not limited to, the breach or failure of any Project Party (excluding Company or any Affiliate of Company) to perform in accordance with the terms and conditions of an applicable Project Agreement, or Customer's underperformance or nonperformance under any Related Agreement or Supplemental Agreement, or (c) any Project Agreement has been terminated due to no fault of Company or expired and has not been renewed or Company determines that the Indicative Clean Capacity Resource Portfolio (as such term is defined in the Clean Capacity Accelerator Agreement) is not feasible based on commercially reasonable standards and Prudent Industry Practice, then in any case Company shall provide prompt Notice, and the Parties shall meet and confer within ten (10) Business Days following such notification to negotiate in good faith (i) a mutually agreeable adjustment to either the Indicative Clean Capacity Portfolio or the Customer Committed Capacity Ramp, and/or (ii) the details of a pass-through mechanism by which Customer shall reimburse Company for the incremental cost of providing Electric Service to the Facility in accordance with the Customer Committed Capacity Ramp; provided, however, that the obligation to negotiate in good faith shall not require Company to agree to any solution under clause (i) or (ii) that could reasonably be expected, in Company's reasonable judgment, to put Company's system at risk, including any risk to its safety, reliability, security, or integrity. Such adjustment and/or reimbursement shall be based on Company's ability to use commercially reasonable efforts to provide Electric Service from alternate sources as a result of the termination, lack of approval, or modification of the Clean Capacity Accelerator Agreement, the Demand Response Agreement, and/or any Supplemental Agreement.

2.4.2. If the Parties, acting in good faith, are unable to reach mutual agreement on an adjustment to the Customer Committed Capacity Ramp, the Indicative Clean Capacity Portfolio, and/or, the details of a pass-through mechanism in accordance with Section 2.4.1 within thirty (30) calendar days after such meeting, or such later date as may be agreed by the Parties in writing (the "**Negotiation Period**"), then Company shall provide Customer with a revised Customer Committed Capacity Ramp (the "**Revised Ramp Schedule**") reflecting

the Electric Service that Company determines, in its reasonable discretion, it is capable of providing to Customer notwithstanding a Project Party's or Customer's (excluding Company or any Affiliate of Company) failure to perform or the termination of the Clean Capacity Accelerator Agreement, the Demand Response Agreement, and/or any Supplemental Agreement. Upon no more than thirty (30) calendar days' Notice after the end of the Negotiation Period, Customer shall notify Company that Customer is electing either to (a) allow this Agreement to remain in effect with Company's delivery obligations governed by the Revised Ramp Schedule, or (b) terminate this Agreement by providing Notice to Company, at which time this Agreement shall terminate and cease to be of any force or effect with no further obligation or liability to any Party except (i) for any Termination Payment owed by Customer under this Agreement pursuant to Section 7.3, (ii) to the extent provided in the Clean Capacity Accelerator Agreement, the Demand Response Agreement, and/or any Supplemental Agreement, any Termination Payment (as defined in such agreement) owed by Customer for terminating the Clean Capacity Accelerator Agreement, the Demand Response Agreement, and/or any Supplemental Agreement. For the avoidance of doubt, in the event that the Parties (x) convene pursuant to Section 2.4.1 due to a termination of the Clean Capacity Accelerator Agreement, the Demand Response Agreement, and/or any Supplemental Agreement, as set forth in Section 2.4.1(a), and (y) this Agreement is terminated in accordance with this Section 2.4.2, then any Termination Payment owed by Customer pursuant to Section 7.3 shall be calculated as of the date that the Clean Capacity Accelerator Agreement, the Demand Response Agreement, and/or any Supplemental Agreement, as applicable, was originally terminated. If Customer does not terminate this Agreement within thirty (30) calendar days of the end of the Negotiation Period, then (a) this Agreement shall remain in full force and effect, subject to the Revised Ramp Schedule, and (b) the Customer Committed Capacity Ramp set forth on Exhibit B-1 as of the date hereof shall no longer be in effect and the Revised Ramp Schedule shall become the Customer Committed Capacity Ramp for purposes of this Agreement.

3. **Term**

- 3.1. Term. The term (the "**Initial Term**") of this Agreement shall commence upon the Commencement Date and shall continue until 11:59 p.m. EPT on the date which is the twentieth (20th) anniversary of the Commencement Date.
- 3.2. Renewal Term. The Initial Term shall automatically renew for up to two additional five (5) year terms (each, a "**Renewal Term**") unless either Party provides Notice of non-renewal at least thirty-six (36) months prior to the end of the Initial Term or then-current Renewal Term. The Initial Term together with any Renewal Term shall be the "Term" of this Agreement. The Initial Term or a Renewal Term may be terminated earlier in accordance with the provisions of this Agreement.

4. **Conditions Precedent**

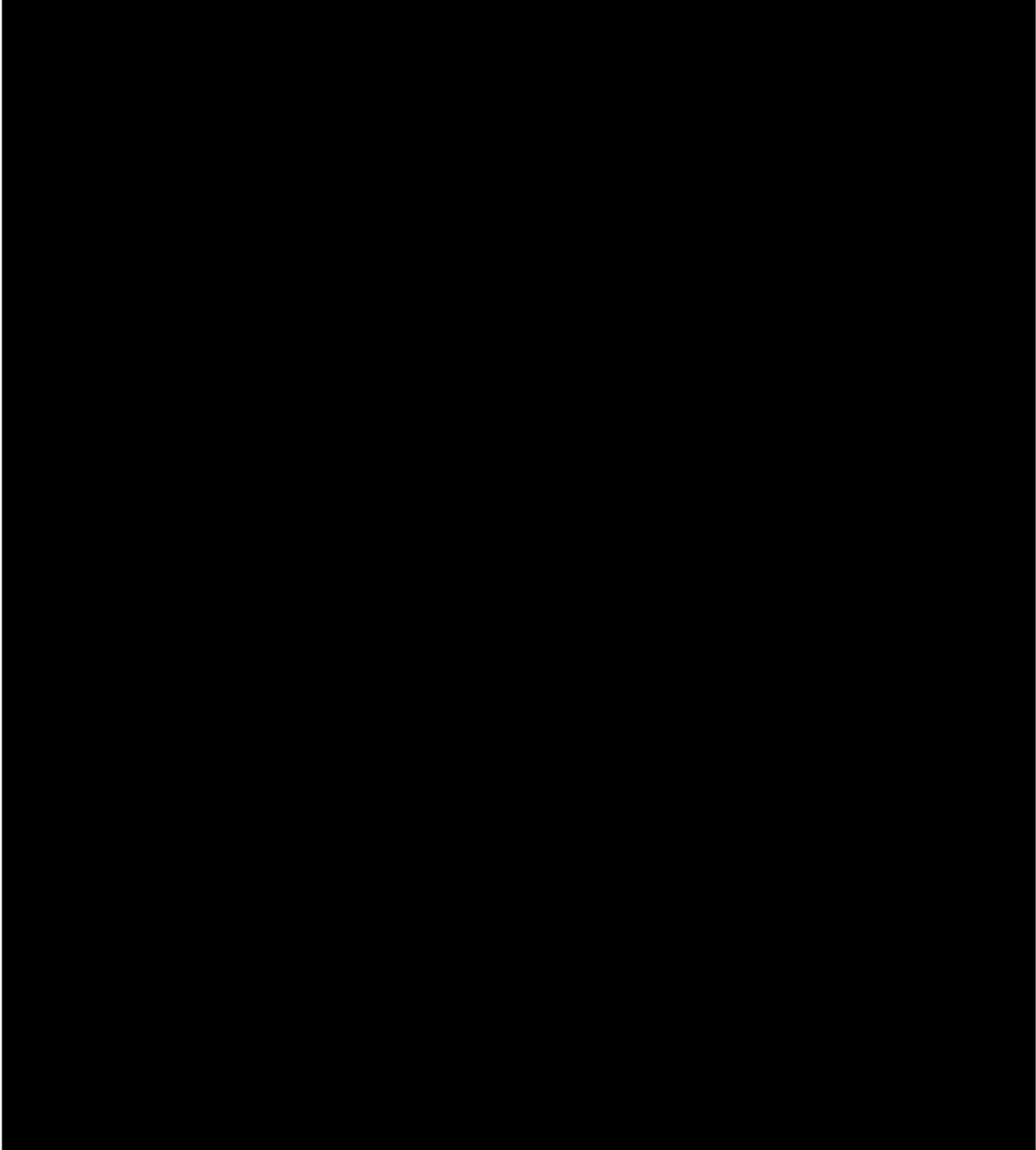
- 4.1. With the exception of the obligations under Sections 4, 9.5, 9.6 and 10, which shall be effective as of the Contract Date, each Party's performance of its respective obligations under this Agreement are specifically conditioned on completion of the items listed below pursuant to the terms set forth in this Section 4 (the "**Conditions Precedent**"):

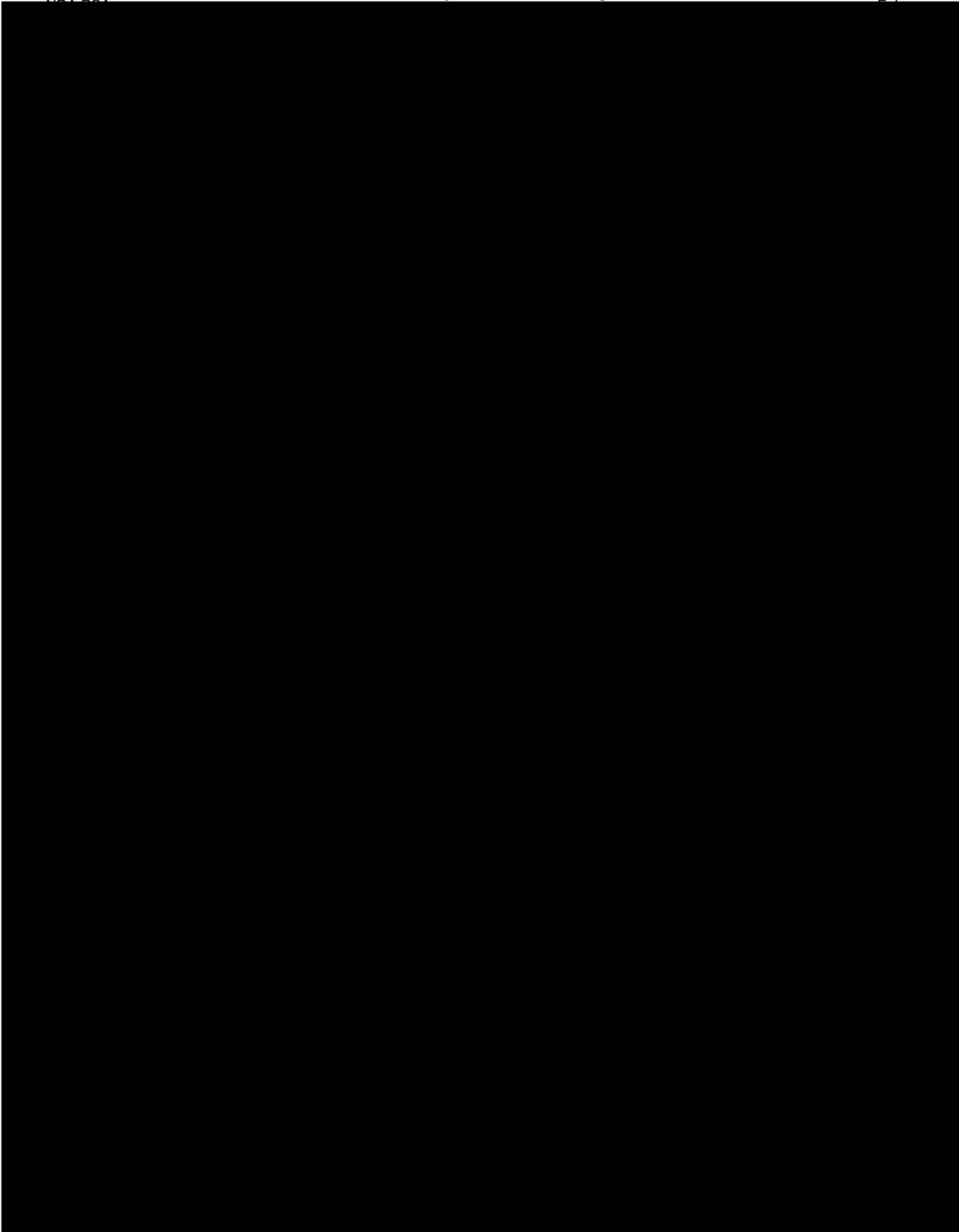
- 4.1.1. Each of the Parties shall execute (a) the Clean Capacity Accelerator Agreement, and (b) the Demand Response Agreement;

- 4.1.2. Each of the Parties shall execute the Line Extension Agreement;
 - 4.1.3. [Reserved];
 - 4.1.4. The Commission shall approve of this Agreement and the Clean Capacity Accelerator Agreement in accordance with Section 4.4;
 - 4.1.5. Within ten (10) Business Days following the Commission Approval Date, Customer shall provide Customer Credit Support in form and substance as required pursuant to Section 8; and
 - 4.1.6. Company's board of directors approves this Agreement and Company delivers Notice to Customer of such approval.
- 4.2. Conditions Precedent Deadline. The date the Conditions Precedent are satisfied shall be referred to herein as the "**Effective Date.**"
- 4.2.1. If the Condition Precedent set forth in Section 4.1.1 is not satisfied by [REDACTED] then either Party may terminate this Agreement and any Related Agreement upon thirty (30) calendar days' Notice to the other Party, in which case (1) this Agreement shall cease to be of any force or effect and (2) no Party shall have any further obligations or liability to the other under this Agreement.
 - 4.2.2. If the Conditions Precedent set forth in Sections 4.1.2, and 4.1.6 are not satisfied by [REDACTED] then Company may terminate this Agreement and any Related Agreement upon thirty (30) calendar days' Notice to Customer, in which case (1) this Agreement shall cease to be of any force or effect and (2) no Party shall have any further obligations or liability to the other under this Agreement.
 - 4.2.3. If the Condition Precedent set forth in Section 4.1.4 is not satisfied by [REDACTED] then either Party may terminate this Agreement and any Related Agreement upon thirty (30) calendar days' Notice to the other Party, in which case (1) this Agreement shall cease to be of any force or effect and (2) no Party shall have any further obligations or liability to the other under this Agreement.
 - 4.2.4. If the Condition Precedent set forth in Section 4.1.5 is not satisfied by [REDACTED] then Company may terminate this Agreement and any Related Agreement upon thirty (30) calendar days' Notice to Customer, in which case (1) this Agreement shall cease to be of any force or effect and (2) no Party shall have any further obligations or liability to the other under this Agreement.
- 4.3. Application. No later than thirty (30) days following the Related Agreement Completion Date, Company will apply to the Commission for approval of this Agreement and the Clean Capacity Accelerator Agreement. Until such application for Commission approval is made, this Agreement and any Related Agreements shall be considered Confidential Information. To the extent applicable, Company shall also promptly apply to the Commission for approval of any applicable amendment to this Agreement pursuant to Section 4.4.1.1(a), Section 4.4.2.3(a) or Section 4.5. Each Party agrees to notify the other Party of any significant developments in obtaining such Commission approval. Each Party shall use commercially reasonable efforts to obtain such required approval and shall exercise due diligence and shall act in good faith to cooperate with and assist the other Party in acquiring such Commission approval. Customer may at its sole

discretion, and at its sole costs and expense, file a petition for leave to intervene in the Commission proceeding related to the approval of this Agreement, retain counsel to represent Customer in such proceeding. The Parties agree to support the Agreement in such approval proceeding and not advocate in such intervention efforts to revise or change (a) the Agreement as executed as of the Contract Date, or (b) any Related Agreement as executed as of the effective date of such agreement.

4.4. Commission Approval.





5. **Fees for Electric Service**

5.1. Rate.

- 5.1.1. Customer agrees to pay for the Electric Service beginning on the Commencement Date in accordance with the Rate Schedule. After the second (2nd) anniversary of the Load Ramp Completion Date, Customer may seek to change the Rate Schedule applicable under this Agreement to a new qualifying rate schedule from Company's Rate Book; provided that: (a) Customer provides not less than twenty-four (24) months' Notice to Company of its intent to change the Rate Schedule, (b) the Facility meets the eligibility requirements, as set forth in Company's Rate Book, to receive Electric Service under such rate schedule, (c) the new rate schedule was approved by the Commission after the Contract Date, and (d) Customer's new rate schedule shall not be cross-subsidized by any other customer of Company.
- 5.1.2. If at any time during Term, the Commission orders the termination or replacement of the Rate Schedule in effect at the time, then Company shall provide Notice to Customer of any replacement Rate Schedule(s) that Customer is eligible to take service under, subject to the qualifications set forth in Section 5.1.1(b)-(c).
- 5.1.3. The Parties acknowledge 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. The Parties also acknowledge that the combined revenues received by the Company under this Agreement and the applicable Related Agreements along with any avoided costs attributable to Google should be considered in regulatory proceedings applicable to Company's cost to serve Customer, and the Parties shall act in good faith to ensure such combined revenues and avoided costs are presented in such proceedings to the extent applicable. If, at any time during the Term, the Commission (a) 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 (b) disallows Company's recovery of costs to the extent attributable to serving Customer, then, in either case, Customer agrees to comply with any such ruling or order to ensure that Customer pays all costs associated with its service from Company, and, as applicable, Customer shall reimburse Company for any unrecovered costs, plus interest accrued on such amount at the Interest Rate within ninety (90) days of any such order; provided, however, that notwithstanding the foregoing, Customer shall not be required to reimburse

Company for unrecovered costs incurred due to the gross negligence or willful misconduct of Company.

- 5.1.4. Notwithstanding the foregoing process for the Parties' acceptance of Commission approval of this Agreement and the Clean Capacity Accelerator Agreement, at all times that this Agreement is in effect, Customer reserves all rights available to it to challenge before the Commission and on appeal any increases or changes to the rates or terms and conditions applicable to Customer that may be proposed to Company's Rate Book or the Rate Schedule (or any rate schedule pursuant to which Customer receives service subject to this Agreement) after the Contract Date.
- 5.2. Minimum Monthly Charge. If for any billing period Customer's Monthly On-Peak Billing Demand is less than or equal to (i) eighty percent (80%), *multiplied by* (ii) the applicable Customer Committed Capacity Ramp (in kW), then Company shall invoice Customer based on Customer's usage for the billing period at the prevailing monthly rates for "Full Service Customers" set forth in Customer's Rate Schedule in effect on the date that such invoice is calculated, except that any Demand Charges set forth in such Rate Schedule shall be calculated using: the lesser of (A) eighty percent (80%), *multiplied by* the applicable Customer Committed Capacity Ramp (in kW) in such billing period, and (B) the maximum capacity Company was actually capable of providing Customer in such billing period (in kW) (the "**Minimum Monthly Charge**"); provided that Customer may, in accordance with Section 2.1, by Notice prior to the implementation of any increase in the Customer Committed Capacity Ramp, delay the implementation of any increase in the Customer Committed Capacity Ramp in accordance with the terms of the Ramp Grace Period.
- 5.3. Effect of Exceeding Customer Committed Capacity Ramp.
 - 5.3.1. If Customer's Monthly Billing Demand exceeds the applicable Customer Committed Capacity Ramp demand level in any given billing period (such difference between the Monthly Billing Demand and applicable Customer Committed Capacity Ramp demand level in any given billing period, an "**Overage**"), then (a) Customer shall use its commercially reasonable efforts to reduce any such Overage to zero (0) in subsequent billing periods and (b) only to the extent that (i) such Overage is less than or equal to five percent (5%) of the Customer Committed Capacity Ramp for the applicable billing period, and (ii) for up to three (3) billing periods in any rolling twelve (12) billing periods, Company shall use commercially reasonable efforts to accommodate such Overage. Customer shall reimburse Company for all reasonable, documented costs and expenses actually incurred by Company in connection with accommodating any Overage, including any third-party charges and incremental costs for temporary measures, system adjustments, or upgrades; such amounts shall be invoiced and payable in accordance with Section 6.1. For the avoidance of doubt, Company shall have no obligation to use commercially reasonable efforts to accommodate any future Overage if (I) such Overage is greater than five percent (5%), (II) Customer's Monthly Billing Demand exceeds the applicable Customer Committed Capacity Ramp demand level for more than three (3) billing periods in any rolling (12) billing periods, or (III) in Company's sole discretion, not accommodating the Overage is necessary to protect the integrity of Company's electrical distribution system.
 - 5.3.2. In the event that Customer's Overage exceeds five percent (5%) for three (3) or more billing periods in any rolling twelve (12) billing periods, then (a) Company, upon providing Notice to Customer, shall have the right, but not the obligation, to adjust the

Customer Committed Capacity Ramp in its sole discretion to reflect the persistent Overages, and (b) the Parties shall negotiate in good faith any amendments to this Agreement that the Parties agree are necessary to address the impacts of ongoing Overages, while still attempting to preserve the Parties' original intent regarding their respective rights and obligations under this Agreement.

- 5.3.3. If at any time during the Term, Company receives an emergency notice, alert, or declaration from MISO of a potential capacity shortage ("**MISO Notice**"), then Company shall promptly upon receipt provide Notice to Customer in accordance with Section 18.1 of such MISO Notice, and Customer shall use commercially reasonable efforts to ensure that Customer's Half-Hour Demand does not exceed the Customer Committed Capacity Ramp for any 30-minute interval during such defined period of time. Company shall have no obligation to use commercially reasonable efforts to accommodate Customer's demand to the extent it exceeds the Customer Committed Capacity Ramp in any such 30-minute interval; provided that Customer received a MISO Notice from Company. Notwithstanding anything in this Agreement, the emergency electrical procedures in Company's Rate Book shall apply at all times. For the avoidance of doubt, this Section 5.3.3 shall not apply to notices the Company receives from MISO in connection with Customer's participation in any Company demand response program.
- 5.4. Interim Procurement Cost Pass-Through. If at any time during the Term, Sections 2.4.1(a), 2.4.1(b) or 2.4.1(c) are triggered, then Company may source additional capacity from the MISO Planning Resource Auction to provide Electric Service to Customer in accordance with the Customer Committed Capacity Ramp (such amount (in MW), the "**Shortfall Capacity**"), and Company shall, to the extent practicable, notify Customer of its intent to cure such Shortfall Capacity and Customer shall pay to Company, for each MW of such Shortfall Capacity, the Shortfall Capacity Rate, as invoiced in accordance with Section 6.1. Following Company's participation in the MISO Planning Resource Auction to cure the Shortfall Capacity, Company shall notify Customer of the Shortfall Capacity Rate and, upon Customer's request, provide reasonable supporting documentation evidencing such transaction.
- 5.5. Operational Parameters.
- 5.5.1. Customer Facility Operations. Customer acknowledges and agrees that fluctuations in Customer's load have the potential to (a) impact Company's ability to serve other customers, and (b) damage Company's generation and distribution system. Customer shall operate the Facility (i) in a manner that minimizes the frequency and magnitude of load fluctuations at all times, and (ii) in accordance with the Operating Procedures (as defined below).
- 5.5.2. Initial Operating Parameters. Within ninety (90) calendar days following the Contract Date (the "**Operating Parameter Deadline**"), or such later date as may be mutually agreed by the Parties, Customer shall provide Company with any information reasonably requested by Company regarding Customer's intended operations at the Facility, including details regarding the hardware Customer has procured or plans to procure to operate the Facility, sufficient for Company to determine, reasonably and in good faith and subject to input from Customer, MISO and the Transmission Owner, a base set of operating parameters for the Facility (the "**Operating Parameters**"). Such Operating Parameters shall include (a) a minimum power factor for the Facility that Company requires Customer to maintain at all times (subject to the occurrence of a Force Majeure Event), (b) constraints on the operational load ramp for load usage fluctuations of the Facility, (c) minimum standards to

which Customer's equipment shall conform to minimize harmonic distortions, (d) any requirements for the Facility to remain connected to the grid for voltage and/or frequency conditions, as similarly defined by NERC Reliability Standards, PRC-024, and (e) any other mandatory operating parameters, including but not limited to "low voltage ridethrough" and "transient operations". Customer's Ramp Grace Period shall be ratably reduced for each day following the Operating Parameter Deadline that Customer fails to provide to Company any required information, as reasonably requested by Company, for Company to determine the Operating Parameters in accordance with this Section 5.5.2.

5.5.3. Operating Procedures. Following the Operating Parameter Deadline, the Parties shall work together diligently and in good faith to finalize a final operating plan and procedures for Customer's Facility (the "**Operating Procedures**") by no later than December 31, 2026, or such later date as may be mutually agreed by the Parties. The Operating Procedures shall incorporate the Operating Parameters and set forth any storage capacity, other equipment or mitigation measures that Customer shall install or implement at the Facility in connection with Customer's obligation to operate the Facility in a manner consistent with such Operating Parameters. Customer shall be solely responsible for the cost of installing any such storage capacity or other equipment, or implementing any mitigation measures required under the Operating Procedures. In the event that the Parties fail to finalize the Operating Procedures by December 31, 2026, or such later date as may be mutually agreed by the Parties, the Parties shall continue to negotiate to finalize the Operating Procedures, and until such time as the Operating Procedures are finalized, the draft Operating Procedures last proposed by Company shall govern and be deemed to be the effective Operating Procedures.

5.5.4. Right to Suspend Service. Company reserves the right at all times to temporarily suspend service to Customer pursuant to Mich. Admin Code R 460.136 if Customer fails to comply with the Operating Procedures at any time during the Term.

5.5.5. No Company Liability. Company shall have no liability to Customer for any damages to Customer equipment or property due to Customer load transients.

5.6. Demand Response. Customer shall comply with all Customer obligations under the Demand Response Agreement, including, but not limited to, any load reduction directives provided to Customer. Notwithstanding anything to the contrary set forth in this Agreement, Company shall be permitted to interrupt Customer's Electric Service in accordance with the terms and conditions set forth in the Demand Response Agreement and shall not be liable to Customer for failing to deliver Electric Service in accordance with the Customer Committed Capacity Ramp during any such interruptions. Any payments owed by a Party to the other Party under and in accordance with the Demand Response Agreement shall be invoiced in accordance with Section 6.

6. Invoicing and Payment

6.1. Invoicing. Except as set forth in this Agreement, Company shall invoice Customer in accordance with Company's Rate Book. Customer shall pay all amounts owed in full on or before the due date and shall pay each invoice within thirty (30) calendar days of receipt of each invoice in the form substantially included in Exhibit D to this Agreement. For any payments to Company made after an applicable due date, Customer shall pay Company late fees in accordance with Section C4.8 of Company's Rate Book. Any Disputes regarding an invoice or related events may be raised within six (6) months of the date of receipt of the disputed invoice by Notice to Company only after Customer has paid the invoiced amount in full, and Customer shall not withhold or

delay payment pending resolution of any such Dispute. If Customer does not provide Notice of such Dispute within six (6) months of the date of the applicable invoice, Customer waives any claims related to that invoice.

- 6.2. Netting of Payments. Notwithstanding any other provision in this Agreement or any other agreement between the Parties, if at any time Customer is required to make payments to the Company under this Agreement and any Related Agreement, then on each payment date, the payment obligations of Customer shall be netted against any payment obligations of Company under the applicable agreements.

7. **Default; Termination**

- 7.1. Default. A Party shall be in default under this Agreement upon the occurrence of any of the following events (such Party, the “**Defaulting Party**” and each such event, an “**Event of Default**”):

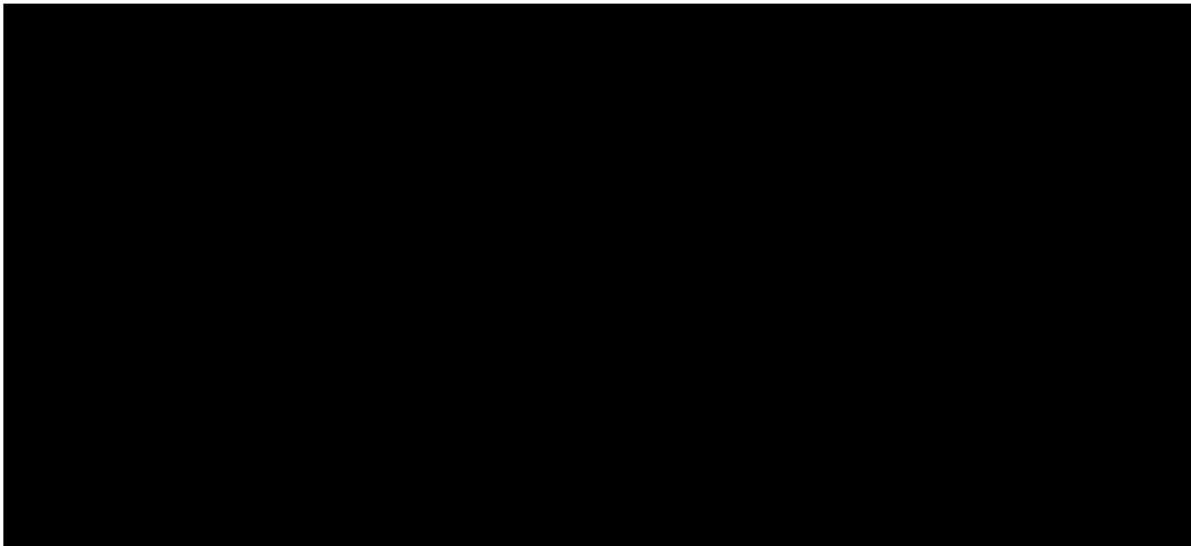
- 7.1.1. a Party fails to pay any amount when due under this Agreement only if that amount is not cured within ten (10) Business Days after receipt of Notice thereof from the other Party;
- 7.1.2. a Party breaches any material provision of this Agreement (not otherwise a payment default) that is not cured within thirty (30) calendar days after receipt of Notice thereof from the other Party (or for breaches for which the breaching Party has notified the other Party cannot be cured within thirty (30) calendar days despite its use of reasonable efforts but can be cured within sixty (60) calendar days, and such default has not been so cured by the extended sixty (60) day deadline);
- 7.1.3. the occurrence of a Bankruptcy in respect of a Party (or, in the case of Customer, the Customer Parent Guarantor), and such proceedings are not terminated, stayed or dismissed within ninety (90) calendar days after the commencement thereof;
- 7.1.4. in the case of Customer, if Customer fails to maintain the collateral requirements required pursuant to Section 8 and such failure is not cured within ten (10) Business Days after receipt of Notice thereof from Company; or
- 7.1.5. in the case of Customer, if Customer defaults in its performance or payment obligations under any Related Agreement and such default is not cured within the applicable cure period specified therein.

7.2. Termination.

- 7.2.1. This Agreement may be terminated upon five (5) Business Days prior Notice (unless otherwise set forth in this Agreement) pursuant to Section 7.1 and any other termination right set forth in this Agreement; provided that this Agreement shall automatically terminate upon the occurrence of an Event of Default with respect to Section 7.1.3. Notwithstanding anything else in this Agreement, the Customer Parent Guaranty, or any other agreement among the Parties, no notice of default or demand is required of any entity that is subject to a Bankruptcy or any other stay, injunction, or moratorium against payment demands, and any requirement to provide such notice of default or demand is excused, waived, and deemed satisfied.

- 7.2.2. Any date on which this Agreement is terminated after the Effective Date but before the end of the Term shall be an “**Early Termination Date.**” Customer’s obligations to pay or reimburse Company for any termination set forth above shall be provided as set forth in Section 7.3.
- 7.2.3. In the event that this Agreement is terminated by Company for any reason other than a Company Event of Default, Company or Customer has the right, but not the obligation, to terminate any Related Agreement.
- 7.3. Termination Payment. In the event of an early termination of this Agreement, except if due to a Company Event of Default, Company will suffer damages, and such damages would be uncertain and difficult (if not impossible) to accurately estimate. Accordingly, Customer agrees that if this Agreement is so terminated on or after the Effective Date:
- (1) prior to the fifteenth (15th) anniversary of the Load Ramp Completion Date (other than due to a Company Event of Default or Customer Event of Default), then Customer shall pay to Company, as a fair estimate of such damages and not as a penalty, liquidated damages in an amount equal to the sum of the Minimum Monthly Charge for each month between the Early Termination Date and the fifteenth (15th) anniversary of the Load Ramp Completion Date;
 - (2) prior to the thirteenth (13th) anniversary of the Commencement Date, by Company due to a Customer Event of Default, then Customer shall pay to Company, as a fair estimate of such damages and not as a penalty, liquidated damages in an amount equal to the sum of the Minimum Monthly Charge for each month between the Early Termination Date and the fifteenth (15th) anniversary of the Load Ramp Completion Date; and
 - (3) after the thirteenth (13th) anniversary of the Commencement Date, by Company due to a Customer Event of Default, then Customer shall pay to Company, as a fair estimate of such damages and not as a penalty, liquidated damages in an amount equal to the sum of the Minimum Monthly Charge for the lesser of: (a) twenty-four (24) months, and (b) each month between the Early Termination Date and the expiration date of the Term (each of the payments described in (1), (2), or (3), the “**Termination Payment**”. A sample calculation of the Termination Payment is illustrated in Exhibit E.
- 7.3.1. As soon as practicable after the Early Termination Date, Company shall provide Customer with Notice of the amount of the Termination Payment, as applicable. The Notice shall include a written statement explaining in reasonable detail the calculation of the Termination Payment.
- 7.3.2. The Termination Payment, as applicable, shall be due to Company, and shall be paid by Customer within thirty (30) calendar days after such notice is received by Customer.
- 7.3.3. For the avoidance of doubt, no Termination Payment shall be payable by Customer hereunder if this Agreement is terminated as a result of a Company Event of Default.
- 7.4. Post Termination Obligations.

- 7.4.1. Upon termination of this Agreement, Company's obligations to provide Electric Service to the Data Center Location pursuant to this Agreement shall cease.
- 7.4.2. Customer shall be obligated to pay all amounts invoiced and unpaid for the provision of Electric Service to the Data Center Location for time periods prior to the Early Termination Date.
- 7.4.3. If applicable, Customer shall be obligated to pay the Termination Payment, as applicable, as calculated in Section 7.3.



- 7.4.5. This Section 7.4 shall survive termination of this Agreement.
 - 7.5. Remedies for Company. In the event of a Customer Event of Default pursuant to Section 7.1, Company shall have the right to pursue any and all remedies available under applicable Law, in equity, and under the Rules and Company's Rate Book, including but not limited to the suspension or termination of Electric Service, collection of all amounts due to Company, and the imposition of other penalties as permitted. The exercise of any one remedy shall not preclude the exercise of any other remedy available to Company under Company's Rate Book or otherwise.
- 8. Customer Collateral Requirements.**

- 8.1. Customer Credit Support. Within ten (10) Business Days of the Commission Approval Date, Customer shall provide Company with Customer Credit Support in the amount of the Required Amount. Customer Credit Support may be comprised of the following: (a) a guaranty substantially in the form set forth in Exhibit C ("**Customer Parent Guaranty**") from an Affiliate of Customer with a Suitable Rating (the "**Customer Parent Guarantor**"), pursuant to which the Customer Parent Guarantor has guaranteed the payment obligations of Customer under this Agreement; (b) one or more Letters of Credit; and/or (c) any combination of the above. Should Customer have provided any portion of the Customer Credit Support in the form of a Customer Parent Guaranty, then within ten (10) Business Days following a decrease in Customer Parent Guarantor's Credit Rating such that it no longer has a Suitable Rating, Customer shall provide one or more Letters of Credit such that the total amount available to draw under all such Letters of Credit is not less than the then-applicable Required Amount. Should there be a subsequent increase in the Credit Rating of the Customer Parent Guarantor such that it then has a Suitable Rating, then Customer shall be entitled to replace some or all of its Letters of Credit with a new

Customer Parent Guaranty, so long as the total Customer Credit Support is not less than the then-applicable Required Amount.

8.2. Letter of Credit.

8.2.1. If Customer provides Customer Credit Support in the form of a Letter of Credit, such Letter of Credit must be issued for a minimum term of three hundred sixty-five (365) days and for an amount, together with any other applicable forms of Customer Credit Support provided by Customer, not less than the then-applicable Required Amount. At least thirty (30) days prior to the expiration of any Letter of Credit provided by Customer as Customer Credit Support, Customer shall notify Company in writing, and at least thirty (30) days prior to the expiration of such Letter of Credit, Customer shall renew or substitute such outstanding Letter of Credit, establish one or more additional Letters of Credit, or provide replacement Customer Credit Support in an amount, together with any other applicable forms of Customer Credit Support provided by Customer, not less than the then-applicable Required Amount. If Customer fails to comply with its obligations under this Section 8.2.1, Company may, prior to the expiration date of the affected Letter of Credit, draw upon the entire undrawn portion of the affected Letter of Credit (the "**Customer LC Proceeds**") and deposit the Customer LC Proceeds with Company. Upon Customer's providing, at a later time, replacement Customer Credit Support, Company shall return to Customer an amount equal to the lesser of (x) the amount of replacement Customer Credit Support and (y) the amount equal to (a) the Customer LC Proceeds, *minus* (b) any undisputed amounts due Company by Customer under this Agreement, and *minus* (c) any amounts previously applied against Customer's obligations from such Customer LC Proceeds by Company in accordance with this Agreement.

8.2.2. If at any time during which the Customer Credit Support provided to Company includes a Letter of Credit and a Letter of Credit Default occurs with respect to such Letter of Credit, then Customer shall, within three (3) Business Days following such Letter of Credit Default, either replace the Letter of Credit with a replacement Letter of Credit (or alternative Customer Credit Support) so that the aggregate amount of Letter of Credit (or alternative Customer Credit Support) provided to Company equals the Required Amount then required. Customer shall have the right, upon no less than five (5) Business Days written notice to Company, to replace the Letter of Credit then outstanding with a replacement Customer Credit Support, provided, however, that the aggregate amount of Customer Credit Support provided to Company equals the Required Amount then required. If Customer provides replacement Customer Credit Support to Company, the Letter of Credit being replaced by such replacement Customer Credit Support shall be cancelled, and the obligations thereunder released, effective as of the date of Customer's posting to Company of the replacement Customer Credit Support.

8.3. Release. Upon any reduction of the Required Amount pursuant to this Section 8 and within thirty (30) calendar days following the end of the Term and the satisfaction of all of Customer's obligations under this Agreement and the Related Agreements, Company shall release to Customer the applicable portion of the Customer Credit Support and, if reasonably requested by Customer or the issuer of such Customer Credit Support following the end of the Term and the satisfaction of all of Customer's obligations under this Agreement, Company shall provide a written form of release and termination of such Customer Credit Support in a form reasonably acceptable to Customer (or such issuer of the Customer Credit Support) and Company.

8.4. Draws Upon Customer Credit Support.

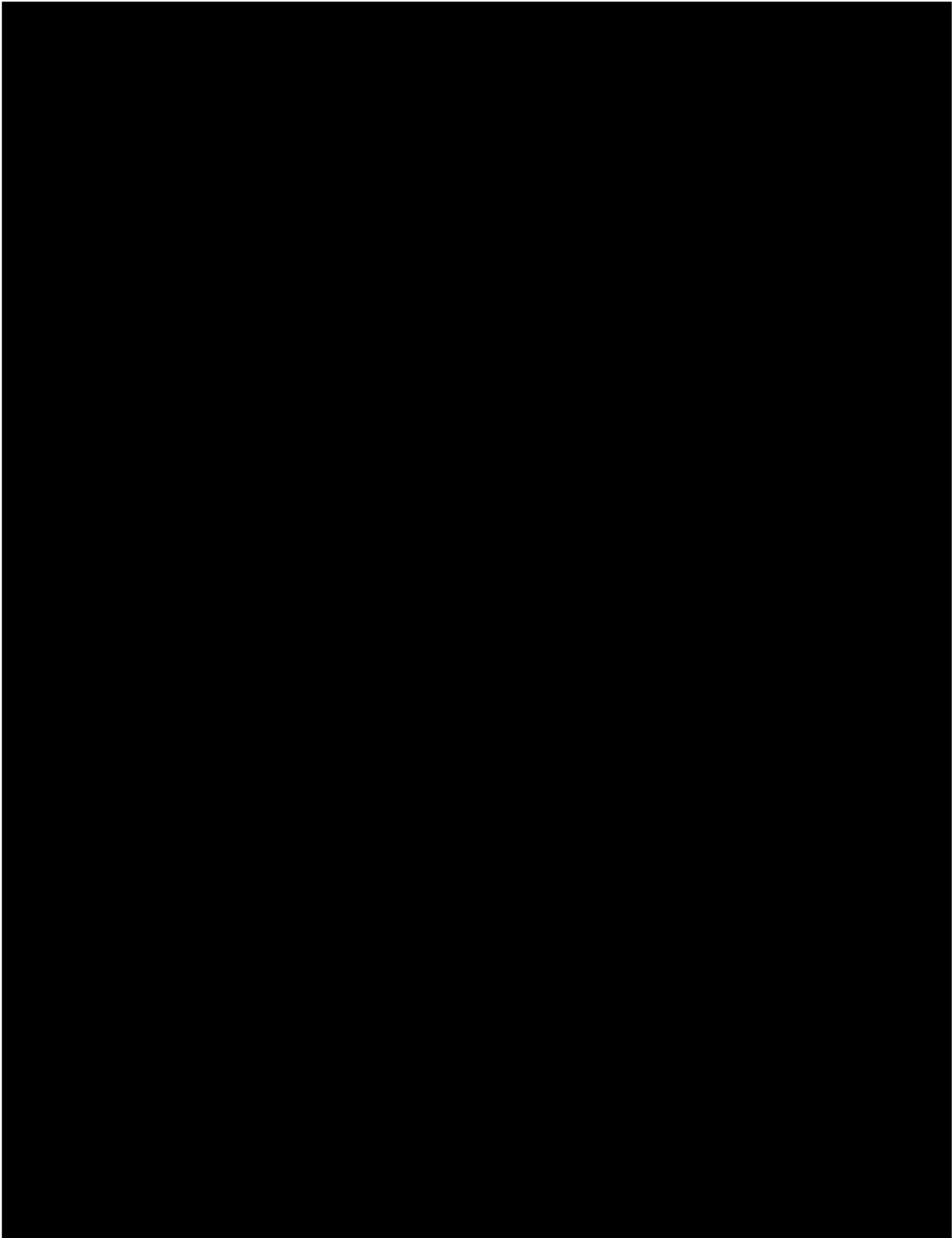
- 8.4.1. Upon, or at any time after, the occurrence of (i) any payment obligation under this Agreement that is past due and owing to Company, or (ii) an Event of Default by Customer for which there exists any unsatisfied payment obligations, including a Termination Payment, and the applicable cure period has expired, Company may immediately draw on any Customer Credit Support in its possession for any such amounts then due and owing. For the avoidance of doubt, if Customer has provided Customer Credit Support in a combination of the Customer Parent Guaranty and one or more Letters of Credit, Company shall have no obligation to provide notice, make demand, or engage in litigation or otherwise enforce its rights under the Customer Parent Guaranty prior to making any draw on any Letter of Credit, all of which are hereby waived to the maximum extent permitted by law.
- 8.4.2. Customer shall remain liable for any amounts still owing to Company and remaining unpaid after any draw by Company on the Customer Credit Support under this Section 8.4. If Company draws on the Customer Credit Support for any payment obligation other than a Termination Payment, as applicable, then Customer shall, within five (5) Business Days of such draw, replenish the Customer Credit Support to the Required Amount.
- 8.5. Customer Credit Support Costs. In all cases, the costs and expenses of posting, renewing, substituting, replenishing, and canceling the amount of the Customer Credit Support shall be borne by the Customer.

9. Customer Obligations

- 9.1. Customer shall provide information requested by Company in a timely manner necessary for Company to perform all design, engineering, procurement, and construction activities in a timely manner so that Company can make reasonable efforts to provide Electric Service to Customer in accordance with the Customer Committed Capacity Ramp. This information shall include the design basis and project planning information including but not limited to Facility, Data Center Location, Customer Committed Capacity Ramp, access to site for survey and geotechnical investigation, construction power needs, redundancy requirements, confirmation of substation design basis, site access plans during construction, and other information identified as necessary to the design and construction of the Electric Facilities.
- 9.2. Customer shall undertake all efforts in a commercially reasonable manner to begin receiving Electric Service in accordance with Customer Committed Capacity Ramp.
- 9.3. Customer shall at its sole costs and expense construct, operate and maintain in accordance with Prudent Industry Practice any and all additional facilities (including a substation pursuant to the Line Extension Agreement) necessary to connect the Facility to Company's distribution system and Electric Facilities to receive Electric Service to Customer.
- 9.4. 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.



CONFIDENTIAL - Subject to Nondisclosure Agreement



10. Confidentiality

- 10.1. For the purpose of this Agreement, a party disclosing Confidential Information shall be referred to as the “**Disclosing Party**” and a party receiving Confidential Information shall be referred to as the “**Recipient**”. “**Confidential Information**” includes any and all information hereafter disclosed by or at the direction of the Disclosing Party to Recipient that is designated in writing as confidential or a reasonable party would consider to be of a confidential nature including but not limited to this Agreement and the Related Agreements; provided, however, Confidential Information does not include (i) information that, at the time of disclosure or thereafter, was generally available to and known by the public, other than as a result of a disclosure by Recipient in violation of this Section 10; (ii) information that, at the time of disclosure or thereafter was available to Recipient or its Representatives (as defined below) from a source not known by Recipient to be bound by a duty of confidentiality to the Disclosing Party with respect to such information; (iii) information that, prior to disclosure by or at the direction of the Disclosing Party, was known to Recipient or its Representatives; or (iv) information that is independently developed by Recipient or its Representatives by persons without reliance on the Confidential Information and without violating the obligations hereunder.
- 10.2. Confidential Information is and shall, at all times, remain the property of the Disclosing Party. Recipient may disclose Confidential Information to any of its officers, directors, employees, advisors, shareholders, members, managers, attorneys or agents (collectively, “**Representatives**”). The Recipient shall advise such persons of the existence of this Agreement, of the confidential nature of the information and of the Recipient’s obligations regarding the same under this Agreement. Recipient agrees that it shall maintain the Disclosing Party’s Confidential Information in confidence and shall not use the Confidential Information except to the extent necessary to carry out its obligations under this Agreement. Recipient shall be responsible for any breach of this Agreement by such Representatives.
- 10.3. In the event that Recipient is requested or required under compulsion of legal process to disclose such Confidential Information, Recipient shall not, unless required by Law, disclose the information until the Disclosing Party has first (i) received prompt Notice of such request or requirements to disclose and (ii) had an adequate opportunity to obtain a protective order or other reliable assurance that confidential treatment shall be accorded to the Confidential Information. If required by Law to disclose Confidential Information prior to providing Notice to the Disclosing Party, the Recipient shall (x) use reasonable efforts to limit the amount of Confidential Information that is disclosed, and (y) provide Notice to the Disclosing Party of the disclosure of such Confidential Information as promptly as reasonably practicable after the disclosure.
- 10.4. Notwithstanding the foregoing, nothing in this Agreement shall restrict, impair or otherwise prohibit Company from disclosing any Confidential Information to the Commission or other applicable regulatory governmental agency as Company deems appropriate or necessary in its sole discretion provided that Company shall use commercially reasonable efforts to file such information under seal if permissible, and to notify Customer in advance of such disclosures (or if advance notification is not practicable, as promptly as reasonably practicable after such disclosure).

11. Complete Agreement

- 11.1. This Agreement and the Related Agreements contain the full and complete understanding of Company and Customer as to the provision of Electric Service to the Facility at the Data Center Location. Notwithstanding the obligations set forth in the Related Agreements, this Agreement

supersedes any prior understandings, commitments, agreements and authorizations, whether oral or written, regarding the Electric Facilities and the provision of Electric Service and the payment thereof. No other representations or promises regarding the Electric Facilities or the Electric Service, written or oral, shall survive the execution hereof.

12. **Limitation of Liability**

- 12.1. Limitation of Liability for Delays. To the fullest extent permitted by Law, Company shall not be liable for any damages, penalties, liquidated damages, or claims (“Losses”) arising from Customer’s failure, delay or non-performance in connection with its obligations under this Agreement or any Related Agreement (including, but not limited to, Customer’s obligation to operate and maintain the substation in accordance with Prudent Industry Practice).
- 12.2. Customer Limitation of Liability for Delays. To the fullest extent permitted by Law, Customer shall not be liable for any Losses arising from (a) delays, disruptions or failures to perform caused by any Force Majeure Event or Change in Law as set forth in Section 17 or (b) Company’s failure, delay or non-performance in connection with its obligations under this Agreement.
- 12.3. Limitation of Liability for Provision of Electric Service. Company shall not be liable to Customer or any of its Affiliates for damages for any failure to provide the Electric Service or for an interruption, limitation, or curtailment of the Electric Service; provided that any such interruption, limitation, or curtailment is not due to Company’s willful misconduct or gross negligence.
- 12.4. Limitation of Liability for Use of Electricity. Company shall not be liable for damages resulting to Customer or to third persons from the presence or use of electricity after the point of delivery to Customer’s Facility, and except with respect to Customer’s operation and maintenance of the substation, Customer shall not be liable for damages resulting to Company or to third persons from the presence or use of electricity at or before the point of delivery to Customer’s Facility.
- 12.5. Notwithstanding anything to the contrary in this Agreement, and in addition to any rights set forth herein, Customer shall have the right to file a complaint with, or to otherwise initiate formal or informal proceedings before, the Commission related to the Electric Service or any other cause, matter, or issue subject to Commission jurisdiction.
- 12.6. Consequential Damages. Neither Party shall be liable under this Agreement or under any cause of action related to the subject matter of this Agreement, whether in contract, warranty, tort including negligence, strict liability, professional liability, product liability, contribution, or any other cause of action for special, exemplary, punitive, indirect, incidental or consequential losses or damages, including loss of profit, loss of use, loss of opportunity, loss of revenues, or loss of good will; provided, however, that the foregoing shall not apply to any Party’s obligations to indemnify, defend and hold harmless any Indemnified Party for claims and liabilities in respect of claims by third persons that are indemnified by such Party hereunder.
- 12.7. Disclaimer of Warranty. EXCEPT AS EXPRESSLY SET FORTH IN THIS AGREEMENT, THE RATE SCHEDULE OR COMPANY’S RATE BOOK, COMPANY EXPRESSLY DISCLAIMS AND NEGATES ALL REPRESENTATIONS AND WARRANTIES, EXPRESSED OR IMPLIED, WITH RESPECT TO THE ELECTRIC SERVICE OR ANY OTHER SUBJECT MATTER OF THIS AGREEMENT INCLUDING WITHOUT LIMITATION, WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE. The Electric Service is not supplied pursuant to or guaranteed to

meet, comply with or qualify for any industry, governmental, statutory, regulatory, taxation or other standard unless expressly stated in this Agreement.

13. Assignment

13.1. Without the prior written consent of the non-assigning Party (such consent not to be unreasonably withheld, delayed or denied), neither Party may assign or transfer this Agreement or its rights and obligations under this Agreement, and any such assignment or transfer without such consent is void. Notwithstanding the foregoing, a Party may make the following assignments without the prior written consent of the other Party, but shall provide Notice to the other Party thirty (30) calendar days prior to such assignment:

13.1.1. Customer may assign this Agreement (i) to an Affiliate of Customer, so long as Notice of such assignment is provided to Company at least thirty (30) days prior to such assignment and such assignee remains in compliance with the obligations of Customer under Section 8, or (ii) to any Creditworthy Assignee, provided, that replacement Customer Credit Support has been provided by such Creditworthy Assignee pursuant to the requirements of Section 8; provided, however, that until the seventh (7th) anniversary of the Load Ramp Completion Date, if the sum of cash and cash equivalents reflected on the balance sheet of a proposed assignee (whether an Affiliate or a Creditworthy Assignee), as set forth in such proposed assignee's most recent audited financial statements prepared in accordance with generally accepted accounting principles, in an aggregate amount is less than three times (3x) the greater of (a) a Termination Payment calculated in accordance with Section 7.3 of this Agreement, (b) a potential "Termination Payment" as that term is defined in the Clean Capacity Accelerator Agreement, and (c) a potential "Termination Payment" as that term is defined in any Supplemental Agreement, each (a), (b) and (c), as calculated as of the effective date of the proposed assignment, then Customer shall obtain Company's prior written consent to such assignment. Any assignee of Customer permitted pursuant to this Section 13.1.1 shall enter into an assignment and assumption agreement in a form reasonably acceptable to Company by which such assignee expressly assumes all of the assignor's obligations under this Agreement.

Customer may also assign this Agreement as collateral security to a Financing Party providing Customer's long-term financing for the construction and/or operation of the Facility; provided that such assignment does not materially or adversely affect any of the Company's rights or obligations under this Agreement.

13.1.2. Company may without consent of Customer assign this Agreement to: (a) a legally authorized governmental or quasi-governmental agency charged with providing retail electric service in Michigan; (b) to any successor to Company that is a public utility regulated as to rates and service by the Commission pursuant to applicable Law; (c) as otherwise required by Law or by operation of Law; or (d) to an Affiliate of Company that is reasonably expected by the Parties to be capable of performing Company's obligations under this Agreement. Customer agrees that such assignment and delegation shall operate to release Company from all (or such portion of) its responsibilities under this Agreement, except as may have accrued up to the effective date of such assignment. Upon an

assignment consistent with this Section 13.1.2, the assignor shall be relieved of any and all liabilities and obligations under this Agreement.

- 13.2. This Agreement may not be assigned to a Sanctioned Person. Neither Party may suffer a change of ownership or control, whether direct or indirect, voluntary or by operation of Law, such that a Party becomes a Sanctioned Person.

14. **Dispute Resolution; Governing Law; Venue**

- 14.1. Dispute Resolution. In the event a controversy, claim or dispute arises between the Parties regarding the application or interpretation of any provision of this Agreement or the breach, termination or validity thereof (each, a “**Dispute**”), the Party alleging the Dispute shall provide Notice to the other Party of the Dispute. If the Parties shall have failed to resolve the Dispute within thirty (30) calendar days after delivery of such written notice, each Party shall, within ten (10) Business Days after receipt of a written demand from the other Party to do so, direct a senior executive (Vice President level or above) to confer in good faith with a senior executive of the other Party to resolve the Dispute. Should the Parties be unable to resolve the Dispute to their mutual satisfaction within twenty (20) Business Days after the initial meeting of the senior executives, each Party shall have the right to pursue its rights under Law or in equity.
- 14.2. Governing Law. This Agreement and all Disputes arising between the Parties under this Agreement shall be governed exclusively by the Laws of the State of Michigan, without reference to its choice of Law rules, except as to any matters subject to federal Law and the exclusive jurisdiction of FERC.
- 14.3. Venue. Any controversy or claim outside the jurisdiction of the Commission or FERC shall be settled or appealed, as applicable, in the federal courts located in the Eastern District of Michigan, and only to the extent that federal jurisdiction cannot be established for such controversy or claim, the state courts located in the Eastern District of Michigan, and each Party hereby submits itself to the exclusive jurisdiction of such courts.

15. **Indemnification**

- 15.1. Notwithstanding any other provision of this Agreement and to the fullest extent permitted by Law, each Party agrees to protect, defend, indemnify and hold the other Party, including its directors, officers, employees, attorneys-in-fact, agents and Affiliated companies (“**Indemnified Parties**”), free and harmless from and against (a) any and all loss, damage, and liability to third-parties for property damage, and (b) any and all third-party claims for damages on account of or by reason of bodily injury, including death, which may be sustained or claimed to be sustained by any person, each (a) and (b) to the extent arising in connection with this Agreement and due to the gross negligence or willful misconduct of the indemnifying Party or its agents, employees or subcontractors.
- 15.2. To the extent permitted by Law, Company and Customer waive the benefit for themselves and all subcontractors, insofar as the indemnification of the other is concerned, of the provisions of any applicable Workers' Compensation Law limiting the tort or other liability of any employer on account of injuries to the employer's employees.
- 15.3. Notwithstanding the foregoing, the Indemnified Party shall be entitled, at its own cost, if it so elects, to representation by attorneys of its own selection, including attorneys employed by it.

- 15.4. The Indemnified Party shall be the sole judge of the acceptability of any compromise or settlement of any claims or actions and no such compromise or settlement shall be made by the indemnifying Party without the Indemnified Party's prior written consent, which shall not be unreasonably withheld; provided, that such consent shall not be required if (x) the settlement agreement contains a complete and unconditional release of the Indemnified Parties, (y) the settlement agreement obligates the indemnifying Party to pay the full amount of any claims attributable to the Indemnified Parties concurrently with the settlement, and (z) the settlement agreement does not contain any direct or indirect requirements upon or provisions for the Indemnified Parties, directly or indirectly encumber any of the assets of the Indemnified Parties, require any admission of liability by the Indemnified Parties or involve criminal liability.
- 15.5. The obligation of each Party to indemnify the other hereunder shall survive the termination or cancellation of this Agreement.

16. Relationship Clause.

The execution of this Agreement or any Related Agreements shall not create, nor shall this Agreement or any Related Agreements be construed as creating any partnership, joint venture or agency relationship between the Parties hereto.

17. Relief Events

17.1. Notice and Mitigation.

17.1.1. In the event of a Force Majeure Event, or Customer Caused Event or Excusable Event ("Relief Event") impacting Company, the Company shall provide Notice to Customer describing the particulars of the occurrence of such Relief Event within ten (10) Business Days after Company first gains knowledge of such Relief Event. Such Notice will, to the extent of Company's knowledge thereof at such time, describe (i) the details and factual basis of the cause and nature of such Relief Event, (ii) the anticipated length of delay due to such Relief Event, (iii) the estimated additional costs (beyond those anticipated before the occurrence of such Relief Event) to be incurred by Company as a result of such Relief Event and (iv) any other effect on Company's performance of its obligations hereunder.

17.1.2. Any delay in performance caused by any Relief Event will be of no greater scope and of no longer duration than is reasonably required by such occurrence. The Company will furnish the Customer with regular reports with respect thereto during the continuation of any such Relief Event. The Company shall use commercially reasonable efforts to mitigate the cause of and effect on the Company's performance hereunder of any such Relief Event and the Company will promptly resume full performance of its obligations hereunder once it is able to do so. For the avoidance of doubt, such commercially reasonable efforts shall, at a minimum, require compliance with the provisions set forth in Section 17.1, as applicable.

17.1.3. Company shall not be responsible or liable for any damages, or be deemed to be in breach of this Agreement because of any failure or delay in complying with its obligations under or pursuant to this Agreement, in each case, to the extent that such failure is caused by a Relief Event and the Company has otherwise complied with this Section 17.

17.2. Changes in Law Rendering Performance Illegal. In the event of a Change in Law at any time during the Term which renders the performance of this Agreement by either or both Parties illegal

or all or a material portion of this Agreement unenforceable, this Agreement shall be automatically terminated effective upon Notice from a Party to the other Party. If this Agreement is terminated in accordance with this Section 17.2, either Party shall have the right, but not the obligation, to terminate the Related Agreements.

- 17.3. Cost and Schedule Relief for Customer Caused Event. In the event of a Customer Caused Event, in addition to its rights under Section 17.1, Company shall be entitled to (i) an equitable extension of all of its obligations pursuant to this Agreement that are actually and demonstrably delayed by such Customer Caused Event, and (ii) reimbursement for all costs and expenses actually and demonstrably incurred by the Company as a result of such Customer Caused Event.
- 17.4. Relief for Excusable Events and Force Majeure Events. In the event of an Excusable Event, or a Force Majeure Event that is reasonably expected to result in a delay in Company's ability to meet its obligations under this Agreement, then Company shall be entitled to an equitable extension of its obligations pursuant to this Agreement.
- 17.5. Schedule Relief for Change in Law. In the event of a Change in Law, Company shall be entitled to an equitable extension of all of its obligations pursuant to this Agreement that are actually and demonstrably delayed by such Change in Law.

18. **Miscellaneous**

- 18.1. Notice. Any notice, consent, approval or other communication under this Agreement (each a "Notice") shall be in writing (which shall include electronic mail) and shall be personally delivered or sent by a courier or transmitted by electronic mail to a Party as follows or to such other address as the Party may substitute by Notice in accordance with this Section 18.1 after the date of this Agreement:

If to Company:

DTE Electric Company
One Energy Plaza



CONFIDENTIAL - Subject to Nondisclosure Agreement



- 18.2. Company's Rate Book shall be incorporated herein. As of the Contract Date, the link to access Company's Rate Book can be found at <https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/electric/dte/dtee1cur.pdf?rev=cf55d05b027a43fc9d4f762672e9aa9e&hash=D28CE34BD%20%2007DCDD7279069015BB8121A>, which may be updated, revised and/or modified during the Term of the Agreement as approved or agreed to by the Commission.
- 18.3. All headings and captions contained in this Agreement are for convenience of reference only and shall not, in any way, affect the meaning of any provision hereof. No provision of this Agreement shall be interpreted more or less favorably towards either Party because its counsel drafted all or a portion hereof. The recitals set forth in this Agreement are an integral part hereof and shall have the same contractual significance as any other language contained in this Agreement. The provisions of this Section 18.3 shall survive termination or expiration of this Agreement.
- 18.4. The terms and provisions of this Agreement shall not be modified or waived except by the execution by the Parties of a written amendment to this Agreement. The waiver by a Party of a breach or violation of any provision of this Agreement will not operate as or be construed to be a waiver of any subsequent breach or violation thereof.

- 18.5. Each term and condition of this Agreement is deemed to have independent effect and the invalidity of any partial or whole paragraph or article shall not invalidate the remaining paragraphs or articles. The obligation to perform all of the terms and conditions shall remain in effect regardless of the performance of any invalid term by the other Party. Any entity that succeeds by purchase, merger, consolidation or other transfer to the properties of Company or Customer either substantially or as an entirety, shall be entitled to the rights and will be subject to the obligations of its predecessor in interest under this Agreement.
- 18.6. This Agreement shall not create any rights in third parties, and no provision of this Agreement will be construed as creating any obligations for the benefit of, or rights in favor of, any person or entity other than the Parties.
- 18.7. This Agreement shall be binding on the Parties hereto and on their respective successors, heirs and permitted assigns.
- 18.8. This Agreement and the Related Agreements, together with the Rate Schedule and Company's Rate Book, as may be amended from time to time, reflect the entire agreement among the Parties with respect to the subject matter hereof and supersedes all prior agreements and understandings among the Parties with respect to the subject matter hereof.
- 18.9. This Agreement may be executed by Pdf signatures or electronically, or in multiple counterparts, each of which will be deemed an original and all of which will constitute one and the same instrument.
- 18.10. Under no circumstances shall Customer transition to any Company Retail Access Service Rider as defined in Company's Rate Book during the Term of this Agreement.
- 18.11. Any provision of this Agreement that contemplates performance or observance subsequent to termination or expiration of this Agreement, or that is necessary to give effect to rights or obligations arising prior to such termination or expiration, shall survive and continue in full force and effect.
- 18.12. The Parties shall meet semi-annually to discuss operational and administrative matters and any other matters related to this Agreement or any Related Agreement.

[Remainder of Page Blank – Signatures on the Next Page]



CONFIDENTIAL - Subject to Nondisclosure Agreement

IN WITNESS WHEREOF, Company and Customer have each caused this Agreement to be duly executed by their authorized representatives identified below, effective as of the Contract Date.

COMPANY

DTE Electric Company



CONFIDENTIAL - Subject to Nondisclosure Agreement

Schedule 1

Required Amount Schedule

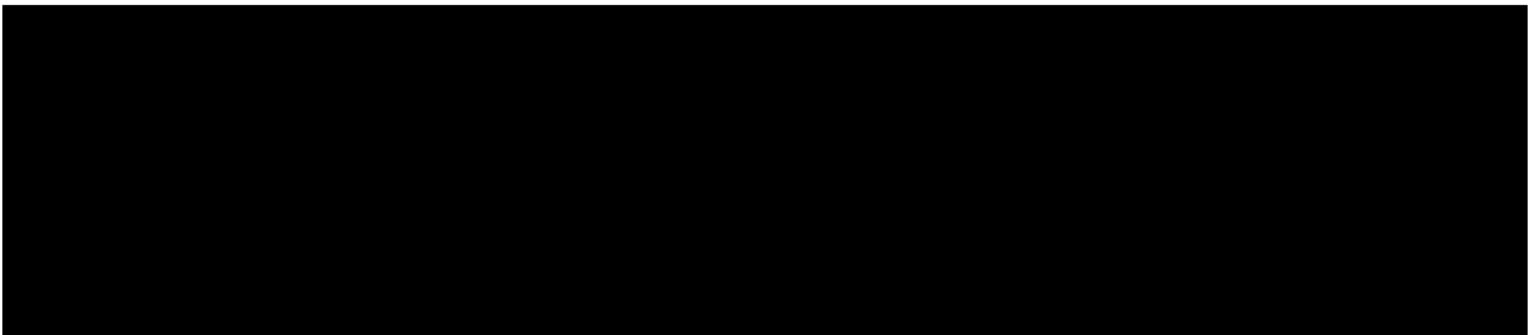
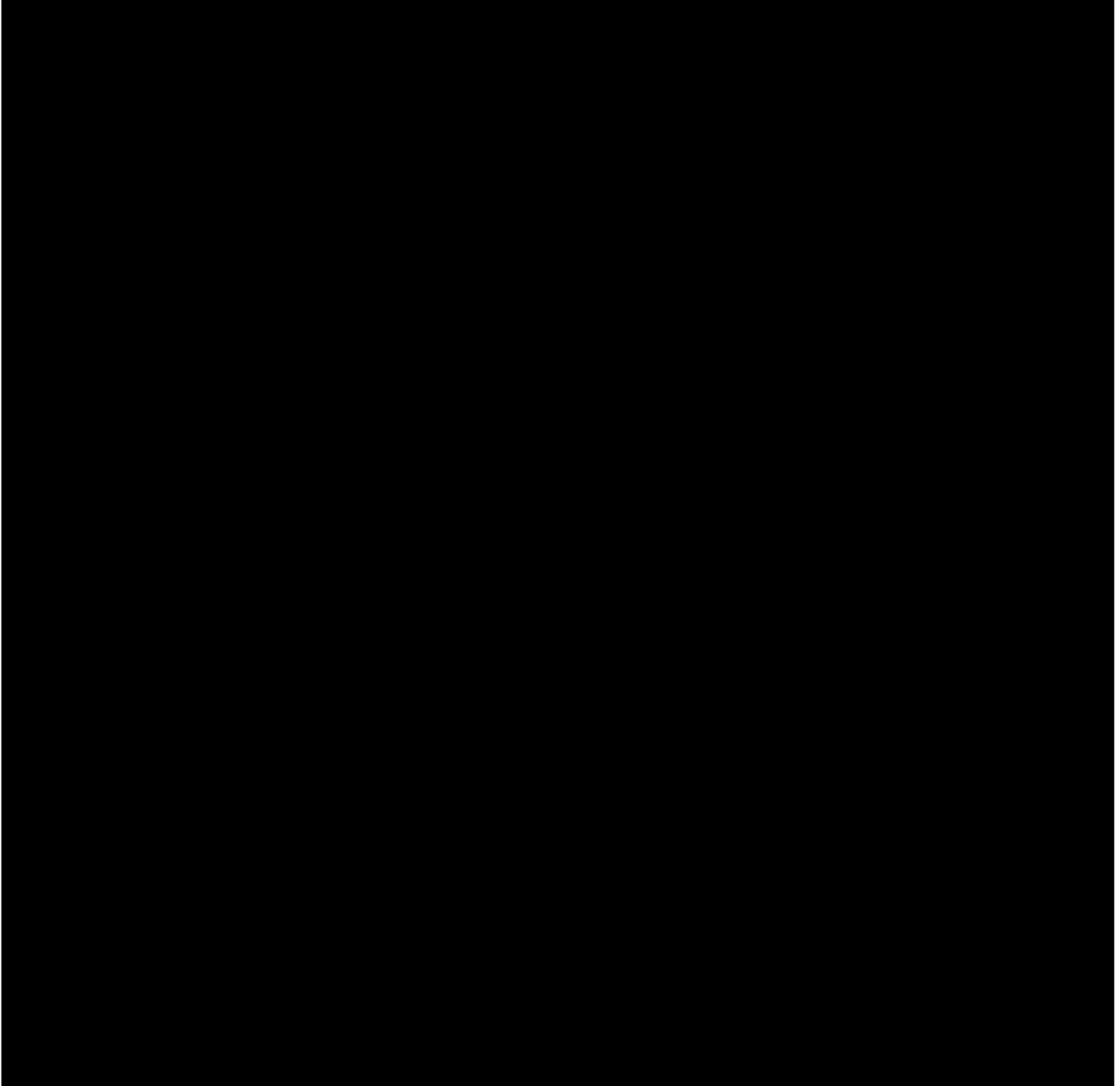


Exhibit A

Applicable Definitions

Capitalized terms used in the Agreement but not otherwise defined therein shall have the following meanings:

“**Affected Party**” has the meaning set forth in Section 4.4.2.

“**Affiliate**” means with regard to a Party, any person that directly or indirectly: (a) controls that Party; (b) is controlled by that Party; or (c) is under common control with that Party; where for each of (a), (b), and (c), “control” is defined as possession of the power to direct or cause the direction of the management and policies of a legally recognizable entity, through direct or indirect majority ownership or minimum percentage ownership that would grant the party a controlling interest in such entity.

“**Agreement**” has the meaning set forth in the preamble to this Agreement.

“**Appeal Order**” has the meaning set forth in Section 4.5.1.

“**Bankruptcy**” means that (i) an entity shall voluntarily commence any proceeding or file any petition seeking relief under Title 11 of the United States Code, as now constituted or hereafter amended, or any other federal, state or foreign bankruptcy, insolvency, receivership or similar law, (ii) an involuntary proceeding shall be commenced or an involuntary petition shall be filed in a court of competent jurisdiction seeking (A) relief in respect of an entity, or of a substantial part of its property or assets, under Title 11 of the United States Code, as now constituted or hereafter amended, or any other Federal, state or foreign bankruptcy, insolvency, receivership or similar law, (B) the appointment of a receiver, trustee, custodian, sequestrator, conservator or similar official for such entity or for a substantial part of its property or assets or (C) the winding-up or liquidation of an entity; and such proceeding or petition shall continue undismissed for 60 days or an order or decree approving or ordering any of the foregoing shall be entered; (iii) an entity shall consent to the institution of, or fail to contest in a timely and appropriate manner, any proceeding or the filing of any petition described in the foregoing clause (ii), (iv) an entity shall apply for or consent to the appointment of a receiver, trustee, custodian, sequestrator, conservator or similar official for itself or for a substantial part of its property or assets, (v) an entity shall file an answer admitting the material allegations of a petition filed against it in any such proceeding, (vi) an entity shall make a general assignment for the benefit of creditors, (vii) an entity shall become unable, admit in writing its inability or fail generally to pay its debts as they become due, or (viii) an entity shall take any action for the purpose of effecting any of the foregoing.

“**Business Days**” means any day other than Saturday, Sunday, Federal Reserve Bank holiday, or other day that is a holiday observed by Company.

“**Change in Law**” means the adoption, enactment or other effectuation, or any change in the judicial, regulatory or administrative application or interpretation, or any amendment, repeal or other modification, by any Governmental Authority of any Law that adversely affects either Party’s performance under this Agreement (including any Executive Order or similar directive from a state executive branch or the federal Executive Branch that changes the interpretation of any of the foregoing), in each case, after the Contract Date; provided, however, in the case of any new Law, order or any other legally binding requirement or directive or change to any existing Law, order or other legally binding requirement applicable to either Party’s performance of its obligations under this Agreement, in either case that is enacted prior to the Contract Date, but for which the effectiveness thereof occurs after the Contract Date, shall not constitute a Change in Law hereunder.

CONFIDENTIAL - Subject to Nondisclosure Agreement

“**Clean Capacity Accelerator Agreement**” means that certain Clean Capacity Accelerator Agreement entered into between the Parties as of even date hereof.

“**Commencement Date**” means the date on which the Customer first receives Electric Service at the Facility under this Agreement.

“**Commission**” has the meaning set forth in paragraph C of the Recitals to this Agreement.

“**Commission Approval Date**” means the earlier of: (i) the date on which the Commission issues its initial approval of this Agreement, (ii) the date on which the Parties reach mutual agreement on an amendment to this Agreement and/or waive their respective rights to terminate this Agreement in accordance with Section 4.4.1 following the Commission’s failure to grant approval (conditional or unconditional) of this Agreement, and (iii) the date on which the Parties reach mutual agreement on an amendment to this Agreement and/or waive their respective rights to terminate this Agreement in accordance with Section 4.4.2 following the Commission’s conditional approval of this Agreement.

“**Company**” has the meaning set forth in the preamble to this Agreement.

“**Company’s Rate Book**” has the meaning set forth in Section 1.

“**Conditions Precedent**” has the meaning set forth in Section 4.1.

“**Confidential Information**” has the meaning set forth in Section 10.1.

“**Contract Date**” has the meaning set forth in the preamble to this Agreement.

“**Credit Rating**” means with respect to an entity on any date of determination: (1) the respective rating then assigned to its senior unsecured and unsubordinated long-term debt or deposit obligations (not supported by third party credit enhancement) by S&P or Moody’s, as applicable, or (2) if such entity does not have a rating for its unsecured, senior, long-term debt, then the corporate rating or issuer rating, as applicable, then assigned to such entity by S&P or Moody’s, as applicable.

“**Customer**” has the meaning set forth in the preamble to this Agreement.

“**Customer Caused Event**” means (a) any demonstrable failures, delays or increased costs, in each case, in connection with Company’s performance of its obligations under this Agreement to the extent due to (i) any failure, delay or non-performance by Customer that adversely impacts Company’s performance of its obligations under this Agreement, or (ii) any Customer assignment and/or relocation pursuant to Section 13.1.1, (b) Customer’s failure to deliver ZRC Product (as such term is defined in the Clean Capacity Accelerator Agreement) to Company pursuant to Customer’s obligation in the Clean Capacity Accelerator

Agreement, or (c) Customer's failure to enter into an agreement with Company to backstop the costs associated with the Transmission Owner's Underground Cable Work pursuant to Section 9.7.

"Customer Committed Capacity Ramp" has the meaning set forth in paragraph A of the Recitals.

"Customer Credit Support" means the credit support provided by Customer to Company in the form of a Customer Parent Guaranty or Letter of Credit (or combination thereof) to support all of Customer's payment obligations due and owing under this Agreement, as required pursuant to Section 8.

"Customer LC Proceeds" has the meaning set forth in Section 8.2.1.

"Customer Parent Guarantor" has the meaning set forth in Section 8.1.

"Customer Parent Guaranty" has the meaning set forth in Section 8.1.

"Customer's Half-Hour Demand" means the single highest 30-minute integrated reading of Company's demand meter located at the Facility, which measures Customer's electrical usage.

"Data Center Location" means Van Buren Township, Michigan.

"Defaulting Party" has the meaning set forth in Section 7.1.

"Demand Charges" means the sum of all applicable demand charges (per kW) set forth in the Rate Schedule.

"Demand Response Agreement" means the Rider 12 Capacity Release Agreement entered into between the Parties as of even date hereof.

"Disclosing Party" has the meaning set forth in Section 10.1.

"Dispute" has the meaning set forth in Section 14.1.

"Early Termination Date" has the meaning set forth in Section 7.2.2.

[REDACTED]

"Effective Date" has the meaning set forth in Section 4.2.

"Electric Facilities" has the meaning set forth in in paragraph A of the Recitals to this Agreement.

"Electric Service" has the meaning set forth in in paragraph A of the Recitals to this Agreement.

[REDACTED]

"Event of Default" has the meaning set forth in Section 7.1.

"Excusable Event" has the meaning set forth in Section 2.3.

"Facility" means the data center facility that Customer intends to construct, commission, own and operate in Van Buren Township, Michigan.

"FERC" means the Federal Energy Regulatory Commission or its successor.

“**Financing Party**” means any lender providing debt or equity financing to Company in connection with its use of the Facilities.

“**Force Majeure Event**” means any event or circumstance, or combination of events or circumstances, arising after the Contract Date, whether impacting a Party directly or impacting a Party’s Affiliates or any applicable contractor, subcontractor or supplier of a Party, that wholly or partly prevents or delays a Party or Project Party from performing any obligation under this Agreement, but only if and to the extent:

- (a) such event or circumstance, or combination of events or circumstances, is not within the reasonable control of the Party or Project Party, as applicable;
- (b) The Party or Project Party has used reasonably diligent efforts in taking precautions and measures to (i) avoid the effect of such event or circumstance, or combination of events or circumstances, on the Party or Project Party and (ii) mitigate the consequences thereof;
- (c) such event or circumstance, or combination of events or circumstances, does not result from the failure of the Party or Project Party to perform any of its obligations under this Agreement; and
- (d) such event or circumstance, or combination of events or circumstances, could not have been (i) reasonably anticipated or (ii) avoided by the exercise of reasonable diligence and care.

A “**Force Majeure Event**” shall include, without limitation, the following; provided, that such event, circumstance, or combination of events or circumstances, meets all of the requirements in clauses (a)-(d) of the immediately preceding sentence: expropriation; invasion; drought, landslide, tornado, hurricane, tsunami, flood, lightning, earthquake, and other acts of God; fire; explosion; plague, epidemic and/or pandemic; invasion, acts of terrorism, war (declared or undeclared), or other armed conflict; riot, revolution, insurrection, or similar civil disturbance or commotion; acts of the public enemy; perils of sea; blockade; port closure; sabotage or vandalism; except as set forth in the next sentence below, strikes and other labor disputes (including collective bargaining disputes and lockouts) involving a Party or Project Party and not directed exclusively at such Party or Project Party; material physical damage caused by third parties; transportation accidents; delays in transportation caused by an independent Force Majeure Event, including delays due to closure of roads or other transportation route by Governmental Authorities or otherwise due to a Force Majeure Event; embargoes; other acts or omissions of a Governmental Authority (other than such acts or omissions in response to acts or omissions of the affected Party or Project Party); and in the event that Company does not achieve the Indicative Clean Capacity Portfolio, Company’s failure to procure supply from the market to meet the Customer Committed Capacity Ramp due to a lack of available MISO capacity (as reasonably determined by Company on a non-discriminatory basis and taking into account any applicable import restrictions placed on Company by MISO, the Transmission Owner or any Governmental Authority). Nothing in this provision shall obligate a Party to prevent or settle any labor disturbance or dispute involving its employees or contractors on terms it does not, in its sole discretion, consider advisable.

In addition, notwithstanding anything to the contrary set forth in this Agreement, to the extent any event or circumstance, or combination of events or circumstances qualifies as a “Force Majeure Event” or other similar defined term in any agreement executed by Company, or its Affiliate on behalf of Company, in connection with performing Company’s obligations under this Agreement, then such event, circumstance, or combination of events or circumstances shall qualify as a Force Majeure Event pursuant to this Agreement.

“**Governmental Authority**” means any federal, state, local, municipal, or other governmental, regulatory, administrative, quasi-governmental, judicial, public or statutory instrumentality, court or governmental tribunal, agency, commission authority, body or entity, or any political subdivision thereof, including MISO or its successor, having legal jurisdiction over the matter or person in question.

“**Indicative Clean Capacity Portfolio**” has the meaning ascribed to that term in the Clean Capacity Accelerator Agreement.

“**Initial Term**” has the meaning set forth in Section 3.1.

“**Interest Rate**” means the prime rate as published in The Wall Street Journal (or its successor publication) on the first Business Day of each calendar month, plus 200 basis points per annum.

“**kW**” means kilowatt.

“**Large Load Customer Tariff**” has the meaning set forth in Section 4.5.2.

“**Law**” or “**Laws**” means all laws, treaties, ordinances, statutes, judgments, decrees, injunctions, writs, orders, rules, regulations, tariffs, interpretations and permits of any Governmental Authority having jurisdiction of the transmission of electricity, performance of the work, all and each document, instrument and agreement delivered hereunder or in connection herewith, health and safety, or the environmental condition of the Data Center Location.

“**Letter of Credit**” means an irrevocable stand-by letter of credit, in a form agreed to by Company in writing, provided by Customer pursuant to Section 8 and issued by a Qualified Issuer.

“**Letter of Credit Default**” means, with respect to a Letter of Credit, the occurrence of any of the following events: (a) the Qualified Issuer that has issued such Letter of Credit (i) becomes subject to any Bankruptcy, (ii) fails to comply with or perform its obligations under such Letter of Credit if such failure shall be continuing after notice thereof and the lapse of any applicable grace period or (iii) disaffirms, disclaims, repudiates or rejects, in whole or in part, or challenges the validity of such Letter of Credit; (b) such Letter of Credit ceases to be in full force and effect during the period required by this Agreement; or (c) the issuer of such Letter of Credit ceases to meet the qualifications of a Qualified Issuer.

“**Line Extension Agreement**” means that certain Line Extension Agreement between Company and Customer entered into as of even date hereof.

“**Load Ramp Completion Date**” means the earlier of: (a) the date on which the final phase of the Customer Committed Capacity Ramp, as set forth in Exhibit B-1, is achieved, as such date shall be memorialized by the Parties in accordance with this Agreement; and (b) December 31, 2028, as such date may be revised pursuant to Section 2.1.

“**Losses**” has the meaning set forth in Section 12.1.

“**Meet and Confer Request**” has the meaning set forth in Section 4.4.2.

“**Minimum Monthly Charge**” has the meaning set forth in Section 5.2.

“**MISO**” means the Midcontinent Independent System Operator.

“**MISO Notice**” has the meaning set forth in Section 5.3.3.

“**MISO Planning Resource Auction**” has the meaning ascribed to the term “Planning Resource Auction” in the MISO Tariff and shall include any successor term and mechanism used by MISO to purchase and sell capacity.

“**MISO Tariff**” means the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.

“**Monthly Billing Demand**” means the single highest 30-minute integrated reading of Customer’s demand meter in a given billing period.

“**Monthly On-Peak Billing Demand**” means the single highest 30-minute integrated reading of the demand meter during the on-peak hours (as defined in the Company’s Rate Book) of the billing period. The Monthly On-Peak Billing Demand will not be less than 65% of the highest monthly on-peak metered billing demand during the billing months of June, July, August, September, and October of the preceding eleven billing months, nor less than 50 kilowatts.

“**Moody’s**” means Moody’s Investors Service, Inc. or its successor.

“**MW**” means megawatt.

“**Negotiation Period**” has the meaning set forth in Section 2.4.2.

“**Notice**” has the meaning set forth in Section 18.1.

“**Operating Parameter Deadline**” has the meaning set forth in Section 5.5.2.

“**Operating Parameters**” has the meaning set forth in Section 5.5.2.

“**Operating Procedures**” has the meaning set forth in Section 5.5.3.

“**Original PSA**” has the meaning set forth in paragraph A of the Recitals.

“**Overage**” has the meaning set forth in Section 5.3.1.

“**Parties**” has the meaning set forth in the preamble to this Agreement.

“**Party**” has the meaning set forth in the preamble to this to this Agreement.

“**Project**” means any asset, resource, or project that Company develops, constructs, leases, utilizes, and/or purchases to provide Electric Service to Customer’s Facility pursuant to agreements in connection with the Clean Capacity Accelerator Agreement, any Supplemental Agreement, and/or Company’s 2026 Electric Integrated Resource Plan, including without limitation tolling agreements, purchase and sale agreements, build-transfer agreements, development agreements, construction agreements, equipment supply agreements, lease agreements, capacity purchase agreements, demand response agreements, and similar agreements.

“**Project Agreement**” means any agreement entered into by Company with a Project Party to develop, construct, lease, utilize, purchase, and/or otherwise acquire a Project.

“**Project Party**” means, in connection with the development, construction, lease, utilization, purchase, ownership, operation or maintenance of a Project, Company or any counterparty to a Project Agreement or any of Company’s or such counterparty’s respective Affiliates, contractors, subcontractors or suppliers. For

the avoidance of doubt Customer, as counterparty to Company for the transfer of Zonal Resource Credits under the Clean Capacity Accelerator Agreement, shall be deemed a Project Party for purposes of this Agreement and any Related Agreement.

“Prudent Industry Practice” means the practices, methods and acts engaged in or approved by regulated electric utilities in the United States, that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected by a reasonably prudent business company of established reputation in the regulated electric utility industry to accomplish the desired result in a manner consistent with applicable Laws, regulations, codes, standards, equipment manufacturers’ recommendations, reliability, safety, environmental protection, economy and expedition. Prudent Industry Practice is a range of reasonable practices and does not necessarily mean the highest standard in the industry. For the avoidance of doubt, any practices, methods and/or acts approved by the Commission or as set forth in Company’s Rate Book shall be deemed “Prudent Industry Practice.”

“Qualified Issuer” means a commercial bank or trust company organized under the Laws of the United States or a political subdivision thereof or validly existing in the country of its organization that is registered to do business in the United States and has a branch office located in the United States, with (a) a Credit Rating of at least (i) “A-” by S&P or (ii) “A3” by Moody’s at any point in time and (b) a net worth of at least Ten Billion Dollars (\$10,000,000,000) at the time of issuance of a Letter of Credit.

“Ramp Grace Period” has the meaning set forth in Section 2.1.

“Rate Schedule” means Schedule D11 and may be changed in accordance with Section 5.1.

“Recipient” has the meaning set forth in Section 10.1.

“Related Agreement Completion Date” means the latest date on which the Parties execute: (a) the Clean Capacity Accelerator Agreement, (b) the Line Extension Agreement, and (c) the Demand Response Agreement.

“Related Agreements” means (a) the Clean Capacity Accelerator Agreement, (b) the Line Extension Agreement, (c) the Demand Response Agreement, and (d) any Supplemental Agreement.

“Relief Event” has the meaning set forth in Section 17.1.1.

“Renewal Term” has the meaning set forth in Section 3.2.

“Representatives” has the meaning set forth in Section 10.2.

“Revised Ramp Schedule” has the meaning set forth in Section 2.4.2.

“Sanctioned Country” means, at any time, a country or territory that is itself the target of comprehensive Sanctions (as of the date of this Agreement, Cuba, Iran, North Korea, the Crimea region of Ukraine, the so-called Donetsk People’s Republic, and the so-called Luhansk People’s Republic).

“**Sanctioned Person**” means (a) any person listed in any sanctions-related list of designated persons maintained by the Office of Foreign Assets Control of the U.S. Department of the Treasury (“OFAC”) or the U.S. Department of State, the United Nations Security Council, the European Union, any Member State of the European Union, or the United Kingdom; (b) any person operating, organized, or resident in a Sanctioned Country; (c) the government of a Sanctioned Country or the Government of Venezuela; or (d) any person 50% or more owned or, where relevant under applicable Sanctions, controlled by any such person or persons or acting for or on behalf of such person or persons.

“**Sanctions**” means economic or financial sanctions or trade embargoes imposed, administered or enforced from time to time by (a) the U.S. government, including those administered by OFAC or the U.S. Department of State, or (b) the United Nations Security Council, the European Union, any European Union Member State or the United Kingdom.

“**Schedule D11**” means Primary Supply Rate Schedule No. D11, as published in Company’s Rate Book and approved by the Commission as of the Contract Date, which is subject to change from time to time by order issued by the Commission.

“**Shortfall Capacity**” has the meaning set forth in Section 5.4.

“**Shortfall Capacity Rate**” means the auction clearing price, as established in the MISO Planning Resource Auction, for “Local Resource Zone 7” for the applicable billing period.

“**Standard & Poor’s**” or “**S&P**” means S&P Global Ratings or its successor.

“**Study Fee**” has the meaning set forth in Section 9.6.

“**Supplemental Agreement**” means any agreement entered into between the Parties following the Contract Date in connection with (i) another Related Agreement, (ii) providing electric capacity and/or energy to Customer’s Facility, or (iii) the construction of facilities to allow for provision of Electric Service to Customer.

“**Term**” has the meaning set forth in Section 3.2.

“**Termination Payment**” has the meaning set forth in Section 7.3.

“**Transition Date**” has the meaning set forth in Section 4.5.2.

“**Transmission Owner**” means ITC Holdings Corporation and its Affiliates.

“**Underground Cable MOU**” has the meaning set forth in Section 9.7.

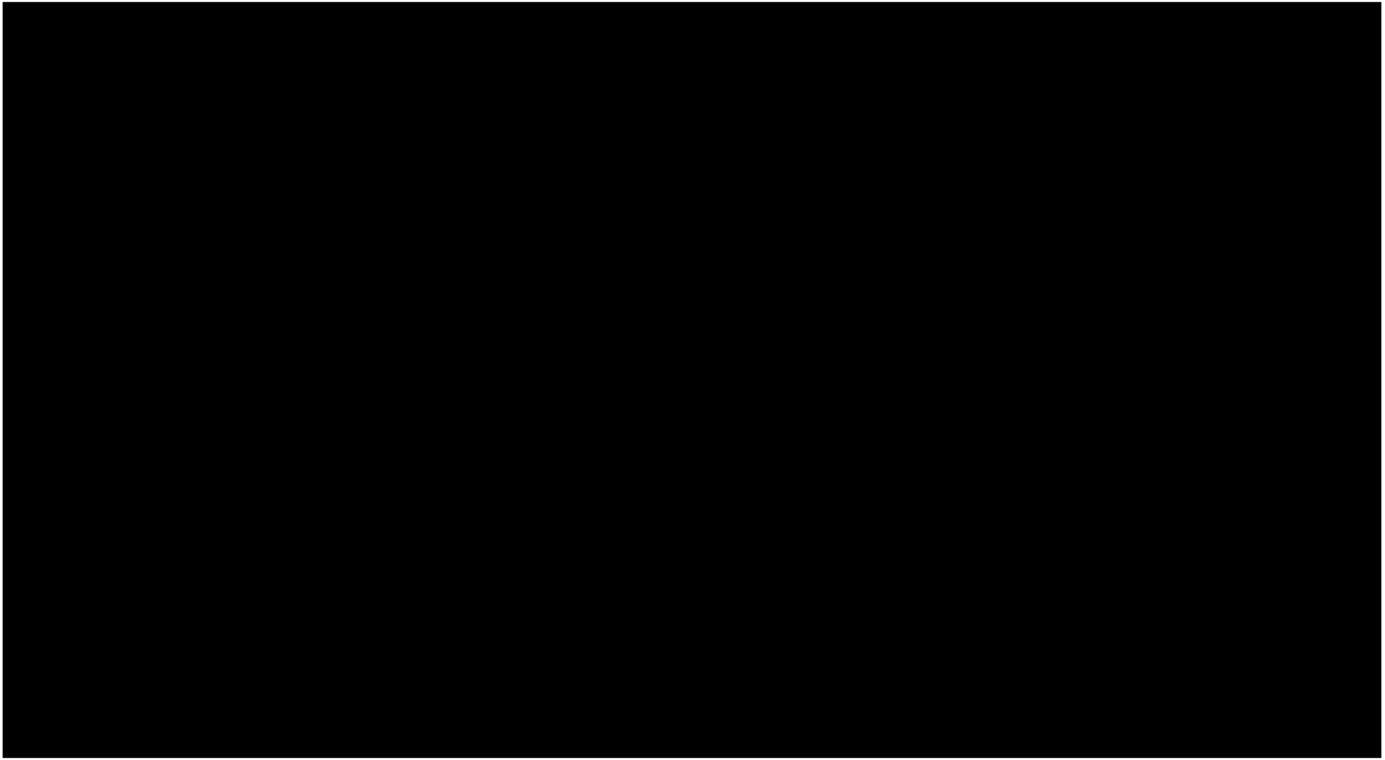
“**Underground Cable Work**” has the meaning set forth in Section 9.7.

“**Zonal Resource Credits**” has the meaning ascribed to that term in the MISO Tariff.

CONFIDENTIAL - Subject to Nondisclosure Agreement

Exhibit B-1

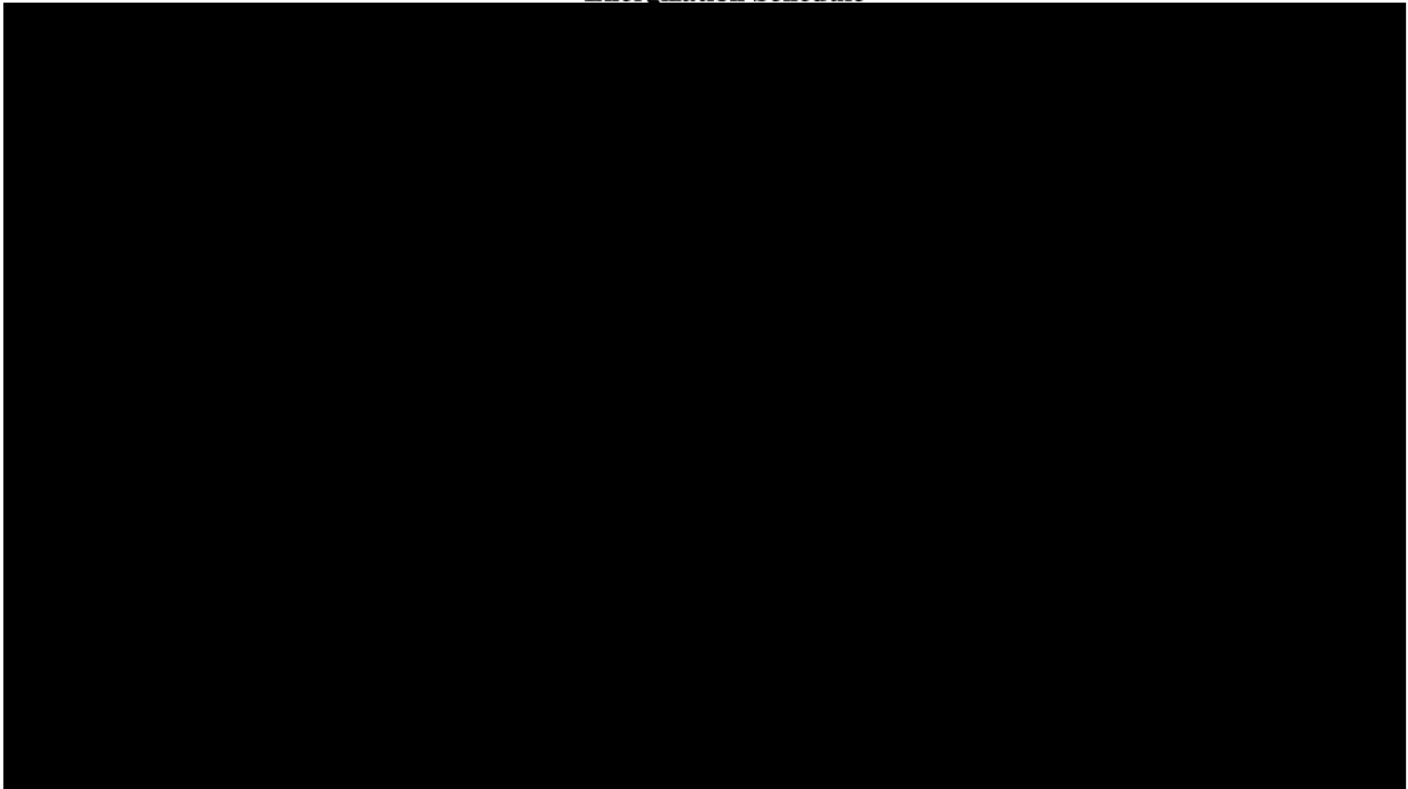
Customer Committed Capacity Ramp



CONFIDENTIAL - Subject to Nondisclosure Agreement

Exhibit B-2

Energization Schedule

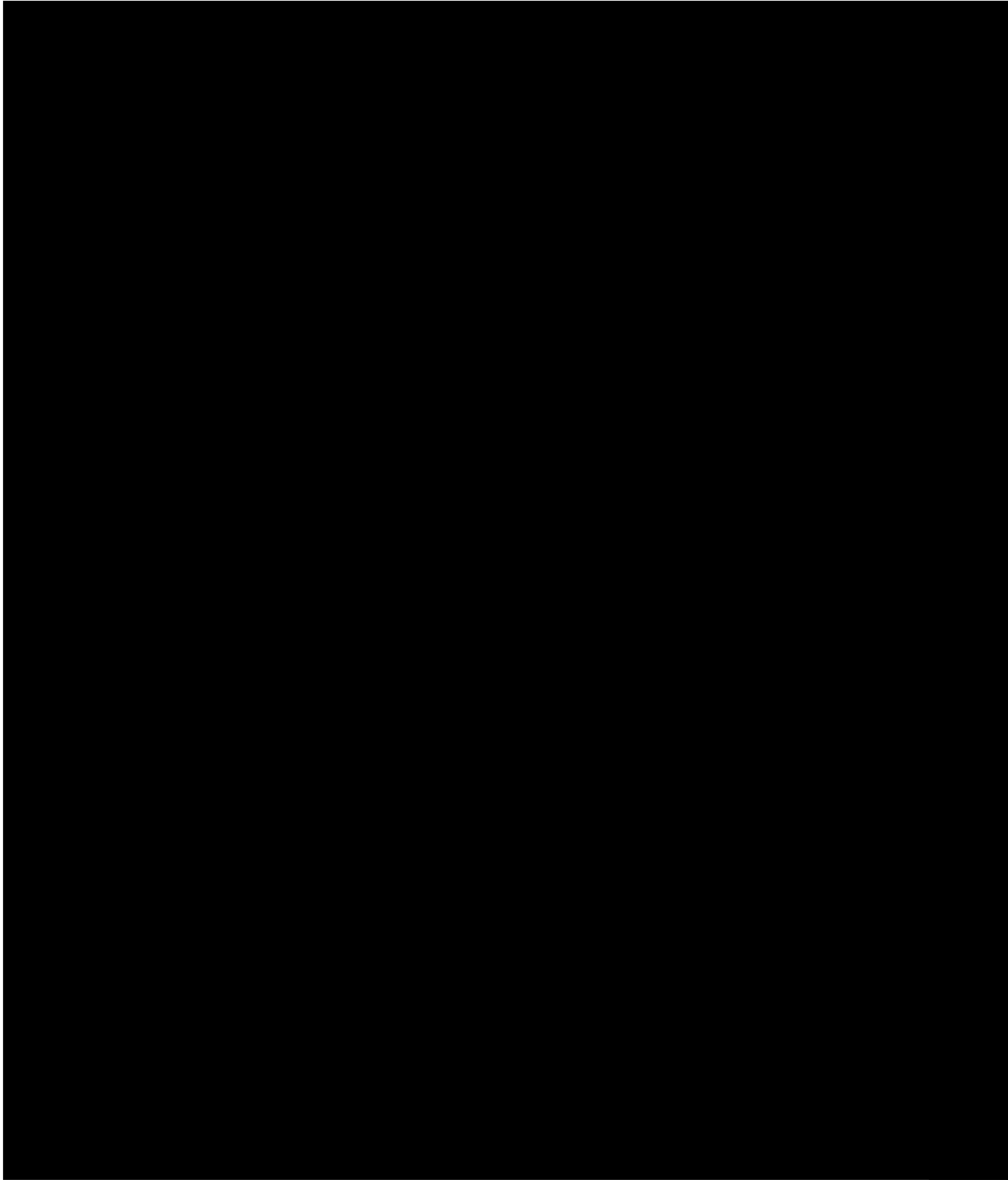




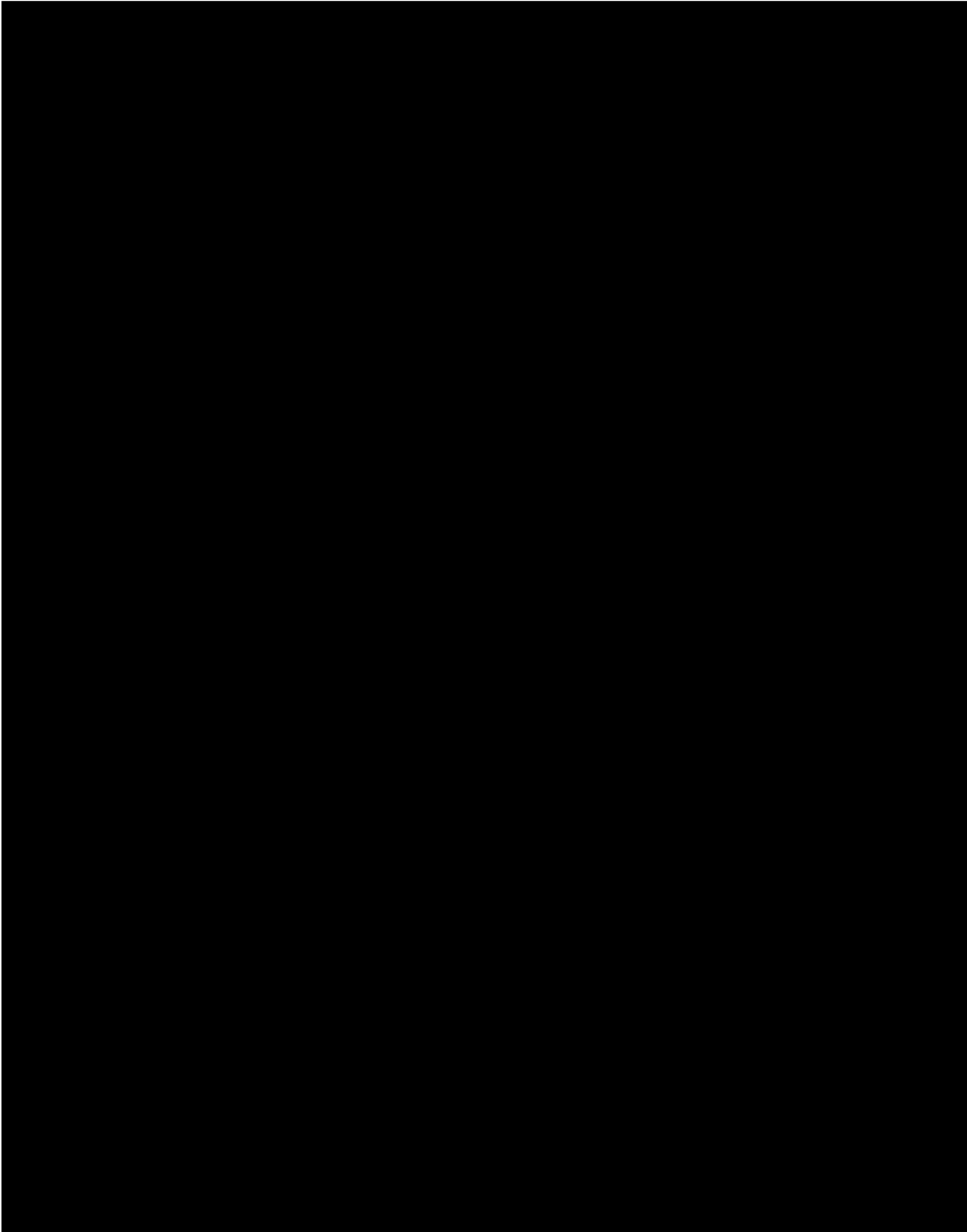
CONFIDENTIAL - Subject to Nondisclosure Agreement

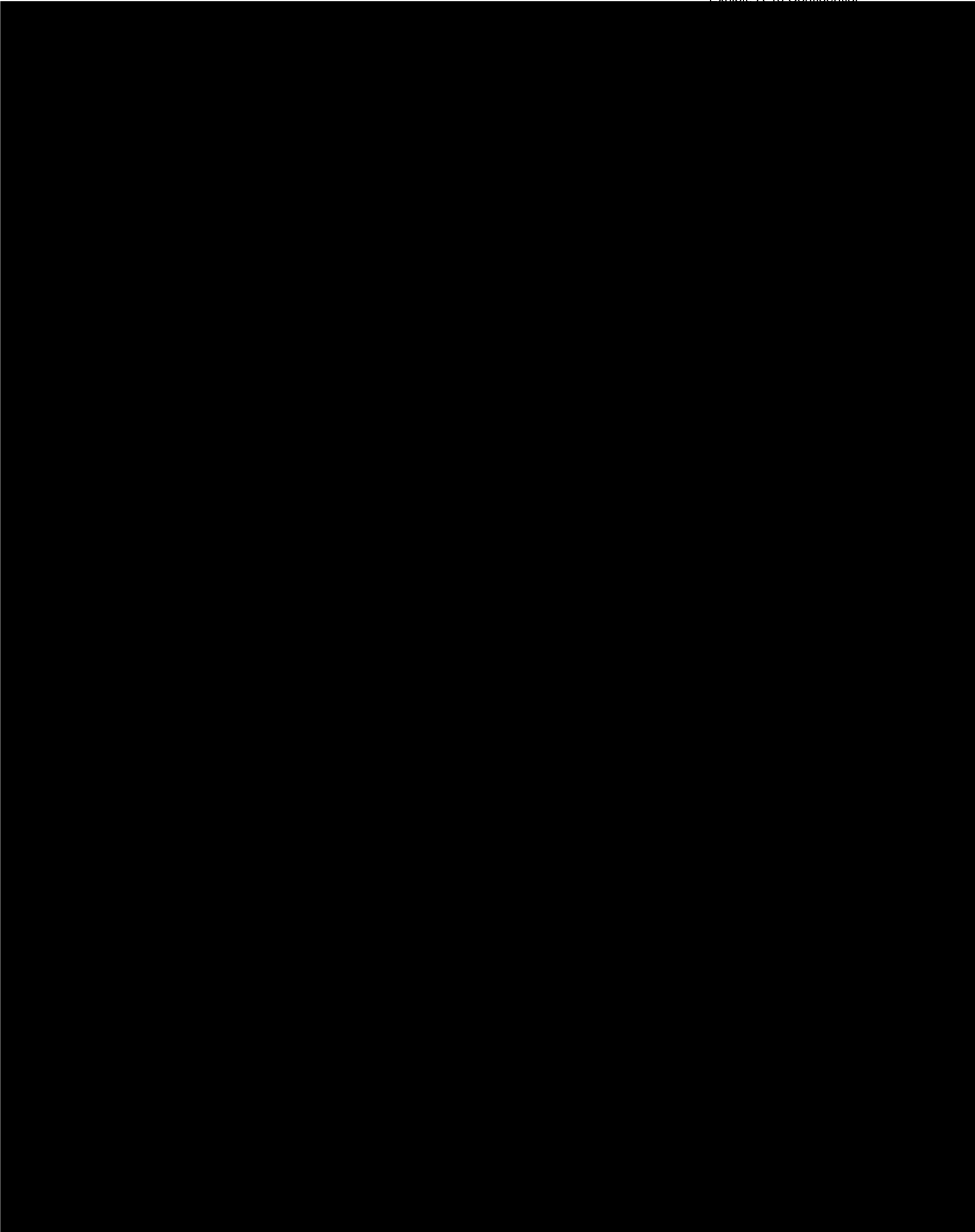
Exhibit C

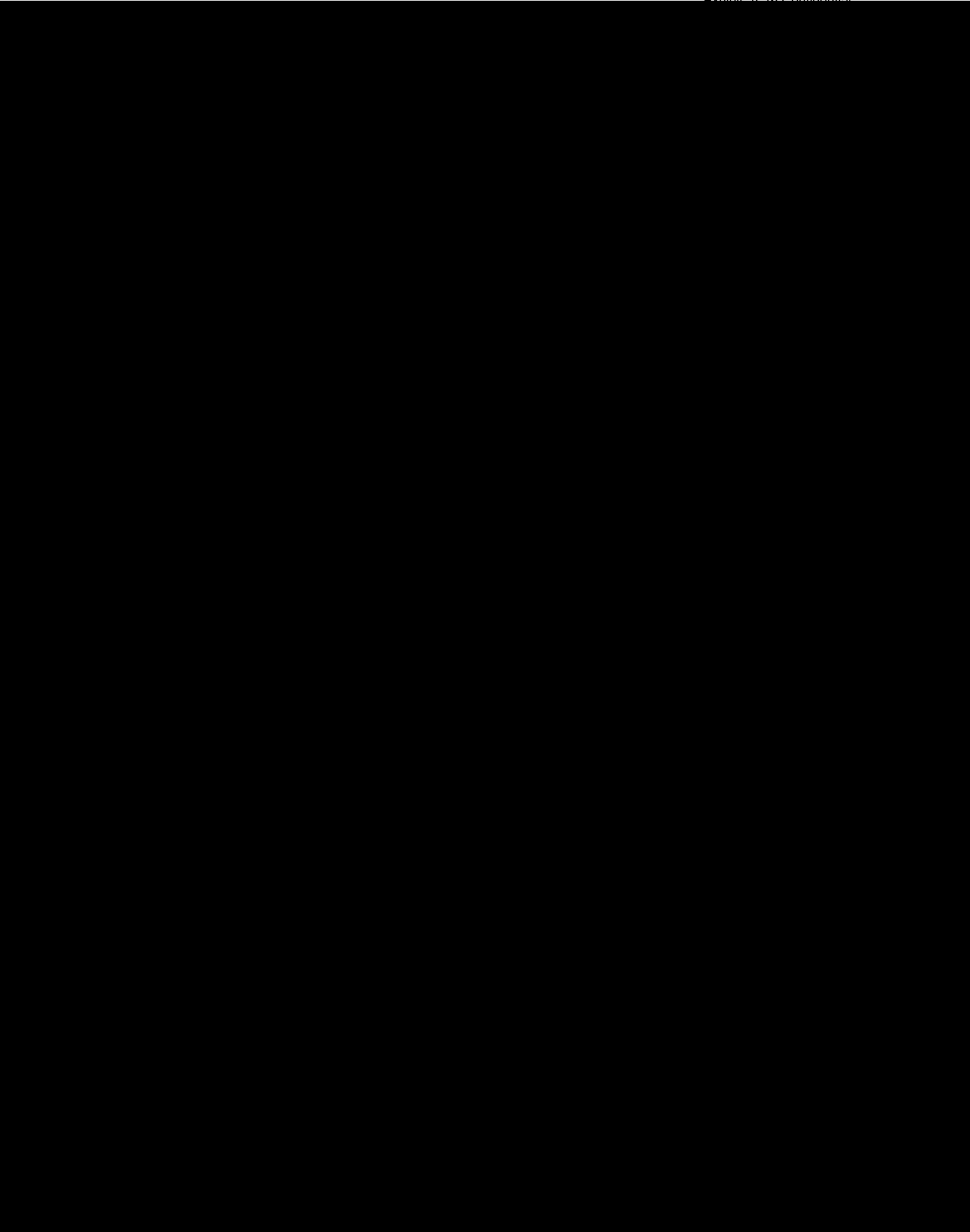
Form of Customer Parental Guaranty



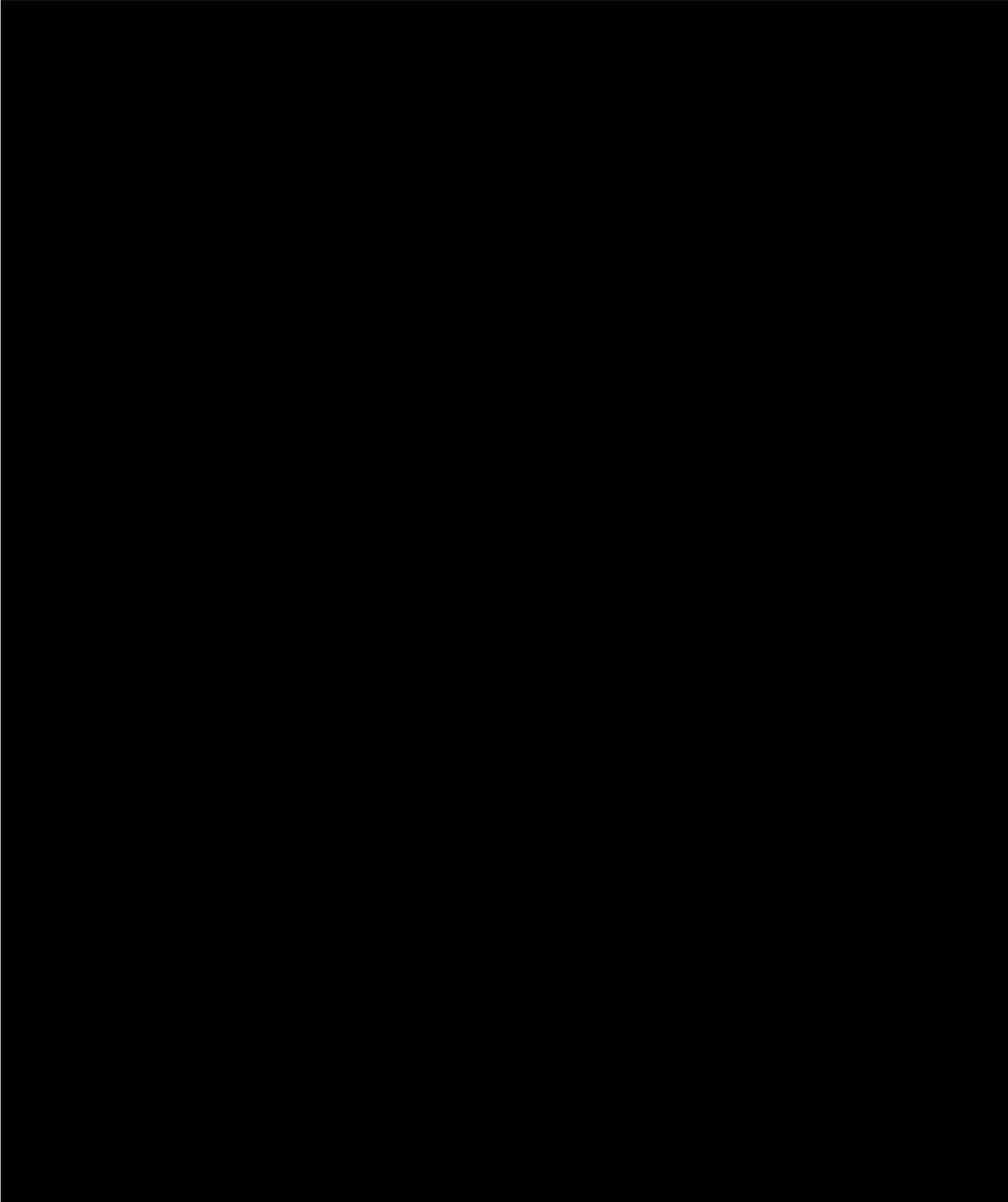
CONFIDENTIAL - Subject to Nondisclosure Agreement







Schedule 1

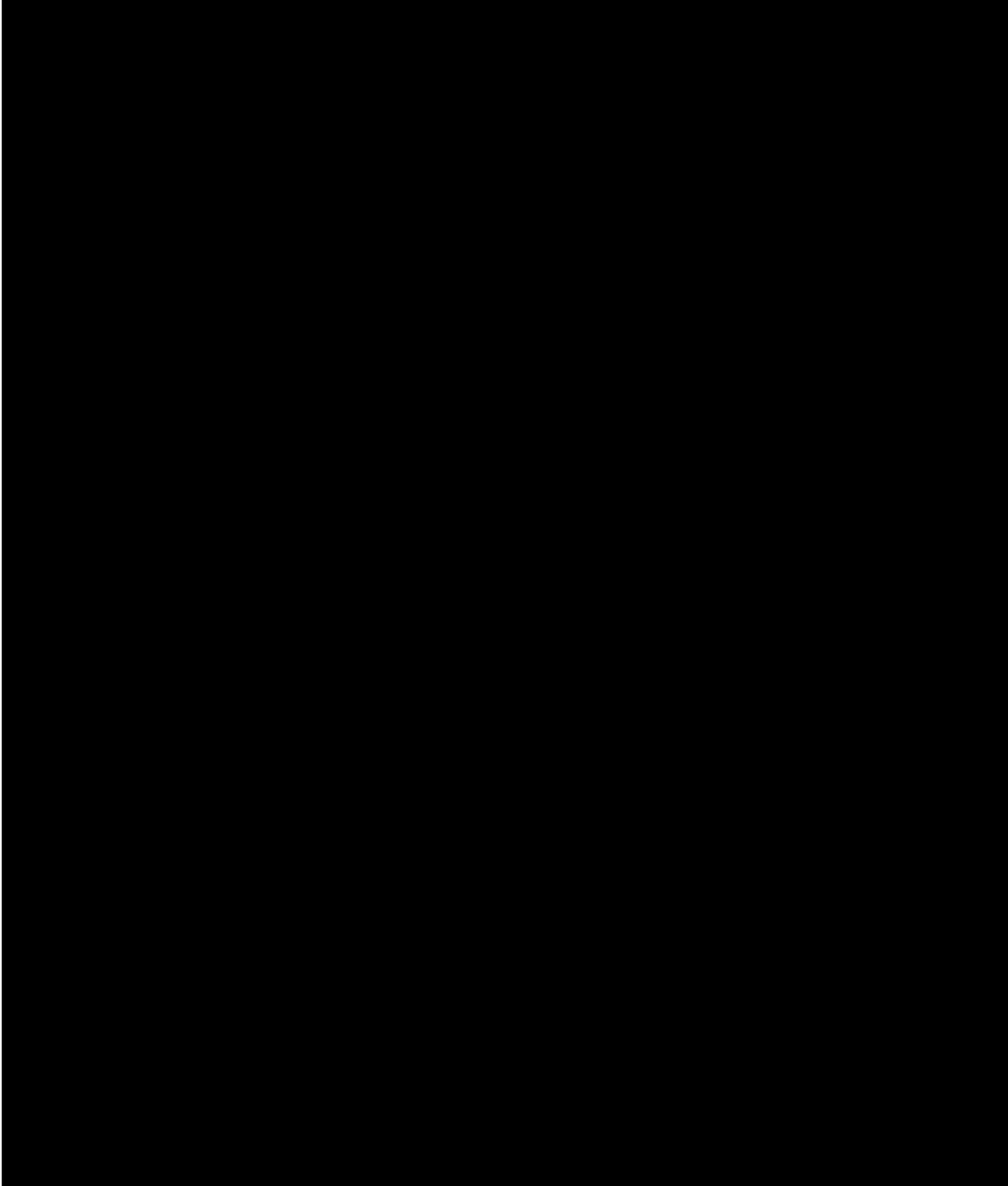




CONFIDENTIAL - Subject to Nondisclosure Agreement

Exhibit D

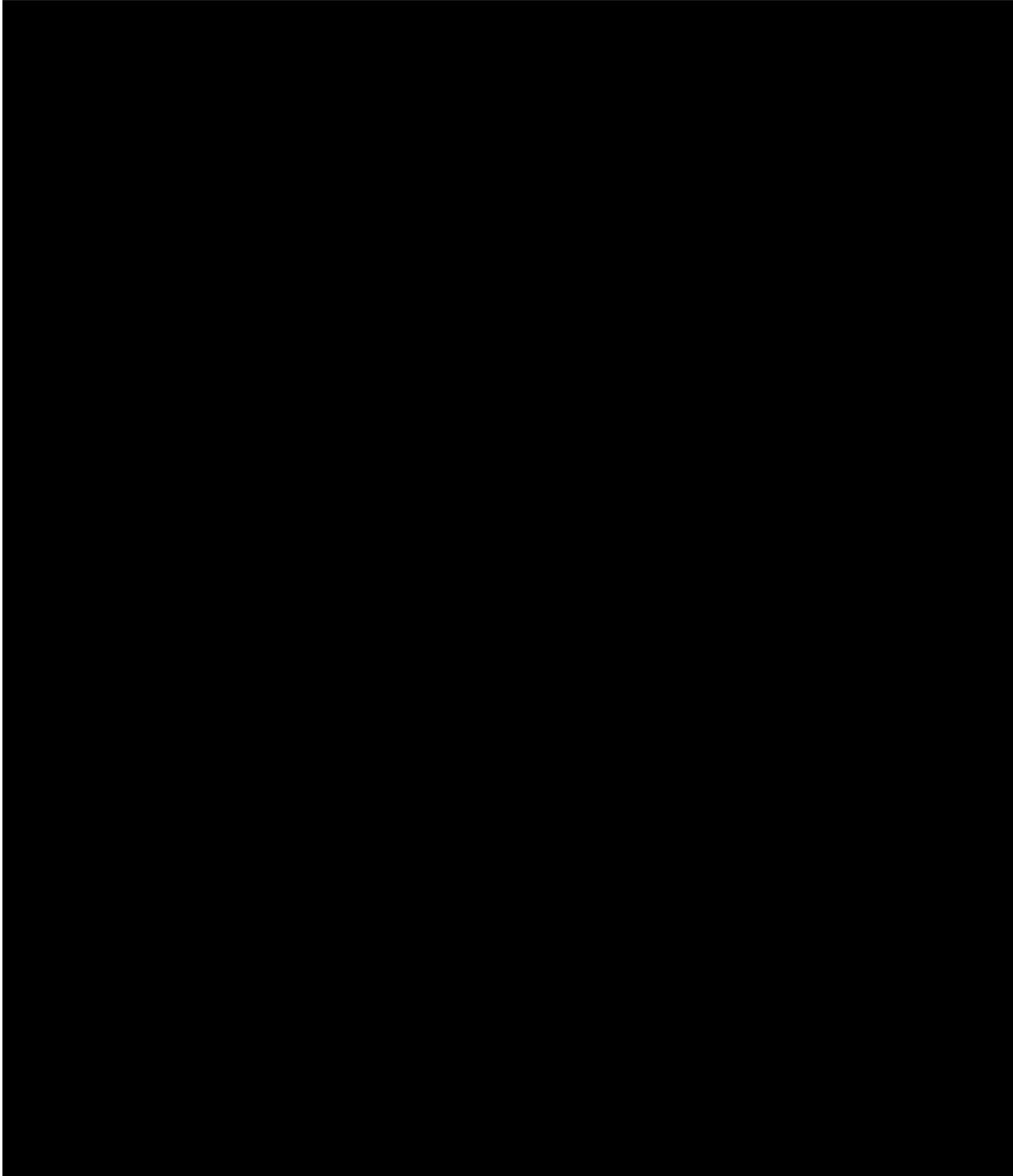
Sample Invoices

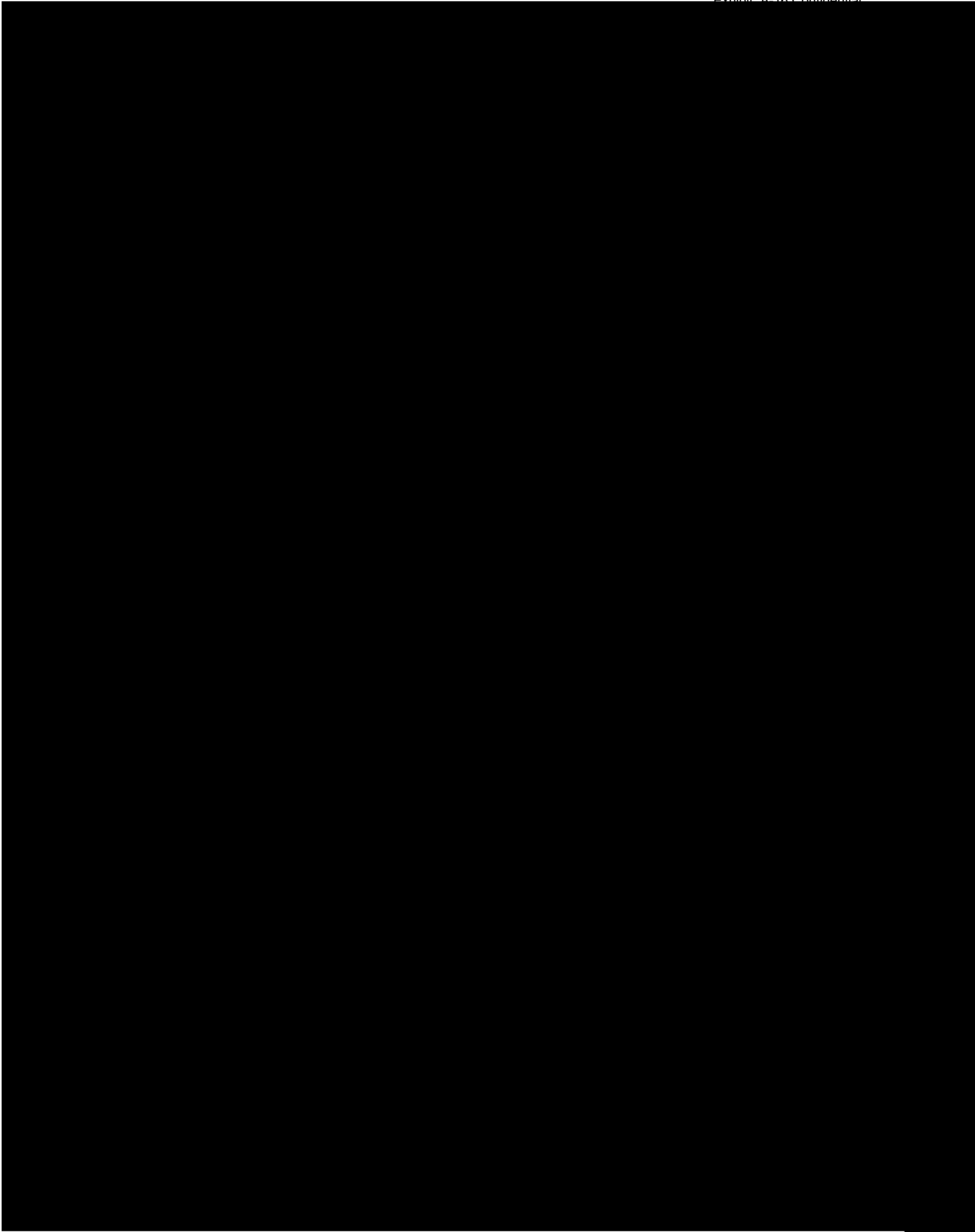


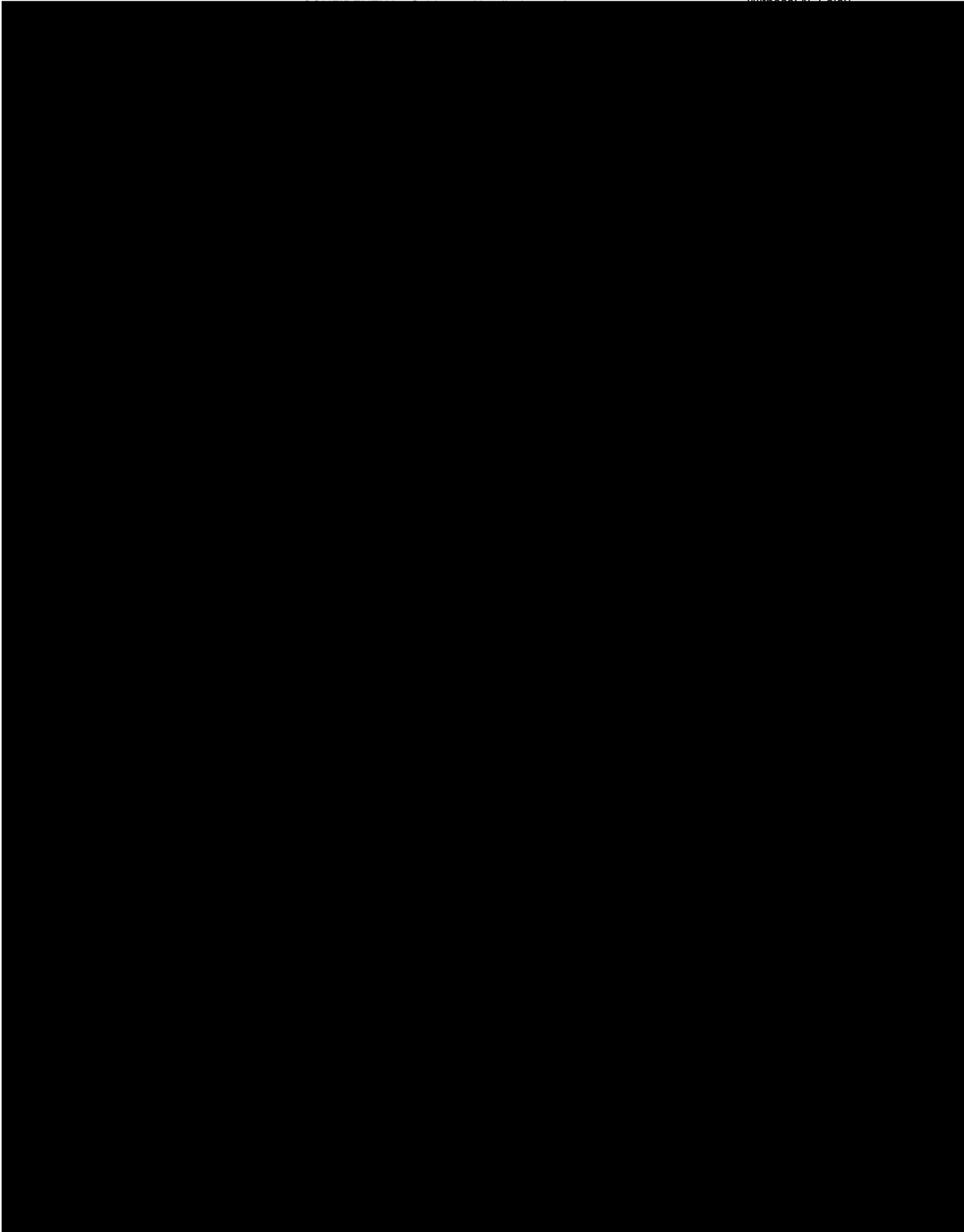
CONFIDENTIAL - Subject to Nondisclosure Agreement

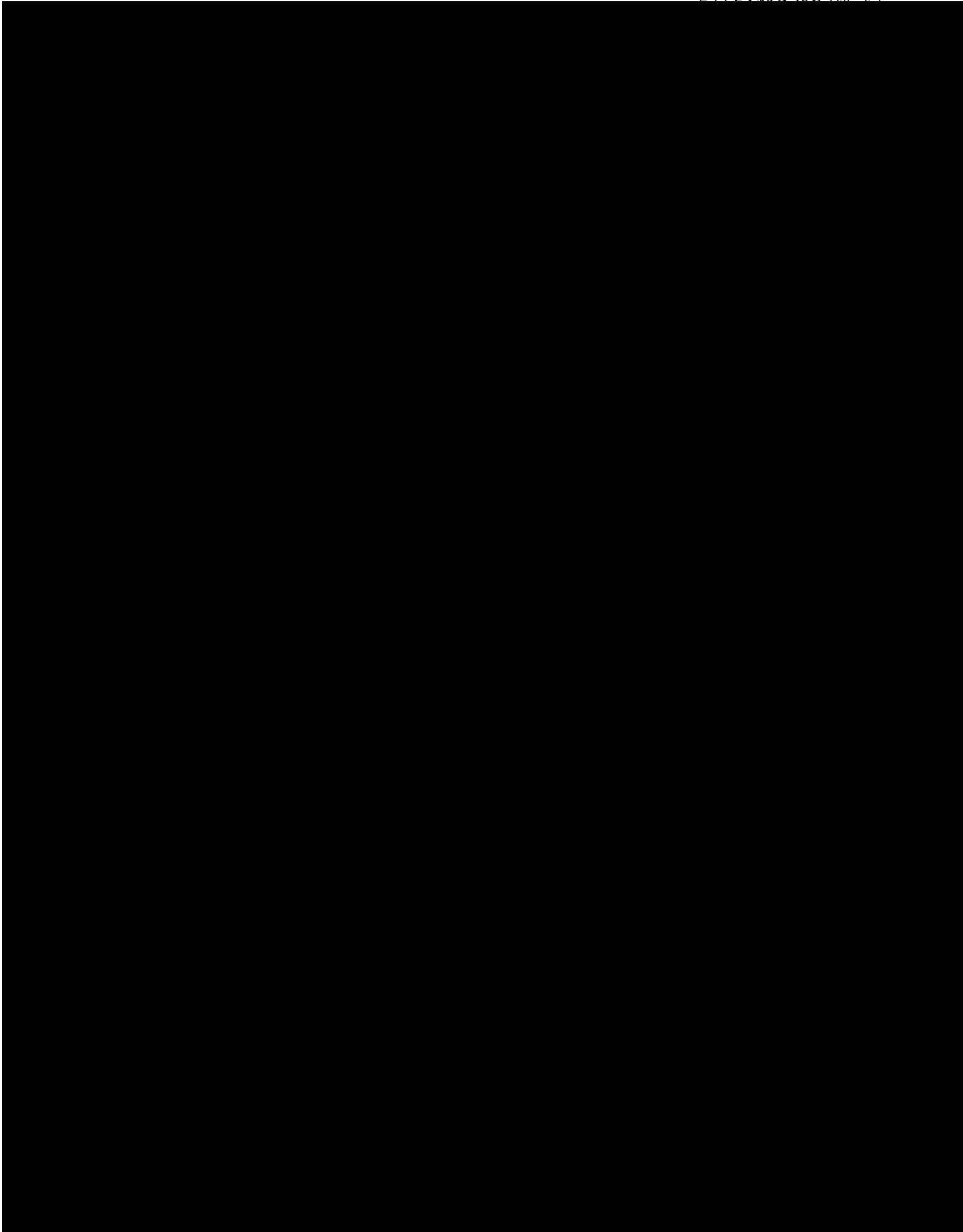
Exhibit E

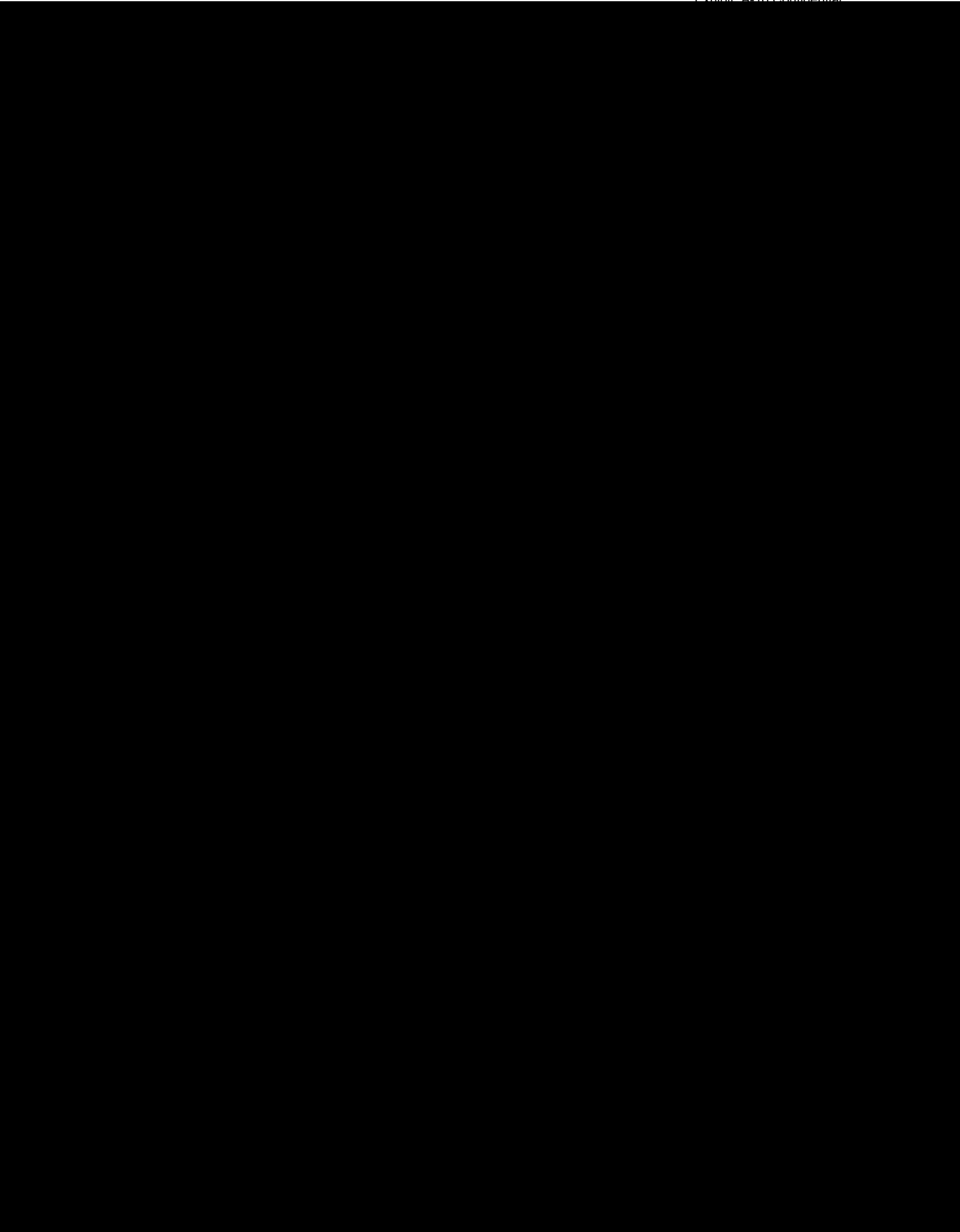
Sample Termination Payment Calculation











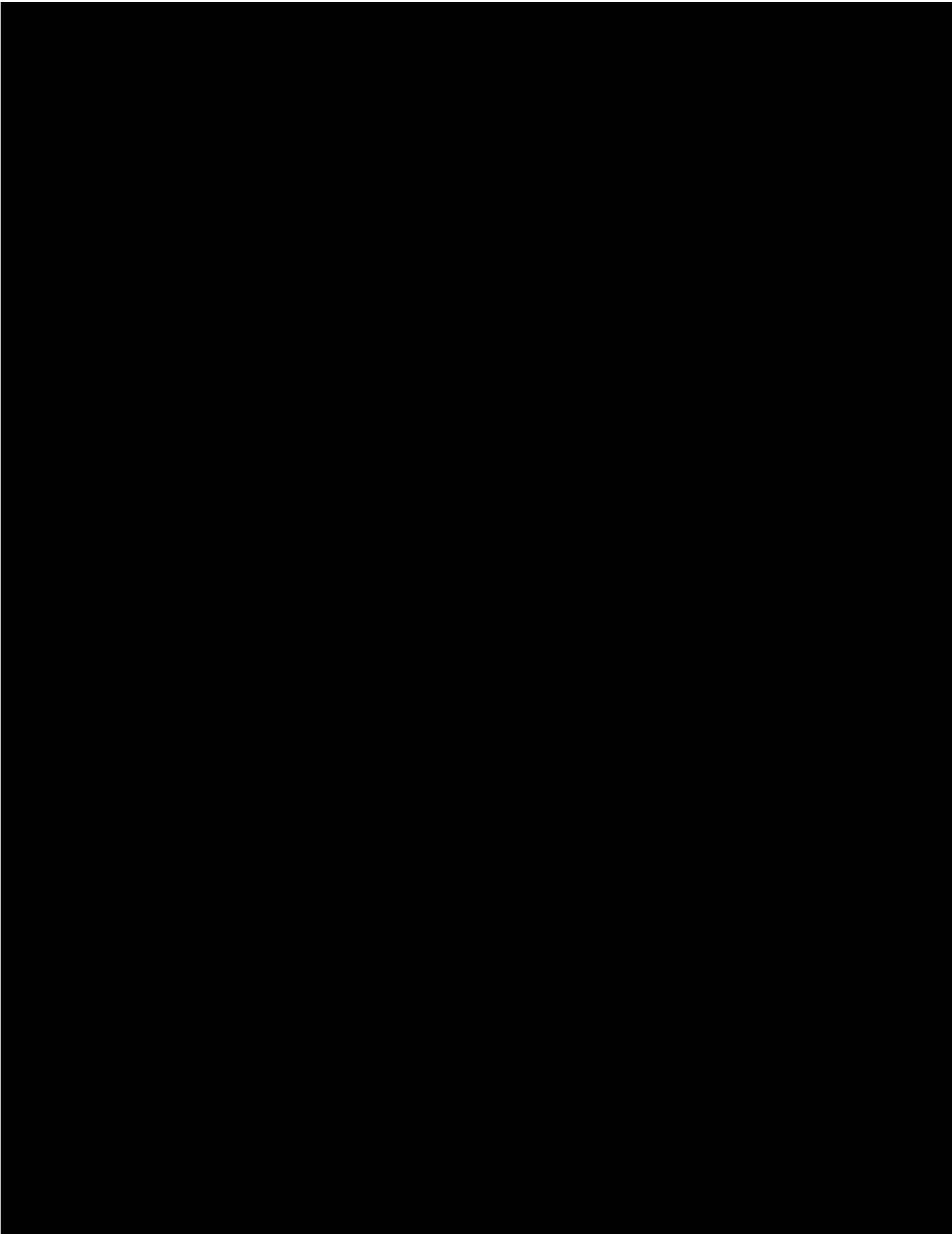


EXHIBIT A-17

Intentionally Left Blank

CLEAN CAPACITY ACCELERATOR AGREEMENT

This Clean Capacity Accelerator Agreement (this “**Agreement**”) is entered into as of March 12, 2026 (“**Contract Date**”) by and between DTE Electric Company, a Michigan corporation with offices at One Energy Plaza, 2101 WCB, Detroit, Michigan 48226 (“**Company**”) and Google LLC, a Delaware limited liability company with a principal address of [REDACTED] (“**Customer**”). Each of Company and Customer may be referred to herein individually as a “**Party**” or collectively as the “**Parties**.” Capitalized terms shall have the meaning set forth in Exhibit A.

RECITALS

WHEREAS:

- (A) Customer and Company have entered into: (i) that certain Amended and Restated Schedule Designation D11 Primary Supply Agreement (the “**PSA**”) dated as of the date hereof whereby Company has agreed to provide Electric Service to Customer’s data center facility (the “**Facility**”) located in Van Buren Township, Michigan (the “**Data Center Location**”), (ii) that certain Rider 12 Capacity Release Agreement dated as of the date hereof to assist Customer in managing its electricity usage patterns (the “**Demand Response Agreement**”), and that certain Line Extension Agreement dated as of the date hereof whereby Company will complete certain distribution system upgrades to serve Customer’s Facility (the “**Line Extension Agreement**”).
- (B) Customer desires to procure Clean capacity from or through Company and to deliver Zonal Resource Credits to Company to facilitate the receipt of Electric Service in accordance with the PSA within the accelerated timeframe requested by Customer.
- (C) On June 9, 2021, Company received approval from the Commission under the Partial Settlement Agreement in Docket No. U20713 & U-20851 (the “**Settlement**”), that allows for ahead-of-meter customer-requested offerings whereby a customer can contract to receive all the Renewable Energy Credits from a specified Renewable Energy Project.
- (D) Customer desires to procure RECs from the generation of one or more Renewable Energy Projects of up to 1,600 MW in aggregate consistent with the Settlement (collectively, the “**Renewable Portfolio RECs**”) from the project(s) described in the Renewable Portfolio.
- (E) Company desires to develop, procure, construct, own, lease, utilize and/or acquire Clean Capacity Projects and Renewable Energy Projects in MISO as necessary to provide (i) Electric Service and (ii) the Renewable Portfolio RECs to Customer.

NOW, THEREFORE, in consideration of the mutual covenants and agreements contained in this Agreement, and intending to be legally bound, Company and Customer agree as follows:

1. **Term**

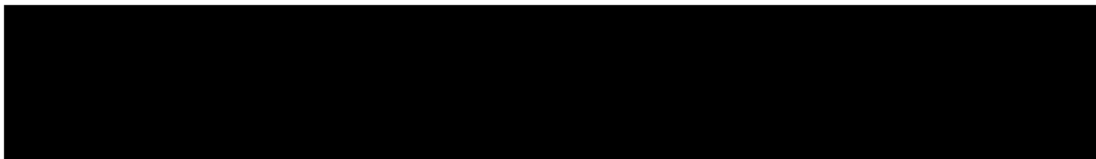
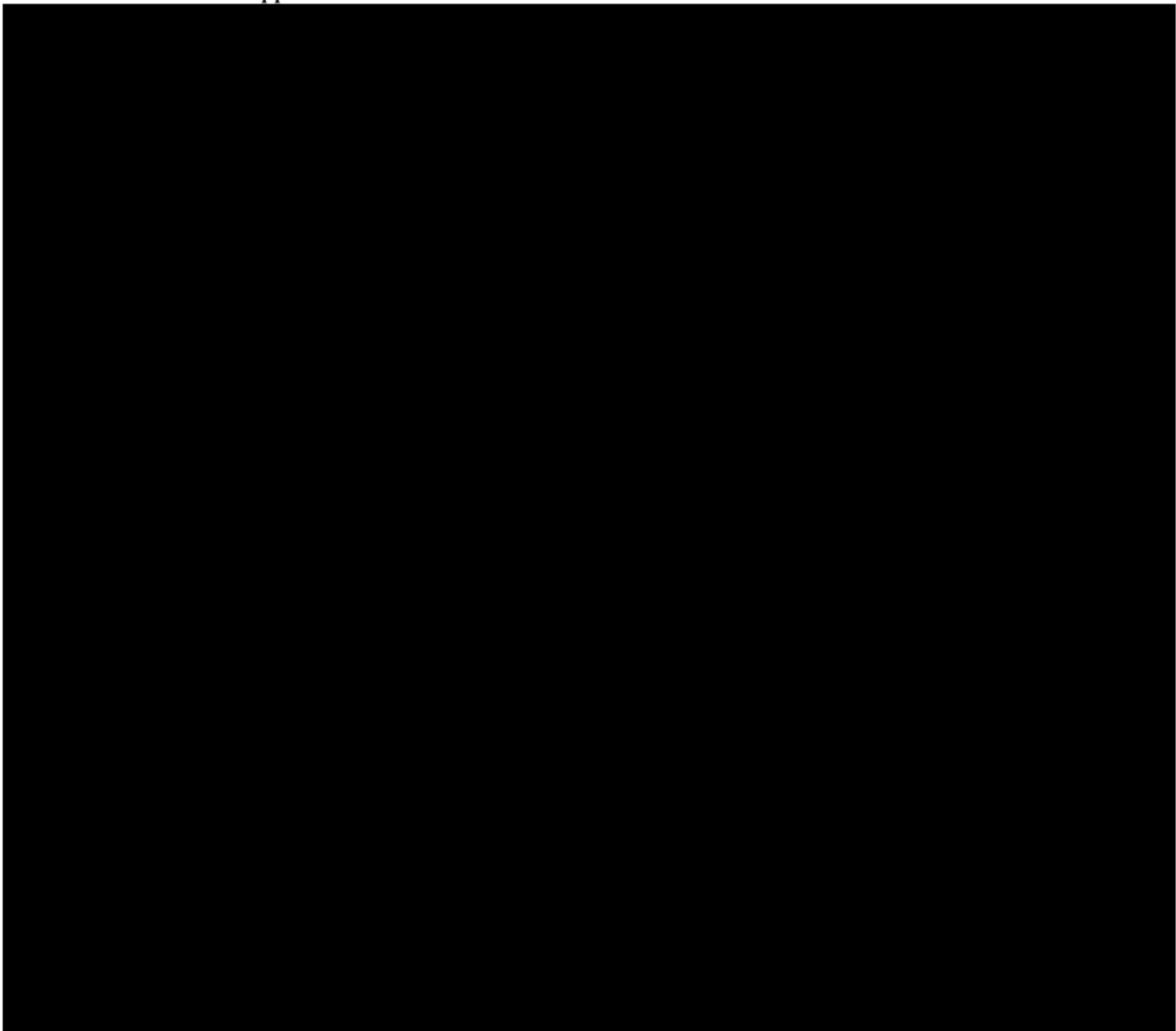
The term of this Agreement (the “**Term**”) shall commence upon the Contract Date, and shall continue, unless earlier terminated in accordance with this Agreement, until the twentieth (20th) anniversary of the “**Commencement Date**,” as such term is defined in the PSA.

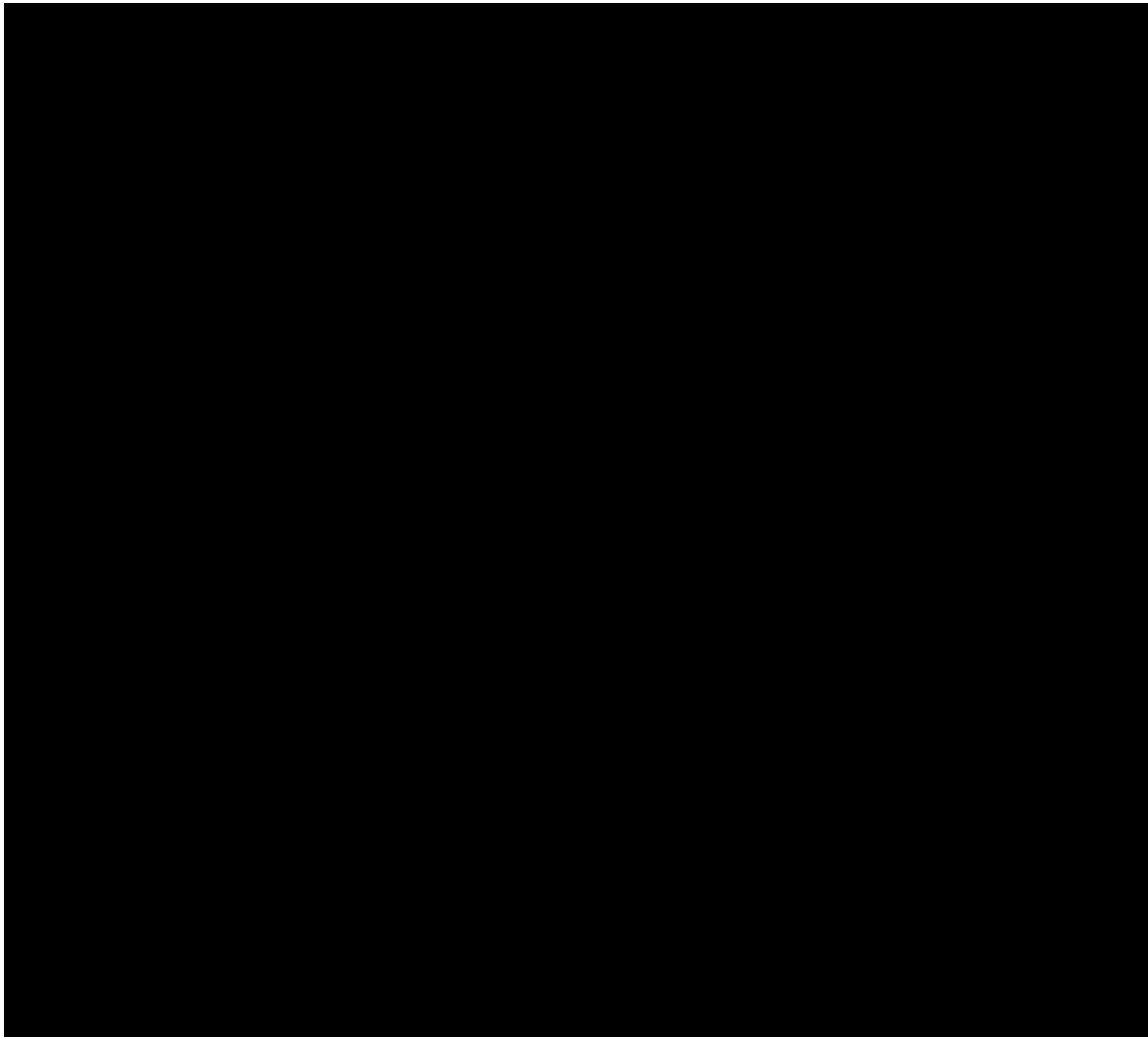
2. Conditions Precedent

- 2.1. With the exception of the obligations under this Section 2 and under Section 12, which shall be effective as of the Contract Date, each Party's performance of its respective obligations under this Agreement are specifically conditioned on completion of the items listed below pursuant to the terms set forth in this Section 2 (the "**Conditions Precedent**"):
- 2.1.1. Each of the Parties shall execute (a) the PSA, and (b) the Demand Response Agreement;
 - 2.1.2. Each of the Parties shall execute the Line Extension Agreement;
 - 2.1.3. The "Conditions Precedent" as defined in the PSA shall have been satisfied;
 - 2.1.4. The Commission shall approve of this Agreement and the PSA in accordance with Section 2.4;
 - 2.1.5. Within ten (10) Business Days following the Commission Approval Date, Customer shall provide the Customer Credit Support in form and substance as required pursuant to Section 11; and
 - 2.1.6. Company's board of directors shall approve this Agreement and Company shall deliver Notice to Customer of such approval.
- 2.2. Conditions Precedent Deadline. The date the Conditions Precedent are satisfied shall be referred to herein as the "**Effective Date**".
- 2.2.1. If the Condition Precedent set forth in Section 2.1.1 is not satisfied by [REDACTED] either Party may terminate this Agreement and any Related Agreement upon thirty (30) calendar days' Notice to the other Party, in which case (1) this Agreement shall cease to be of any force or effect and (2) no Party shall have any further obligations or liability to the other under this Agreement.
 - 2.2.2. If the Conditions Precedent set forth in Sections 2.1.2 and 2.1.6 are not satisfied by [REDACTED] Company may terminate this Agreement and any Related Agreement upon thirty (30) calendar days' Notice to Customer, in which case (1) this Agreement shall cease to be of any force or effect and (2) no Party shall have any further obligations or liability to the other under this Agreement.
 - 2.2.3. If the Condition Precedent set forth in Section 2.1.4 is not satisfied by [REDACTED] then either Party may terminate this Agreement and any Related Agreement upon thirty (30) calendar days' Notice to the other Party, in which case (1) this Agreement shall cease to be of any force or effect and (2) no Party shall have any further obligations or liability to the other under this Agreement.
 - 2.2.4. If the Condition Precedent set forth in Section 2.1.5 is not satisfied by [REDACTED] then Company may terminate this Agreement and any Related Agreement upon thirty (30) calendar days' Notice to Customer, in which case (1) this Agreement shall cease to be of any force or effect and (2) no Party shall have any further obligations or liability to the other under this Agreement.

2.3. Application. No later than thirty (30) days following the Related Agreement Completion Date, Company will apply to the Commission for approval of this Agreement and the PSA. Each Party agrees to notify the other Party of any significant developments in obtaining such Commission approval. To the extent applicable, Company shall also promptly apply to the Commission for approval of any applicable amendment to this Agreement pursuant to Section 2.4.1.1(a) or Section 2.4.2.3(a). Each Party agrees to notify the other Party of any significant developments in obtaining such Commission approval. Each Party shall use reasonable efforts to obtain such required approval and shall exercise due diligence and shall act in good faith to cooperate with and assist the other Party in acquiring such Commission approval. Customer may, at its sole discretion, and its sole cost and expense, file a petition for leave to intervene in the Commission proceeding related to the approval of this Agreement and retain counsel to represent Customer in such proceeding. The Parties agree to actively support the Agreement in such approval proceeding and not advocate for any revision or change to the Agreement (as executed as of the Contract Date).

2.4. Commission Approval.

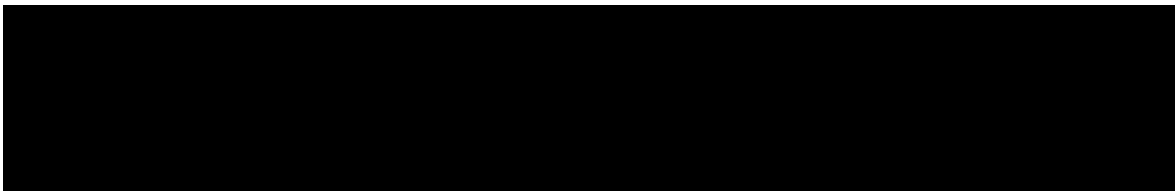




3. Clean Capacity Project Portfolio

3.1. Development of Clean Capacity Projects.

3.1.1. Clean Capacity Project Agreements. Company shall use commercially reasonable efforts to enter into agreements (including without limitation tolling agreements, power purchase agreements, purchase and sale agreements, build transfer agreements, development agreements, construction agreements, equipment supply agreements, lease agreements and the like) to develop, construct, lease, utilize, acquire capacity and/or energy, procure and/or acquire Clean assets/projects (each, a "**Clean Capacity Project**") for the Clean Capacity Project Portfolio as Company deems sufficient in its sole discretion, subject to Company's obligations under this Section 3 and in accordance with the applicable resource type set forth in the Indicative Clean Capacity Portfolio set forth in Exhibit F (each such agreement to develop, construct, lease, utilize, acquire capacity and/or energy, procure and/or acquire a Clean Capacity Project, a "**Clean Capacity Project Agreement**"). As applicable, Company will adhere to Michigan's competitive procurement guidelines. Company will maintain the Installed Capacity for each resource type specified in the Indicative Clean Capacity Portfolio set forth in Exhibit F throughout the Term. Customer acknowledges and agrees that the Clean



Capacity Project Portfolio reflects an overbuild of capacity at Customer's request for the purpose of avoiding the cost of augmentation in connection with (a) the 4-Hour Energy Storage Projects over the Term, and (b) the Long Duration Energy Storage Projects for a period of three (3) years from the Commercial Operation Date of each Long Duration Energy Storage Project.

- 3.1.2. Company shall consult with Customer and consider in good faith Customer's or Customer's agent's input with respect to the selection, procurement, leasing, development and/or construction of Clean Capacity Projects. To that end, the Parties shall meet no less than once per quarter to discuss progress relating to: (i) the development and construction of Customer's Facility, (ii) Customer's load ramp requirements, and (iii) the selection, procurement, development, leasing and construction status of the Clean Capacity Projects in the Clean Capacity Project Portfolio. Subject to the other terms and conditions of this Agreement, Company shall select, procure, develop, lease and/or construct Clean Capacity Projects to include in the Clean Capacity Project Portfolio, and, as between the Parties, Company shall be solely responsible for making all decisions pertaining to the procurement, development, construction and operation of all such Clean Capacity Projects and will make such decisions in a reasonable manner taking into account Prudent Industry Practice.
- 3.1.3. Company will provide Customer with quarterly written reports on the status of the selection, procurement, development, leasing and/or construction of the Clean Capacity Projects. These reports will also include an up-to-date projection of the Clean Capacity Project Portfolio Revenue Requirement as of the time of the report.
- 3.1.4. Application for Clean Capacity Project Agreements. If Company determines in its reasonable discretion that Commission approval is required for any Clean Capacity Project Agreement, then Company will apply to the Commission for approval of such Clean Capacity Project Agreement within thirty (30) calendar days after execution of such agreement (a "**Clean Capacity Project Agreement Filing**"). Each Party agrees to notify the other Party of any significant developments in obtaining such Commission approval. Each Party shall use reasonable efforts to obtain such required approval and shall exercise due diligence and shall act in good faith to cooperate with and assist the other Party in acquiring such Commission approval. If the Commission considers and expressly denies approval of any Clean Capacity Project Agreement, then Company may in its discretion source an alternative Clean Capacity Project to align with the Indicative Clean Capacity Portfolio to replace such rejected Clean Capacity Project (and seek Commission approval for the new Clean Capacity Project Agreement Filing in accordance with this Section 3.1.4).
- 3.1.5. Commission Approval of Clean Capacity Project Agreements. No later than thirty (30) calendar days after receipt of the Commission's approval of any Clean Capacity Project Agreement, Company shall deliver to Customer a revised list of all approved Clean Capacity Projects supporting the Customer Committed Capacity Ramp (collectively, the "**Clean Capacity Project Portfolio**") in the form of Exhibit B-1 (the "**Clean Capacity Project Portfolio Matrix**"). For the avoidance of doubt, Company shall have no obligation to develop, construct, own, operate, lease, utilize, acquire capacity and/or energy, procure and/or acquire any Clean Capacity Project unless the Commission issues an unconditional approval of the applicable Clean Capacity Project Agreement Filing or, in the event the Commission issues a conditional approval, the conditions imposed are acceptable to Company in its sole discretion.

- 3.1.6. Clean Capacity Project Portfolio Matrix. Company shall provide Customer with a revised Clean Capacity Project Portfolio Matrix at least thirty (30) calendar days prior to the Commercial Operation Date of each Clean Capacity Project, which reflects for such Clean Capacity Project the estimated Clean Capacity Project Revenue Requirement (including any costs attributable to Customer Caused Events or Relief Events). No later than ninety (90) calendar days following the Commercial Operation Date of such Clean Capacity Project, Company shall deliver to Customer an updated version of such Clean Capacity Project Portfolio Matrix. Company shall thereafter deliver to Customer a Clean Capacity Project Portfolio Matrix annually as set forth in Section 3.2.2. Customer acknowledges and agrees that the Clean Capacity Project Billing Period Charge will not be a levelized cost of storage and will instead reflect the actual Clean Capacity Project Revenue Requirement for each Clean Capacity Project in the Clean Capacity Project Portfolio. Company shall begin billing Customer for each Clean Capacity Project from the first billing period following the Commercial Operation Date of such Clean Capacity Project based on the estimated Clean Capacity Project Revenue Requirement for such project, subject, to the extent necessary, to a true up of such amounts pursuant to the updated Clean Capacity Project Portfolio Matrix for such Clean Capacity Project.
- 3.1.7. The Parties agree that regardless of the Commercial Operation Date of any Clean Capacity Project in the Clean Capacity Project Portfolio, Customer shall pay the Clean Capacity Project Revenue Requirement in full for each Clean Capacity Project in the Clean Capacity Project Portfolio during the Initial Term. If the Cost Recovery Period for any Clean Capacity Project extends beyond the Initial Term, then Company shall recover the portion of such project's Clean Capacity Project Revenue Requirement that Company would have otherwise recovered after the Initial Term (such amount, the "**CCP Recovery Amount**") during the Initial Term by dividing the CCP Recovery Amount by the number of billing periods from such project's Commercial Operation Date through the end of the Initial Term, and adding the quotient to such project's Clean Capacity Project Billing Period Charge.
- 3.1.8. The Parties agree that Company may, at its reasonable discretion: (a) add Clean Capacity Projects to the Clean Capacity Project Portfolio, and/or (b) replace any Clean Capacity Project in the Clean Capacity Project Portfolio, including in the event that a Clean Capacity Project Agreement is terminated or canceled, to align with the Indicative Clean Capacity Portfolio during the Term.
- 3.1.9. The Parties agree that this Agreement does not grant Customer any right, title to or interest in the Clean Capacity Projects, other than as explicitly set forth in this Agreement.
- 3.1.10. If Company determines that the Indicative Clean Capacity Portfolio is not feasible based on commercially reasonable standards and Prudent Industry Practice, then Company shall provide Notice to Customer, and the Parties shall meet within one hundred and twenty (120) calendar days of such Notice to agree on a new Indicative Clean Capacity Portfolio.

3.2. Reimbursement for Clean Capacity Projects.

- 3.2.1. Clean Capacity Project Reimbursement. Customer agrees that, subject to the terms and conditions of this Agreement, Customer shall be responsible for reimbursing Company for all documented and reasonably incurred costs related to the Clean Capacity Project(s) during the Term through its payment to Company of (a) the Clean Capacity Project Billing Period

Charge, *minus* (b) any applicable Clean Capacity Credits for each Clean Capacity Project in the Clean Capacity Project Portfolio.

3.2.2. Clean Capacity Project Revenue Requirement. Customer acknowledges and agrees that for all Clean Capacity Projects in the Clean Capacity Project Portfolio, the Clean Capacity Project Revenue Requirement and the Clean Capacity Project Portfolio Revenue Requirement shall increase or decrease, as applicable, for increases or decreases to Company's total cost of developing, procuring, constructing, purchasing, contracting for, leasing and/or operating each Clean Capacity Project. Following the conclusion of each calendar year, Company shall compare the actual costs of operating and maintaining such Clean Capacity Projects with the estimated costs provided in the Clean Capacity Project Portfolio Matrix (such over collection or under collection, the "**Clean Capacity Project Reconciliation**") and the Clean Capacity Project Revenue Requirement for such Clean Capacity Projects will be adjusted to account for any Clean Capacity Project Reconciliation; provided that, subject to Section 6.5, the levelized weighted average cost of 4-Hour Energy Storage Projects within the Clean Capacity Project Portfolio shall not exceed [REDACTED] per kW-month (the "**4-Hour Cost Cap**"), or as otherwise agreed between the Parties in writing. On or before April 1st of each year of the Term, Company shall provide Customer with a revised Clean Capacity Project Portfolio Matrix reflecting the adjusted Clean Capacity Project Portfolio Revenue Requirement, Clean Capacity Project Billing Period Charge, and Clean Capacity Project Revenue Requirement for each year of the Term for such Clean Capacity Projects that have achieved commercial operation, each of which shall take effect on May 1st of that year.

4. Renewable Portfolio

4.1. Development of Renewable Energy Projects.

4.1.1. Renewable Energy Project Agreements. Company shall use commercially reasonable efforts to enter into agreements (including without limitation purchase and sale agreements, build transfer agreements, development agreements, construction agreements, equipment supply agreements and the like) to develop, construct, lease, utilize, acquire capacity and/or energy and/or purchase Renewable Energy Projects for the Renewable Portfolio as Company deems sufficient in its sole discretion, subject to Section 4.1.10, in accordance with the applicable Indicative Renewable Portfolio (subject to the limits set forth under the column titled "MW Amount") set forth in Exhibit F (each such agreement to develop, construct, lease, utilize, acquire capacity and/or energy, procure and/or acquire a Renewable Energy Project, a "**Renewable Energy Project Agreement**"). Company will adhere to the procurement requirements set forth in the July 2, 2024 settlement agreement in Case No. U-21172 and will target the acquisition of a minimum of fifty percent (50%) of the capacity required to fulfill the Indicative Renewable Portfolio through build transfer agreements with unaffiliated third parties.

4.1.2. Application for Renewable Energy Project Agreements. If Company determines in its reasonable discretion that Commission approval is required for any Renewable Energy Project Agreement, then Company shall apply to the Commission for approval of such Renewable Energy Project Agreement within sixty (60) calendar days after execution of such agreement (a "**Renewable Energy Project Agreement Filing**"). Each Party agrees to notify the other Party of any significant developments in obtaining such Commission approval. Each Party shall use reasonable efforts to obtain such required approval and shall exercise

due diligence and shall act in good faith to cooperate with and assist the other Party in acquiring such Commission approval. If the Commission considers and expressly denies approval of any Renewable Energy Project Agreement, then Company may in its discretion source an alternative Renewable Energy Project to align with the Indicative Renewable Portfolio to replace such rejected Renewable Energy Project (and seek Commission approval for the new Renewable Energy Project Agreement Filing in accordance with this Section 4.1.2).

- 4.1.3. Commission Approval of Renewable Energy Project Agreements. No later than thirty (30) calendar days after receipt of Commission's approval of any Renewable Energy Project Agreement, Company shall deliver to Customer a revised list of all approved Renewable Energy Projects under this Agreement (collectively, the "**Renewable Portfolio**") in the form of Exhibit B-2 (the "**Renewable Portfolio Matrix**"). For the avoidance of doubt, Company shall have no obligation to develop, construct, own, operate, lease, utilize, acquire capacity and/or energy, procure and/or acquire any Renewable Energy Project unless the Commission issues an unconditional approval of the applicable Renewable Energy Project Agreement Filing or, in the event the Commission issues a conditional approval, the conditions imposed are acceptable to Company in its sole discretion.
- 4.1.4. Renewable Energy Project Portfolio Matrix. Company shall provide Customer with a revised Renewable Portfolio Matrix at least thirty (30) calendar days prior to the Commercial Operation Date of each Renewable Energy Project, which reflects for such Renewable Energy Project the estimated Renewable Energy Project Revenue Requirement (including any costs attributable to Customer Caused Events or Relief Events). No later than ninety (90) calendar days following the Commercial Operation Date of such Renewable Energy Project, Company shall deliver to Customer an updated version of such Renewable Portfolio Matrix. Company shall thereafter deliver to Customer a Renewable Portfolio Matrix annually as set forth in Section 4.2.2. Customer acknowledges and agrees that the Renewable Energy Project Billing Period Charge will not be a levelized cost of energy and will instead reflect the actual Renewable Energy Project Revenue Requirement for each Renewable Energy Project in the Renewable Portfolio. Company shall begin billing Customer for each Renewable Energy Project from the first billing period following the Commercial Operation Date of such Renewable Energy Project based on the estimated Renewable Energy Project Revenue Requirement for such project, subject, to the extent necessary, to a true up of such amounts pursuant to the updated Renewable Portfolio Matrix for such Renewable Energy Project.
- 4.1.5. The Parties agree that regardless of the Commercial Operation Date of any Renewable Energy Project in the Renewable Portfolio, Customer shall pay the Renewable Energy Project Revenue Requirement in full for each Renewable Energy Project in the Renewable Portfolio during the Term of this Agreement. If the Cost Recovery Period for any Renewable Energy Project extends beyond the Initial Term, then Company shall recover the portion of such project's Renewable Energy Project Revenue Requirement that Company would have otherwise recovered after the Initial Term (such amount, the "**REP Recovery Amount**") during the Initial Term by dividing the REP Recovery Amount by the number of billing periods from such project's Commercial Operation Date through the end of the Initial Term, and adding the quotient to such project's Renewable Energy Project Billing Period Charge.
- 4.1.6. Subject to Section 4.1.10, the Parties agree that Company may, at its reasonable discretion:
(a) add Renewable Energy Projects to the Renewable Portfolio, and/or (b) replace any

Renewable Energy Project in the Renewable Portfolio, including in the event that a Renewable Energy Project Agreement is terminated or canceled, to align with the Indicative Renewable Portfolio during the Term.

- 4.1.7. The Parties agree that this Agreement does not grant Customer any right, title to or interest in the Renewable Energy Projects, other than as explicitly set forth in this Agreement.
- 4.1.8. Company shall consult with Customer and consider in good faith Customer's or Customer's agent's input with respect to the selection, procurement, leasing, development and/or construction of Renewable Energy Projects. To that end, the Parties shall meet no less than once per quarter to discuss progress relating to the selection, procurement, development, leasing and construction status of the Renewable Energy Projects in the Renewable Portfolio. Subject to the other terms and conditions of this Agreement, Company shall select, procure, develop, lease and construct Renewable Energy Projects to include in the Renewable Portfolio, and, as between the Parties and subject to Section 4.1.10, Company shall be solely responsible for making all decisions pertaining to the procurement, development, construction and operation of all such Renewable Energy Projects and will make such decisions in a reasonable manner taking into account Prudent Industry Practice.
- 4.1.9. Company will provide Customer with quarterly written reports on the status of the selection, procurement, development, leasing and/or construction of the Renewable Energy Projects. These reports will also include an up-to-date projection of the Renewable Portfolio Revenue Requirement as of the time of the report.
- 4.1.10. Renewable Cost Target.
- 4.1.10.1. If, prior to the execution of any Renewable Energy Project Agreement, Company determines that the Renewable Energy Project Agreement will not cause the Levelized Weighted Renewable Portfolio Cost to exceed [REDACTED] per kWh (the "**Renewable Cost Target**"), then Company, in its sole discretion, may include such Renewable Energy Project in the Renewable Portfolio, subject to the Commission's approval of such Renewable Energy Project Agreement.
- 4.1.10.2. If, [REDACTED] Company determines that it is not feasible, based on commercially reasonable standards and Prudent Industry Practice, for Company to achieve the Indicative Renewable Portfolio without exceeding the Renewable Cost Target, then Company shall provide Notice to Customer and the Parties shall meet within thirty (30) days to negotiate in good faith any appropriate measures required for Company to achieve the Indicative Renewable Portfolio while still adhering to the original Renewable Cost Target or, if necessary, an adjusted Renewable Cost Target. If the Parties are not able to agree on such measures within sixty (60) days following the Parties' meeting, then Customer agrees to reimburse Company for any incremental costs incurred by Company in meeting the renewable portfolio standard as set forth in the Act, to the extent such costs are attributable to Customer's load.
- 4.1.10.3. The Renewable Cost Target shall be utilized solely, as set forth in this Section 4.1.10, to determine whether Company may select a Renewable Energy Project for inclusion in the Renewable Portfolio. The Renewable Cost Target shall not be used to determine or otherwise affect or limit Company's recovery of the Renewable Energy

Project Revenue Requirement from Customer for any Renewable Energy Project in the Renewable Portfolio, which shall be subject to adjustment to reflect the actual costs incurred in accordance with the Renewable Energy Project Reconciliation set forth in Section 4.2.2.

4.2. Reimbursement for Renewable Energy Projects.

4.2.1. Renewable Energy Project Reimbursement. Customer agrees that, subject to the terms and conditions of this Agreement, Customer shall be responsible for reimbursing Company for all documented and reasonably incurred costs related to the Renewable Energy Project(s) during the Term through its payment to Company of: (a) the Renewable Energy Project Billing Period Charge set forth in the Renewable Portfolio Matrix, *minus* (b)(i) any applicable Renewable Capacity Credits, *plus* (ii) any Renewable Generation Credits for each Renewable Energy Project in the Renewable Portfolio.

4.2.2. Renewable Energy Project Revenue Requirement. Customer acknowledges and agrees that for all Renewable Energy Projects the Renewable Energy Project Revenue Requirement and the Renewable Portfolio Revenue Requirement shall increase or decrease, as applicable, for increases or decreases to Company's total cost of developing, procuring, constructing, purchasing, contracting for, leasing and/or operating each Renewable Energy Project. Following the conclusion of each calendar year, Company shall compare the actual costs of operating and maintaining such Renewable Energy Projects with the estimated costs provided in the Renewable Portfolio Matrix (such over collection or under collection, the "**Renewable Energy Project Reconciliation**") and the Renewable Energy Project Revenue Requirement for such Renewable Energy Projects will be adjusted to account for any Renewable Energy Project Reconciliation. On or before April 1st of each year of the Term, Company shall provide Customer with a revised Renewable Portfolio Matrix reflecting the adjusted Renewable Portfolio Revenue Requirement and Renewable Energy Project Revenue Requirement for each year of the Term for such Renewable Energy Projects that have achieved commercial operation, each of which shall take effect on May 1st of that year.

4.3. Delivery of Renewable Energy Credits.

4.3.1. For each Renewable Energy Project in the Renewable Portfolio, Company shall deliver to Customer, and Customer shall receive, RECs in an amount equal to the applicable REC Quantity by May 31st following the end of the calendar year in which such REC Quantity was generated. Company shall be responsible for transferring the REC Quantity to Customer via a Qualified REC Tracking System. Each Party shall maintain a tracking account for transferring and tracking RECs in the Qualified REC Tracking System. Customer will be responsible for costs associated with registering and maintaining its own account in the Qualified REC Tracking System. Except for Customer's responsibility to maintain its own account in the prior sentence, all Qualified REC Tracking System and other third-party charges (including all costs associated with Company establishing and maintaining Company's required registrations and accounts, transferring and tracking RECs) are the responsibility of Company throughout the Term.

4.3.2. Customer shall be responsible for all arrangements and other actions required to receive the RECs to be transferred to Customer under this Agreement. Risk of loss of any such RECs

shall transfer from Company to Customer upon transfer within the Qualified REC Tracking System.

5. Retaining Projects Beyond the Cost Recovery Period.

- 5.1. If the end date of the Cost Recovery Period occurs before the end date of the Term for any Clean Capacity Project or Renewable Energy Project, then Customer may provide Notice to Company no later than twenty-four (24) months before the end of the applicable Cost Recovery Period of its request to keep such project in the Clean Capacity Project Portfolio or Renewable Portfolio, as applicable, for the remainder of the Term (or such earlier period as the Parties may agree), which continuation shall be subject to Company's approval in its sole discretion. If the Parties decide to keep such project in the Clean Capacity Project Portfolio or Renewable Portfolio, as applicable, then Customer shall pay Company for: (a) the operation and maintenance costs for such project, (b) the Administrative Fee, and (c) the cost of any augmentation for such project. If the Parties do not decide to keep such project in the Clean Capacity Project Portfolio or Renewable Portfolio, as applicable, then such project shall be removed from the applicable project portfolio in accordance with Section 5.2.
- 5.2. If a Clean Capacity Project or Renewable Energy Project is removed from the Clean Capacity Project Portfolio or Renewable Portfolio, as applicable, in accordance with Section 6.5 or Section 5.1, then: (a) Company shall deliver to Customer a revised Clean Capacity Project Portfolio Matrix or Renewable Portfolio Matrix, as applicable, and (b) if such project is a Clean Capacity Project, then Company shall equitably revise the Customer Committed Capacity Ramp under the PSA and the revised Customer Committed Capacity Ramp shall thereafter be the Customer Committed Capacity Ramp for purposes of the PSA.

6. Relief for Changes in Law, Force Majeure Events, and Customer Caused Events

- 6.1. Notice. In the event of a Relief Event or Customer Caused Event impacting Company, any Project Party, and/or one or more of the Clean Capacity Projects or Renewable Energy Projects and thereby affecting Company's ability to perform its obligations under this Agreement, Company shall provide Notice to Customer describing the particulars of the occurrence of such Relief Event or Customer Caused Event on a project specific basis within ten (10) Business Days after Company first gains knowledge of such Relief Event or Customer Caused Event. Such notice will, to the extent of Company's knowledge thereof at such time, describe (i) the details and factual basis of the cause and nature of such Relief Event or Customer Caused Event, (ii) the anticipated length of delay due to such Relief Event or Customer Caused Event, (iii) the estimated additional costs, if any, (beyond those anticipated before the occurrence of such Relief Event or Customer Caused Event) to be incurred by Company as a result of such Relief Event or Customer Caused Event and (iv) any other effect on Company's performance of its obligations hereunder.
- 6.2. Mitigation. Any delay in Company's performance caused by any Relief Event will be of no greater scope and of no longer duration than is reasonably required by such occurrence; provided that, if Company's performance in connection with such Relief Event is delayed due to the actions or inactions of a Project Party, then Company shall use commercially reasonable efforts to cause such Project Party to limit the scope and duration of any delay. Company will furnish Customer with regular reports with respect thereto during the continuation of any such Relief Event. Company shall use commercially reasonable efforts and Prudent Industry Practice to mitigate the cause of and effect on its performance hereunder of any such Relief Event and Company will

promptly resume full performance of its obligations hereunder once it is able to do so. For the avoidance of doubt, such commercially reasonable efforts shall, at a minimum, require compliance with the provisions set forth in this Section 6.2, as applicable.

- 6.3. No Liability for Relief Event or Customer Caused Event. Company shall not be responsible or liable for any damages, or be deemed to be in breach of this Agreement because of any failure or delay in complying with its obligations under or pursuant to this Agreement, in each case, to the extent that such failure is caused by a Relief Event or Customer Caused Event and Company has otherwise complied with this Section 6.3.
- 6.4. Cost and Schedule Relief for Customer Caused Event. In the event of a Customer Caused Event, Company shall be entitled to (i) an equitable extension of all of its obligations pursuant to this Agreement that are actually and demonstrably delayed by such Customer Caused Event and (ii) reimbursement for all costs and expenses actually and demonstrably incurred by Company as a result of such Customer Caused Event
- 6.5. Relief Event. In the event of a Relief Event that occurs after the Commercial Operation Date of an impacted Renewable Energy Project or Clean Capacity Project (such project, an “**Impacted Project**”) that results in, or is reasonably expected to result in (a) an increase in the costs to Company to make available the Customer Committed Capacity Ramp, or (b) an increase in Company’s cost of performing its obligations pursuant to this Agreement, then Company may provide Notice to Customer regarding any such increased cost (such notice, the “**Relief Event Notice**”, and such costs, the “**Relief Event Costs**”); provided that, in the case of a 4-Hour Energy Storage Project, an Impacted Project shall include such projects where such increases in costs would exceed the 4-Hour Cost Cap, whether such costs are incurred before or after the Commercial Operation Date. The Relief Event Notice shall include: (i) reasonable supporting documentation regarding any Relief Event Costs, (ii) the impact, if any, to the Clean Capacity Project Portfolio Revenue Requirement or Renewable Portfolio Revenue Requirement, as applicable, and (iii) a revised Clean Capacity Project Portfolio Matrix or Renewable Portfolio Matrix, as applicable, reflecting the impact to and updated Clean Capacity Project Revenue Requirement or Renewable Energy Project Revenue Requirement, as applicable, for each Impacted Project and the updated Clean Capacity Project Portfolio Revenue Requirement or Renewable Portfolio Revenue Requirement, as applicable, and the following provisions shall apply:

6.5.1

6.5.2

6.5.3

Should the amount of any Relief Event Costs exceed, on an aggregate basis per Impacted Project, the Relief Event Cost Cap, then the Parties shall have a period of up to thirty (30) calendar days following Company's delivery of the Relief Event Notice to negotiate in good faith any amendments or changes to this Agreement the Parties agree are necessary to address the impacts of the applicable Relief Event, while still attempting to preserve the Parties' original intent regarding their respective rights and obligations under this Agreement. If the Parties fail to reach agreement on such amendments or changes within thirty (30) calendar days following initiation of discussions, then Company at its option may: (a) remove the Impacted Project(s) from the Clean Capacity Project Portfolio or Renewable Portfolio, as applicable, in accordance with Section 5.2, and/or replace the Impacted Project(s) in accordance with Section 3.1.8 or Section 4.1.6, as applicable, (b) elect to keep the Impacted Project(s) in the Clean Capacity Project Portfolio or Renewable Portfolio, as applicable, or (c) terminate this Agreement via Notice to Customer within thirty (30) calendar days following the conclusion of such discussion period. If Company elects to keep the Impacted Project(s) in the Clean Capacity Project Portfolio or Renewable Portfolio, as applicable, and does not elect to terminate this Agreement in accordance with this Section 6.5, then Company will be solely responsible for all net Relief Event Costs in excess of the Relief Event Cost Cap attributable to such Impacted Project(s).

6.6. Changes in Law Rendering Performance Illegal. In the event of a Change in Law at any time during the Term which renders the performance of this Agreement by either or both Parties illegal or all or a material portion of this Agreement unenforceable, this Agreement shall be automatically terminated effective upon Notice from a Party to the other Party.

7. Zonal Resource Credits

7.1. Sale, Receipt and Delivery of Zonal Resource Credits. Customer shall deliver to Company, and Company shall receive for each Seasonal Accreditation Period of the ZRC Delivery Term the ZRC Product. For each applicable Seasonal Accreditation Period of the ZRC Delivery Term, Customer shall deliver the ZRC Product to Company by submitting the appropriate transaction(s) in the ZRC Tracking System to electronically assign such ZRC Product to Company. Customer must submit all such transactions into the MISO Module E-1 Capacity Tracking Tool at least ten (10) Business Days prior to the applicable MISO FRAP Submission Deadline for each contracted "Planning Year" (as such term is defined in the MISO Tariff) of the ZRC Delivery Term. Company shall confirm receipt of the ZRC Product by confirming the appropriate transaction(s) submitted by Customer in the MECT no later than five (5) Business Days after delivery. Each Customer submission and Company confirmation described in this Section 7.1 shall be conducted in accordance with the requirements set forth in the MISO Tariff and/or any other applicable rules adopted by MISO regarding the MECT.

7.2.

7.3.

7.4. Title and Risk of Loss. Title to, and risk of loss with respect to, any ZRC Product that Company purchases from Customer under this Agreement shall transfer to Company upon Company's receipt of ZRC Product in the ZRC Tracking System.

7.5. Representations and Warranties of Customer. Customer hereby represents and warrants to Company on each such date that Customer assigns ZRC Product to Company in the ZRC Tracking System that:

- (1) Customer has good and marketable title to the ZRC Product;
- (2) Customer has the right to deliver such ZRC Product to Company;
- (3) Customer has not, and will not, sell or otherwise transfer the ZRC Product to any other party;
- (4) such ZRC Product complies with the requirements of, and is qualified under, the ZRC Tracking System as it exists on each such date that Customer initiates assignment of such ZRC Product; and
- (5) Customer will transfer to Company all right, title to and interest in such ZRC Product, free and clear of any liens, security interests, claims or other encumbrances or title defects.

8. Invoicing and Payment; Taxes

8.1. Invoicing. Except as set forth in this Agreement, Company shall bill Customer in accordance with the provision of Company's Rate Book. Customer shall pay all amounts owed in full on or before the due date and shall pay each invoice within thirty (30) calendar days of receipt of each invoice in the form substantially included in Exhibit D to this Agreement. For any payments to Company made after an applicable due date, Customer shall pay Company late fees in accordance with Section C4.8 of Company's Rate Book. Any Disputes regarding an invoice or related events may be raised by Notice to Company within six (6) months of the date of receipt of the disputed invoice only after Customer has paid the invoiced amount in full, and Customer shall not withhold or delay payment pending resolution of any Dispute. If Customer does not provide Notice of such Dispute within six (6) months of the date of the applicable invoice, Customer waives any claims related to that invoice.

8.2. Netting of Payments. Notwithstanding any other provision in this Agreement or any other agreement between the Parties, if at any time Customer is required to make payments to Company under this Agreement and any Related Agreement, then on each payment date, the payment obligations of Customer shall be netted against any payment obligations of Company under such Related Agreement.

8.3. [Reserved].

8.4. Settlements. Company shall include with each invoice delivered to Customer, information sufficient to demonstrate, for each Clean Capacity Project and Renewable Energy Project in the Clean Capacity Project Portfolio and Renewable Portfolio, as applicable, the actual MISO settlement statements received by Company during the billing period. Company will retain the Clean Capacity Market Revenues, Renewable Capacity Market Revenues and Renewable Generation Market Revenues, as applicable, for each of the Clean Capacity Projects and Renewable Energy Projects in the Clean Capacity Project Portfolio and Renewable Portfolio, respectively, as applicable.

9. Customer Default

9.1. Customer shall be in default under this Agreement upon the occurrence of any of the following events (each, an “**Customer Event of Default**”):

9.1.1. Customer fails to pay when due any amount required to be paid under this Agreement only if that amount is not cured within five (5) Business Days after receipt of Notices thereof from the other Party;

9.1.2. Customer breaches any material term of this Agreement (not otherwise a payment default) that is not cured within thirty (30) calendar days after receipt of Notice thereof from Company (or for breaches for which Customer has notified Company cannot be cured within thirty (30) calendar days despite its use of reasonable efforts but can be cured within sixty (60) calendar days, and such default has not been so cured by the extended sixty (60) calendar day deadline);

9.1.3. Customer Bankruptcy;

9.1.4. Customer fails to maintain the collateral requirements in Section 11 or fails to comply with its obligations under Section 11 and such failure is not cured within ten (10) Business Days after receipt of Notice thereof from Company; or

9.1.5. Customer defaults in its performance or payment obligations under any Related Agreement (and such default is not cured within any applicable grace period), Company terminates any Related Agreement for any reason or Customer terminates any Related Agreement due to any reason (other than a default by Company).

9.2. Termination. Company may terminate this Agreement upon five (5) Business Days prior Notice if any such Customer Event of Default is not cured, with regard to Sections 9.1.1, 9.1.2, 9.1.4, and 9.1.5 above, within the time period stated. This Agreement shall automatically terminate upon the occurrence of a Customer Event of Default with respect to Section 9.1.3. Notwithstanding anything else in this Agreement, the Customer Parent Guaranty, or any other agreement among the Parties, no notice of default or demand is required of any entity that is subject to a Bankruptcy or any other stay, injunction, or moratorium against payment demands, and any requirement to provide such notice of default or demand is excused, waived, and deemed satisfied.

9.3. Termination Payment. If Company elects to terminate this Agreement in accordance with this Section 9, or this Agreement is terminated in accordance with Section 6.5, then: (i) Customer shall

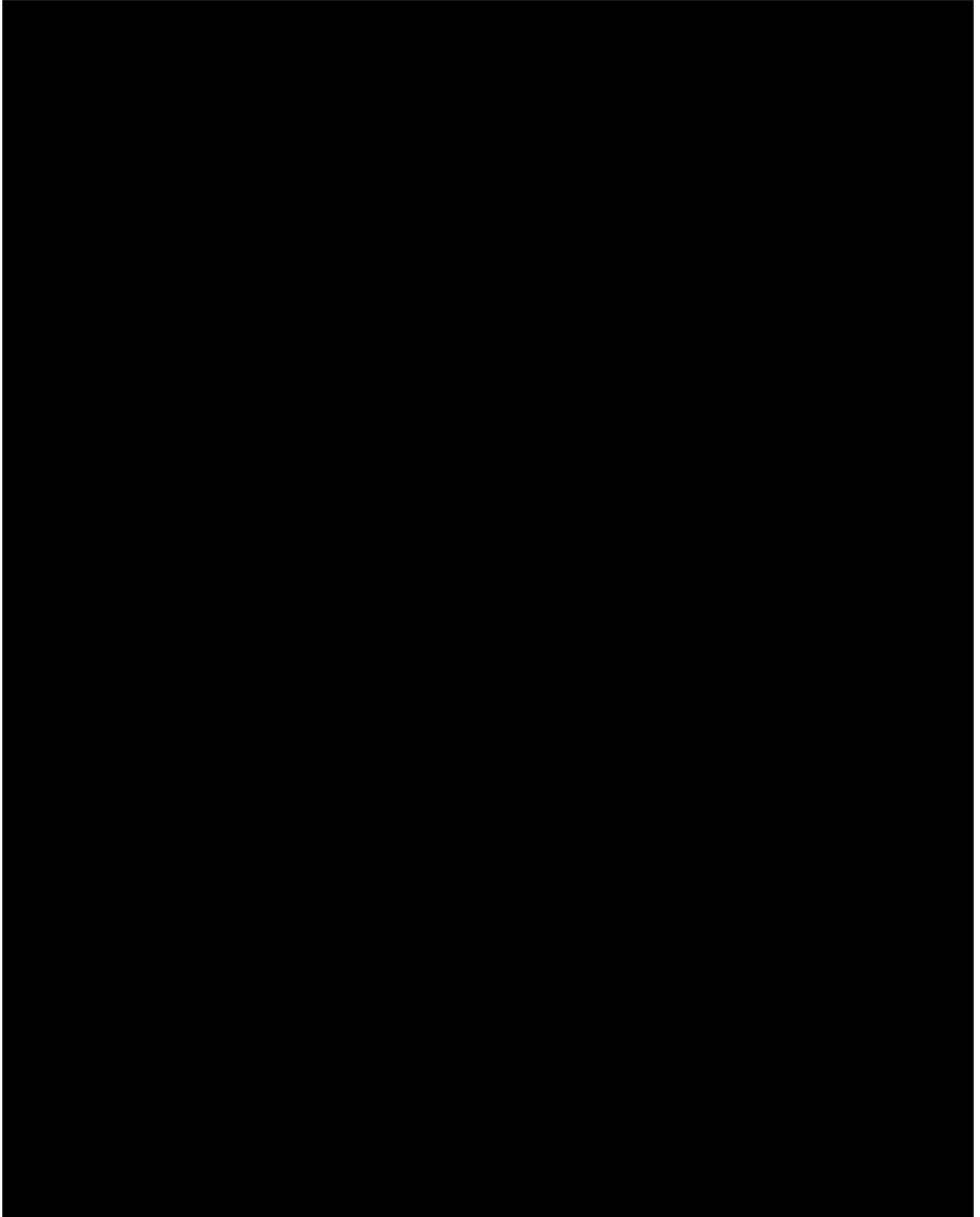
pay to Company within thirty (30) calendar days of receipt of such Notice, as damages and not a penalty, an amount equal to the sum of (a) the sum of the applicable “Clean Capacity Project Billing Period Charge” as set forth in the Clean Capacity Project Portfolio Matrix for each Clean Capacity Project in the Clean Capacity Project Portfolio for the remaining months in the Term, and (b) the sum of the applicable “Renewable Energy Project Billing Period Charge” as set forth in the Renewable Portfolio Matrix for each Renewable Energy Project in the Renewable Portfolio for the remaining months in the Term (the sum of subclauses (a) and (b), the “**Termination Payment**”), and (ii) provided that Company has received full payment of the Termination Payment from Customer, Customer shall be entitled to reimbursement on a monthly basis of: (w) the applicable Clean Capacity Credits, *plus* (x) the applicable Renewable Capacity Credits, *plus* (y) the applicable Renewable Generation Credits, *minus* (z) the Administrative Fee for such billing period actually received by Company during the period to which the Termination Payment applies (collectively, the “**Customer Credit Payments**”).

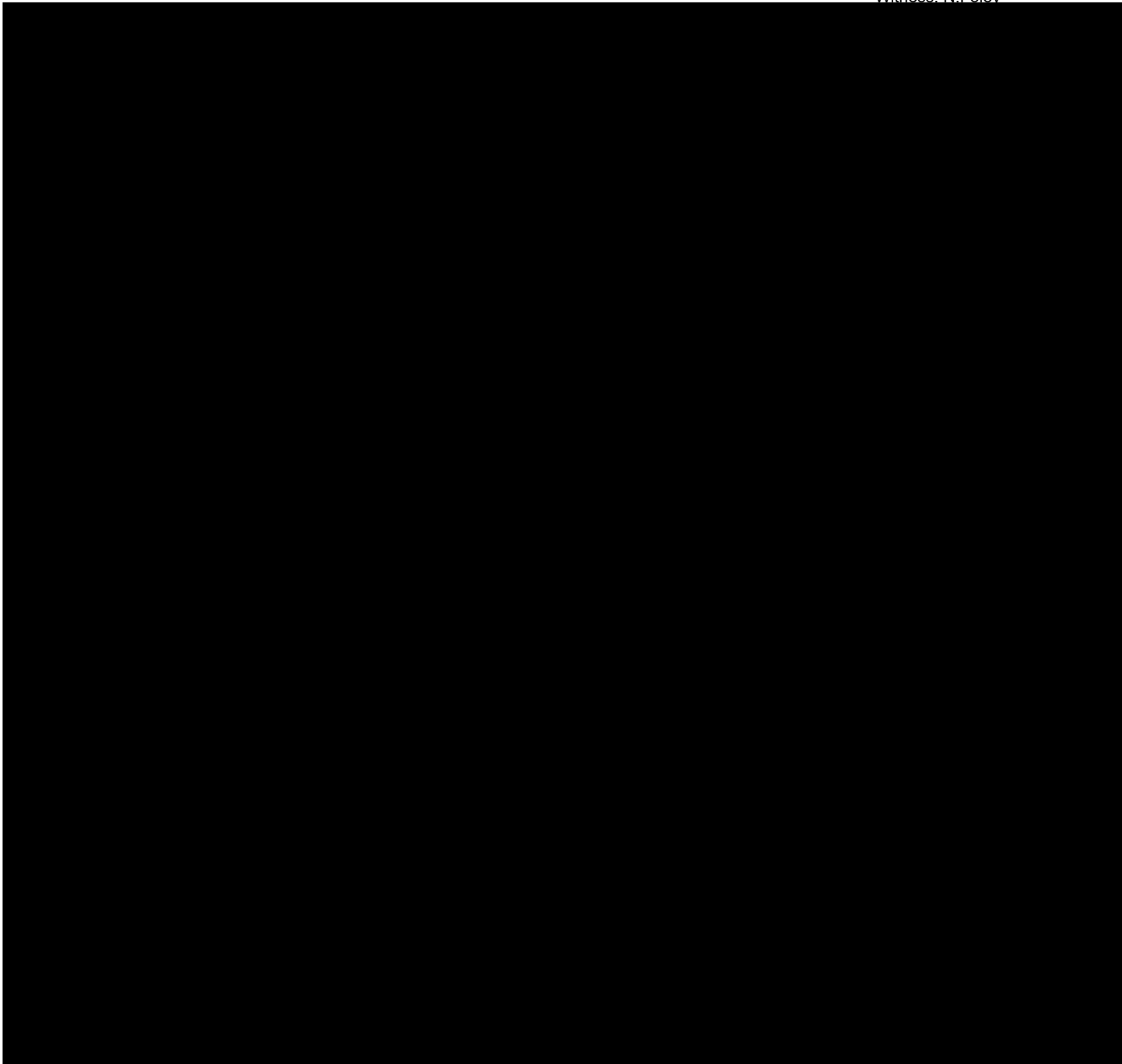
- 9.4. Potential Customer Credits Settlement. Notwithstanding Section 9.3(ii), Company shall notify Customer, and the Parties will meet and confer to negotiate a possible reduction in the Termination Payment in lieu of Company having to pay the Customer Credit Payments. Nothing in this Section 9.4 shall require the Parties to reach an agreement. If the Parties are not able to agree on the amount of such reduction within thirty (30) days following Company’s Notice, then Customer shall pay the applicable Termination Payment and, if applicable, Company shall pay the Customer Credit Payments, in each case, in accordance with the terms of Section 9.3. The Notice obligation and meet and confer process set forth in this Section 9.4 shall not be applicable in the event Customer is subject to a Bankruptcy or any other stay, injunction, or moratorium against payment demands, and any requirement to provide such Notice and/or negotiate a Termination Payment discount is excused, waived, and deemed satisfied.

10. Company Default

- 10.1. Company shall be in default under this Agreement upon the occurrence of any of the following events (each an “**Company Event of Default**”):
- 10.1.1. Company breaches any material term of this Agreement (not otherwise a payment default) that is not cured within thirty (30) calendar days after receipt of Notice thereof from Customer (or such longer period of time as is reasonable under the circumstance to cure such default as long as Company commenced actions to cure such default within such thirty (30) calendar day period and is diligently proceeding to cure the same thereafter);
 - 10.1.2. Company Bankruptcy; or
 - 10.1.3. Company fails to return Customer Credit Support in accordance with Section 11 and such failure is not cured within ten (10) Business Days after receipt of Notice from Customer.
- 10.2. Termination. Customer may terminate this Agreement upon five (5) Business Days prior Notice if any such Company Event of Default is not cured within the applicable cure periods, with regard to Sections 10.1.1 or 10.1.3 above, within the time period stated. This Agreement shall automatically terminate upon the occurrence of a Company Event of Default with respect to Section 10.1.2.

11. Customer Collateral Requirements.





12. Confidentiality

- 12.1. For the purpose of this Agreement, a party disclosing Confidential Information shall be referred to as the “**Disclosing Party**” and a party receiving Confidential Information shall be referred to as the “**Recipient**”. “**Confidential Information**” includes any and all information hereafter disclosed by or at the direction of the Disclosing Party to Recipient that is designated in writing as confidential or a reasonable party would consider to be of a confidential nature including but not limited to this Agreement and any Related Agreement; provided, however, Confidential Information does not include (i) information that, at the time of disclosure or thereafter, was generally available to and known by the public, other than as a result of a disclosure by Recipient



in violation of this Section 12; (ii) information that, at the time of disclosure or thereafter was available to Recipient or its Representatives (as defined below) from a source not known by Recipient to be bound by a duty of confidentiality to the Disclosing Party with respect to such information; (iii) information that, prior to disclosure by or at the direction of the Disclosing Party, was known to Recipient or its Representatives; or (iv) information that is independently developed by Recipient or its Representatives by persons without reliance on the Confidential Information and without violating the obligations hereunder.

- 12.2. Confidential Information is and shall, at all times, remain the property of the Disclosing Party. Recipient may disclose Confidential Information to any of its officers, directors, employees, advisors, shareholders, members, managers, attorneys or agents (collectively, “**Representatives**”). The Recipient shall advise such persons of the existence of this Agreement, of the confidential nature of the information and of the Recipient’s obligations regarding the same under this Agreement. Recipient shall be responsible for any breach of this Agreement by such Representatives.
- 12.3. In the event that Recipient is requested or required under compulsion of legal process to disclose such Confidential Information, Recipient shall not, unless required by Law, disclose the information until the Disclosing Party has first (i) received prompt Notice of such request or requirements to disclose and (ii) had an adequate opportunity to obtain a protective order or other reliable assurance that confidential treatment shall be accorded to the Confidential Information.
- 12.4. To the extent Confidential Information, including this Agreement, must be filed with the Commission or other applicable regulatory governmental agency, Company shall notify Customer in advance of such disclosures (or if advance notification is not practicable, as promptly as reasonably practicable after such disclosure), and, before a filing is required to be made, collaborate with Customer to identify redactions that will, to the greatest extent possible under the circumstances, limit the amount of Confidential Information that is publicly disclosed.

13. **Limitation of Liability**

- 13.1. Limitation of Liability for Delays. To the fullest extent permitted by Law, Company shall not be liable for any damages, penalties, liquidated damages, or claims arising from delays, disruptions or failures to perform caused by any Relief Event or Customer Caused Event as set forth in Section 6. In the event of a delay caused by a Relief Event, Customer’s sole remedy shall be an extension of time to meet the Customer Committed Capacity Ramp.
- 13.2. Consequential Damages. Neither Party shall be liable under this Agreement or under any cause of action related to the subject matter of this Agreement, whether in contract, warranty, tort including negligence, strict liability, professional liability, product liability, contribution, or any other cause of action for special, exemplary, punitive, indirect, incidental or consequential losses or damages, including loss of profit, loss of use, loss of opportunity, loss of revenues, or loss of good will; provided, however, that the foregoing shall not apply to any Party’s obligations to indemnify, defend and hold harmless any Indemnified Party (defined below) for claims and liabilities in respect of claims by third persons that are indemnified by such Party hereunder.

14. Assignment

- 14.1. Without the prior written consent of the non-assigning Party (such consent not to be unreasonably withheld, delayed or denied), neither Party may assign or transfer this Agreement or its rights and obligations under this Agreement, and any such assignment or transfer without such consent is void. Notwithstanding the foregoing, a Party may make the following assignments without the prior written consent of the other Party, but shall provide Notice to the other Party thirty (30) calendar days prior to such assignment:
- 14.1.1. Customer may assign this Agreement (i) to an Affiliate of Customer, so long as Notice of such assignment is provided to Company at least thirty (30) days prior to such assignment and such assignee remains in compliance with the obligations of Customer under Section 11, or (ii) to any Creditworthy Assignee, provided, that replacement Customer Credit Support has been provided by such Creditworthy Assignee pursuant to the requirements of Section 11; provided, however, that until the seventh (7th) anniversary of the Load Ramp Completion Date (as such term is defined in the PSA), if the sum of cash and cash equivalents reflected on the balance sheet of a proposed assignee (whether an Affiliate or a Creditworthy Assignee), as set forth in such proposed assignee's most recent audited financial statements prepared in accordance with generally accepted accounting principles, in an aggregate amount is less than three times (3x) the greater of (a) a "Termination Payment" calculated in accordance with Section 7.3 of the PSA, and (b) a Termination Payment calculated in accordance with Section 9.3 of this Agreement, each (a) and (b), as calculated as of the effective date of the proposed assignment, then Customer shall obtain Company's prior written consent to such assignment. Any assignee of Customer permitted pursuant to this Section 14.1.1 shall enter into an assignment and assumption agreement in a form reasonably acceptable to Company by which such assignee expressly assumes all of the assignor's obligations under this Agreement. Customer may also assign this Agreement as collateral security to a Financing Party providing Customer's long-term financing for the construction and/or operation of the Facility; provided that such assignment does not materially or adversely affect any of Company's rights or obligations under this Agreement.
- 14.1.2. Company may without consent of Customer assign this Agreement to: (a) a legally authorized governmental or quasi-governmental agency charged with providing retail electric service in Michigan; (b) to any successor to Company that is a public utility regulated as to rates and service by the Commission pursuant to applicable Law; (c) as otherwise required by Law or by operation of Law; or (d) to an Affiliate of Company that is reasonably expected by the Parties to be capable of performing Company's obligations under this Agreement. Customer agrees that such assignment and delegation shall operate to release Company from all (or such portion of) its responsibilities under this Agreement, except as may have accrued up to the effective date of such assignment. Upon an assignment consistent with this Section 14.1.2, the assignor shall be relieved of any and all liabilities and obligations under this Agreement.
- 14.2. This Agreement may not be assigned to a Sanctioned Person. Neither Party may suffer a change of ownership or control, whether direct or indirect, voluntary or by operation of Law, such that a Party becomes a Sanctioned Person.

15. Dispute Resolution; Governing Law; Venue

- 15.1. Dispute Resolution. In the event a controversy, claim or dispute arises between the Parties regarding the application or interpretation of any provision of this Agreement or the breach, termination or validity thereof (each, a “**Dispute**”), the Party alleging the Dispute shall provide Notice to the other Party of the Dispute. If the Parties shall have failed to resolve the Dispute within thirty (30) calendar days after delivery of such Notice, each Party shall, within ten (10) Business Days after receipt of a written demand from the other Party to do so, direct a senior executive (Vice President level or above) to confer in good faith with a senior executive of the other Party to resolve the Dispute. Should the Parties be unable to resolve the Dispute to their mutual satisfaction within twenty (20) Business Days after the initial meeting of the senior executives, each Party shall have the right to pursue its rights under Law or in equity.
- 15.2. Venue. Any controversy or claim outside the jurisdiction of the Commission or FERC shall be settled or appealed, as applicable, in the federal courts located in the Eastern District of Michigan, and only to the extent that federal jurisdiction cannot be established for such controversy or claim, the state courts located in the Eastern District of Michigan, and each Party hereby submits itself to the exclusive jurisdiction of such courts.
- 15.3. Governing Law. This Agreement and all Disputes arising between the Parties under this Agreement shall be governed exclusively by the Laws of the State of Michigan, without reference to its choice of Law rules, except as to any matters subject to federal Law and the exclusive jurisdiction of FERC.

16. Indemnification

- 16.1. Notwithstanding any other provision of this Agreement and to the fullest extent permitted by Law, each Party agrees to protect, defend, indemnify and hold the other Party, including its directors, officers, employees, attorneys-in-fact, agents and affiliated companies (“**Indemnified Parties**”), free and harmless from and against (a) any and all loss, damage, and liability to third-parties for property damage, and (b) any and all third-party claims for damages on account of or by reason of bodily injury, including death, which may be sustained or claimed to be sustained by any person, each (a) and (b) to the extent arising in connection with this Agreement and due to the gross negligence or willful misconduct of the indemnifying Party or its agents, employees or subcontractors.
- 16.2. To the extent permitted by Law, Company and Customer waive the benefit for themselves and all subcontractors, insofar as the indemnification of the other is concerned, of the provisions of any applicable Workers' Compensation Law limiting the tort or other liability of any employer on account of injuries to the employer's employees.
- 16.3. Notwithstanding the foregoing, the indemnified Party shall be entitled, at its own cost, if it so elects, to representation by attorneys of its own selection, including attorneys employed by it.
- 16.4. The indemnified Party shall be the sole judge of the acceptability of any compromise or settlement of any claims or actions and no such compromise or settlement shall be made by the indemnifying Party without the indemnified Party's prior written consent, which shall not be unreasonably withheld; provided, that such consent shall not be required if (x) the settlement agreement contains a complete and unconditional release of the Indemnified Parties, (y) the

settlement agreement obligates the indemnifying Party to pay the full amount of any claims attributable to the Indemnified Parties concurrently with the settlement, and (z) the settlement agreement does not contain any direct or indirect requirements upon or provisions for the Indemnified Parties, directly or indirectly encumber any of the assets of the Indemnified Parties, require any admission of liability by the Indemnified Parties or involve criminal liability.

16.5. The obligation of each Party to indemnify the other hereunder shall survive the termination or cancellation of this Agreement.

17. Miscellaneous

17.1. Administrative Fee. Company shall include as a separate line item on Customer's monthly bill the Administrative Fee to cover the administrative services performed by Company in connection with this Agreement. The Administrative Fee shall be fixed during the Term.

17.2. Notice. Any notice, consent, approval or other communication under this Agreement (each a "Notice") shall be in writing (which shall include electronic mail) and shall be personally delivered or sent by a courier or transmitted by electronic mail to a Party as follows or to such other address as the Party may substitute by Notice in accordance with this Section 17.2 after the date of this Agreement:

If to Company:

DTE Electric Company
One Energy Plaza



[REDACTED]

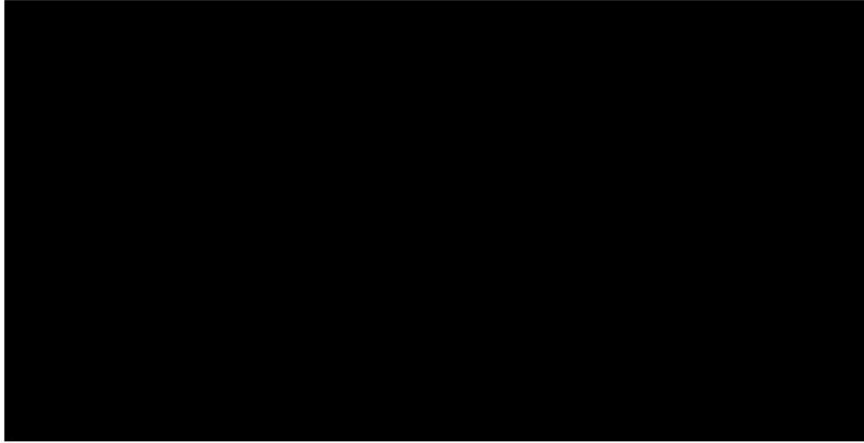
If to Customer:

[REDACTED]

- 17.3. To the extent there is any conflict or inconsistencies between Company's Rate Book, this Agreement, the PSA, and/or the Rate Schedule, any conflict or inconsistency shall be resolved in the following order of precedence: (i) the PSA, (ii) this Agreement, (iii) Company's Rate Book, and (iv) the Rate Schedule
- 17.4. During the Term, Company shall use commercially reasonable efforts or, to the extent applicable, use commercially reasonable efforts to cause Project Parties, to operate and maintain the Clean Capacity Project(s) and Renewable Energy Project(s) in accordance with Prudent Industry Practice.
- 17.5. The terms and provisions of this Agreement shall not be modified or waived except by the execution by the Parties of a written amendment to this Agreement. The waiver by a Party of a breach or violation of any provision of this Agreement will not operate as or be construed to be a waiver of any subsequent breach or violation thereof.
- 17.6. Each term and condition of this Agreement is deemed to have independent effect and the invalidity of any partial or whole paragraph or article shall not invalidate the remaining paragraphs or articles. The obligation to perform all of the terms and conditions shall remain in effect regardless of the performance of any invalid term by the other Party. Any entity that succeeds by purchase, merger, consolidation or other transfer to the properties of Company or Customer either substantially or as an entirety, shall be entitled to the rights and will be subject to the obligations of its predecessor in interest under this Agreement. Except as provided in Section 14 above, neither Customer nor Company may assign this Agreement, or any of its rights or obligations under this Agreement, without the prior written consent of the other Party.
- 17.7. This Agreement shall not create any rights in third parties, and no provision of this Agreement will be construed as creating any obligations for the benefit of, or rights in favor of, any person or entity other than the Parties.
- 17.8. The execution of this Agreement shall not create, nor shall this Agreement be construed as creating any partnership, joint venture or agency relationship between the Parties hereto.
- 17.9. This Agreement shall be binding on the Parties hereto and on their respective successors, heirs and permitted assigns.

- 17.10. This Agreement and the Related Agreements, together with Company's Rate Book, as may be amended from time to time, reflect the entire agreement among the Parties with respect to the subject matter hereof and supersedes all prior agreements and understandings among the Parties with respect to the subject matter hereof.
- 17.11. All headings and captions contained in this Agreement are for convenience of reference only and shall not, in any way, affect the meaning of any provision hereof. No provision of this Agreement shall be interpreted more or less favorably towards either Party because its counsel drafted all or a portion hereof. The recitals set forth in this Agreement are an integral part hereof and shall have the same contractual significance as any other language contained in this Agreement. Unless otherwise defined herein, any capitalized terms in this Agreement shall have the meaning set forth in Company's Rate Book or the applicable Related Agreement, as the context may require.
- 17.12. This Agreement may be executed by pdf signatures or electronically, or in multiple counterparts, each of which will be deemed an original and all of which will constitute one and the same instrument.
- 17.13. Company acknowledges to Customer that the retirement of Units 3 and 4 of Company's Monroe Power Plant will proceed as currently planned absent any intervening law, statute, ordinance, regulation, rule, decree, ruling, order or other legal requirement of any Governmental Authority extending its operations. Company also acknowledges that the retirement of Units 1 and 2 of Company's Monroe Power Plant will proceed as currently planned absent such units remaining operational to address a resource adequacy shortfall or an intervening law, statute, ordinance, regulation, rule, decree, ruling, order or other legal requirement of any Governmental Authority extending its operations. Under no circumstance shall any extension of Monroe Power Plant be considered as a Clean Capacity Project under this Agreement.
- 17.14. Any provision of this Agreement that contemplates performance or observance subsequent to termination or expiration of this Agreement, or that is necessary to give effect to rights or obligations arising prior to such termination or expiration, shall survive and continue in full force and effect.

IN WITNESS WHEREOF the Parties have executed this Agreement as of the date and year first written above.



DTE Electric Company



Schedule 1

Required Amount Schedule

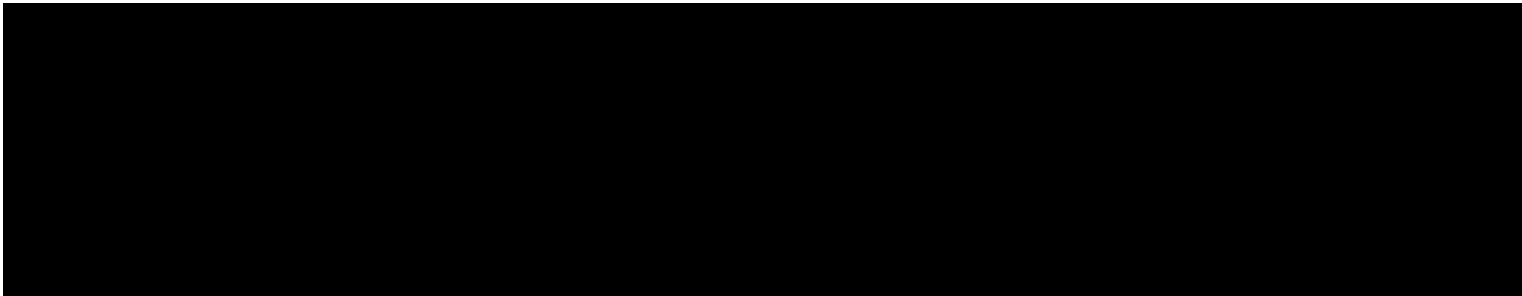
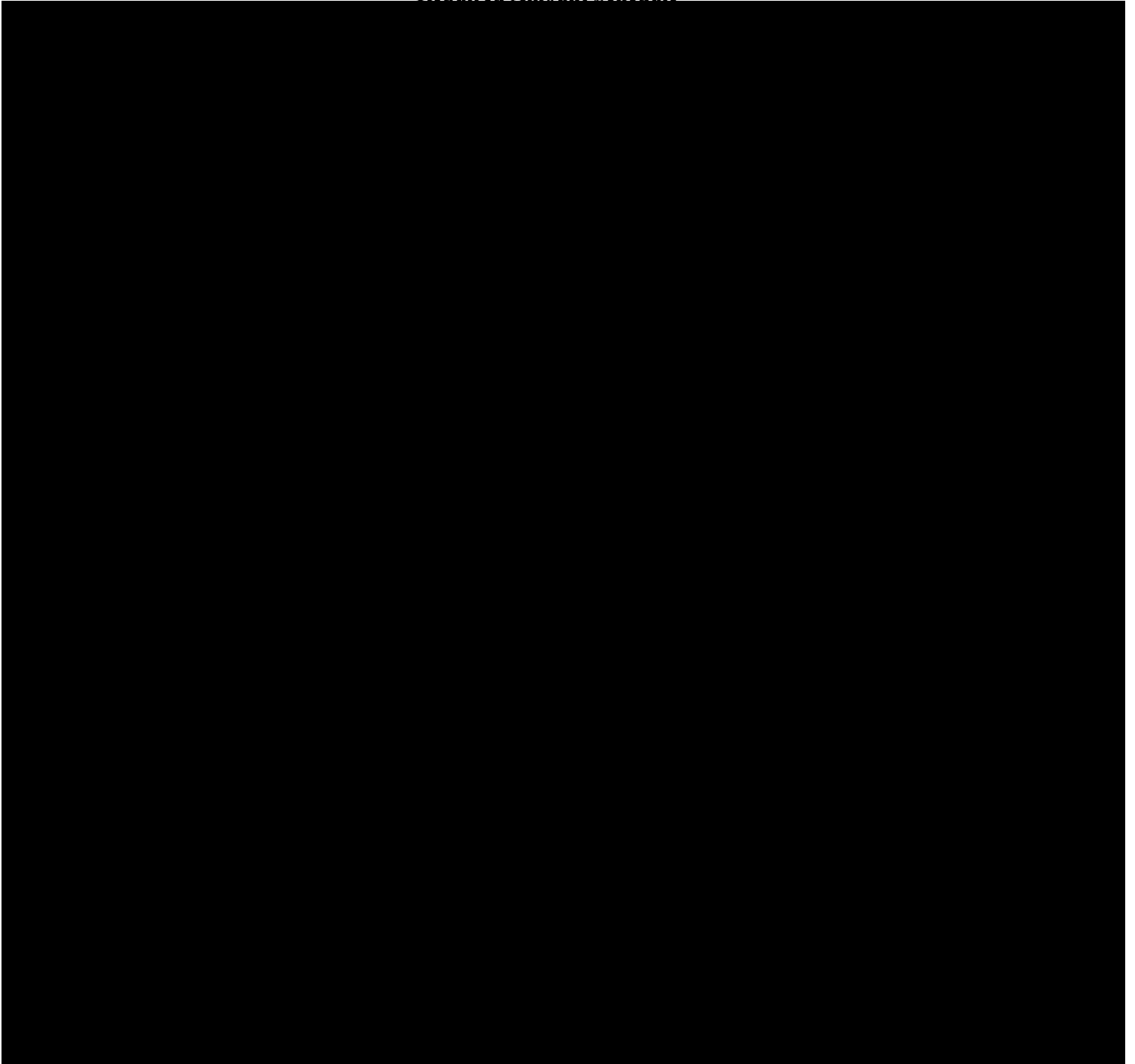


Exhibit A

Applicable Definitions

“**4-Hour Cost Cap**” has the meaning set forth in Section 3.2.2 of this Agreement.

“**4-Hour Energy Storage Project**” means a utility-scale battery or other energy storage system engineered to discharge electricity continuously for a duration of four (4) hours at its full rated power capacity.

“**Act**” means the Clean and Renewable Energy and Energy Waste Reduction Act, 2008 PA 295, as amended, MCL 460.1001 et seq., and the regulations promulgated thereunder.

“**Adjusted Capacity Credit Rate**” means, for any billing period, the “Capacity Demand Charge” (in \$ per kw of on-peak billing demand) set forth in Customer’s applicable Rate Schedule in effect as of such billing period, divided by the quantity of one plus the applicable MISO Planning Reserve Margin for the relevant billing period.

“**Administrative Fee**” means, for each billing period, the sum of: (a) the product of [REDACTED] per kW-month multiplied by the Installed Capacity of the Clean Capacity Project Portfolio, and (b) the product of [REDACTED] per MWh multiplied by the total energy (in MWh) generated by all Renewable Energy Projects in the Renewable Portfolio.

“**Affiliate**” means with regard to a Party, any person that directly or indirectly: (a) controls that Party; (b) is controlled by that Party; or (c) is under common control with that Party; where for each of (a), (b), and (c), “control” is defined as possession of the power to direct or cause the direction of the management and policies of a legally recognizable entity, through direct or indirect majority ownership or minimum percentage ownership that would grant the party a controlling interest in such entity.

“**Agreement**” has the meaning set forth in the preamble to this Agreement.

“**Bankruptcy**” means that (i) an entity shall voluntarily commence any proceeding or file any petition seeking relief under Title 11 of the United States Code, as now constituted or hereafter amended, or any other federal, state or foreign bankruptcy, insolvency, receivership or similar law, (ii) an involuntary proceeding shall be commenced or an involuntary petition shall be filed in a court of competent jurisdiction seeking (A) relief in respect of an entity, or of a substantial part of its property or assets, under Title 11 of the United States Code, as now constituted or hereafter amended, or any other Federal, state or foreign bankruptcy, insolvency, receivership or similar law, (B) the appointment of a receiver, trustee, custodian, sequestrator, conservator or similar official for such entity or for a substantial part of its property or assets or (C) the winding-up or liquidation of an entity; and such proceeding or petition shall continue undismissed for 60 days or an order or decree approving or ordering any of the foregoing shall be entered; (iii) an entity shall consent to the institution of, or fail to contest in a timely and appropriate manner, any proceeding or the filing of any petition described in the foregoing clause (ii), (iv) an entity shall apply for or consent to the appointment of a receiver, trustee, custodian, sequestrator, conservator or similar official for itself or for a substantial part of its property or assets, (v) an entity shall file an answer admitting the material allegations of a petition filed against it in any such proceeding, (vi) an entity shall make a general assignment for the benefit of creditors, (vii) an entity shall become unable, admit in writing its inability or fail generally to pay its debts as they become due or (viii) an entity shall take any action for the purpose of effecting any of the foregoing.

“**Business Days**” means any day other than Saturday, Sunday, any Federal Reserve Bank holiday, or other day that is a holiday observed by Company.

“**CCP Recovery Amount**” has the meaning set forth in Section 3.1.7 of this Agreement.

“**Change in Law**” means the adoption, enactment or other effectuation, or any change in the judicial, regulatory or administrative application or interpretation, or any amendment, repeal or other modification, by any Governmental Authority of any Law that adversely affects either Party’s (or any Project Party’s) performance under this Agreement or any Project Party’s performance under any Clean Capacity Project Agreement and/or Renewable Energy Project Agreement, as applicable (including any Executive Order or similar directive from a state executive branch or the federal Executive Branch that changes the interpretation of any of the foregoing), in each case, after the Contract Date; provided, however, in the case of any new Law, order or any other legally binding requirement or directive or change to any existing Law, order or other legally binding requirement applicable to either Party’s performance of its obligations under this Agreement or to a Project Party’s performance of its obligations under a Clean Capacity Project Agreement or Renewable Energy Project Agreement, as applicable, in either case that is enacted prior to the Contract Date, but for which the effectiveness thereof occurs after the Contract Date, shall not constitute a Change in Law hereunder.

“**Clean**” means electric energy or capacity produced from 4-Hour Energy Storage Projects or Long Duration Energy Storage Projects selected by Company, or other generation facilities of a type agreed by the Parties in writing.

“**Clean Capacity Credits**” means:

- (1) for each Clean Capacity Project in the Clean Capacity Project Portfolio and for the relevant billing period: (a) the number of Zonal Resource Credits assigned to the Clean Capacity Project in the MISO Planning Resource Auction for Zone 7, *multiplied by* (b) the sum of: (i) (x) the Adjusted Capacity Credit Rate, *multiplied by* (y) the ratio of the monthly on-peak billing demand, *divided by* (z) the Customer Committed Capacity Ramp (as set forth in Exhibit B-1 of the PSA), and (ii) (x) the MISO Net Cost of New Entry applicable to Zone 7, *multiplied by* (y) one (1), *minus* (z) the ratio of the monthly on-peak billing demand *divided by* the Customer Committed Capacity Ramp; *plus*
- (2) for the ZRC Product delivered to Company pursuant to Section 7, the number of Zonal Resource Credits assigned to such ZRC Product, *multiplied by* (b) the sum of: (i) (x) the Adjusted Capacity Credit Rate, *multiplied by* (y) the ratio of the monthly on-peak billing demand, *divided by* (z) the Customer Committed Capacity Ramp (as set forth in Exhibit B-1 of the PSA), and (ii) (x) the MISO Net Cost of New Entry applicable to Zone 7, *multiplied by* (y) one (1), *minus* (z) the ratio of the monthly on-peak billing demand *divided by* the Customer Committed Capacity Ramp.

The Clean Capacity Credits may not exceed the sum of the Clean Capacity Market Revenues for the relevant billing period. In the case where the Clean Capacity Credits exceed the total Clean Capacity Market Revenues received by Company from MISO in connection with any applicable Clean Capacity Projects and/or ZRC Product, the Clean Capacity Credits for such Clean Capacity Projects and/or ZRC Product shall be equal to the sum of the Clean Capacity Market Revenues received by Company from MISO in connection with such projects and/or ZRC Product.

“Clean Capacity Market Revenues” means, for each (1) Clean Capacity Project in the Clean Capacity Project Portfolio, and (2) each MW of ZRC Product delivered to Company in accordance with Section 7, all actual, incremental net revenue received by Company or its Affiliates from MISO as a result of the participation of such Clean Capacity Project or ZRC Product, as the case may be, in the MISO Planning Resource Auction as a “Self-Scheduled Resource”. For the avoidance of doubt, for any Clean Capacity Project that is co-located with a project that is not in the Clean Capacity Project Portfolio, the Clean Capacity Market Revenues shall be estimated by Company to equal the incremental net revenue collected by Company in excess of the revenue Company would have otherwise collected from such co-located project’s participation in the MISO Planning Resource Auction.

“Clean Capacity Project” has the meaning set forth in Section 3.1.1 of this Agreement.

“Clean Capacity Project Agreement” has the meaning set forth in Section 3.1.1 of this Agreement.

“Clean Capacity Project Agreement Filing” has the meaning set forth in Section 3.1.4 of this Agreement.

“Clean Capacity Project Billing Period Charge” has the meaning set forth in the Clean Capacity Project Portfolio Matrix.

“Clean Capacity Project Portfolio” has the meaning set forth in Section 3.1.5 of this Agreement.

“Clean Capacity Project Portfolio Matrix” has the meaning set forth in Section 3.1.5 of this Agreement.

“Clean Capacity Project Portfolio Revenue Requirement” means, the sum of the Clean Capacity Project Revenue Requirement for each year for all Clean Capacity Projects that have achieved commercial operation and have not yet achieved the end of their Cost Recovery Period.

“Clean Capacity Project Reconciliation” has the meaning set forth in Section 3.2.2 of this Agreement.

“Clean Capacity Project Revenue Requirement” means, with respect to a Clean Capacity Project, the cost to Company (including Company’s Commission authorized rate of return, and any financial incentives authorized by MCL 460.1028) of developing, procuring, constructing, leasing, utilizing, and/or purchasing such project including reasonable contingencies and acquisition and transaction costs, as well as the cost of operating such project, over its projected Cost Recovery Period, each as reasonably determined by Company in a commercially reasonable manner. The Clean Capacity Project Revenue Requirement for Long Duration Energy Storage Projects shall also include augmentation costs.

“Code” means the Internal Revenue Code of 1986, as amended.

“Commercial Operation Date” means, with respect to any Clean Capacity Project or Renewable Energy Project, as applicable, the date by which such project achieves regular operation as an integrated whole, including delivery of the full electrical energy output of such project to and from such project’s point of interconnection with the MISO system, consistent with Prudent Industry Practices and in accordance with the other applicable terms and conditions of this Agreement; provided, however, that for any project procured or acquired by Company that achieved commercial operation prior to the date that Company obtained ownership of such project, the Commercial Operation Date for purposes of this Agreement shall be the date that Company obtained ownership of such project.

“**Commission**” means the Michigan Public Service Commission.

“**Commission Approval Date**” means the earlier of: (i) the date on which the Commission issues its initial approval of this Agreement, (ii) the date on which the Parties reach mutual agreement on an amendment to this Agreement and/or waive their respective rights to terminate this Agreement in accordance with Section 2.4.1 following the Commission’s failure to grant approval (conditional or unconditional) of this Agreement, and (iii) the date on which the Parties reach mutual agreement on an amendment to this Agreement and/or waive their respective rights to terminate this Agreement in accordance with Section 2.4.2 following the Commission’s conditional approval of this Agreement.

“**Company**” means DTE Electric Company, a Michigan corporation.

“**Company Event of Default**” has the meaning set forth in Section 10.1 of this Agreement.

“**Company’s Rate Book**” means Company’s Rate Book for Electric Service. Company’s Rate Book as of the Contract Date can be found at <https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/consumer/rate-books/electric/dte/dtee1cur.pdf?rev=cf55d05b027a43fc9d4f762672e9aa9e&hash=D28CE34BD%20%207DCDD7279069015BB8121A> and may be updated, revised and/or modified as approved or agreed to by the Commission.

“**Conditions Precedent**” has the meaning set forth in Section 2.1 of this Agreement.

“**Confidential Information**” has the meaning set forth in Section 12.1 of this Agreement.

“**Contract Date**” has the meaning set forth in the preamble to this Agreement.

“**Cost Recovery Period**” means, for each Clean Capacity Project or Renewable Energy Project, as applicable, the Commission approved depreciable life of such project.

“**Credit Rating**” means with respect to an entity on any date of determination: (1) the respective rating then assigned to its senior unsecured and unsubordinated long-term debt or deposit obligations (not supported by third party credit enhancement) by S&P or Moody’s, as applicable, or (2) if such entity does not have a rating for its unsecured, senior, long-term debt, then the corporate rating or issuer rating, as applicable, then assigned to such entity by S&P or Moody’s, as applicable.

“**Customer**” has the meaning set forth in the preamble to this Agreement.

“**Customer Caused Event**” means any demonstrable failures, delays or increased costs, in each case, in connection with Company’s performance of its obligations under this Agreement to the extent due to any

failure, delay or non-performance by Customer that adversely impacts Company's performance of its obligations under this Agreement, including, but not limited to, Customer's failure to deliver ZRC Product to Company pursuant to Customer's obligation in Section 7.

"Customer Committed Capacity Ramp" has the meaning set forth in the PSA.

"Customer Credit Payments" has the meaning set forth in Section 9.3 of this Agreement.

"Customer Credit Support" means the credit support provided by Customer to Company in the form of a Customer Parent Guaranty or Letter of Credit (or combination thereof) to support all of Customer's payment obligations due and owing under this Agreement, as required pursuant to Section 11.

"Customer Event of Default" has the meaning set forth in Section 9.1 of this Agreement.

"Customer LC Proceeds" has the meaning set forth in Section 11.2.1 of this Agreement.

"Customer Parent Guarantor" has the meaning set forth in Section 11.1 of this Agreement.

"Customer Parent Guaranty" has the meaning set forth in Section 11.1 of this Agreement.

"Data Center Location" has the meaning set forth in paragraph A of the Recitals to this Agreement.

"Demand Response Agreement" has the meaning set forth in paragraph A of the Recitals to this Agreement.

"Disclosing Party" has the meaning set forth in Section 12.1 of this Agreement.

"Dispute" has the meaning set forth in Section 15.1 of this Agreement.

"Effective Date" has the meaning set forth in Section 2.2 of this Agreement.

"Electric Service" has the meaning set forth in the PSA.

"Energy" has the meaning ascribed to that term in the MISO Tariff.

"Excusable Event" means any of the following events or circumstances: (i) supply chain disruptions and delays not attributable to the fault of Company; (ii) to the extent not within the reasonable control of Company or a result of Company's failure to perform its obligations under this Agreement, delays or other impacts to Company's or Customer's ability to perform here under which arise from the actions or inactions of the Transmission Owner, MISO, Commission or any other regulatory body governing the generation or transmission of Electric Service or energy, or (iii) any delays otherwise excused pursuant to Company's Rate Book, as amended, as applicable.

"Expected Commercial Operation Date" means the date set forth the Clean Capacity Project Portfolio Matrix or Renewable Portfolio Matrix, as applicable, for each Clean Capacity Project or Renewable Energy Project, as applicable.

"Facility" has the meaning set forth in paragraph A of the Recitals to this Agreement.

"FERC" means the Federal Energy Regulatory Commission or its successor.

“**Financing Party**” means any lender providing debt or equity financing to Company in connection with its use of the Facilities.

“**Force Majeure Event**” means any event or circumstance, or combination of events or circumstances, arising after the Contract Date that wholly or partly prevents or delays a Party from performing any obligation under this Agreement or wholly or partly prevents or delays a Project Party from performing any obligation under a Clean Capacity Project Agreement or Renewable Energy Project Agreement, in either case, but only if and to the extent:

- (a) such event or circumstance, or combination of events or circumstances, is not within the reasonable control of the Party or Project Party, as applicable;
- (b) The Party or Project Party, as applicable, has used reasonably diligent efforts in taking precautions and measures to (i) avoid the effect of such event or circumstance, or combination of events or circumstances, on the Party or Project Party, as applicable, and (ii) mitigate the consequences thereof;
- (c) such event or circumstance, or combination of events or circumstances, does not result from the failure of the Party or Project Party, as applicable, to perform any of its obligations under this Agreement or the applicable Clean Capacity Project Agreement or Renewable Energy Project Agreement, as the case may be; and
- (d) such event or circumstance, or combination of events or circumstances, could not have been (i) reasonably anticipated or (ii) avoided by the exercise of reasonable diligence and care.

A “**Force Majeure Event**” shall include, without limitation, the following; provided, that such event, circumstance, or combination of events or circumstances, meets all of the requirements in clauses (a)-(d) of the immediately preceding sentence: expropriation; invasion; drought, landslide, tornado, hurricane, tsunami, flood, lightning, earthquake, and other acts of God; fire; explosion; plague, epidemic and/or pandemic; invasion, acts of terrorism, war (declared or undeclared), or other armed conflict; riot, revolution, insurrection, or similar civil disturbance or commotion; acts of the public enemy; perils of sea; blockade; port closure; sabotage or vandalism; except as set forth in the next sentence below, strikes and other labor disputes (including collective bargaining disputes and lockouts) involving a Party (or Project Party) and not directed exclusively at such Party (or Project Party); material physical damage caused by third parties; transportation accidents; delays in transportation (not attributable to the fault of Company or Project Party, as applicable, or resulting from another Force Majeure Event), including delays due to closure of roads or other transportation route by Governmental Authorities or otherwise due to a Force Majeure Event; embargoes; or other acts or omissions of a Governmental Authority (other than such acts or omissions in response to acts or omissions of the affected Party (or Project Party)), and a Force Majeure declared by a subcontractor to this Agreement that meets the requirements of clauses (a)-(d).

“**Governmental Authority**” means any federal, state, local, municipal, or other governmental, regulatory, administrative, quasi-governmental, judicial, public or statutory instrumentality, court or governmental tribunal, agency, commission authority, body or entity, or any political subdivision thereof, including MISO or its successor, having legal jurisdiction over the matter or person in question.

“**Impacted Project**” has the meaning set forth in Section 6.5 of this Agreement.

“**Incentive RECs**” means incentive RECs granted under sections 39(2)(a)-(e), as applicable, of the Act.

“**Indicative Clean Capacity Portfolio**” means the portfolio set forth in Exhibit F, or as otherwise revised by the Parties in accordance with Section 3.1.10 of this Agreement.

“**Indicative Renewable Portfolio**” means the portfolio set forth in Exhibit F, or as otherwise revised by the Parties in accordance with this Agreement.

“**Initial Term**” has the meaning set forth in the PSA.

“**Installed Capacity**” means, for each Clean Capacity Project or Renewable Energy Project, the actual or expected nameplate capacity of such project expressed in MW as the rate at which such project can deliver electric energy to its point of interconnection with the MISO system, as set forth in the Clean Capacity Project Portfolio Matrix or Renewable Portfolio Matrix, as applicable, for such project.

“**Law**” or “**Laws**” means all laws, treaties, ordinances, statutes, judgments, decrees, injunctions, writs, orders, rules, regulations, tariffs, interpretations, open-access transmission tariffs, and permits of any Governmental Authority having jurisdiction of the transmission of electricity, performance of the work, all and each document, instrument and agreement delivered hereunder or in connection herewith, health and safety, or the environmental condition of the locations of the Clean Capacity Projects and Renewable Energy Projects in the Clean Capacity Project Portfolio and Renewable Portfolio, as applicable, or Customer’s facilities.

“**Letter of Credit**” means an irrevocable stand-by letter of credit, in a form agreed to by Company in writing, provided by Customer pursuant to Section 11 and issued by a Qualified Issuer.

“**Letter of Credit Default**” means, with respect to a Letter of Credit, the occurrence of any of the following events: (a) the Qualified Issuer that has issued such Letter of Credit (i) becomes subject to any insolvency or Bankruptcy event, (ii) fails to comply with or perform its obligations under such Letter of Credit if such failure shall be continuing after notice thereof and the lapse of any applicable grace period or (iii) disaffirms, disclaims, repudiates or rejects, in whole or in part, or challenges the validity of such Letter of Credit; (b) such Letter of Credit ceases to be in full force and effect during the period required by this Agreement; or (c) the issuer of such Letter of Credit ceases to meet the qualifications of a Qualified Issuer.

“**Levelized Weighted Renewable Portfolio Cost**” means the levelized weighted average cost of the Renewable Energy Projects in the Renewable Portfolio, which shall be determined by dividing the net present value of the Renewable Energy Project Revenue Requirement for all Renewable Energy Projects in the Renewable Portfolio by the net present value of the forecasted generation of each Renewable Energy Project in the Renewable Portfolio. For the purposes of calculating the Levelized Weighted Renewable Portfolio Cost, the Renewable Energy Project Revenue Requirement and the forecasted generation for each Renewable Energy Project in the Renewable Portfolio shall be calculated over a technical useful life of thirty-five (35) years and not over the cost recovery period of the Renewable Energy Project. For any Renewable Energy Project with less than thirty-five (35) years of technical useful life remaining, the Renewable Energy Project Revenue Requirement and forecasted generation shall be calculated over the remaining useful life from such project’s Commercial Operation Date. A sample calculation of the Levelized Weighted Renewable Portfolio Cost is illustrated in Exhibit G.

“**Line Extension Agreement**” has the meaning set forth in paragraph A of the Recitals to this Agreement.

“**Long Duration Energy Storage Project**” means a utility-scale battery system or other energy storage system engineered to discharge electricity continuously for a duration of at least eight (8) hours at its full rated power capacity.

“**Meet and Confer Request**” has the meaning set forth in Section 2.4.2 of this Agreement.

“**MISO**” means Midcontinent Independent System Operator, Inc.

“**MISO Cost of New Entry**” has the meaning ascribed to that term in the MISO Tariff.

“**MISO Day-Ahead Energy and Operating Reserve Market**” has the meaning ascribed to that term in the MISO Tariff.

“**MISO FRAP Submission Deadline**” means the date when Company must submit a Fixed Resource Adequacy Plan (“FRAP”) to MISO pursuant to MISO Tariff Section 69A.9(a).

“**MISO Module E-1 Capacity Tracking Tool**” or “**MECT**” means the title tracking and registration tool administered by MISO pursuant to MISO Tariff Section 69A.2 to enable market participants and load serving entities to meet their resource adequacy obligations.

“**MISO Net Cost of New Entry**” has the meaning ascribed to that term in the MISO Tariff.

“**MISO Planning Reserve Margin**” has the meaning ascribed to that term in the MISO Tariff.

“**MISO Planning Resource Auction**” has the meaning ascribed to the term “Planning Resource Auction” in the MISO Tariff and shall include any successor term and mechanism used by MISO to purchase and sell capacity.

“**MISO Real-Time Energy and Operating Reserve Market**” has the meaning ascribed to that term in the MISO Tariff.

“**MISO Tariff**” means the MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.

“**Notice**” has the meaning set forth in Section 17.2 of this Agreement.

“**Parties**” has the meaning set forth in the preamble to this Agreement.

“**Party**” has the meaning set forth in the preamble to this Agreement.

“**Project Party**” means, in connection with the development, construction, lease, utilization, purchase, ownership, operation or maintenance of a Clean Capacity Project or Renewable Energy Project, as applicable, Company or any counterparty to a Clean Capacity Project Agreement or Renewable Energy Project Agreement, as applicable or any of Company’s or such counterparty’s respective Affiliates, contractors, subcontractors or suppliers. For the avoidance of doubt Customer, (i) as counterparty to Company for the transfer of Zonal Resource Credits under this Agreement, and/or (ii) as counterparty to a Supplemental Agreement, in either case, shall be deemed a Project Party for purposes of this Agreement and any Related Agreement.

“**Prudent Industry Practice**” means the practices, methods and acts engaged in or approved by regulated electric utilities in the United States, that, at a particular time, in the exercise of reasonable judgment in light of the facts known or that should reasonably have been known at the time a decision was made, would have been expected by a reasonably prudent business company of established reputation in the regulated electric utility industry to accomplish the desired result in a manner consistent with applicable Laws,

regulations, codes, standards, equipment manufacturers' recommendations, reliability, safety, environmental protection, economy and expedition. Prudent Industry Practice is a range of reasonable practices and does not necessarily mean the highest standard in the industry. For the avoidance of doubt, any practices, methods and/or acts approved by the Commission or as set forth in Company's Rate Book shall be deemed "Prudent Industry Practice."

"PSA" has the meaning set forth in the Recitals to this Agreement.

"Qualified Issuer" means a commercial bank or trust company organized under the Laws of the United States or a political subdivision thereof or validly existing in the country of its organization that is registered to do business in the United States and has a branch office located in the United States, with (A) a Credit Rating of at least (x) "A-" by S&P or (y) "A3" by Moody's at any point in time and (B) a net worth of at least Ten Billion Dollars (\$10,000,000,000) at the time of issuance of a Letter of Credit.

"Qualified REC Tracking System" means the Midwest Renewable Energy Tracking System, and any other renewable energy tracking system agreed upon by the Parties.

"Rate Schedule" means Schedule D11 and may be changed in accordance with Section 5.1 of the PSA.

"REC Quantity" means for each calendar year during the Term, an amount (expressed in MWh) equal to the net electric energy generation from all Renewable Energy Projects in the Renewable Portfolio.

"Recipient" has the meaning set forth in Section 12.1 of this Agreement.

"Related Agreement" means (a) the PSA, (b) the Line Extension Agreement, (c) the Demand Response Agreement, and (d) any Supplemental Agreement.

"Related Agreement Completion Date" means the latest date on which the Parties execute: (a) the PSA, (b) the Line Extension Agreement, and (c) the Demand Response Agreement.

"Relief Event" means a Force Majeure Event, Change in Law or Excusable Event.

"Relief Event Cost Cap" has the meaning set forth in Section 6.5.3 of this Agreement.

"Relief Event Costs" has the meaning set forth in Section 6.5 of this Agreement.

"Relief Event Notice" has the meaning set forth in Section 6.5 of this Agreement.

"Renewable Capacity Credits" means, for each Renewable Energy Project in the Renewable Portfolio and for the relevant billing period: (a) the number of Zonal Resource Credits assigned to the Renewable Energy Project in the MISO Planning Resource Auction for the applicable Zone, *multiplied by* (b) the sum of: (i) (x) the Adjusted Capacity Credit Rate *multiplied by* (y) the ratio of the monthly on-peak billing demand, *divided by* (z) the Customer Committed Capacity Ramp (as set forth in Exhibit B-1 of the PSA) and (ii) (x) the MISO Net Cost of New Entry for the applicable Zone, *multiplied by* (y) one (1), *minus* (z) the ratio of the monthly on-peak billing demand *divided by* the Customer Committed Capacity Ramp. The sum of the Renewable Capacity Credits for each Renewable Energy Project in the Renewable Portfolio may not exceed the sum of the Renewable Capacity Market Revenues for the relevant billing period. In the case where the sum of Renewable Capacity Credits received by Company from MISO in connection with a Renewable Energy Project in the Renewable Portfolio exceeds the total Renewable Capacity Market Revenues received by Company from MISO in connection with such project, the sum of the Renewable

Capacity Credits for such Renewable Energy Project shall be equal to the sum of the Renewable Capacity Market Revenues received by Company from MISO in connection with such project.

“**Renewable Capacity Market Revenues**” means, for each Renewable Energy Project in the Renewable Portfolio, all actual, incremental net revenue received by Company or its Affiliates from MISO as a result of the participation of such Renewable Energy Project in the MISO Planning Resource Auction as a “Self-Scheduled Resource”. For the avoidance of doubt, for any Renewable Energy Project that is co-located with a project that is not in the Renewable Portfolio, the Renewable Capacity Market Revenues shall be estimated by Company to equal the incremental net revenue collected by Company in excess of the revenue Company would have otherwise collected from such co-located project’s participation in the MISO Planning Resource Auction.

“**Renewable Cost Target**” has the meaning set forth in Section 4.1.10.1 of this Agreement.

“**Renewable Energy Credits**” or “**RECs**” means a credit granted pursuant to Section 39 of the Act and transferrable to DTE pursuant to Section 41 of the Act that represents generated renewable energy. To the extent generated by any Renewable Energy Project, RECs will include Incentive RECs.

“**Renewable Energy Project**” means a Company owned and operated utility-scale solar photovoltaic or wind energy project that complies with the requirements of the Act and qualifies for Renewable Energy Credits.

“**Renewable Energy Project Agreement**” has the meaning set forth in Section 4.1.1 of this Agreement.

“**Renewable Energy Project Agreement Filing**” has the meaning set forth in Section 4.1.2 of this Agreement.

“**Renewable Energy Project Billing Period Charge**” has the meaning set forth in the Renewable Portfolio Matrix.

“**Renewable Energy Project Reconciliation**” has the meaning set forth in Section 4.2.2 of this Agreement.

“**Renewable Energy Project Revenue Requirement**” means, with respect to a Renewable Energy Project, the cost to Company (including Company’s Commission authorized rate of return, and any financial incentives authorized by MCL 460.1028) of developing, procuring, constructing, leasing, utilizing, and/or purchasing such project, including reasonable contingencies and acquisition and transaction costs, as well as the cost of operating such project over its projected Cost Recovery Period, each as reasonably determined by Company in a commercially reasonable manner.

“**Renewable Generation Credits**” means, for each Renewable Energy Project in the Renewable Portfolio and for the relevant billing period, the product of: (i) the generation of the Renewable Energy Project, *multiplied by* (ii) the weighted average of the on and off peak values of the Power Supply, Non-Capacity Energy Charges as set forth in Customer’s applicable Rate Schedule in effect as of such billing period, calculated as follows: (A) the sum of: (1)(I) the on-peak “Energy Charge”, *multiplied by* (II) the number of on-peak hours in the applicable billing period, and (2)(I) the off-peak Energy Charge, *multiplied by* (II) the number of off-peak hours in the applicable billing period, *divided by* (B) the total number of hours in the applicable billing period. The sum of the Renewable Generation Credits for each Renewable Energy Project in the Renewable Portfolio may not exceed the sum of the Renewable Generation Market Revenues for the relevant billing period. In the case where the sum of Renewable Generation Credits for a Renewable Energy Project in the Renewable Portfolio exceeds the total Renewable Generation Market Revenues received by

Company from MISO in connection with such project, the sum of the Renewable Generation Credits for such Renewable Energy Project shall be equal to the sum of the Renewable Generation Market Revenues.

“Renewable Generation Market Revenues” means all actual, incremental net revenues received by Company or its Affiliates from MISO as a result of the participation of each Renewable Energy Project in the Renewable Portfolio in the MISO Day-Ahead Energy and Operating Reserve Market and/or the MISO Real-Time Energy and Operating Reserve Market.

“Renewable Portfolio” has the meaning set forth in Section 4.1.3 of this Agreement.

“Renewable Portfolio Matrix” has the meaning set forth in Section 4.1.3 of this Agreement.

“Renewable Portfolio RECs” has the meaning set forth in paragraph C of the Recitals to this Agreement.

“Renewable Portfolio Revenue Requirement” means the sum of the Renewable Energy Project Revenue Requirement for each year for all Renewable Energy Projects that have achieved commercial operation and have not yet achieved the end of their Cost Recovery Period.

“REP Recovery Amount” has the meaning set forth in Section 4.1.5 of this Agreement.

“Replacement ZRC Price” means the higher of: (A) the sum of: (i) the “Zone 7 Auction Clearing Price” in dollars per MW-day (as determined by MISO) for the applicable Seasonal Accreditation Period *plus* (ii) the MISO Net Cost of New Entry applicable to Zone 7 in dollars per MW-day, and (B) (i) three (3) *multiplied by* (ii) the MISO Net Cost of New Entry applicable to Zone 7 in dollars per MW-day.

“Representatives” has the meaning set forth in Section 12.2 of this Agreement.

“Sanctioned Country” means, at any time, a country or territory that is itself the target of comprehensive Sanctions (as of the date of this Agreement, Cuba, Iran, North Korea, the Crimea region of Ukraine, the so-called Donetsk People’s Republic, and the so-called Luhansk People’s Republic).

“Sanctioned Person” means (a) any person listed in any sanctions-related list of designated persons maintained by the Office of Foreign Assets Control of the U.S. Department of the Treasury (“OFAC”) or the U.S. Department of State, the United Nations Security Council, the European Union, any Member State of the European Union, or the United Kingdom; (b) any person operating, organized, or resident in a Sanctioned Country; (c) the government of a Sanctioned Country or the Government of Venezuela; or (d) any person 50% or more owned or, where relevant under applicable Sanctions, controlled by any such person or persons or acting for or on behalf of such person or persons.

“Sanctions” means economic or financial sanctions or trade embargoes imposed, administered or enforced from time to time by (a) the U.S. government, including those administered by OFAC or the U.S. Department of State, or (b) the United Nations Security Council, the European Union, any European Union Member State or the United Kingdom.

“**Schedule D11**” means Primary Supply Rate Schedule No. D11, as published in Company’s Rate Book and approved by the Commission as of the Contract Date, which is subject to change from time to time by order issued by the Commission.

“**Seasonal Accreditation Period**” means a given Season, as such term is defined in MISO Tariff Section 1.S, in a Planning Year, as such term is defined in MISO Tariff Section 1.P.

“**Self-Scheduled Resource**” has the meaning ascribed to that term in the MISO Tariff.

“**Settlement**” has the meaning set forth in paragraph C of the Recitals to this Agreement.

“**Standard & Poor’s**” or “**S&P**” means S&P Global Ratings or its successor.

“**Supplemental Agreement**” means any agreement entered into between the Parties following the Contract Date in connection with: (i) another Related Agreement, (ii) providing electric capacity and/or energy to Customer’s Facility or (iii) the construction of facilities to allow for provision of Electric Service to Customer.

“**Term**” has the meaning set forth in Section 1 of this Agreement.

“**Termination Payment**” has the meaning set forth in Section 9.3 of this Agreement.

“**Transmission Owner**” means ITC Holdings Corporation and its Affiliates.

“**Zonal Resource Credits**” or “**ZRCs**” has the meaning ascribed to that term in the MISO Tariff.

“**ZRC Delivery Term**” means the period that commences on June 1, 2028 and ends on May 31, 2033.

“**ZRC Product**” means MISO Zone 7 Zonal Resource Credits in an amount equal to 300MW.

“**ZRC Tracking System**” means the MECT, or any successor system.

Exhibit B-1

Form of Clean Capacity Project Portfolio Matrix

Clean Capacity Project Detail (one for each project in Clean Capacity Project Portfolio):

Clean Capacity Project:

Installed Capacity (MW):

Expected Commercial Operation Date:

Cost Recovery Period:

Clean Capacity Project Revenue Requirement:

Year	(a) Number of Billing Periods	(b) Clean Capacity Project Revenue Requirement (\$)	(c) = (b)/(a) Clean Capacity Project Billing Period Charge (\$)

Clean Capacity Project Portfolio Revenue Requirement

Total Clean Capacity Portfolio Installed Capacity (MW):

Clean Capacity Project Portfolio Revenue Requirement:

Year	(a) Clean Capacity Project Portfolio Revenue Requirement (\$)

Exhibit B-2

Form of Renewable Portfolio Matrix

Renewable Energy Project Detail (one for each project in Renewable Portfolio):

Renewable Energy Project:

Installed Capacity (MW):

Expected Commercial Operation Date:

Cost Recovery Period:

Renewable Energy Project Revenue Requirement:

Year	(a) Number of Billing Periods	(b) Renewable Energy Project Revenue Requirement (\$)	(c) = (b)/(a) Renewable Energy Project Billing Period Charge (\$)

Renewable Portfolio Revenue Requirement

Total Renewable Portfolio Installed Capacity (MW):

Renewable Portfolio Revenue Requirement:

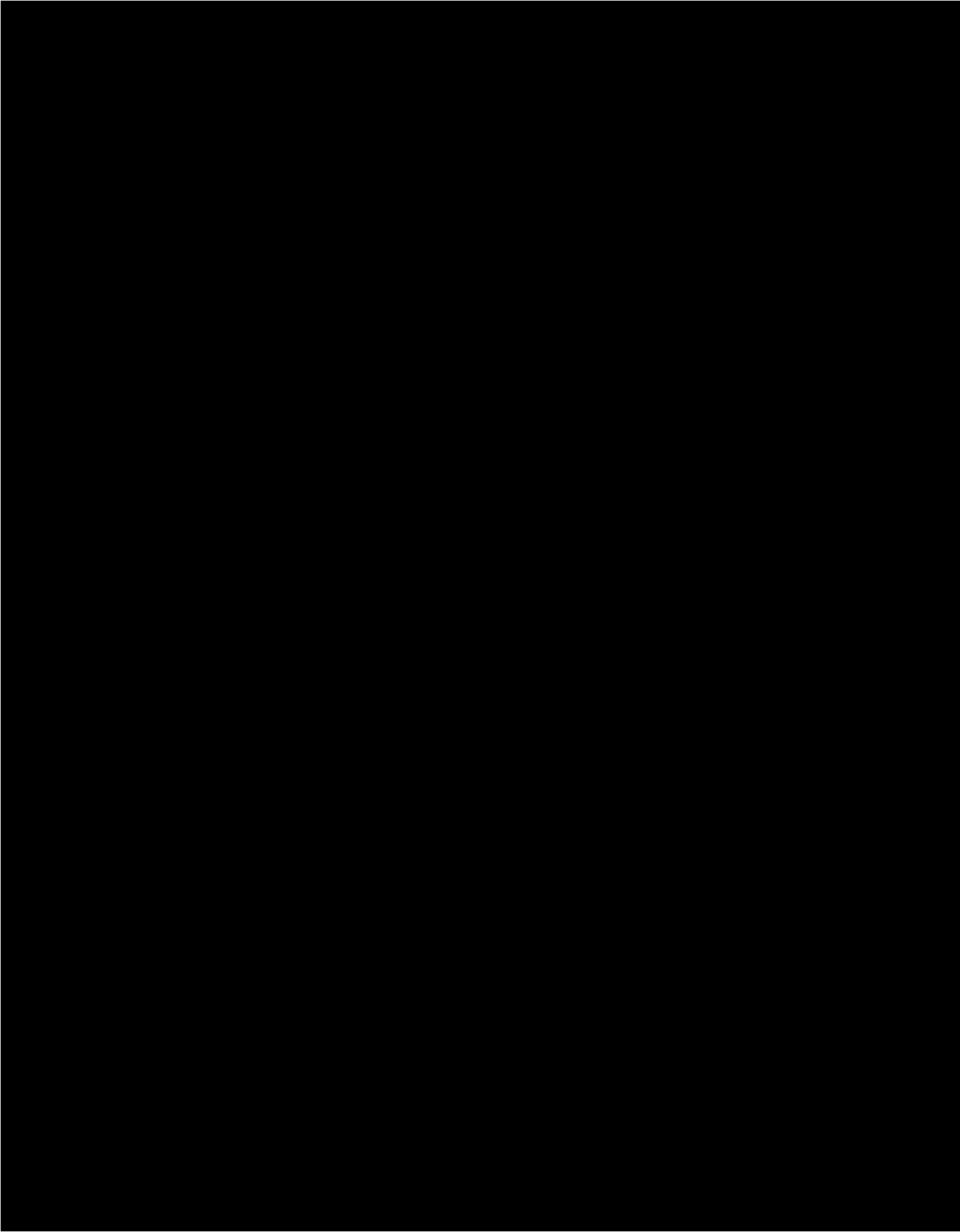
Year	(a) Renewable Portfolio Revenue Requirement (\$)

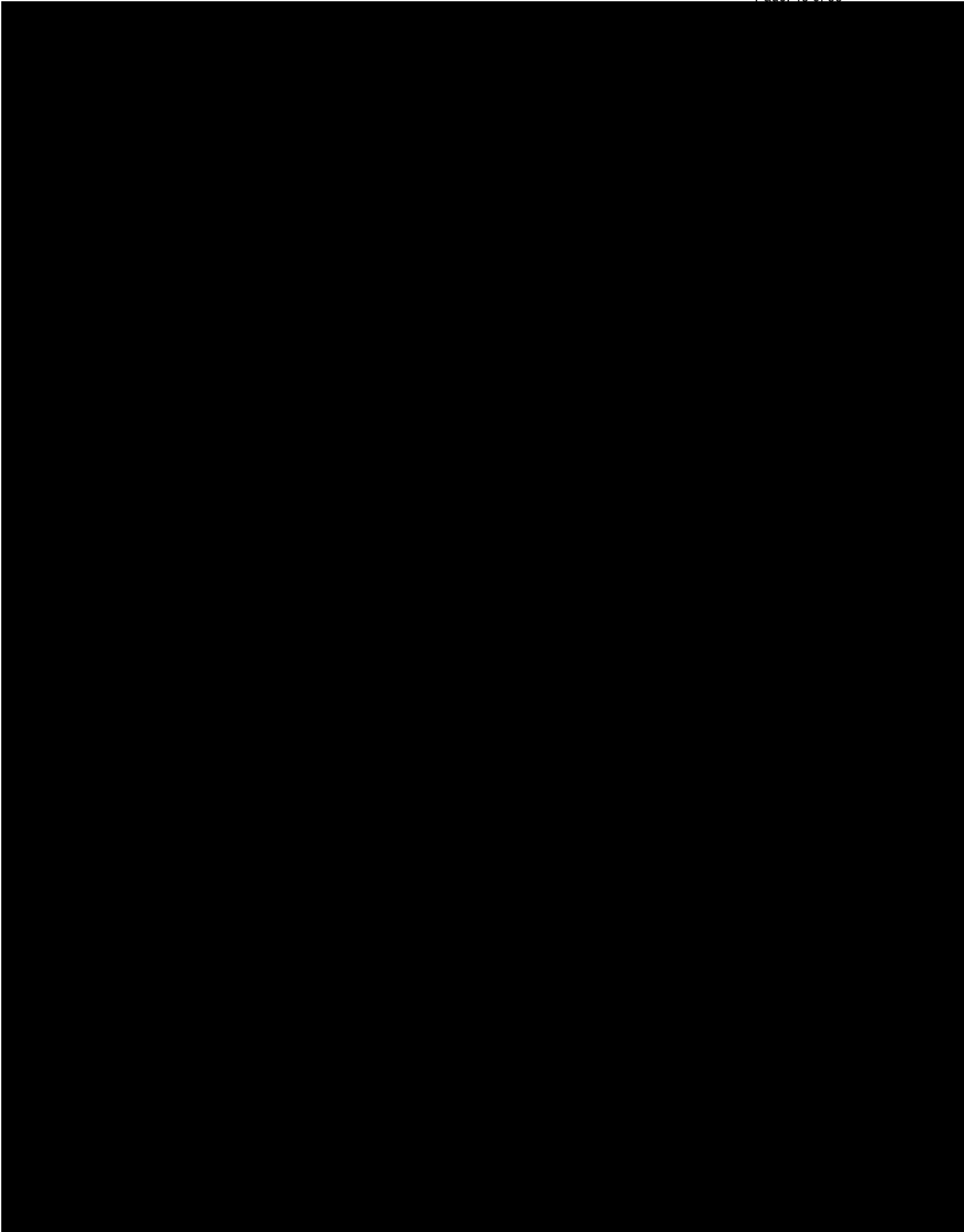
Exhibit C

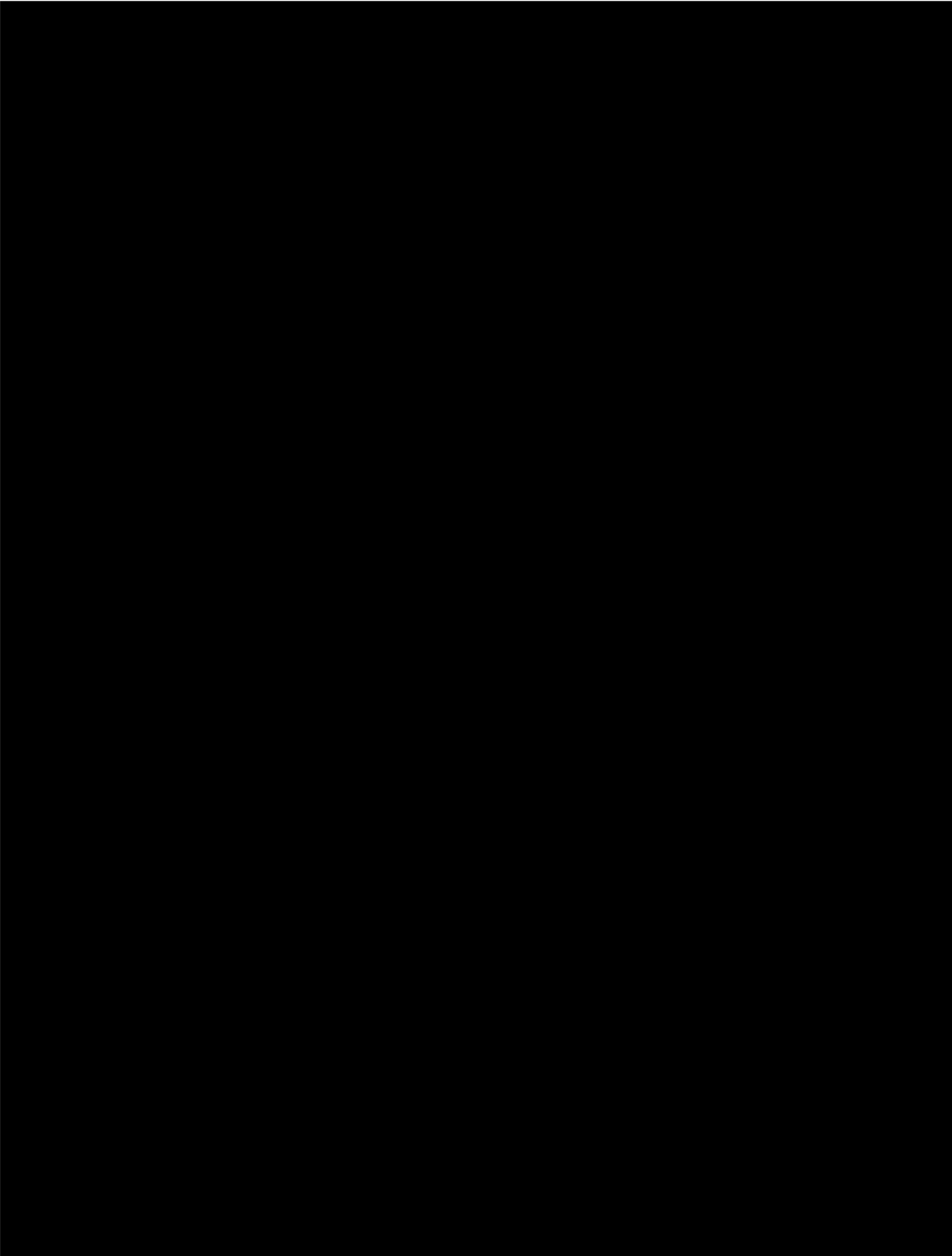
Form of Customer Parent Guaranty

GUARANTY









Schedule 1

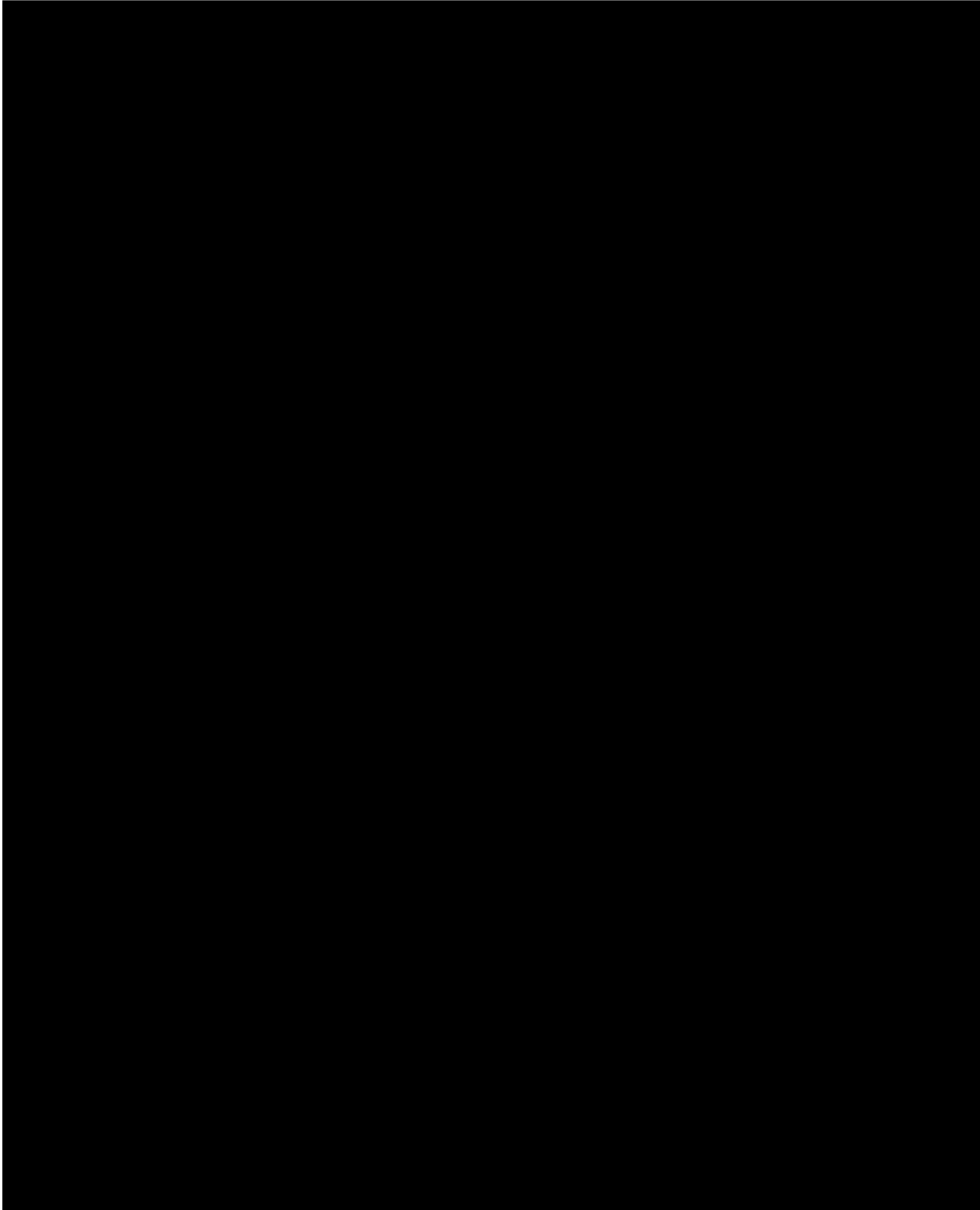


Exhibit D – Sample Invoices

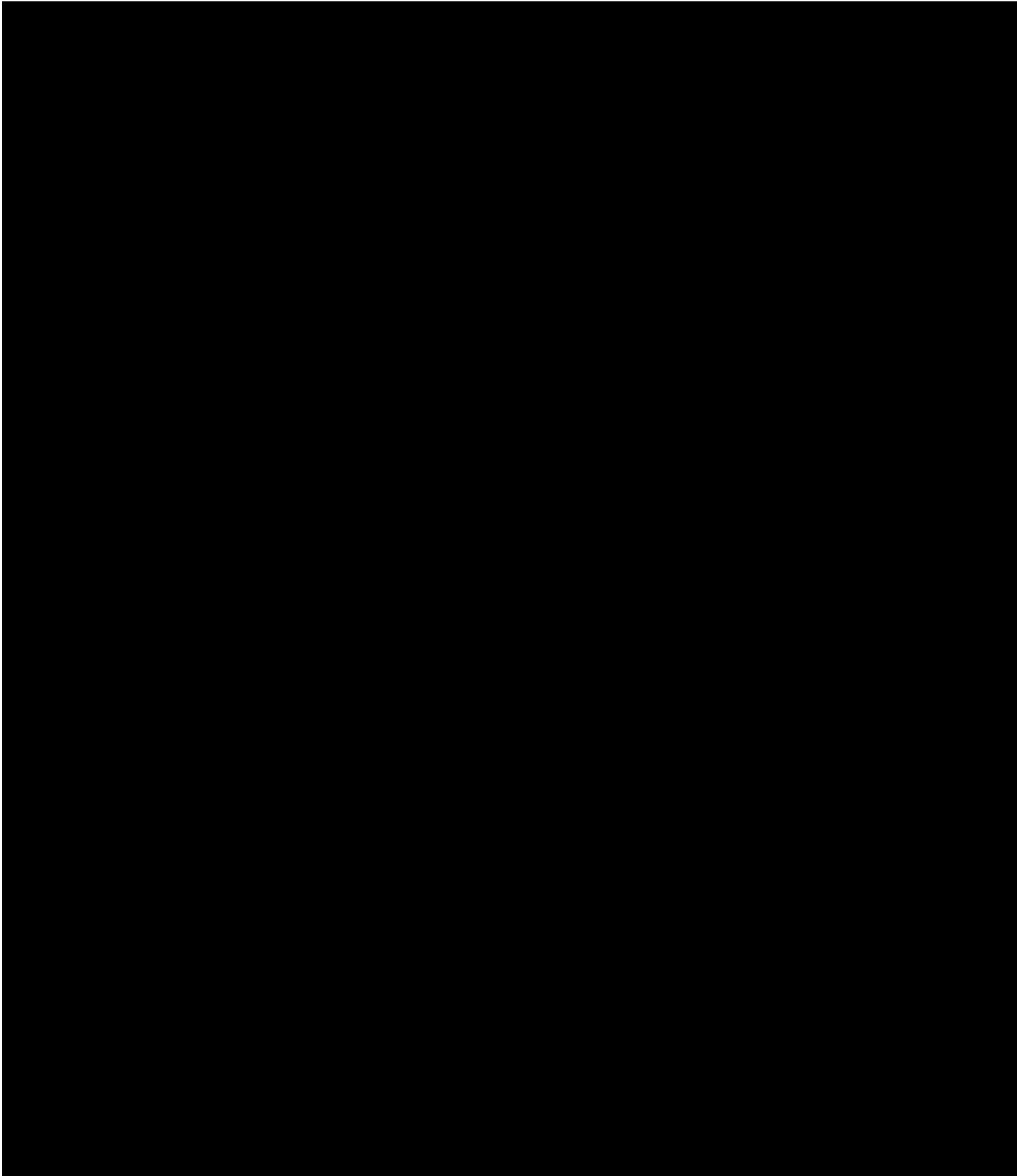
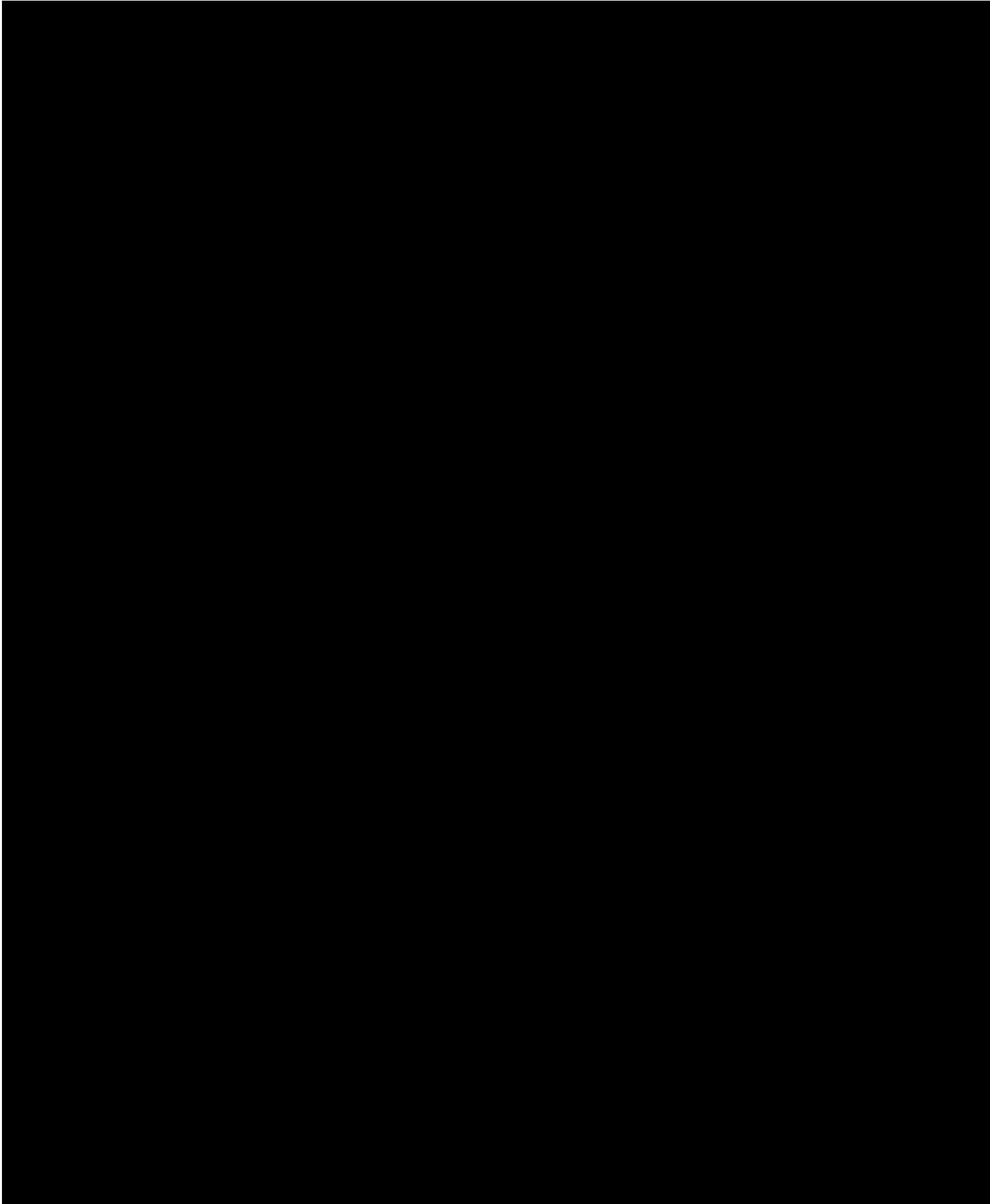
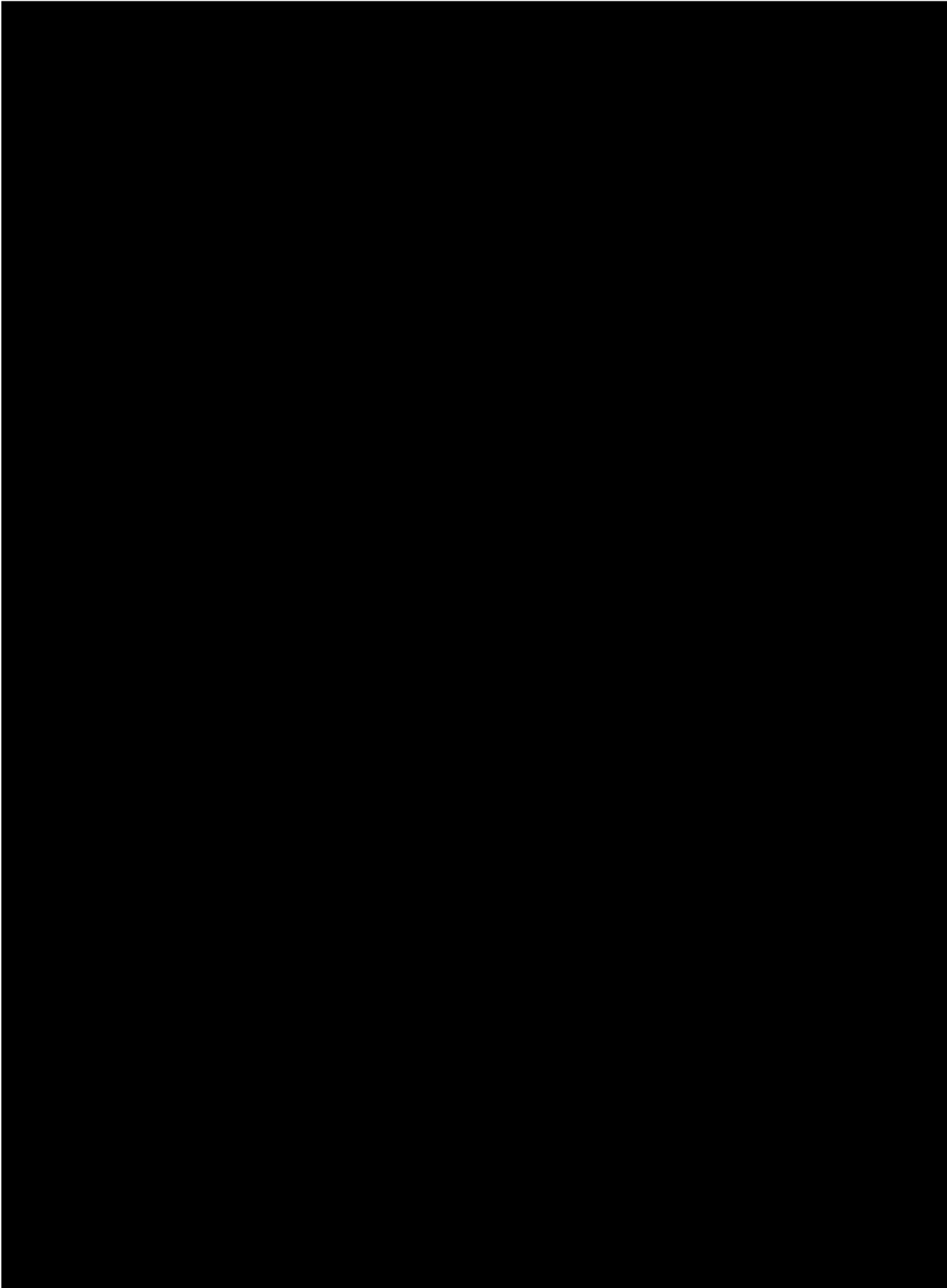
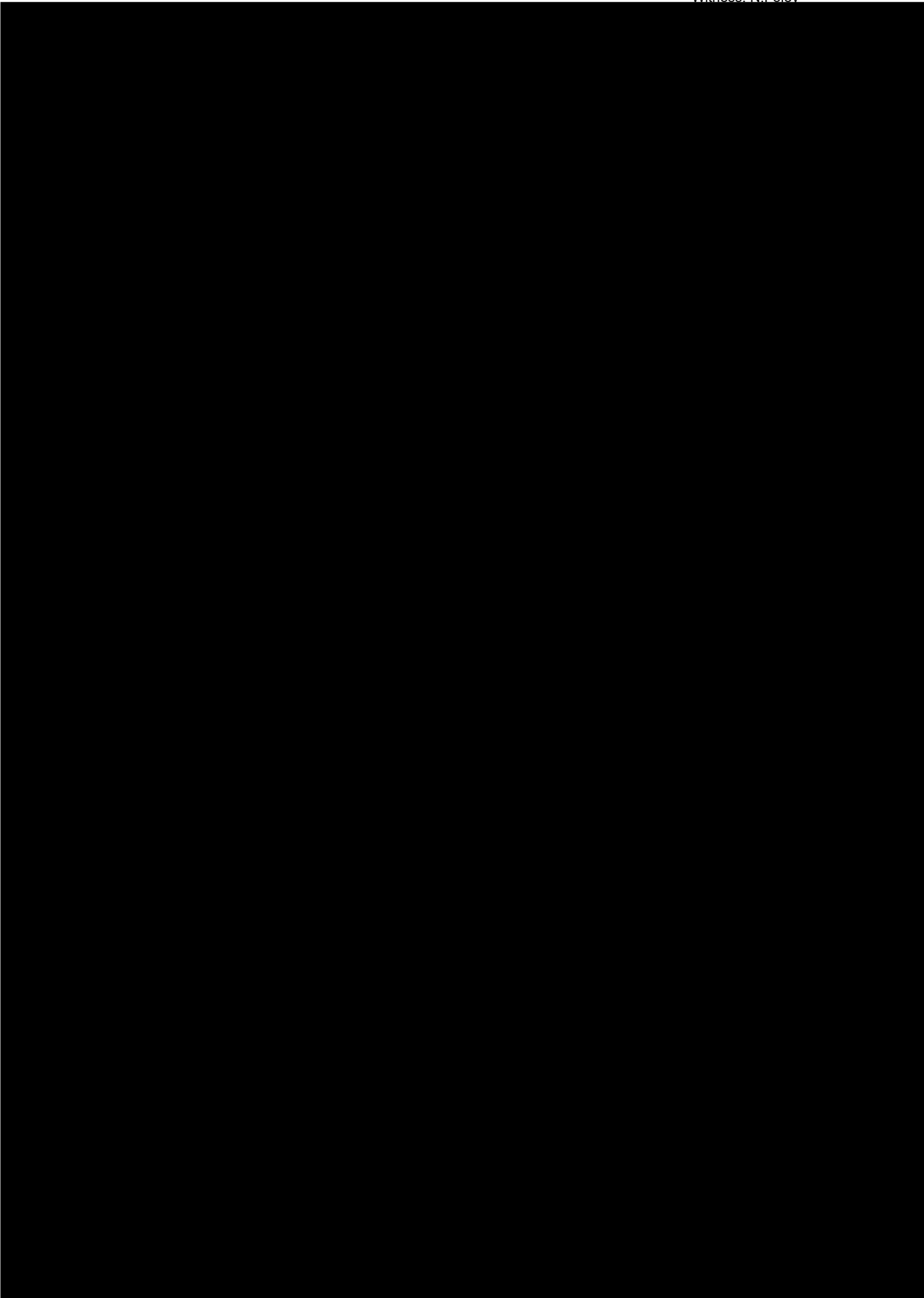
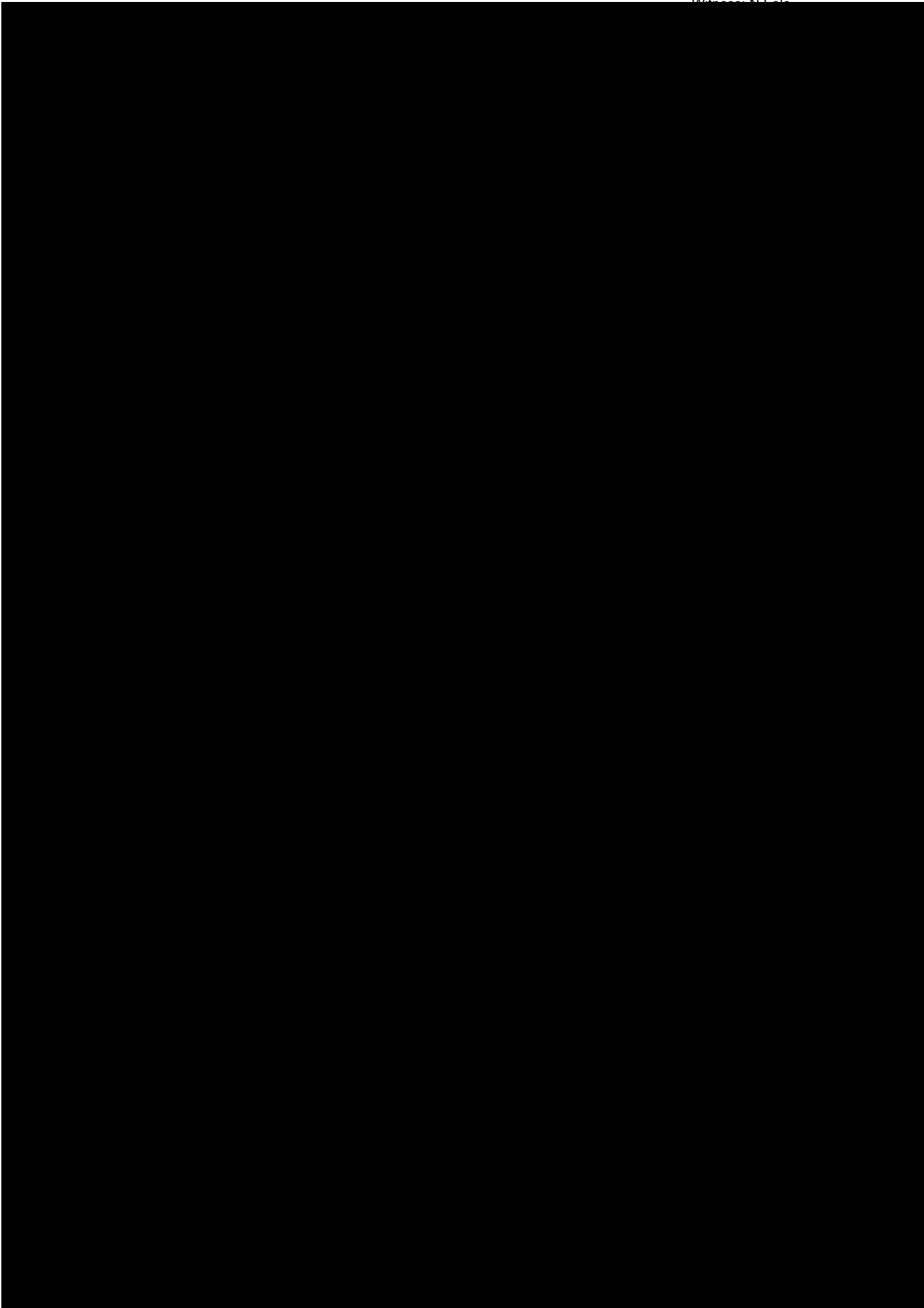


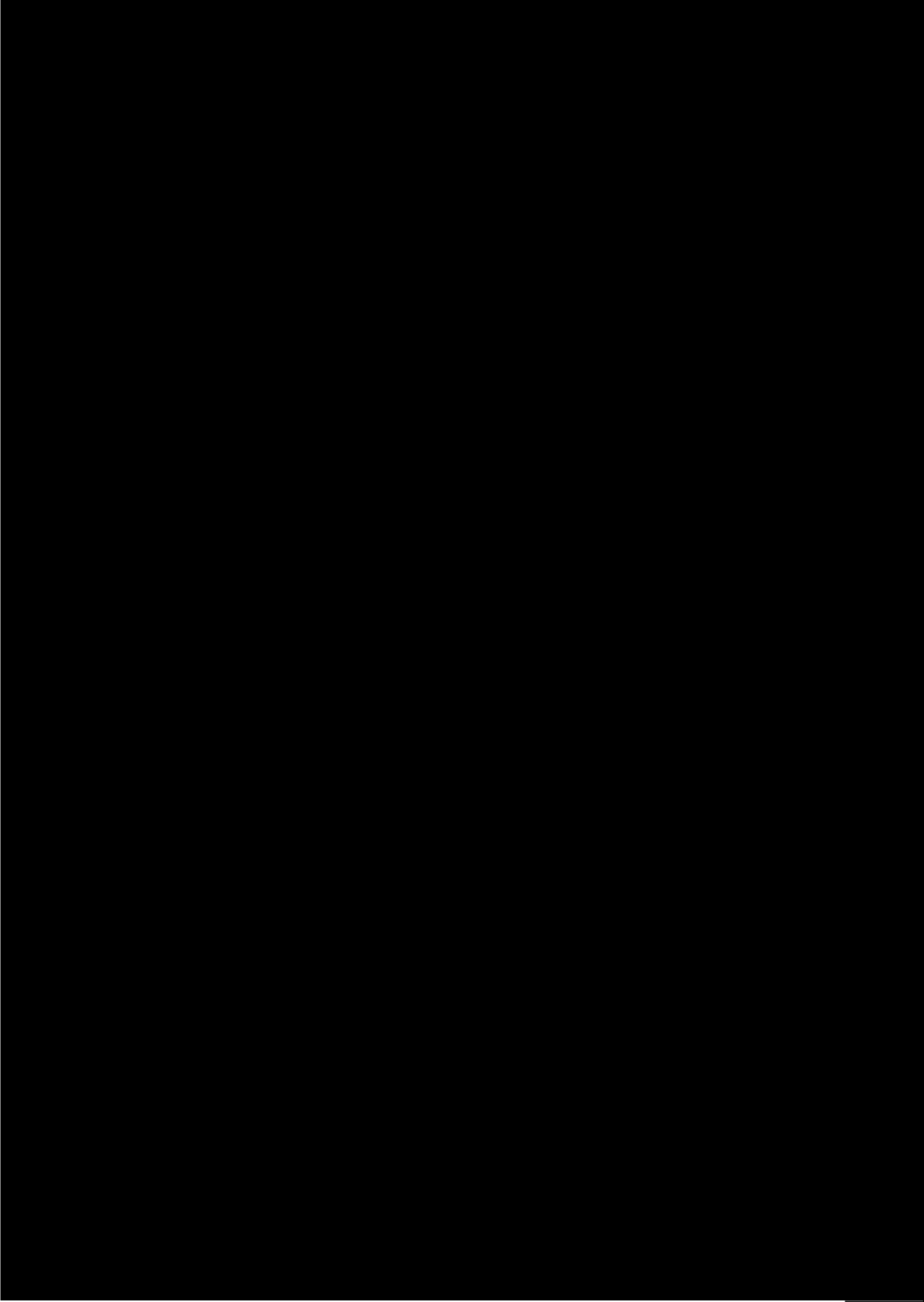
Exhibit E – Sample Termination Payment Calculation











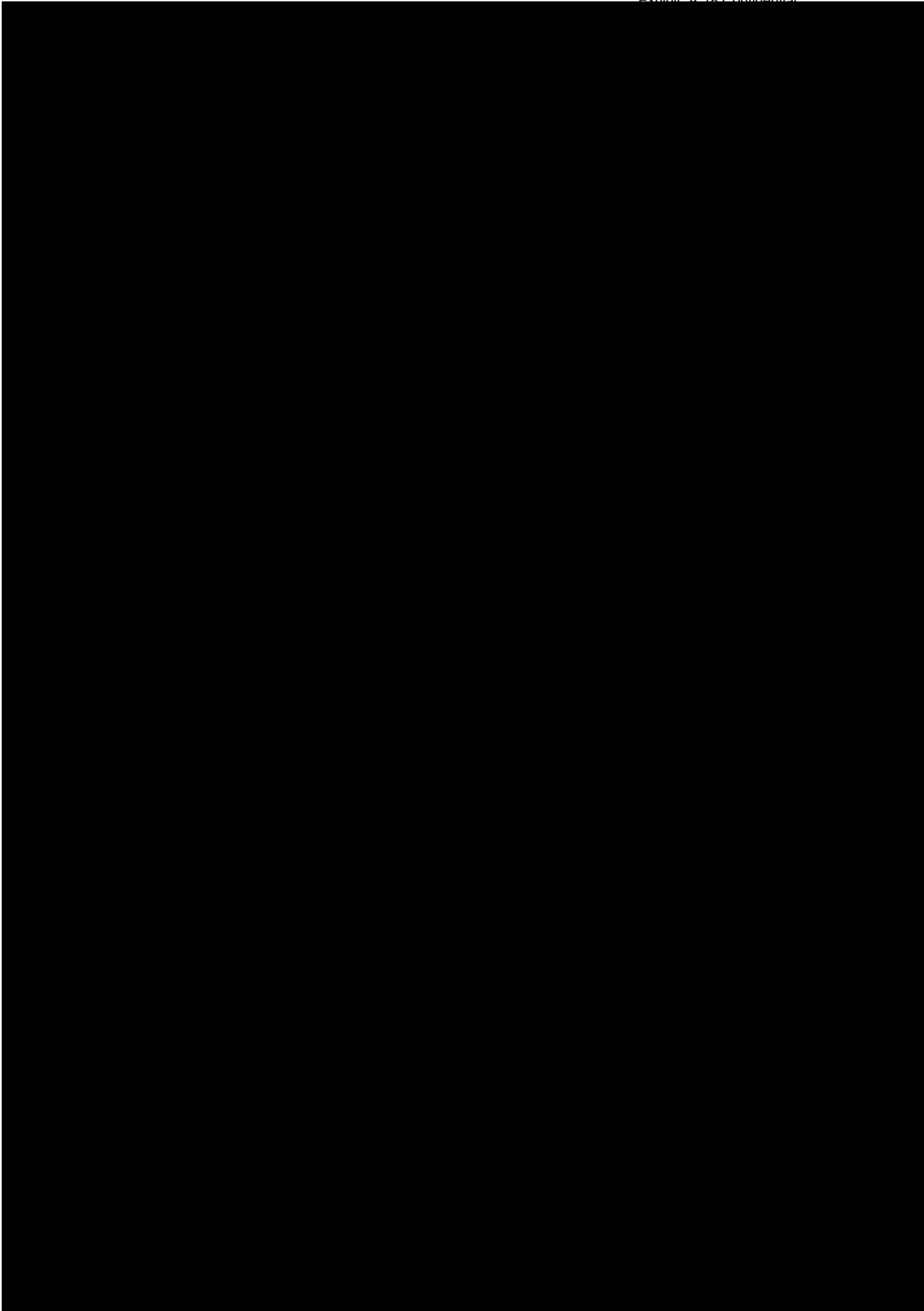


Exhibit F

Indicative Clean Capacity Portfolio

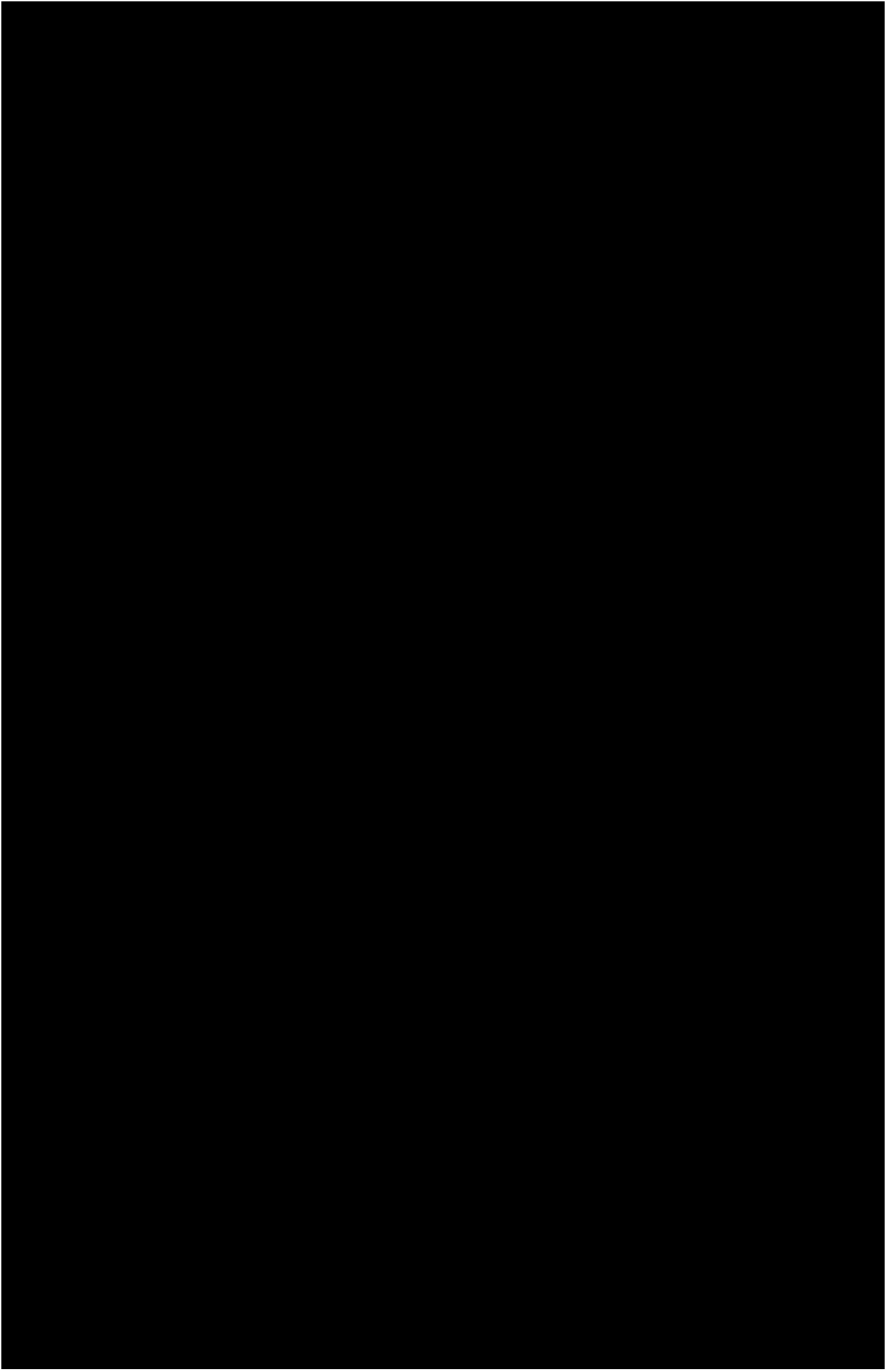
Resource Type	Installed Capacity (MW)	Cost Cap (\$/kW-month)
4-Hour Energy Storage Projects	Up to 425	[REDACTED]
Long Duration Energy Storage Projects	Up to 55	[REDACTED]

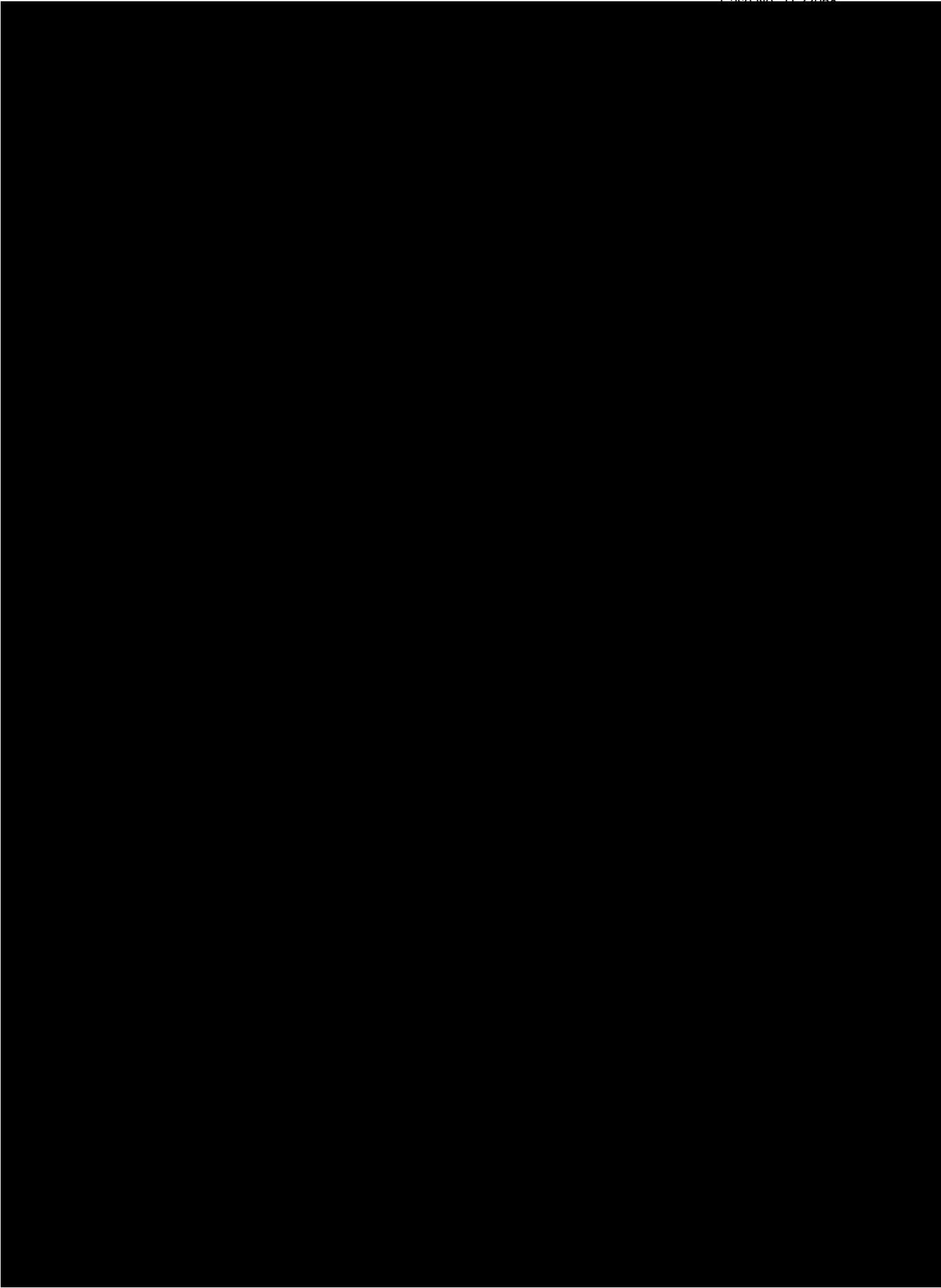
Indicative Renewable Portfolio

Resource Type	MW Amount
Renewable Energy Projects	Up to 1,600

Exhibit G

Levelized Weighted Renewable Portfolio Cost





STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
STEVEN N. BENYARD

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF STEVEN N. BENYARD

Line
No.

1 **Q1. What is your name, business address and by whom are you employed?**

2 A1. My name is Steven Benyard. My business address is: One Energy Plaza, Detroit,
3 Michigan 48226. I am employed by DTE Energy Corporate Services LLC, a
4 subsidiary of DTE Energy Company (DTE).

5

6 **Q2. On whose behalf are you testifying?**

7 A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

8

9 **Q3. What is your educational background?**

10 A3. I received a bachelor's degree in electrical engineering from Florida International
11 University and a Master of Business Administration from Nova Southeastern
12 University's Huizenga College of Business and Entrepreneurship.

13

14 **Q4. What work experience do you have?**

15 A4. I have over two decades of experience leading various areas of operations including
16 transmission, substation and distribution, project management, along with
17 engineering functions that included reliability performance. Prior to my
18 employment with the Company, I served in various distribution leadership
19 positions at NextEra Energy for approximately 15 years, which included: General
20 Manager of Major Projects and Construction Services, Area Manager, Operations
21 Leader, Production Lead, Resource Lead, and Sr. Project Manager. After accepting
22 a position with Entergy New Orleans (ENO), from February 2021 to June 2022, I
23 served as Director of Distribution Operations, where I was responsible for the
24 operation and maintenance of the distribution systems. From June to October 2022,
25 I served as ENO's Director of Reliability, where I continued to be responsible for

Line
No.

1 ENO's distribution system with the addition of the substation grid portfolio across
2 the ENO footprint. In 2022, I was promoted to Vice President, Reliability
3 (Transmission, Substation, and Distribution) for Entergy Louisiana, including New
4 Orleans. In 2024, I joined DTE in my current role as Vice President of Distribution
5 Operations Capital Delivery.

6

7 **Q5. Do you hold any certifications or are you a member of any professional**
8 **organizations?**

9 A5. I am a Certified Project Management Professional, and I have a Six Sigma Green
10 Belt.

11

12 **Q6. What are your current duties and responsibilities?**

13 A6. As Vice President of Distribution Operations Capital Delivery, I am responsible for
14 the execution of DTE Electric's major capital investments in alignment with the
15 Company's distribution grid plan. This responsibility encompasses resource
16 coordination, collaboration with communities and contract partners, adherence to
17 schedules, and monitoring of capital investment performance.

18

19 **Q7. Have you previously sponsored testimony before the Michigan Public Service**
20 **Commission (MPSC or Commission)?**

21 A7. No, although I have participated in regulatory proceedings before the Louisiana
22 Public Service Commission. Specifically, I sponsored the testimony in:

- 23 • Case No. U-36959 for Entergy Louisiana, LLC

Line
No.

1 **Purpose of Testimony**

2 **Q8. What is the purpose of your testimony?**

3 A8. As described by Witness Foley, Google LLC (the Customer) is seeking to build a
4 data center and connect 1 GW of new load to the Company’s electric system. The
5 data center will be located in Van Buren Township, Michigan, which is within DTE
6 Electric’s service territory. DTE Electric plans to supply the Customer service at
7 transmission voltage levels (345KV), which the Customer will receive in each of
8 their two self-build substations and modulate to meet their needs.

9

10 The purpose of my testimony is to describe the projects that are required to provide
11 safe and reliable service to the Customer. I will also describe the cost estimate for
12 distribution and transmission upgrades to support the Customer’s connection to the
13 electric grid.

14

15 **Q9. How is your testimony organized?**

16 A9. My testimony includes the following sections:

17 1. Project Descriptions

18 2. Estimated Company Project Costs

19

20 **Q10. Are you sponsoring any exhibits in this proceeding?**

21 A10. Yes. I am sponsoring the following exhibits:

22 Exhibit

Description

23 A-1

Line Extension Agreement (LEA)

Line
No.

1 **Q11. Were these exhibits prepared by you or under your direction?**

2 A11. Yes, they were.

3

4 **Part I: Project Descriptions**

5 **Q12. Can you describe what projects are necessary to connect the Customer to the**
6 **electric grid?**

7 A12. There are three separate projects to achieve the Customer's connection in a safe and
8 reliable manner: 1) work to be completed by the Customer; 2) work to be completed
9 by DTE Electric and 3) work to be completed by the transmission provider. Projects
10 attributed to other entities are provided for contextual purposes only and do not
11 represent work that is within the Company's ownership, control, or cost
12 responsibility.

13

14 **Q13. What does the Customer's project include?**

15 A13. The Customer will be designing and constructing as well as owning two distribution
16 substations on their site.

17

18 **Q14. Can you describe the Company's project?**

19 A14. The distribution upgrades provided by the Company will connect the Customer's
20 substations to the transmission system through new overhead power lines. This
21 work includes installing the necessary equipment and metering to ensure the
22 equipment operates safely and reliably. The Company's project design is based on
23 the information that is currently available. I provide additional detail on the
24 Company's project in Part II.

Line
No.

1 **Q15. What does the Transmission Provider’s project include?**

2 A15. The high-voltage transmission system is primarily owned and operated by ITC
3 Transmission (ITC). ITC is an independent transmission company that serves
4 southeastern Michigan, including the areas where DTE Electric provides electric
5 distribution service. ITC is a fully regulated company under the jurisdiction of the
6 Federal Energy Regulatory Commission.

7

8 ITC’s project description is outlined in [MISO Expedited Review Request Cannoli](#)¹.

9 Associated costs for ITC’s project are currently estimated at \$308 million² as shown
10 in Figure 1 below. Refer to Witness Burgdorf’s testimony for a discussion on
11 transmission costs within the power supply cost categories.

12

Figure 1 Detail of ITC Cost Estimate

Description	Network Upgrade Description	Cost (\$)
Toll Road-Shoal_Sag Remediation	Remove sag on Toll Road-Shoal 120 kV line.	[REDACTED]
Monroe-Wayne_Reconductor	Reconductor Monroe-Wayne 345 kV to high temperature conductor.	
Brownstown-Monroe2_Reconductor	Reconductor Brownstown-Monroe #2 345 kV to high temperature conductor.	
Total:		\$38,529,000
Description	Network Upgrade Description	Cost (\$)
Project Cannoli 345kV New Station	Build a new 345kV 5-row breaker-and-a-half configuration station. Install 15 breakers.	[REDACTED]
Double circuit 345 kV UG line trenches	Install 2 double circuit 345 kV UG line trenches (total 2 miles)	
Install 3 Cap Banks at Cannoli	Install 3 116 MVAR capacitor banks at Cannoli station.	
Total:		\$229,000,000
Project Total (W/ 15% Adder):		\$308,000,000

¹ https://cdn.misoenergy.org/MISO_Expedited_Review_Request_Cannoli740599.docx

² Project costs provided by ITC

Line
No.

1 **Part II: Estimated Company Project Costs**

2 **Q16. How did the Company develop the cost estimates associated with the project?**

3 A16. The Company developed the cost estimates for the project using a structured
4 approach consistent with its established project management, engineering, and
5 estimating practices. The estimate reflects the defined project scope, applicable
6 design criteria, and execution requirements known at this stage of project
7 development. The cost estimate includes costs such as labor, materials, equipment,
8 and construction activities using current supplier pricing, historical purchase data,
9 recent contractor bid information, and established unit rates reflective of anticipated
10 site conditions.

11

12 **Q17. What is the estimated cost of the Company's project?**

13 A17. The project estimated cost ranges from \$29.1 million to \$44.3 million³, which is
14 necessary to account for cost variability associated with the different configuration
15 options still under consideration by the Customer.

16

17 **Q18. How will the costs of the new industrial substation needed to serve the
18 Customer be recovered?**

19 A18. The Line Extension Agreement (Exhibit A-1) commits the Customer to pay for up
20 to \$50 million of electric infrastructure upgrades to serve their facility. The LEA
21 also designates that the Customer is responsible for the costs of any unexpected site
22 conditions or events, including, but not limited to, environmental conditions, below
23 grade obstructions, or permitting/zoning issues. In the event the cost of the project
24 is greater than \$50 million and not related an unexpected site condition or event,

³ See WP SNB-1 for details

Line
No.

1 the Company will propose adding the net cost (i.e., actual costs less the \$50 million)
2 to its rate base for recovery in a future rate case consistent with Company's Rate
3 Book.

4

5 **Q19. How would the Customer have typically paid for the project?**

6 A19. Typically, the Customer would pay, through a Contribution in Aid of Construction
7 ("CIAC") payment, for the cost of the infrastructure needed for grid interconnection
8 less an allowance based on the Customer's load ("a CIAC allowance⁴"). If the
9 actual costs of the new overhead power lines exceeded the CIAC allowance, the
10 Customer would be responsible for paying for the difference through the CIAC
11 payment.

12

13 In this case, the Customer's CIAC allowance would be approximately \$550 million,
14 far exceeding the expected cost of the new overhead power lines. Under the
15 approved CIAC policy, the Customer would not be directly responsible for any costs
16 related to the new overhead power lines and instead the capital would be proposed
17 to be added to the Company's rate base with the associated costs allocated according
18 to approved methods.

19

20 The Company is not proposing to change the current CIAC policy.

21

22 **Q20. Does this conclude your direct testimony?**

23 A20. Yes, it does.

⁴ Standard Allowance per Rate Book section C6.2

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

EXHIBITS

STEVEN N. BEYNARD

**Michigan Public Service Commission
DTE Electric Company
LINE EXTENSION AGREEMENT**

Case No.: U-22058
Exhibit: A-1 Confidential
Witness: S. Benyard
Page: 1 of 1

EXHIBIT A-1

Access to Confidential Exhibit A-1 will be provided upon issuance of a protective order and receipt of a signed nondisclosure agreement.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
KEVIN L. BILYEU

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF KEVIN L. BILYEU

Line
No.

1 **Q1. What is your name, business address and by whom are you employed?**

2 A1. My name is Kevin L. Bilyeu (he/him/his). My business address is One Energy
3 Plaza, Detroit, Michigan 48226. I am employed by DTE Electric Company (“DTE
4 Electric” or “Company”).

5

6 **Q2. On whose behalf are you testifying?**

7 A2. I am testifying on behalf of DTE Electric.

8

9 **Q3. What is your educational background?**

10 A3. I graduated from Walsh College in 2008 with a Bachelor of Business
11 Administration. In 2012, I received a Master of Business Administration degree
12 from the University of Michigan.

13

14 **Q4. What is your work experience?**

15 A4. Starting in 2006, I began my professional career with SEMCO Energy Gas
16 Company, progressing through a range of roles with increasing responsibility. In
17 2008, I took on the position of Billing Analyst, utilizing my expertise in the subject
18 matter to aid stakeholders, conducting reviews, managing projects, and devising
19 process enhancements. After that, I became Supervisor of Customer Accounting in
20 2011, leading tasks such as customer billing, remittance processing, inactive
21 collections, bad debt management, and financial reporting for the Customer
22 Accounting Department. Then, in 2013, I assumed the position of Manager,
23 Customer Energy Management, where I oversaw the administration, monitoring,
24 and development of Energy Waste Reduction (“EWR”) Programs, testified and
25 supported EWR plan and reconciliation cases at the Michigan Public Service

Line
No.

1 Commission (“MPSC” or “Commission”), and managed the home protection
2 warranty program.

3

4 In 2015, I transitioned to DTE Electric, taking on the role of Principal Marketing
5 Analyst of EWR Pilot Programs, where my responsibilities encompassed the
6 development and management of new EWR programs. In 2016, I accepted the
7 position of Principal Marketing Specialist of EWR Strategy, where my tasks
8 included modeling energy efficiency in Integrated Resource Plans (“IRP”) for long-
9 term strategy planning and developing sensitivities and recommendations to support
10 EWR plan filings with the MPSC.

11

12 In 2018, I advanced to the position of Principal Supervisor of EWR Strategy, where
13 I had overall responsibility for strategic development and planning of EWR
14 programs, including IRPs and EWR regulatory filings. Subsequently, in 2021, I
15 assumed the role of Manager for EWR Strategy and Evaluation Measurement &
16 Verification. As Manager, I had overall responsibility for strategic development and
17 planning of EWR programs, which included IRPs and EWR regulatory filings.
18 Additionally, I was responsible for ensuring program cost-effectiveness, evaluating
19 EWR programs, and applying the results to further enhance DTE Electric and DTE
20 Gas's offerings. I accepted a position as Manager for Renewable Energy Strategy
21 and Special Projects in 2023, where I supported activities related to maintaining
22 Renewable Portfolio Standard (“RPS”) compliance, planning and executing special
23 projects for renewable energy, and filing applications with the MPSC. I was
24 promoted to my current position in 2025.

Line
No.

1 **Q5. What is your current position with the Company?**

2 A5. My title is Director, Renewable Energy Planning and Strategy.

3 **Q6. What are your duties and responsibilities in your current position?**

4 A6. I continue to lead activities related to maintaining RPS compliance, planning and
5 executing special projects for renewable energy, and filing applications with the
6 MPSC, as I did in my previous role. In addition, I support activities related to land
7 acquisition, capital planning, and financial modeling for DTE Electric's renewable
8 energy portfolio.

9

10 **Q7. Have you previously sponsored testimony before the MPSC?**

11 A7. Yes. I have sponsored testimony in the following cases:

12 U-17362 SEMCO Energy Gas Company EO Plan Filing

13 U-18091 DTE Electric 2024 PURPA Filing

14 U-18419 DTE Electric Certificate of Necessity

15 U-20471 2019 DTE Electric Integrated Resource Plan

16 U-20876 2021-2022 DTE Electric EWR Plan

17 U-20881 2021-2022 DTE Gas EWR Plan

18 U-21193 2022 DTE Electric Integrated Resource Plan

19 U-21313 2022 DTE Electric and DTE Gas EWR Reconciliation

20 U-21353 2022 DTE Electric Renewable Energy Cost Reconciliation

21 U-21496 2023 DTE Electric Renewable Energy Plan Accounting Application

22 U-21550 2023 DTE Electric Renewable Energy Cost Reconciliation

23 U-21662 2024 DTE Electric Amended Renewable Energy Plan

24 U-21990 2025 DTE Electric Special Contract for Electric Service

Line
No.

1 **Purpose of Testimony**

2 **Q8. What is the purpose of your testimony?**

3 A8. The purpose of my direct testimony is to:

- 4 1) Provide an overview of the RPS framework and compliance requirements;
- 5 2) Explain how Renewable Energy Credits (“RECs”) are calculated to meet DTE
- 6 Electric’s RPS target;
- 7 3) Describe the Company’s Voluntary Green Pricing (“VGP”) program included
- 8 within the Clean Capacity Accelerator Agreement (“CCAA”);
- 9 4) Detail the impact of Google LLC’s (“the Customer”) load on DTE Electric’s
- 10 RPS requirements;
- 11 5) Describe any changes in REC demand relative to the Company’s Amended
- 12 Renewable Energy Plan (“REP”) resulting from the Customer’s load;
- 13 6) Discuss the Company’s request to increase the build plan for its VGP program;
- 14 7) Provide a brief explanation of how revenue from the special contract is
- 15 recovered; and
- 16 8) Summarize the Company’s approach to updating its plans in future regulatory
- 17 filings.

18

19 **Q9. Are you sponsoring any exhibits in this proceeding?**

20 A9. Yes. I am sponsoring the following exhibits:

21 Exhibit Description

22 A-2 Renewable Portfolio Standard Compliance Summary

23

24 **Q10. Were these exhibits prepared by you or under your direction?**

25 A10. Yes, they were.

Line
No.

1 **Q11. How is the remainder of your testimony organized?**

2 A11. My testimony consists of the following four parts:

3 Part I: Statutory Framework

4 Part II: Clean Capacity Accelerator Agreement

5 Part III: Evaluation of the Customer's Load on DTE Electric's RPS Requirements

6 Part IV: DTE Electric's Strategy and Build Plan

7 Part V: Summary and Conclusions

8 **PART I: STATUTORY FRAMEWORK**

9 **Q12. What are the RPS targets established in Public Act 235 of 2023 ("PA 235")?**

10 A12. PA 235 establishes that an electric provider shall achieve a REC portfolio of at least
11 the following:

12 a) Through 2029, 15% of total retail sales

13 b) In 2030 through 2034, 50% of total retail sales

14 c) In 2035 and each year thereafter, 60% of total retail sales

15

16 **Q13. What total retail sales figure does the Company use to determine its RPS
17 targets?**

18 A13. Consistent with Section 28(2)(b) of PA 235, the Company uses weather normalized
19 megawatt-hours of bundled load sold during the previous year, less the amount of
20 sales attributable to customers participating in a VGP program and the outflow from
21 customers participating in the distributed generation program.

Line
No.

1 **Q14. How are RECs generated to meet the RPS targets?**

2 A14. In general, one REC is granted for each megawatt hour of electricity generated from
3 the renewable energy system. RECs can be generated through several methods
4 outlined in Section 28(5) of PA 235. This includes “(a) Generating electricity from
5 renewable energy systems for sale to retail customers. (b) Purchasing or otherwise
6 acquiring renewable energy and capacity. (c) Purchasing or otherwise acquiring
7 renewable energy credits without the associated renewable energy or capacity...”
8 REC-only purchases made under Section 28(5)(c) shall not exceed 5% of the
9 Company’s compliance amount.

10

11 **Q15. Can RECs be banked if not used towards RPS compliance in the year in which
12 they are generated?**

13 A15. Yes. Under Section 39(3) of PA 235, “A renewable energy credit expires at the
14 earliest of the following times: (a) When used by an electric provider to comply
15 with its renewable energy standard. (b) When substituted for an energy waste
16 reduction credit under section 77. (c) Five years after the end of the month in which
17 the renewable energy credit was generated.” Based on this provision, DTE Electric
18 may bank RECs for up to five years from their creation date.

19

20 **Q16. What is the purpose of the Company’s VGP programs?**

21 A16. Section 61 of 2016 Public Act 342 mandated that all utilities offer voluntary
22 renewable energy programs to their customers. Voluntary green pricing programs
23 allow customers to choose how much of their electricity usage will be supported by
24 renewable energy. Under this program, the electric provider offers a set of
25 renewable energy options, and customers may elect the portion of their electricity

Line
No.

1 that they want to be sourced from renewable generation. Participation is optional,
2 and the program is designed to give customers a direct, flexible way to increase
3 their use of renewable energy beyond renewable portfolio standards.
4

5 **Q17. How do sales associated with VGP programs impact RPS requirements?**

6 A17. As noted above, load participating in the Company's VGP program is removed
7 from the bundled retail load, thereby lowering the RPS obligation. When a
8 customer enrolls, whether through the standard offering or a special contract, the
9 enrolled portion of their load does not contribute to increases in RPS targets.
10

11 **Q18. Does the Company offer VGP special contracts to accommodate unique
12 customer situations?**

13 A18. Yes. In the June 9, 2021 Order in Case No. U-20713, the Commission approved a
14 settlement agreement ("Section 61 Settlement Agreement") that established a
15 customer requested offering within the Company's VGP program. This offering
16 supports unique, customer driven renewable energy projects that fall outside the
17 standard Rider 17 options. Under this structure, the Company designs and
18 constructs dedicated renewable energy projects that support each participating
19 customer's specific sustainability goals.
20

21 **Q19. Do VGP special contracts require customers to pay for all of the associated
22 costs from the renewable energy projects that supply their VGP special
23 contracts?**

24 A19. Yes. All costs associated with the development of the renewable energy project(s)
25 to supply VGP special contracts are fully recovered through the subscription fees

Line
No.

1 that are featured in the VGP special contracts and are billed to the subscriber. Any
2 early termination or default of the contract from the subscriber's actions or
3 inactions results in a termination fee, designed to ensure all costs of participation
4 and termination are borne by subscribers and that no costs are subsidized by non-
5 subscribers.

6

7

PART II: CLEAN CAPACITY ACCELERATOR AGREEMENT

8 **Q20. Is the Customer enrolling in a VGP Special Contract within the CCAA?**

9 A20. Yes, the Customer has requested that the Company build up to 1.6 GW of
10 renewable energy projects through a VGP special contract with DTE Electric.
11 Rather than entering into a standalone special contract for customer requested
12 renewable energy projects, the VGP Special Contract terms were incorporated into
13 the CCAA. The CCAA outlines the terms and conditions governing the agreement
14 between the Customer and DTE Electric. The CCAA terms governing the
15 deployment of renewable energy comply with the Section 61 Settlement Agreement
16 discussed above. Therefore, the renewable energy resources included in the CCAA
17 are considered part of a customer-requested VGP special contract and treated as
18 such for RPS purposes. Throughout my testimony, I refer to the relevant CCAA
19 terms as "VGP Special Contract." Refer to Witness Foley's testimony which
20 provides additional details regarding the CCAA.

21

22 **Q21. What portion of the Customer's load is enrolled in a VGP Special Contract?**

23 A21. The Customer has chosen to enroll 40% of their total load in a VGP Special
24 Contract, thereby reducing the RECs required by the Company for compliance.

Line
No.

1 Under this VGP Special Contract, the Company will deploy a portfolio of
2 renewable energy projects to support the enrolled portion of the Customer’s load.

3

4 **Q22. Will the portion of load covered under the VGP Special Contract enable the**
5 **Customer to reach 100% renewable energy?**

6 A22. Yes. Many large customers use the RPS to meet a considerable share of their clean
7 energy targets and rely on VGP programs to close the remaining gap to reach goals
8 such as 100% renewable energy. By allocating 1.6 GW to a VGP Special Contract,
9 the Customer may claim 100% renewable energy usage once the Company hits the
10 60% RPS target. See Table 1 below for additional details.

11

12 Table 1 Customer Build Required to Support 100% Renewable Energy

13

Claim

Customer Load	7,884 GWh¹
Converted to GW ²	4.0 GW
Renewable Energy from RPS by 2035	60%
Gap from RPS and 100% Renewable Energy Target	40%
VGP GW to achieve 100% Renewable Energy	1.6 GW

14

15 **Q23. How is the Company proposing to recover the revenue associated with the**
16 **additional build required to fulfill the VGP Special Contract?**

17 A23. Under the CCAA, the Company will develop a portfolio of renewable energy
18 projects to meet the Customer’s needs. The Customer will cover the full cost (i.e.,
19 the revenue requirement) of these projects over their depreciable life, enabling the

¹ Estimate is based on an assumed load factor of 88.5%.

² 7,884 GWh / 8760 Hours Annually / 22.5% Solar NCF = 4.0 GW

Line
No.

1 Company to recover the associated revenue from the new investments. The CCAA
2 will ensure no costs related to Customer projects are paid for by other customers.
3 Witness Foley's testimony provides additional detail on how the revenue
4 requirement for this project portfolio is determined and recovered.
5

6 **PART III: EVALUATION OF THE CUSTOMER'S LOAD IMPACTS ON DTE**

7 **ELECTRIC'S RPS REQUIREMENTS**

8 **Q24. What does Exhibit A-2, "Renewable Portfolio Standard Compliance**
9 **Summary" include?**

10 A24. Exhibit A-2 is an updated analysis of my Exhibit A-2 in the Company's Amended
11 REP, Case No. U-21662. It summarizes the key data underlying the Company's
12 RPS requirement. This exhibit is formatted in a similar manner but has the addition
13 of rows to represent updated information associated with the addition of the
14 Customer's load. The first update is the incremental data center load added in Line
15 6. Incremental VGP sales are then subtracted in Line 10. These two updates provide
16 an updated RPS Requirement as shown in Line 19. Line 24 has also been updated
17 to reflect 5% of the REC requirement in REC-only purchases through 2035. The
18 resulting REC balance without additional generation is then calculated in Line 29.
19 Lines 31-32 are a reference only for the base case values in the Amended REP Case
20 No. U-21662. Line 34 shows the RPS requirement when updating for the first data
21 center load approved in Case No. U-21990, which is an incremental step before
22 Line 35 which shows the RPS requirement after adding the Customer's load. Line
23 37 then gives the resulting REC balance after factoring in the additional 1.8 GW
24 from the first customer, 1.6 GW of VGP from the second customer, and a 250 MW
25 reduction of compliance build.

Line
No.

1 **Q25. What assumptions were considered when assessing the Customer's impact on**
2 **DTE Electric's RPS requirements?**

3 A25. To evaluate the Customer's impact on the Company's RPS requirements, the
4 Company relied on assumptions from the most recently approved Amended REP
5 and on data from the first data center customer approved in Case No. U-21990³.
6 Excluding tax credits, these Amended REP assumptions were applied to new
7 renewable energy build for the Customer. The assumptions also reflect the first data
8 center customer's impact on REC compliance and the 1.8 GW of additional
9 renewable build assumed for that customer. The projected impact on RPS
10 compliance and incremental build is shown in Line 34 of Exhibit A-2.

11

12 **Q26. What is the projected increase in DTE Electric's load resulting from the**
13 **Customer?**

14 A26. As discussed in Company Witness Foley's testimony, the Customer's max load will
15 be 1 GW and their annual usage would be approximately 7.88 TWh.

16

17 **Q27. Relative to the Company's latest Amended REP and including the first data**
18 **center customer's load, what is the revised RPS target after adjusting for the**
19 **Customer's load?**

20 A27. The RPS target from the Company's most recent Amended Renewable Energy
21 Plan, Case No. U-21662, is presented in Line 31 of Exhibit A-2, with the inclusion
22 of the first data center customer's load factored in for Line 34. The updated RPS
23 target reflecting the Customer's load adjustments is shown in Line 35 of Exhibit A-
24 2. While the projected load increases total bundled sales, only 60% of the

³ Assumptions used from the approved Amended REP Case No. U-21662, include installed costs, net capacity factors, commercial operating dates, etc.

Line
No.

1 Customer's load affects the RPS target due to the VGP enrollment, resulting in an
2 approximate 10.8% increase in the RPS target, calculated by comparing the sum of
3 Line 35 to the sum of Line 34.

4

5 **Q28. How will the Company adjust its renewable build plan, given the load enrolled**
6 **in the VGP Special Contract, to ensure it meets its RPS targets?**

7 A28. With 40% of customer load participating in the VGP Special Contract, and with a
8 projected surplus of RECs carried forward, the Company is able to pursue an
9 efficient and cost-effective approach to its renewable build plan. Between 2030
10 through 2032, the Company plans to construct up to 1.6 GW⁴ of new renewable
11 capacity dedicated to serving the Customer's VGP Special Contract load. The
12 Customer and DTE Electric have agreed that this timeframe is flexible and may
13 shift as needed. This renewable energy build not only supports the Customer but
14 also creates flexibility in later years.

15

16 Because of the VGP Special Contract build and the REC surplus, the Company can
17 reduce its planned additions by 200 MW in 2033 and 50 MW in 2034, directly
18 lowering costs for RPS customers without compromising compliance. This
19 approach positions the Company to achieve the 60% RPS requirement by 2035
20 while maintaining a positive REC balance throughout the period, as shown on line
21 37 of Exhibit A-2.

22

23 **Q29. With these additions to the REP, is the Company still projected to achieve the**
24 **RPS targets under PA 235?**

⁴ 500 MW in 2030, 700 MW in 2031, and 400 MW in 2032 (a total of 1,600 MW)

Line
No.

1 A29. Yes. With the additional 1.6 GW enrolled in the VGP Special Contract, the
2 Company can maintain a positive REC balance and meet the RPS requirements
3 under PA 235. Line 37 of Exhibit A-2 shows the REC balance reflecting the
4 proposed VGP capacity adjustments.

5

6 **Q30. If the Customer covers the full revenue requirement for the Special Contract**
7 **build, do they still pay their share of RPS assets through the power supply cost**
8 **recovery (“PSCR”) mechanism?**

9 A30. Yes. With the Customer being subject to the PSCR, they will contribute to the
10 Company’s existing and future renewable and transmission costs. This ensures any
11 incremental renewable generation for RPS compliance associated with the
12 Customer’s load is appropriately offset. Witness Burgdorf’s testimony and Exhibits
13 A-9 and A-10 provide a breakdown of the costs the Customer will pay through the
14 PSCR.

15 **PART IV: DTE ELECTRIC’S STRATEGY AND BUILD PLAN**

16 **Q31. Does the Company expect that sufficient renewable energy projects will be**
17 **available to support the VGP Special Contract?**

18 A31. Yes. DTE Electric has a robust and diversified strategy to meet the renewable
19 energy build requirements associated with the VGP Special Contract. The
20 Company’s approach could include a combination of:

21

22 1. **Company-Owned Projects:** DTE Electric is actively developing new wind
23 and solar facilities, with many projects already in the pre-construction or
24 permitting phases.

Line
No.

1 2. **Strategic Acquisitions:** Where feasible, DTE Electric will evaluate
2 acquisition opportunities for operational or near-operational renewable
3 assets that can be integrated into its portfolio to accelerate compliance
4 timelines.

5 3. **Request for Proposal (“RFP”):** DTE Electric will issue an RFP for a
6 minimum of 50% of the capacity required to fulfill the VGP Special Contract
7 through build transfer agreements (“BTAs”) with unaffiliated third parties
8 consistent with the Section 61 Settlement Agreement in Case No. U-21172.

9

10 **Q32. Is the Company seeking approval, within this proceeding, for the 1.6 GW**
11 **required to support the VGP Special Contract as part of its Amended REP?**

12 A32. Yes. The Company is requesting approval to include additional renewable energy
13 builds up to 500 MW by 2030, 700 MW by 2031, and 400 MW by 2032 (a total of
14 1.6 GW) in its Amended Renewable Energy Plan to support the VGP Special
15 Contract. The Company believes that such inclusion is consistent with 2008 PA
16 295, as amended by 2023 PA 235, Section 9 of the Settlement Agreement in the
17 Company’s Section 61 filing Case No. U-20713, and all other applicable law. As
18 projects are selected to meet the 1.6 GW requirement, each will be filed with the
19 Commission for approval, consistent with the current project approval process used
20 for VGP special contracts.

21

22 **Q33. Has the Commission provided guidance on the renewable energy build plan**
23 **assumptions in an Amended REP?**

24 A33. Yes. In the April 25, 2024 Order in Case No. U-21568, the Commission held “IRPs
25 remain the most appropriate venue to consider generation diversity as well as

Line
No.

1 renewable resource planning because IRPs allow for the full assessment of
2 renewable resources against other resources (including the consideration of the
3 value of the various resource types and attributes as expressed by commenters). In
4 turn, future amended REPs should reflect the assumptions included in the
5 providers' most recently approved IRP."

6

7 **Q34. When is the Company expected to submit its next Amended REP**
8 **incorporating the Customer's load impacts?**

9 A34. In accordance with the order in Case No. U-21990, the Company will file its next
10 Amended REP alongside its IRP later in 2026. As part of the IRP process, the
11 Company will assess any changes to its renewable portfolio through modeling
12 optimization and develop a strategy to support RPS compliance.

13 **Q35. Does the timing of these filings provide DTE Electric with sufficient**
14 **opportunity to address the increased RPS requirements associated with the**
15 **Customer's load?**

16 A35. Yes. The timing of the 2026 IRP and Amended REP aligns well with the anticipated
17 load ramp for the Customer. This provides DTE Electric with a multi-year planning
18 window to develop its renewable energy strategy accordingly.

19

20 The 2026 IRP will detail DTE Electric's approach to maintaining RPS compliance.
21 The 2026 Amended REP will further define these plans, detailing DTE Electric's
22 REC acquisition strategy and further ensuring compliance with RPS targets.
23 Together, these filings provide a structured and timely framework to accommodate
24 the incremental load while maintaining regulatory compliance.

Line
No.

1

PART V: SUMMARY AND CONCLUSIONS

2

Q36. Is DTE Electric well-positioned to meet the increased RPS requirements associated with incremental Customer load?

3

4

A36. Yes. DTE Electric remains committed to supporting the RPS and has a defined path for achieving the additional REC requirements driven by the Customer load. My testimony and exhibits in this filing demonstrate that:

5

6

7

1. With the requested 1.6 GW to support the Customer's VGP Special Contract, the Company can maintain a positive REC balance and meet the RPS requirements;

8

9

10

2. The Company's existing renewable energy portfolio and development pipeline offer a credible and sufficient foundation to meet the elevated renewable energy targets.

11

12

13

3. DTE Electric will reassess its renewable energy build plan in its next IRP filing, which will include consideration of the additional load and REC requirements;

14

15

4. The 1.6 GW supporting the Customer's VGP Special Contract provides incremental customer benefit by enabling a 250 MW reduction by 2034, which directly lowers costs for RPS customers through the addition of this new load.

16

17

18

19

Q37. Does this conclude your direct testimony?

20

A37. Yes, it does.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

EXHIBITS
OF
KEVIN L. BILYEU

Line No.	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
			2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
1	Sales and Requirement Calculation											
2	Method: Weather Normalized or 3 Year Average											
3	If Selected Weather Normalized:											
4	Current Year Sales to Retail Customers	U-21662 Exh A-29 Column (i)	39,634,892	39,497,918	39,869,525	39,910,589	40,013,252	40,203,583	40,511,120	40,702,673	41,076,945	41,418,790
5	Incremental First Data Center Customer Load	U-21990	3,285	5,031,963	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572
6	Incremental Second Data Center Customer Load	WP-1	-	33,480	3,300,480	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000
7	Less Number of Megawatt Hours Sold from Michigan Nuclear Energy											
8	Current Year Weather Normalization Factor		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	Less VGP sales	U-21662 WP-6	2,794,617	5,358,090	6,616,223	7,426,909	7,415,003	7,385,969	7,375,761	7,328,315	7,299,690	7,271,202
10	Less Incremental VGP Sales	WP-1	-	-	-	-	997,527	2,398,048	3,203,084	3,178,360	3,162,468	3,146,656
11	Less Outflow from DG Customers	U-21662 Exh A-29 Column (j)	55,355	68,099	83,171	100,829	121,202	143,020	164,705	185,876	204,715	222,048
12	Current Year Weather Normalized Sales	Calculated	36,788,205	39,137,172	47,374,183	51,170,422	50,267,091	49,064,118	48,555,143	48,797,693	49,197,643	49,566,457
13	If Selected 3 Year Average:											
14	Current Year Retail Sales to Retail Customers											
15	Less Number of Megawatt Hours Sold from Michigan Nuclear Energy											
16	Less VGP sales											
17	Less outflow from DG customers											
18	3 Year Average of sales											
19	RPS Required Energy Credits (For 2026 through 2029 15%, 2030 through 2034 50% 2035 and beyond 60%)	Calculated	5,667,532	5,518,231	5,870,576	7,106,127	25,585,211	25,133,545	24,532,059	24,277,571	24,398,847	29,518,586
20	Energy Credits											
21	Energy Credit Beginning Balance	Line 26	2,455,332	2,833,451	5,401,814	9,327,780	15,308,233	5,072,900	(2,451,067)	(8,173,568)	(11,708,730)	(13,312,505)
22	Plus: Energy Credits Obtained Through Generation/BOT	U-21662 Exh A-4 +WP-4	3,405,313	4,785,213	5,979,683	7,689,837	9,356,714	11,743,705	13,258,615	15,574,681	17,938,444	20,437,898
23	Plus: Energy Credits Obtained Through PPA	U-21662 Exh A-4 +WP-4	2,356,962	3,025,469	3,451,320	4,117,483	4,736,487	4,639,271	4,337,065	3,947,786	3,380,699	3,300,608
24	Plus: Energy Credits Obtained Through REC Purchases ¹	U-21662 Exh A-4 Line 7	283,377	275,912	365,538	1,279,261	1,256,677	1,226,603	1,213,879	1,219,942	1,475,929	1,486,994
25	Less: Energy Credits Sold		-	-	-	-	-	-	-	-	-	-
26	Available Energy Credits (Lines 21 + 22 + 23 + 24 - 25)	Calculated	8,500,983	10,920,045	15,198,356	22,414,360	30,658,111	22,682,478	16,358,491	12,568,841	11,086,342	11,912,994
27	Less: Compliance Requirement (Line 19)	Calculated	5,667,532	5,518,231	5,870,576	7,106,127	25,585,211	25,133,545	24,532,059	24,277,571	24,398,847	29,518,586
28	Less: Energy Credit Expired		-	-	-	-	-	-	-	-	-	-
29	Energy Credit Ending Balance (Lines 26 - 27 - 28)	Calculated	2,833,451	5,401,814	9,327,780	15,308,233	5,072,900	(2,451,067)	(8,173,568)	(11,708,730)	(13,312,505)	(17,605,592)
30	Base Case without Data Center Load											
31	RPS Required Energy Credits (For 2026 through 2029 15%, 2030 through 2034 50% 2035 and beyond 60%)	U-21662 Exh A-2 Line 16	5,667,532	5,517,738	5,110,759	4,975,520	16,191,425	16,238,523	16,337,297	16,485,327	16,594,241	20,143,524
32	Energy Credit Ending Balance	U-21662 Exh A-2 Line 26	2,833,451	5,402,282	9,978,064	17,058,641	15,769,987	16,726,366	18,801,613	22,663,019	28,217,633	32,819,791
33	Updated RPS											
34	Required RECs adjusted to include First Data Center Customer	U-21990 Exh A-3 Line 16	5,667,532	5,518,231	5,865,554	6,611,055	21,643,211	21,690,309	21,789,083	21,937,113	22,046,027	26,685,667
35	Required RECs adjusted to include both Data Center Customers	Line 19	5,667,532	5,518,231	5,870,576	7,106,127	25,585,211	25,133,545	24,532,059	24,277,571	24,398,847	29,518,586
36	With Additional 1800 MW for First Customer (Case U-21990) and 1600 MW VGP for Second Customer											
37	Energy Credit Ending Balance		2,833,451	5,401,814	9,317,548	15,298,001	6,794,075	1,859,360	686,444	1,459,343	3,572,386	2,693,688

1. Updated to represent 5% of RPS requirement through 2035

Line No.	(a)	(b)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
			2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	Sales and Requirement Calculation											
2	Method: Weather Normalized or 3 Year Average											
3	If Selected Weather Normalized:											
4	Current Year Sales to Retail Customers	U-21662 Exh A-29 Column (i)	41,796,601	41,972,411	42,220,700	42,421,326	42,654,688	42,699,590	42,849,878	43,041,817	43,325,884	43,439,572
5	Incremental First Data Center Customer Load	U-21990	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572	10,903,572
6	Incremental Second Data Center Customer Load	WP-1	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000	7,884,000
7	Less Number of Megawatt Hours Sold from Michigan Nuclear Energy		-	-	-	-	-	-	-	-	-	-
8	Current Year Weather Normalization Factor		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
9	Less VGP sales	U-21662 WP-6	7,261,222	7,214,626	7,186,536	7,158,575	7,148,812	7,103,051	7,075,484	7,048,047	7,038,504	6,993,562
10	Less Incremental VGP Sales	WP-1	3,139,501	3,115,268	3,099,692	3,084,193	3,077,180	3,053,429	3,038,161	3,022,971	3,016,097	2,992,817
11	Less Outflow from DG Customers	U-21662 Exh A-29 Column (j)	239,754	257,838	276,311	295,137	313,920	332,890	352,794	373,097	393,673	414,458
12	Current Year Weather Normalized Sales	Calculated	49,943,696	50,172,251	50,445,733	50,670,992	50,902,347	50,997,792	51,171,010	51,385,273	51,665,183	51,826,308
13	If Selected 3 Year Average:											
14	Current Year Retail Sales to Retail Customers											
15	Less Number of Megawatt Hours Sold from Michigan Nuclear Energy											
16	Less VGP sales											
17	Less outflow from DG customers											
18	3 Year Average of sales											
19	RPS Required Energy Credits (For 2026 through 2029 15%, 2030 through 2034 50% 2035 and beyond 60%)	Calculated	29,739,874	29,966,218	30,103,350	30,267,440	30,402,595	30,541,408	30,598,675	30,702,606	30,831,164	30,999,110
20	Energy Credits											
21	Energy Credit Beginning Balance	Line 26	(17,605,592)	(20,860,040)	(21,739,132)	(20,104,865)	(16,009,553)	(9,319,900)	(238,954)	11,275,395	22,809,220	33,986,930
22	Plus: Energy Credits Obtained Through Generation/BOT	U-21662 Exh A-4 +WP-4	23,189,448	25,812,563	28,475,980	31,113,974	33,847,982	36,399,106	38,902,443	39,038,455	38,815,294	38,478,159
23	Plus: Energy Credits Obtained Through PPA	U-21662 Exh A-4 +WP-4	3,295,979	3,274,563	3,261,638	3,248,777	3,244,266	3,223,249	3,210,581	3,197,976	3,193,581	3,172,955
24	Plus: Energy Credits Obtained Through REC Purchases ¹	U-21662 Exh A-4 Line 7	-	-	-	-	-	-	-	-	-	-
25	Less: Energy Credits Sold		-	-	-	-	-	-	-	-	-	-
26	Available Energy Credits (Lines 21 + 22 + 23 + 24 - 25)	Calculated	8,879,834	8,227,086	9,998,486	14,257,886	21,082,695	30,302,455	41,874,071	53,511,826	64,818,094	75,638,043
27	Less: Compliance Requirement (Line 19)	Calculated	29,739,874	29,966,218	30,103,350	30,267,440	30,402,595	30,541,408	30,598,675	30,702,606	30,831,164	30,999,110
28	Less: Energy Credit Expired		-	-	-	-	-	-	-	-	-	-
29	Energy Credit Ending Balance (Lines 26 - 27 - 28)	Calculated	(20,860,040)	(21,739,132)	(20,104,865)	(16,009,553)	(9,319,900)	(238,954)	11,275,395	22,809,220	33,986,930	44,638,934
30	Base Case without Data Center Load											
31	RPS Required Energy Credits (For 2026 through 2029 15%, 2030 through 2034 50% 2035 and beyond 60%)	U-21662 Exh A-2 Line 16	20,355,325	20,577,375	20,699,968	20,854,712	20,980,568	21,115,173	21,158,189	21,252,960	21,372,403	21,536,224
32	Energy Credit Ending Balance	U-21662 Exh A-2 Line 26	39,967,659	49,506,278	61,578,926	76,129,701	93,290,409	112,853,350	134,866,094	156,912,213	178,617,304	199,809,005
33	Updated RPS											
34	Required RECs adjusted to include First Data Center Customer	U-21990 Exh A-3 Line 16	26,897,468	27,119,518	27,242,111	27,396,855	27,522,711	27,657,316	27,700,333	27,795,103	27,914,546	28,078,367
35	Required RECs adjusted to include both Data Center Customers	Line 19	29,739,874	29,966,218	30,103,350	30,267,440	30,402,595	30,541,408	30,598,675	30,702,606	30,831,164	30,999,110
36	With Additional 1800 MW for First Customer (Case U-21990) and 1600 MW VGP for Second Customer											
37	Energy Credit Ending Balance		2,854,161	5,403,494	10,459,073	17,958,589	28,044,705	40,495,900	55,363,645	70,234,099	84,740,852	98,696,202

1. Updated to represent 5% of RPS requirement through 2035

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF SHAWN D. BURGDORF

Line
No.

1 **Q1. What is your name, business address and by whom are you employed?**

2 A1. My name is Shawn D. Burgdorf. My business address is 8001 Haggerty Road,
3 Suite 109, Belleville, Michigan 48111. I am employed by DTE Electric Company
4 (DTE Electric or Company).

5

6 **Q2. On whose behalf are you testifying?**

7 A2. I am testifying on behalf of DTE Electric.

8

9 **Q3. What is your educational background?**

10 A3. I received a Bachelor of Science Degree in Mechanical Engineering from
11 University of Michigan in 2005. I also received a Master of Business
12 Administration Degree from Eastern Michigan University in 2016.

13

14 **Q4. What is your work experience?**

15 A4. After receiving my Bachelor's degree from the University of Michigan in 2005, I
16 was employed by Consumers Energy Company (Consumers Energy). During my
17 initial employment at Consumers Energy, I worked in their production cost
18 modeling group where I supported the development of power supply forecasts using
19 the PROMOD® model. In 2009, I transferred positions to Transmission and
20 Regulatory Strategies where I was responsible for monitoring and analyzing filings
21 by the Midcontinent Independent System Operator ("MISO") at the Federal Energy
22 Regulatory Commission ("FERC"). I was also responsible for forecasting future
23 transmission and certain energy market-related costs in Power Supply Cost
24 Recovery ("PSCR") proceedings before the Michigan Public Service Commission
25 ("Commission" or "MPSC").

Line
No.

1 In 2012, I began my employment at DTE Electric within the Generation
2 Optimization Department. In 2015, I was promoted to a Supervisor position and
3 subsequently in October 2018, I was promoted to a Manager position within
4 Generation Optimization. In May 2025, I assumed responsibility as Manager over
5 the Market Strategy & Settlements team within Generation Optimization.

6

7 **Q5. Have you earned any certifications or are you a member of any professional**
8 **organizations?**

9 A5. Yes, I have attended Utility Rate School and the Advanced Regulatory Studies
10 Program, both hosted by the National Association of Regulatory Utility
11 Commissioners (“NARUC”) and The Institute of Public Utilities Michigan State
12 University. I also earned the certification of North American Electric Reliability
13 Corporation (“NERC”) Balancing and Interchange Operator.

14

15 **Q6. What are your current duties and responsibilities?**

16 A6. My current responsibilities include acquisition of wholesale electric power supply
17 to reliably and economically serve the energy requirements of the Company’s
18 customers including: negotiation and administration of contracts; settlement of
19 wholesale power market transactions; management of renewable energy credit
20 inventory; management of resource adequacy processes and review and advocacy
21 of Company recommendations regarding proposed MISO rules, regulations, and
22 business practices.

Line
No.

- 1 **Q7. Have you previously sponsored testimony before the Michigan Public Service**
2 **Commission (MPSC or Commission)?**
- 3 A7. Yes. I have sponsored testimony in the following MPSC cases:
- 4 U-16149 Consumers Energy's 2010-2011 Gas Cost Recovery ("GCR") Plan
5 U-16485 Consumers Energy's 2011-2012 GCR Plan
6 U-16924 Consumers Energy's 2012-2013 GCR Plan
7 U-16890 Consumers Energy's 2012 PSCR Plan
8 U-17097-R DTE Electric's 2013 PSCR Reconciliation
9 U-17319-R DTE Electric's 2014 PSCR Reconciliation
10 U-17632 DTE Electric's 2013 Renewable Energy Plan Reconciliation
11 U-17680 DTE Electric's 2015 PSCR Plan
12 U-17793 DTE Electric's 2015 Amended Renewable Energy Plan
13 U-17804 DTE Electric's 2014 Renewable Energy Plan Reconciliation
14 U-17920 DTE Electric's 2016 PSCR Plan
15 U-17680-R DTE Electric's 2015 PSCR Reconciliation
16 U-18111 DTE Electric's 2016 Amended Renewable Energy Plan
17 U-18082 DTE Electric's 2015 Renewable Energy Plan Reconciliation
18 U-18143 DTE Electric's 2017 PSCR Plan
19 U-17920-R DTE Electric's 2016 PSCR Reconciliation
20 U-20069 DTE Electric's 2017 PSCR Reconciliation
21 U-20221 DTE Electric's 2019 PSCR Plan
22 U-20471 DTE Electric's 2019 Integrated Resource Plan ("IRP")
23 U-20561 DTE Electric's 2019 Main Rate Case
24 U-20528 DTE Electric's 2020 PSCR Reconciliation
25 U-18091 DTE Electric's 2021 PURPA Avoided Cost

Line
No.

1	U-20836	DTE Electric's 2022 Main Rate Case
2	U-21193	DTE Electric's 2022 IRP
3	U-21297	DTE Electric's 2023 Main Rate Case
4	U-21534	DTE Electric's 2024 Main Rate Case
5	U-21860	DTE Electric's 2025 Main Rate Case

Line
No.

1 **Purpose of Testimony**

2 **Q8. What is the purpose of your testimony in this proceeding?**

3 A8. The purpose of my testimony is to discuss the changes in capacity resource mix and
4 the Power Supply Cost impacts from the addition of Google LLC’s (the Customer)
5 load. I will also discuss the major terms and conditions of the Company’s Rider 12
6 (“R12”) demand response contract with the Customer.

7
8 **Q9. How is your testimony organized?**

9 A9. My testimony consists of the following three sections:

10

11 **Section I:** Discussion of the “base case” capacity resource mix compared
12 to the capacity resource mix with the addition of the Customer’s load in the
13 “Customer datacenter case”.

14

15 **Section II:** Discussion of the Company’s power supply costs projected from
16 2028 through 2047 with and without the Customer’s load.

17

18 **Section III:** Discussion of the R12 demand response contract between the
19 Company and the Customer to support a portion of the capacity needs
20 associated with the Customer’s load.

21

22 **Q10. Are you sponsoring any exhibits in this proceeding?**

23 A10. Yes, I am sponsoring the following exhibits:

24 Exhibit Description

25 A-5 Proxy Combined Cycle Gas Turbine (“CCGT”) and Carbon Capture

Line
No.

1 and Sequestration (“CCS”) Capital and Fixed Costs - Confidential
 2 A-6 Non-Fuel Variable Costs - Confidential
 3 A-7 Projected Fuel, Purchases and Sales of Power, and PSCR Expense,
 4 Years 2028-2047 Base Case
 5 A-8 Projected Purchased Power, Sales, and Expense, Years 2028-2047
 6 Base Case
 7 A-9 Projected Fuel, Purchases and Sales of Power, and PSCR Expense,
 8 Years 2028-2047 – Customer Datacenter Case
 9 A-10 Projected Purchased Power, Sales, and Expense, Years 2028-2047
 10 – Customer Datacenter Case
 11 A-11 Power Supply Cost Recovery Rate – Base Case
 12 A-12 Power Supply Cost Recovery Rate – Customer Datacenter Case
 13 A-13 Power Supply Cost Recovery Rate – Delta (Customer Datacenter
 14 Case minus Base Case)
 15 A-15 Remaining Net Revenue Requirement – Proxy CCGT with CCS and
 16 Solar

17

18 **Q11. Were these exhibits prepared by you or under your direction?**

19 A11. Yes, they were.

20

21 **Q12. Can you provide an overview of the Company’s approach to determining the**
 22 **impact of the Customer’s load on power supply costs?**

23 A12. Yes. The approach was to isolate the impact on power supply costs due to the
 24 addition of the Customer’s load. The Company first modeled¹ a “base case”

¹ Modeling was performed in EnCompass, a power planning software. DTE Electric uses EnCompass for capacity expansion and production cost modeling

Line
No.

1 resource plan based on currently known assumptions that resulted in a resource
2 adequate solution to efficiently serve existing customers.

3

4 The Company then added the Customer's load to the "base case" to determine if
5 incremental capacity resources are required to serve the Customer's load. The
6 second model, "Customer datacenter case", is inclusive of the Customer's load, the
7 additional resources from the Clean Capacity Accelerator Agreement ("CCAA") as
8 discussed by Witness Foley as well as other resources needed to comply with the
9 Midcontinent Independent System Operator ("MISO") requirements and ensure
10 resource adequacy. Witness Brooks defines resource adequacy, discusses the MISO
11 requirements, and modeled the resources of each case to demonstrate resource
12 adequacy, which he describes in his testimony.

13

14 After the resource additions were determined, as further discussed in Section I, the
15 Company assessed the power supply cost impacts between the two cases as
16 discussed in Section II.

17

18 **Q13. Are the modeling results intended to determine the future generation resource**
19 **mix or to identify a preliminary Integrated Resource Plan ("IRP") proposed**
20 **course of action ("PCA") to serve all customers?**

21 A13. No. The Company's future generation resources will be determined through the
22 Company's IRP that will be filed later this year. The modeling results were intended
23 to ensure resource adequacy needs were met with and without the Customer to
24 evaluate the impact on future costs.

Line
No.

1 **Section I: Discussion of the “base case” capacity resource mix compared to the**
2 **capacity resource mix with the addition of the Customer’s load in the “Customer**
3 **datacenter case”.**

4 **Q14. How did the Company develop the “base case” resources for use in this filing?**

5 A14. The Company’s current generation resources are assumed to continue operating
6 through this study period, 2028 to 2047, with the exception of Monroe Units 3 and
7 4, which are expected to retire by the end of 2028, and Monroe Units 1 and 2, which
8 are expected to retire by the end of 2032². The base renewable generation forecast
9 is the Company’s latest Amended Renewable Energy Plan updated with the
10 renewables associated with Oracle (see Witness Bilyeu for further discussion on
11 renewable generation).

12
13 The “base case” also includes a total of approximately 4,800 MW of four-hour
14 lithium-ion energy storage modeled to come online by 2036. The total energy
15 storage resources are made up of (1) resources approved in the Company’s 2022
16 IRP, Case No. U-21193, (2) resources dedicated to the first data center customer
17 (Case No. U-21190), and (3) economically optimized energy storage. These
18 economic selections are driven by tax credits, favorable technology costs, high
19 MISO Direct Loss of Load (“DLOL”)³ capacity accreditation and supporting
20 planned increased levels of renewables. This modeling was performed solely to
21 support the “Customer datacenter case” and is not intended to replace a
22 comprehensive IRP. The 2026 IRP, planned to be filed later this year, will further
23 refine the Company’s energy storage outlook and its role within the DTE Electric
24 fleet.

² Assumption from the Company’s most recently approved IRP (Case No. U-21193).

³ [20241106 RASC Item 10 2024 RRA Update658159.pdf](#)

Line
No.

1 **Q15. Does the Company plan to delay the retirement of Monroe Power Plant to**
2 **serve the Customer?**

3 A15. No, the Company does not plan to delay the retirement of Monroe Power Plant to
4 serve the Customer. Per the 2022 IRP Settlement Agreement approved by the
5 Commission through its July 2023 Order in Case No. U-21193, the planned
6 retirement dates are 2028 for Units 3 and 4 and 2032 for Units 1 and 2. The
7 determination of future generation resources needed to replace Monroe Units 1 and
8 2 will occur in the Company's next IRP.

9
10 For the modeling in this filing, only the differences between the "base case" and
11 the "Customer datacenter case" are relevant for evaluating the cost impacts of
12 adding the Customer's load. The cost to replace Monroe Units 1 and 2 would be
13 identical in both cases. Therefore, in each case, the modeling assumes Monroe
14 Units 1 and 2 continue operating throughout the analysis period, serving as a
15 placeholder in each case for future replacement resources.

16
17 **Q16. How did the Company develop its "Customer datacenter case" resource plan?**

18 A16. The Company included the Customer's load and the resources from the CCAA as
19 described by Witness Foley which include the following:

- 20 • 450 MW⁴ of energy storage made up of:
- 21 ○ 400 MW of 4-hour energy storage
- 22 ○ 50 MW of 8-hour energy storage⁵
- 23 • 1,600 MW renewables⁶

⁴ CCAA specifies up to 480 MW

⁵ CCAA specifies approximately 50 MW of "long duration storage"

⁶ Refer to Witness Bilyeu's testimony for additional details

Line
No.

- 1 • 300 MW zonal resource credits (“ZRC”)

2 The Company also included approximately 250 MW of Customer demand
3 response. This is discussed in more detail in Section III of my testimony.

4

5 As Witness Brooks discusses in his testimony, the DTE Electric system is resource
6 adequate in 2029 with these resources. In 2033, however, additional “perfect
7 capacity⁷” is needed to ensure resource adequacy so a proxy generic combined
8 cycle gas turbine (“CCGT”) and carbon capture and sequestration (“CCS”) was
9 modeled to address this need. The Company’s upcoming IRP, to be filed later this
10 year, will ultimately determine the appropriate long-term resource and generation
11 mix. The CCGT and CCS added in this instant filing serves only as a proxy to
12 estimate the cost of an incremental resource in the customer benefit analysis
13 performed by Witness Willis.

14

15 **Q17. Why were the years 2029 and 2033 studied to determine resource adequacy?**

16 A17. Witness Brooks discusses why it is appropriate to analyze select years within a
17 long-term planning horizon. The year 2029 was selected because it is the first year
18 after the retirement of Monroe Units 3 and 4. The year 2033 was chosen due to the
19 expiration of both the 300 ZRCs under the CCAA and the approximately 250 MWs
20 of demand response in the Customer R12 contract on May 31, 2033. Given the loss
21 of these existing resources and the addition of new resources, it was reasonable to
22 evaluate both years to ensure the portfolio continues to meet the resource adequacy
23 standard.

⁷ Refer to Witness Brooks testimony for additional details on “perfect capacity”

Line
No.

1 **Q18. Can you describe the non-renewable resource changes from the “base case” to**
2 **the “Customer datacenter case”?**

3 A18. The primary resource changes between the “base case” and “Customer datacenter
4 case” are the acceleration of energy storage resources as well as the addition of a
5 “perfect capacity” resource described above (e.g. a proxy CCGT appropriately
6 sized in the “Customer datacenter case”) and defined by Witness Brooks in his
7 testimony. In the “Customer datacenter case,” 500 MW of energy storage capacity
8 is accelerated compared to the “base case” where these resources were projected to
9 come online in later years. As previously discussed in the CCAA, an additional 50
10 MW of 8-hour energy storage, fully funded by the Customer, is shown in 2029. As
11 Witness Foley notes, this can be any long-duration storage technology; for the
12 purposes of this modeling, a 50 MW 8-hour storage asset is assumed to replace 100
13 MWs of 4-hour storage in 2036 from the base case. Additionally, once the ZRC
14 contract and the contracted demand response end on May 31, 2033, a proxy
15 dispatchable resource is modeled to support resource adequacy.

16

17 **Q19. Can you summarize the resource changes occurring between the “base case”**
18 **and “Customer datacenter case”?**

19 A19. Yes. See Table 1 below that shows the change in resources from the “base case” to
20 the “Customer datacenter case.” The addition of 450 MW of storage earlier in the
21 build plan for the “Customer datacenter case” results in a reallocation of 100 MW
22 of lithium-ion four-hour storage reconfigured as 50 MW of 8-hour storage when
23 comparing cases. In addition, including 1,600 MW of customer owned renewables
24 reduces the overall renewable build by 200 MW in 2033 and 50 MW in 2034 in the

Line
No.

1 “Customer datacenter case”. No changes in resources we made after 2036 that differ
2 between the cases.

3

4 **Table 1: “Customer Datacenter Case” resource changes from “Base Case”**

5

(nameplate (MW))

	2028	2029	2030	2031	2032	2033	2034	2035	2036
Demand Response	250					(250)			
Renewable Energy ⁸			500	700	400	(200)	(50)		
4-Hour Energy Storage	200	200						(200)	(300)
8-Hour Energy Storage		50							
ZRC Contract	300					(300)			
Proxy CCGT w/CCS						727		(81)	

6 Black = additions, red = subtractions

7

8 **Q20. What price assumptions were used in the modeling of the proxy CCGT with**
9 **CCS in the “Customer datacenter case”?**

10 A20. The Company utilized a third-party forecast, Wood Mackenzie, for plant capital
11 cost, CCS capital cost, and non-fuel operating and maintenance (O&M)
12 assumptions for a new 727 MW CCGT with CCS. These projected cost inputs from
13 Wood Mackenzie were applied directly into the model and the model calculated the
14 annual revenue requirement for the proxy CCGT with CCS. The annual revenue
15 requirement for the proxy CCGT with CCS was an output of the model which
16 incorporated various components such as depreciation expense, non-fuel O&M,
17 property tax, allowed return, and federal production tax credits associated with the
18 CCS system. The associated revenue requirements are shown in Confidential

⁸ Refer to Witness Bilyeu’s testimony for additional detail

Line
No.

1 Exhibits A-5 and A-6 and were provided to Witness Willis to use in the overall
2 customer benefit analysis. The fuel expense, energy revenues, and capacity
3 revenues associated with the proxy CCGT with CCS resource are also included in
4 the PSCR expense forecast for the “Customer datacenter case.”

5

6 **Q21. What price assumptions were used in the modeling of the energy storage in the**
7 **“Customer datacenter case”?**

8 A21. The Company developed energy storage price assumptions using information from
9 two sources. Capital cost assumptions were based on up-to-date market-based cost
10 information obtained through the Company’s 2025 energy storage Request For
11 Proposal (“RFP”). For fixed operating cost assumptions, the Company relied on
12 data from the National Renewable Energy Laboratory’s (“NREL”) 2024 Annual
13 Technology Baseline (“ATB”). These projected cost inputs were applied directly
14 into the model similar to the proxy CCGT with CCS mentioned above. The
15 associated revenue requirements are shown in Confidential Exhibit A-5 and were
16 provided to Witness Willis to use in the overall customer benefit analysis. The
17 energy and capacity revenues associated with the energy storage resources are also
18 included in the PSCR expense forecast for the “Customer datacenter case.”

19

20 **Q22. Does the proxy CCGT with CCS resource provide value to other customers**
21 **following the conclusion of the Customer contract in 2047?**

22 A22. As described earlier in my testimony, this is a proxy asset used for modeling
23 purposes; the 2026 IRP will determine the appropriate resources needed to serve
24 DTE Electric customers, as well as assumptions on the revenue requirement of the
25 asset(s) over their depreciable lives. In the context of this proxy asset modeled in

Line
No.

1 this case, should the Customer choose to not extend its contract beyond 2047, this
2 asset would provide market value for customers, and may offset potential future
3 resource development costs (e.g., offsetting incremental capacity and energy to
4 replace potential retiring resources in this timeframe).

5

6 **Q23. What is the approximate remaining revenue requirement of a proxy CCGT**
7 **with CCS after 2047?**

8 A23. Wood Mackenzie forecasts a 35-year lifespan of a CCGT with CCS which was
9 used in this analysis. Based on the 35-year lifespan schedule, the remaining revenue
10 requirement after 2047 is forecasted to be approximately \$1.0 billion on a net
11 present value (“NPV”) basis (Exhibit A-15, line 21, column (b)). At the conclusion
12 of the contract with the Customer, 74% of the cost of this asset has been paid off
13 based on a NPV basis.

14

15 **Q24. Are there market revenues that offset the remaining revenue requirement of**
16 **the proxy CCGT with CCS?**

17 A24. Yes. The modeled value of the proxy CCGT with CCS for both energy and capacity
18 is approximately \$142 million annually in 2038. Assuming the proxy CCGT with
19 CCS continued to receive similar market value inflated over 2048 – 2067
20 timeframe, that would equate to approximately \$647 million on an NPV basis
21 (Exhibit A-15, line 22, column (b)).

22

23 **Q25. Can you provide an example of how the proxy CCGT with CCS may displace**
24 **the potential need for another resource in 2048 (e.g., offsetting incremental**
25 **capacity and energy to replace potential retiring resources)?**

Line
No.

1 A25. Yes. In this timeframe, there may be resources within DTE Electric’s existing
2 generation fleet that are nearing retirement. Should one of those resources be
3 scheduled for retirement in this timeframe, this resource could displace the need for
4 new replacement resources. For example, based on the current economic outlook,
5 storage is one of the most economic capacity resources that may be selected as a
6 new resource in 2048 to fill the need created from potential existing asset
7 retirements. A 4-hour lithium-ion storage resource of approximately 576 MW
8 nameplate capacity would receive similar projected MISO capacity accreditation
9 as a proxy CCGT with CCS with a nameplate capacity of 646 MW in the Summer
10 Season. The 576 MW storage resource net revenue requirement over 2048 – 2067
11 on a NPV basis would be approximately \$212 million (Exhibit A-15, line 23,
12 column (c)). Thus, to replace other potentially retiring DTE Electric resources, the
13 proxy CCGT with CCS (Exhibit A-15, line 24, column (b)) avoids the \$212 million
14 net revenue requirement of a 576 MW storage resource.

15

16 **Q26. Is there value in the “Customer Datacenter case” resources (specifically the**
17 **proxy CCGT with CCS and remaining life of solar resources) to recover the**
18 **remaining costs after the contract with the Customer ends in 2047?**

19 A26. Yes. The remaining net revenue requirement, after including the avoided \$212
20 million storage resource as described above, results in approximately \$151 million
21 for the proxy CCGT with CCS (Exhibit A-15, line 24, column (b)). This is offset
22 by the remaining market value of \$226 million from the solar resources resulting in
23 a net benefit of approximately \$75 million (Exhibit A-15, line 26, column (b)) on a
24 NPV basis. This projection after the Customer contract ends in 2047 shows that

Line
No.

1 generation resources will continue to provide customer value beyond the analysis
2 performed by Witness Willis.

3

4 **Section II: Discussion of the Company's power supply costs projected from 2028**
5 **through 2047 with and without the Customer's load.**

6 **Q27. After identifying the resource mix for each case, how did the Company**
7 **determine the impact on the Company's power supply costs?**

8 A27. The Company projected power supply costs for both the "base case" and the
9 "Customer datacenter case" using the modeling results. The Company then
10 calculated and compared the resulting rates to quantify the difference in power
11 supply cost rates between the two cases. This approach was used to isolate the
12 impact of the Customer's load and associated resources on power supply costs.

13

14 **Q28. What are the major assumptions in your "base case"?**

15 A28. Table 2 below shows the major assumptions and the source.

Line
No.

1

Table 2: “Base Case” major assumptions

Topic	Assumption	Source
Timeframe	2028 – 2038 – modeled in Encompass 2039 – 2047 – held 2038 values flat for model assumptions	<ul style="list-style-type: none"> Primary Supply Agreement (PSA), 2039 – 2047: Customer load at full load, no further associated resource changes; modeling is focused on the changes between the two cases
Load Forecast	PSCR Forecast + Oracle Load	<ul style="list-style-type: none"> PSCR Plan (U-21875) + Oracle Filing (U-21990)
Market Price Forecast (energy and capacity)	PSCR Forecast MI Hub basis - energy	<ul style="list-style-type: none"> PSCR Plan (U-21875) Third-party Siemens forecast
Renewables	Amended REP through 2036 plus incremental Oracle renewables	<ul style="list-style-type: none"> Amended REP (U-21662) + Oracle Filing (U-21990)
Monroe Units 3 & 4	Retired in 2028	<ul style="list-style-type: none"> 2022 IRP Settlement (U-21193)
Monroe Units 1 & 2	Operates through 2032 then proxy resource called “TBD Resource(s)” incorporated	<ul style="list-style-type: none"> 2022 IRP Settlement (U-21193). Units 1&2 will retire in 2032; replacement resources will be determined in next IRP as addressed in Section I
Transmission	PSCR Forecast + Oracle Load	<ul style="list-style-type: none"> PSCR Plan (U-21875) + Oracle Filing (U-21990)
Non-PSCR Sales	PSCR Forecast + Oracle Load	<ul style="list-style-type: none"> PSCR Plan (U-21875) + Oracle Filing (U-21990)
Fuel & Chemical Prices	PSCR Forecast	<ul style="list-style-type: none"> Coal - Market Forwards escalated by Consumers Price Index Natural Gas – Third-party Siemens forecast Chemicals – PSCR Plan (U-21875)
Other Existing Generation	Continue to operate	<ul style="list-style-type: none"> PSCR Plan (U-21875) + Oracle Filing (U-21990)
Energy Storage	PSCR Forecast + Oracle energy storage	<ul style="list-style-type: none"> (U-21193) (U-21990) Economically optimized

Line
No.

1 **Q29. What information does Exhibit A-7 and Exhibit A-8 show?**

2 A29. Exhibit A-7 and Exhibit A-8 show a summary by year of the various power supply
3 cost categories for the “base case”.

4

5 **Q30. What were the assumed transmission costs for the base case?**

6 A30. The transmission costs for the “base case” are shown on Exhibit A-7, line 30. These
7 costs are projected based on a forecast of MISO charge types associated with
8 transmission for the International Transmission Company (ITC) pricing zone.
9 These transmission costs are consistent with the costs forecasted in the 2026 PSCR
10 Plan plus estimated costs associated with the first data center customer.

11

12 **Q31. How did the Company forecast fuel prices?**

13 A31. The coal price forecast was based on pricing forwards through 2030 and then
14 escalated by the consumer price index (“CPI”). The natural gas price assumptions
15 utilized the third-party Siemens projections that were used in the PSCR Plan.

16

17 **Q32. What are the Non-PSCR Customer Sales and Transmission Adjustments?**

18 A32. The Non-PSCR Customer Sales and Transmission Adjustments relate to the sales
19 made to R-10 interruptible customers, R-3 Standby and Supplemental Service
20 customers. These sales are not PSCR sales and are not included in determining
21 recoverable PSCR expense. The Non-PSCR Customer Sales and Transmission
22 Adjustments credit PSCR customers incremental expense to serve these sales.

Line
No.

1 **Q33. What information does Exhibit A-9 and Exhibit A-10 show?**

2 A33. Exhibit A-9 and Exhibit A-10 show a summary by year of the various power supply
3 cost components for the “Customer datacenter case”.

4

5 **Q34. What changes were made in the “Customer datacenter case” from the “base
6 case” that impact the power supply costs?**

7 A34. The resource mix changes discussed in Section I of my testimony impact the
8 purchases and sales, capacity and fuel and chemical costs. Other changes made to
9 the “base case” assumptions listed in Table 2 include: the addition of the
10 Customer’s load in the load forecast and the transmission cost assumptions
11 associated with the Customer’s load. Refer to Witness Benyard for additional
12 details on transmission costs.

13

14 **Q35. What are the assumed transmission costs for the “Customer datacenter case”?**

15 A35. The transmission costs for the “Customer datacenter case” are shown on Exhibit A-
16 9, line 30. There are two impacts to transmission expense for the “Customer
17 datacenter case” – the impact from the transmission investments necessary to serve
18 the Customer and the impact from the inclusion of the Customer’s load in the
19 Company’s transmission expense allocation.

20

21 First, transmission expense is impacted by the transmission investments necessary
22 to serve the Customer. Based on initial estimates provided by the Company’s
23 transmission provider and as discussed by Witness Benyard, the Company expects
24 that approximately \$308 million of capital investment by ITC will be needed to
25 upgrade the transmission system to connect the Customer to the electric grid. The

Line
No.

1 transmission provider's investment is recovered from the Company (and others) via
2 MISO Schedule 9, which is a component of the Company's transmission expense.

3
4 Second, transmission expense is impacted by the inclusion of the Customer's load
5 in the Company's transmission expense allocation. The MISO Schedules that
6 comprise the Company's transmission expense, including Schedules 1, 9, 10, 10-
7 FERC, 26, 26-A, and 26-C, are allocated based on the Company's peak demand
8 and energy usage. Since the Customer's load increases both the Company's peak
9 demand and energy use, the Customer's load impacts transmission expense.

10

11 **Q36. Can you explain the impact to transmission expense when comparing the**
12 **"Customer datacenter case" to the "base case"?**

13 A36. Yes. The transmission expense for the "base case" is shown on Exhibit A-7, line
14 30. For 2029, the "base case" transmission expense is \$798 million. The
15 transmission expense for the "Customer datacenter case" is shown on Exhibit A-9,
16 line 30. For 2029, the "Customer datacenter case" transmission expense is \$889
17 million. When comparing the cases, the impact on the 2029 transmission expense
18 is \$91 million.

19

20 **Q37. Are the Company's other customers adversely impacted by the increased**
21 **transmission expense?**

22 A37. No, the Company's existing customers will not be adversely impacted by the
23 increased transmission expense. Even though the overall transmission expense is
24 increasing, the effective transmission rate for all customers decreases due to the
25 large increase in load from the Customer, who also pays a portion of the Company's

Line
No.

1 transmission expense through PSCR allocations. For example, the “base case”
2 transmission expense in 2029 is \$798 million and the load forecast is 53,812 GWh,
3 producing a transmission unit cost of \$0.0148/kWh. Whereas in the “Customer
4 datacenter case”, transmission expense increases to \$889 million in 2029 while the
5 associated load increases to 61,819 GWh, resulting in a lower transmission unit
6 cost of \$0.0144/kWh. The Company’s other customers receive the benefit of the
7 lower transmission unit cost which is included in the PSCR benefit for other
8 customers described below and utilized in Witness Willis’ Exhibit A-19.

9

10 **Q38. What is the impact of the additional Customer load on existing PSCR rates?**

11 A38. The addition of the Customer’s load and resources paid for by the Customer results
12 in a net PSCR benefit to the Company’s other customers. Other customers benefit
13 from the resources paid for by the Customer with total wholesale revenues shown
14 in Exhibit A-10, line 78, being greater than the credits provided to the Customer
15 shown on line 79. Additionally, the Customer’s load is paying for various power
16 supply costs that result in lower rates (e.g. transmission costs as discussed above
17 and renewable compliance build). The PSCR rates are shown for the “base case”
18 in Exhibit A-11 and the “Customer datacenter case” in Exhibit A-12. The
19 differences in the PSCR rates are shown in Exhibit A-13. As described, there is a
20 net benefit over the 20 years to existing PSCR customers and the increased load
21 from the Customer resulting in lower rates. The total power supply cost change for
22 existing customers due to the Customer’s load is shown in Exhibit 13, line 9 and
23 was provided to Witness Willis for use in his customer benefit analysis.

Line
No.

1 **Section III: Discussion of the R12 demand response contract between the Company**
2 **and Customer to support a portion of the capacity needs associated with the**
3 **Customer's load**

4 **Q39. What is the R12 demand response contract that the Company has executed**
5 **with the Customer?**

6 A39. The Company's Rider 12 allows for flexible demand response arrangements with
7 its customers. The Customer's R12 contract accounts for the risks of the large load
8 addition, ensures other customers remain financially unharmed, and accounts for
9 current MISO Rules and future reforms as they relate to Load Modifying Resources
10 ("LMR"). The contract is for a reduction in load to a Firm Service Level ("FSL")
11 of 65% of the customer committed capacity ramp during the load ramp period as
12 well as when the Customer is at full load (65% of the full 1000 MW). The contract
13 is one of the additional resources needed to meet the MISO resource adequacy
14 requirements for the increase in load from the Customer as further discussed above
15 and by Witness Brooks.

16

17 **Q40. What are the major terms and conditions for the R12 demand response**
18 **contract with the Customer?**

19 A40. The contract is for an amount of approximately 250 MWs of demand response with
20 the corresponding accredited ZRCs for MISO's resource adequacy construct. The
21 contract term begins 6/1/2027 and ends 5/31/2033 and requires a firm service level
22 of 650 MW

23

24 **Q41. Does the contract meet the current MISO requirements and those expected to**
25 **be in place beginning in 2028 to receive the full accreditation value?**

Line
No.

1 A41. Yes, the contract meets the current MISO requirements and those expected to be in
2 place beginning in 2028.

3

4 **Q42. How does the Firm Service Level of 650 MW equate to approximately 250 MW**
5 **of load reduction?**

6 A42. The Company modeled the Customer's expected load based on the Customer's
7 input of approximately a 90% load factor for a 1,000 MW load (equates to 900
8 MW). A FSL of 650 MW means that the Customer must reduce their actual load
9 to below 650 MW if called upon by MISO during an emergency. The reduction to
10 650 MW must occur even if the Customer is using 1,000 MW at the time the
11 reduction is called upon. Thus, the amount of actual load reduction can vary, but
12 must reach the 650 MW FSL. The approximate average Customer load of 900 MW
13 minus the 650 MW FSL equates to approximately 250 MW of demand response.

14

15 **Q43. Do the contract damages for non-performance adequately cover any financial**
16 **costs to the Company?**

17 A43. Yes. The damages are structured in a way to ensure that all potential MISO
18 penalties are assessed to the Customer. First, the damages imposed by MISO
19 during the current MISO Planning Year (PY) for any non-performance will be
20 directly assessed, including any accredited ZRCs that are disqualified. The
21 Company also assesses additional damages at two times the contract price for the
22 non-performance amount. Second, any future MISO PY lost accreditation for non-
23 performance will be assessed damages for the lost ACP revenues plus at least the
24 CONE. This ensures full recovery of any lost revenues from the Planning Resource

Line
No.

1 Auction. The addition of CONE is reasonable to incentivize the demand response

2 performance to help ensure reliability.

3

4 **Q44. Does this complete your direct testimony?**

5 A44. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

EXHIBITS
OF
SHAWN D. BURGDORF

**Michigan Public Service Commission
DTE Electric Company**

Case No.: U-22058
Exhibit: A-5 Confidential
Witness: S. Burgdorf
Page: 1 of 1

EXHIBIT A-5

Access to Confidential Exhibit A-5 will be provided upon issuance of a protective order and receipt of a signed nondisclosure agreement.

**Michigan Public Service Commission
DTE Electric Company**

Case No.: U-22058
Exhibit: A-6 Confidential
Witness: S. Burgdorf
Page: 1 of 1

EXHIBIT A-6

Access to Confidential Exhibit A-6 will be provided upon issuance of a protective order and receipt of a signed nondisclosure agreement.

Michigan Public Service Commission
DTE Electric Company
Projected Fuel, Purchases and Sales of Power, and PSCR Expense - Base Case
Years 2028 - 2047

Case No.: U-22058
Exhibit: A-7
Witness: S. D. Burgdorf
Page: 1 of 1

Line No.	(a) Description	(b) 2028	(c) 2029	(d) 2030	(e) 2031	(f) 2032	(g) 2033	(h) 2034	(i) 2035	(j) 2036	(k) 2037	(l) 2038	(m) 2039	(n) 2040	(o) 2041	(p) 2042	(q) 2043	(r) 2044	(s) 2045	(t) 2046	(u) 2047
1	Generation & Fuel																				
2	- GWh	37,864	27,863	25,554	27,110	26,226	26,630	22,512	24,410	22,399	22,884	20,668	20,668	20,668	20,668	20,668	20,668	20,668	20,668	20,668	20,668
3	- \$1,000	\$ 945,589	\$ 724,517	\$ 737,150	\$ 769,861	\$ 773,248	\$ 746,194	\$ 632,624	\$ 670,121	\$ 621,745	\$ 618,134	\$ 591,359	\$ 591,359	\$ 591,359	\$ 591,359	\$ 591,359	\$ 591,359	\$ 591,359	\$ 591,359	\$ 591,359	\$ 591,359
4																					
5	Ludington+Battery Losses																				
6	- GWh	(700)	(1,055)	(1,081)	(1,166)	(1,145)	(1,103)	(1,061)	(1,146)	(1,637)	(1,693)	(1,644)	(1,644)	(1,644)	(1,644)	(1,644)	(1,644)	(1,644)	(1,644)	(1,644)	(1,644)
7																					
8	Net Wholesale Power Purchases/Sales																				
9	- GWh	16,531	27,005	29,549	28,153	29,223	28,823	33,087	31,470	34,309	33,994	36,588	36,588	36,588	36,588	36,588	36,588	36,588	36,588	36,588	36,588
10	- \$1,000	\$ 1,164,982	\$ 1,793,271	\$ 2,025,539	\$ 1,984,108	\$ 2,120,693	\$ 2,206,783	\$ 2,469,713	\$ 2,334,189	\$ 2,277,418	\$ 2,319,688	\$ 2,531,393	\$ 2,531,393	\$ 2,531,393	\$ 2,531,393	\$ 2,531,393	\$ 2,531,393	\$ 2,531,393	\$ 2,531,393	\$ 2,531,393	\$ 2,531,393
11																					
12	Emission Allowances																				
13	NOx Seasonal - \$1,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
14	NOx Annual - \$1,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
15	SO2 (CSAPR) - \$1,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
16	SO2 (ARP) - \$1,000	\$ 0	\$ 0	\$ 0	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
17																					
18	Chemical Costs																				
19	Urea - \$1,000	\$ 21,049	\$ 10,496	\$ 10,057	\$ 10,914	\$ 11,143	\$ 11,437	\$ 8,997	\$ 10,820	\$ 11,086	\$ 11,240	\$ 9,510	\$ 9,510	\$ 9,510	\$ 9,510	\$ 9,510	\$ 9,510	\$ 9,510	\$ 9,510	\$ 9,510	\$ 9,510
20	Limestone - \$1,000	\$ 9,445	\$ 4,710	\$ 4,513	\$ 4,897	\$ 5,000	\$ 5,132	\$ 4,037	\$ 4,855	\$ 4,974	\$ 5,043	\$ 4,267	\$ 4,267	\$ 4,267	\$ 4,267	\$ 4,267	\$ 4,267	\$ 4,267	\$ 4,267	\$ 4,267	\$ 4,267
21	Ammonia - \$1,000	\$ 1,631	\$ 1,567	\$ 1,350	\$ 1,472	\$ 1,555	\$ 1,492	\$ 1,425	\$ 1,375	\$ 1,336	\$ 1,182	\$ 1,297	\$ 1,297	\$ 1,297	\$ 1,297	\$ 1,297	\$ 1,297	\$ 1,297	\$ 1,297	\$ 1,297	\$ 1,297
22	Potassium Iodide - \$1,000	\$ 916	\$ 457	\$ 437	\$ 475	\$ 485	\$ 498	\$ 391	\$ 471	\$ 482	\$ 489	\$ 414	\$ 414	\$ 414	\$ 414	\$ 414	\$ 414	\$ 414	\$ 414	\$ 414	\$ 414
23																					
24	Net System Output																				
25	- GWh	53,696	53,812	54,022	54,098	54,305	54,351	54,539	54,734	55,072	55,185	55,612	55,612	55,612	55,612	55,612	55,612	55,612	55,612	55,612	55,612
26	- \$1,000	\$ 2,143,612	\$ 2,535,018	\$ 2,779,046	\$ 2,771,727	\$ 2,912,124	\$ 2,971,536	\$ 3,117,188	\$ 3,021,830	\$ 2,917,041	\$ 2,955,775	\$ 3,138,241	\$ 3,138,241	\$ 3,138,241	\$ 3,138,241	\$ 3,138,241	\$ 3,138,241	\$ 3,138,241	\$ 3,138,241	\$ 3,138,241	\$ 3,138,241
27	- \$/MWh	\$ 39.92	\$ 47.11	\$ 51.44	\$ 51.24	\$ 53.63	\$ 54.67	\$ 57.16	\$ 55.21	\$ 52.97	\$ 53.56	\$ 56.43	\$ 56.43	\$ 56.43	\$ 56.43	\$ 56.43	\$ 56.43	\$ 56.43	\$ 56.43	\$ 56.43	\$ 56.43
28																					
29	Bundled Transmission																				
30	- \$1,000	\$702,259	\$797,911	\$914,961	\$974,102	\$1,057,734	\$1,164,666	\$1,307,665	\$1,464,381	\$1,488,354	\$1,509,434	\$1,535,282	\$1,561,143	\$1,588,508	\$1,612,167	\$1,637,651	\$1,648,805	\$1,661,770	\$1,642,020	\$1,654,398	\$1,661,912
31																					
32	Non-PSCR Customer Sales Adjustment																				
33	- GWh	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919
34	- \$1,000	\$ 45,917	\$ 45,927	\$ 47,084	\$ 48,769	\$ 48,712	\$ 47,559	\$ 45,401	\$ 45,569	\$ 44,359	\$ 44,661	\$ 45,738	\$ 45,738	\$ 45,738	\$ 45,738	\$ 45,738	\$ 45,738	\$ 45,738	\$ 45,738	\$ 45,738	\$ 45,738
35																					
36	Transmission Adjustment																				
37	- GWh	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919
38	- \$1,000	\$ 12,015	\$ 13,622	\$ 15,560	\$ 16,542	\$ 17,894	\$ 19,686	\$ 22,027	\$ 24,579	\$ 24,828	\$ 25,128	\$ 25,362	\$ 25,789	\$ 26,242	\$ 26,632	\$ 27,053	\$ 27,238	\$ 27,470	\$ 27,143	\$ 27,348	\$ 27,472
39																					
40	PSCR Fuel & Purchased Power																				
41	- GWh	52,777	52,893	53,103	53,179	53,386	53,433	53,620	53,815	54,153	54,267	54,693	54,693	54,693	54,693	54,693	54,693	54,693	54,693	54,693	54,693
42	- \$1,000	\$ 2,787,939	\$ 3,273,380	\$ 3,631,363	\$ 3,680,518	\$ 3,903,252	\$ 4,068,958	\$ 4,357,424	\$ 4,416,063	\$ 4,336,208	\$ 4,395,421	\$ 4,602,422	\$ 4,627,856	\$ 4,654,769	\$ 4,678,038	\$ 4,703,100	\$ 4,714,070	\$ 4,726,804	\$ 4,707,379	\$ 4,719,553	\$ 4,726,943
43	- \$/MWh	\$ 52.82	\$ 61.89	\$ 68.38	\$ 69.21	\$ 73.11	\$ 76.15	\$ 81.26	\$ 82.06	\$ 80.07	\$ 81.00	\$ 84.15	\$ 84.61	\$ 85.11	\$ 85.53	\$ 85.99	\$ 86.19	\$ 86.42	\$ 86.07	\$ 86.29	\$ 86.43

Line No.	(a) Description	(b) 2028	(c) 2029	(d) 2030	(e) 2031	(f) 2032	(g) 2033	(h) 2034	(i) 2035	(j) 2036	(k) 2037	(l) 2038	(m) 2039	(n) 2040	(o) 2041	(p) 2042	(q) 2043	(r) 2044	(s) 2045	(t) 2046	(u) 2047
1	MISO WHOLESALE PURCHASES & SALES																				
2	MISO Wholesale Purchases																				
3	- GWh	5,202	11,287	10,750	7,950	6,716	5,115	6,572	4,631	5,780	5,219	6,515	6,515	6,515	6,515	6,515	6,515	6,515	6,515	6,515	6,515
4	- \$1,000	\$ 185,683	\$ 430,542	\$ 394,517	\$ 291,753	\$ 241,843	\$ 215,375	\$ 289,038	\$ 190,907	\$ 168,522	\$ 167,546	\$ 230,376	\$ 230,376	\$ 230,376	\$ 230,376	\$ 230,376	\$ 230,376	\$ 230,376	\$ 230,376	\$ 230,376	\$ 230,376
5	- \$/MWh	\$ 35.70	\$ 38.15	\$ 36.70	\$ 36.70	\$ 36.01	\$ 42.11	\$ 43.98	\$ 41.22	\$ 29.16	\$ 32.10	\$ 35.36	\$ 35.36	\$ 35.36	\$ 35.36	\$ 35.36	\$ 35.36	\$ 35.36	\$ 35.36	\$ 35.36	\$ 35.36
6																					
7	MISO Wholesale Sales																				
8	- GWh	3,660	2,189	2,457	3,963	4,637	5,664	5,048	6,977	8,238	8,397	7,165	7,165	7,165	7,165	7,165	7,165	7,165	7,165	7,165	7,165
9	- \$1,000	\$ 202,836	\$ 133,236	\$ 167,389	\$ 246,832	\$ 277,852	\$ 272,455	\$ 215,148	\$ 310,172	\$ 437,392	\$ 433,890	\$ 385,606	\$ 385,606	\$ 385,606	\$ 385,606	\$ 385,606	\$ 385,606	\$ 385,606	\$ 385,606	\$ 385,606	\$ 385,606
10	- \$/MWh	\$ 55.41	\$ 60.87	\$ 68.14	\$ 62.28	\$ 59.92	\$ 48.10	\$ 42.62	\$ 44.46	\$ 53.10	\$ 51.67	\$ 53.82	\$ 53.82	\$ 53.82	\$ 53.82	\$ 53.82	\$ 53.82	\$ 53.82	\$ 53.82	\$ 53.82	\$ 53.82
11																					
12	MISO Market Expenses (excluding Sch 16 & 17) - \$1,000	\$ 78,564	\$ 63,698	\$ 55,344	\$ 59,526	\$ 57,442	\$ 58,488	\$ 57,971	\$ 58,237	\$ 58,116	\$ 58,185	\$ 58,164	\$ 58,164	\$ 58,164	\$ 58,164	\$ 58,164	\$ 58,164	\$ 58,164	\$ 58,164	\$ 58,164	\$ 58,164
13																					
14	NET MISO PURCHASES & SALES																				
15	- GWh	1,541	9,098	8,294	3,986	2,078	(550)	1,524	(2,346)	(2,458)	(3,178)	(649)	(649)	(649)	(649)	(649)	(649)	(649)	(649)	(649)	(649)
16	- \$1,000	\$ 61,411	\$ 361,004	\$ 282,473	\$ 104,446	\$ 21,432	\$ 1,408	\$ 131,861	\$ (61,028)	\$ (210,753)	\$ (208,160)	\$ (97,067)	\$ (97,067)	\$ (97,067)	\$ (97,067)	\$ (97,067)	\$ (97,067)	\$ (97,067)	\$ (97,067)	\$ (97,067)	\$ (97,067)
17	- \$/MWh	\$ 39.84	\$ 39.68	\$ 34.06	\$ 26.20	\$ 10.31	\$ (2.56)	\$ 86.51	\$ 26.02	\$ 85.73	\$ 65.50	\$ 149.46	\$ 149.46	\$ 149.46	\$ 149.46	\$ 149.46	\$ 149.46	\$ 149.46	\$ 149.46	\$ 149.46	\$ 149.46
18																					
19	P.A. 295 RENEWABLE PURCHASES																				
20	Renewable Energy Build																				
21	Wind																				
22	- GWh	3,957	3,943	3,943	4,377	4,931	5,454	5,992	8,260	10,988	11,475	11,480	11,480	11,480	11,480	11,480	11,480	11,480	11,480	11,480	11,480
23	- \$1,000	\$ 338,079	\$ 345,520	\$ 353,434	\$ 385,508	\$ 425,443	\$ 463,253	\$ 503,229	\$ 642,800	\$ 812,247	\$ 849,903	\$ 860,453	\$ 860,453	\$ 860,453	\$ 860,453	\$ 860,453	\$ 860,453	\$ 860,453	\$ 860,453	\$ 860,453	\$ 860,453
24	- \$/MWh	\$ 85.44	\$ 87.63	\$ 89.64	\$ 88.07	\$ 86.27	\$ 84.94	\$ 83.98	\$ 77.82	\$ 73.92	\$ 74.07	\$ 74.95	\$ 74.95	\$ 74.95	\$ 74.95	\$ 74.95	\$ 74.95	\$ 74.95	\$ 74.95	\$ 74.95	\$ 74.95
25																					
26	Solar																				
27	- GWh	6,664	8,492	10,815	13,157	15,564	17,287	18,939	18,930	19,132	19,069	19,125	19,125	19,125	19,125	19,125	19,125	19,125	19,125	19,125	19,125
28	- \$1,000	\$ 447,031	\$ 570,624	\$ 752,313	\$ 918,309	\$ 1,102,970	\$ 1,206,922	\$ 1,296,961	\$ 1,292,314	\$ 1,309,369	\$ 1,305,126	\$ 1,310,106	\$ 1,310,106	\$ 1,310,106	\$ 1,310,106	\$ 1,310,106	\$ 1,310,106	\$ 1,310,106	\$ 1,310,106	\$ 1,310,106	\$ 1,310,106
29	- \$/MWh	\$ 67.08	\$ 67.20	\$ 69.56	\$ 69.79	\$ 70.87	\$ 69.82	\$ 68.48	\$ 68.27	\$ 68.44	\$ 68.44	\$ 68.50	\$ 68.50	\$ 68.50	\$ 68.50	\$ 68.50	\$ 68.50	\$ 68.50	\$ 68.50	\$ 68.50	\$ 68.50
30																					
31	Renewable Energy PPA																				
32	Wind																				
33	- GWh	1,771	2,308	2,846	2,950	2,961	2,950	2,950	2,948	2,960	2,949	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950
34	- \$1,000	\$ 113,257	\$ 145,480	\$ 177,565	\$ 183,770	\$ 184,442	\$ 183,765	\$ 183,765	\$ 183,635	\$ 184,399	\$ 183,679	\$ 183,768	\$ 183,768	\$ 183,768	\$ 183,768	\$ 183,768	\$ 183,768	\$ 183,768	\$ 183,768	\$ 183,768	\$ 183,768
35	- \$/MWh	\$ 63.95	\$ 63.04	\$ 62.39	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29
36																					
37	Landfill Gas / Biomass																				
38	- GWh	166	165	165	165	166	165	165	165	166	165	165	165	165	165	165	165	165	165	165	165
39	- \$1,000	\$ 16,395	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,395	\$ 16,350	\$ 16,350	\$ 16,341	\$ 16,392	\$ 16,345	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,350
40	- \$/MWh	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02
41																					
42	Solar																				
43	- GWh	2,124	2,693	3,179	3,211	3,216	3,210	3,210	3,205	3,214	3,207	3,211	3,211	3,211	3,211	3,211	3,211	3,211	3,211	3,211	3,211
44	- \$1,000	\$ 142,098	\$ 186,958	\$ 225,578	\$ 231,145	\$ 234,490	\$ 236,814	\$ 237,981	\$ 238,173	\$ 239,079	\$ 238,875	\$ 239,387	\$ 239,387	\$ 239,387	\$ 239,387	\$ 239,387	\$ 239,387	\$ 239,387	\$ 239,387	\$ 239,387	\$ 239,387
45	- \$/MWh	\$ 66.89	\$ 69.43	\$ 70.96	\$ 71.99	\$ 72.92	\$ 73.76	\$ 74.13	\$ 74.31	\$ 74.39	\$ 74.48	\$ 74.56	\$ 74.56	\$ 74.56	\$ 74.56	\$ 74.56	\$ 74.56	\$ 74.56	\$ 74.56	\$ 74.56	\$ 74.56
46																					
47	TOTAL RENEWABLE ENERGY PURCHASES																				
48	- GWh	14,682	17,600	20,949	23,860	26,837	29,067	31,256	33,509	36,460	36,865	36,931	36,931	36,931	36,931	36,931	36,931	36,931	36,931	36,931	36,931
49	- \$1,000	\$ 1,056,860	\$ 1,264,932	\$ 1,525,239	\$ 1,735,082	\$ 1,963,740	\$ 2,107,104	\$ 2,238,286	\$ 2,373,262	\$ 2,561,485	\$ 2,593,928	\$ 2,610,064	\$ 2,610,064	\$ 2,610,064	\$ 2,610,064	\$ 2,610,064	\$ 2,610,064	\$ 2,610,064	\$ 2,610,064	\$ 2,610,064	\$ 2,610,064
50	- \$/MWh	\$ 71.98	\$ 71.87	\$ 72.81	\$ 72.72	\$ 73.17	\$ 72.49	\$ 71.61	\$ 70.82	\$ 70.25	\$ 70.36	\$ 70.67	\$ 70.67	\$ 70.67	\$ 70.67	\$ 70.67	\$ 70.67	\$ 70.67	\$ 70.67	\$ 70.67	\$ 70.67
51																					
52	OTHER																				
53																					
54	Capacity ¹																				
55	- \$1,000	\$ (2,414)	\$ (994)	\$ 57,308	\$ 15,017	\$ 27,525	\$ 26,141	\$ 63,007	\$ 33,736	\$ (81,982)	\$ (90,741)	\$ (39,342)	\$ (39,342)	\$ (39,342)	\$ (39,342)	\$ (39,342)	\$ (39,342)	\$ (39,342)	\$ (39,342)	\$ (39,342)	\$ (39,342)
56																					
57	Demand Response Customer Capacity Expenses - \$1,000	\$ 14,935	\$ 17,132	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829
58																					
59	ESR Tolling Agreements																				
60	- MW	435	435	435	435	435	435	435	435	435	435	435	435	435	435	435	435	435	435	435	435
61	- \$1,000	\$ 6,743	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910
62	- \$/kW-mnth	\$ 1.29	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50
63																					
64	PURPA/PA2																				
65	- GWh	307	307	307	307	307	307	307	306	307	306	307	307	307	307	307	307	307	307	307	307
66	- \$1,000	\$ 21,346	\$ 21,713	\$ 22,147	\$ 22,590	\$															

Michigan Public Service Commission
DTE Electric Company
Projected Fuel, Purchases and Sales of Power, and PSCR Expense - Customer Datacenter Case
Years 2028 - 2047

Case No.: U-22058
Exhibit: A-9
Witness: S. D. Burgdorf
Page: 1 of 1

Line No.	(a) Description	(b) 2028	(c) 2029	(d) 2030	(e) 2031	(f) 2032	(g) 2033	(h) 2034	(i) 2035	(j) 2036	(k) 2037	(l) 2038	(m) 2039	(n) 2040	(o) 2041	(p) 2042	(q) 2043	(r) 2044	(s) 2045	(t) 2046	(u) 2047
1	Generation & Fuel																				
2	- GWh	38,009	29,865	27,622	28,499	27,015	31,376	27,266	28,884	26,894	27,422	25,207	25,207	25,207	25,207	25,207	25,207	25,207	25,207	25,207	25,207
3	- \$1,000	\$ 950,968	\$ 817,138	\$ 849,803	\$ 852,441	\$ 819,461	\$ 907,947	\$ 796,080	\$ 844,752	\$ 805,735	\$ 810,182	\$ 789,484	\$ 789,484	\$ 789,484	\$ 789,484	\$ 789,484	\$ 789,484	\$ 789,484	\$ 789,484	\$ 789,484	\$ 789,484
4																					
5	Ludington+Battery Losses																				
6	- GWh	(701)	(1,020)	(1,135)	(1,254)	(1,246)	(1,227)	(1,184)	(1,295)	(1,667)	(1,713)	(1,664)	(1,664)	(1,664)	(1,664)	(1,664)	(1,664)	(1,664)	(1,664)	(1,664)	(1,664)
7																					
8	Net Wholesale Power Purchases/Sales																				
9	- GWh	18,941	32,973	35,541	34,859	36,563	32,209	36,463	35,152	37,874	37,483	40,077	40,077	40,077	40,077	40,077	40,077	40,077	40,077	40,077	40,077
10	- \$1,000	\$ 1,307,983	\$ 2,193,765	\$ 2,415,029	\$ 2,364,974	\$ 2,516,458	\$ 2,301,908	\$ 2,572,721	\$ 2,434,788	\$ 2,446,318	\$ 2,505,289	\$ 2,718,578	\$ 2,718,578	\$ 2,718,578	\$ 2,718,578	\$ 2,718,578	\$ 2,718,578	\$ 2,718,578	\$ 2,718,578	\$ 2,718,578	\$ 2,718,578
11																					
12	Emission Allowances																				
13	NOx Seasonal - \$1,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
14	NOx Annual - \$1,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
15	SO2 (CSAPR) - \$1,000	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
16	SO2 (ARP) - \$1,000	\$ 0	\$ 0	\$ 0	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
17																					
18	Chemical Costs																				
19	Urea - \$1,000	\$ 21,058	\$ 10,561	\$ 10,266	\$ 10,944	\$ 11,139	\$ 11,569	\$ 9,067	\$ 11,006	\$ 11,227	\$ 11,372	\$ 9,487	\$ 9,487	\$ 9,487	\$ 9,487	\$ 9,487	\$ 9,487	\$ 9,487	\$ 9,487	\$ 9,487	\$ 9,487
20	Limestone - \$1,000	\$ 9,449	\$ 4,739	\$ 4,607	\$ 4,911	\$ 4,998	\$ 5,191	\$ 4,069	\$ 4,939	\$ 5,038	\$ 5,103	\$ 4,257	\$ 4,257	\$ 4,257	\$ 4,257	\$ 4,257	\$ 4,257	\$ 4,257	\$ 4,257	\$ 4,257	\$ 4,257
21	Ammonia - \$1,000	\$ 1,648	\$ 1,705	\$ 1,447	\$ 1,561	\$ 1,637	\$ 2,496	\$ 2,453	\$ 2,338	\$ 2,327	\$ 2,200	\$ 2,362	\$ 2,362	\$ 2,362	\$ 2,362	\$ 2,362	\$ 2,362	\$ 2,362	\$ 2,362	\$ 2,362	\$ 2,362
22	Potassium Iodide - \$1,000	\$ 916	\$ 459	\$ 447	\$ 476	\$ 485	\$ 503	\$ 394	\$ 479	\$ 488	\$ 495	\$ 413	\$ 413	\$ 413	\$ 413	\$ 413	\$ 413	\$ 413	\$ 413	\$ 413	\$ 413
23																					
24	Net System Output																				
25	- GWh	56,249	61,819	62,029	62,105	62,334	62,358	62,546	62,741	63,101	63,192	63,619	63,619	63,619	63,619	63,619	63,619	63,619	63,619	63,619	63,619
26	- \$1,000	\$ 2,292,022	\$ 3,028,366	\$ 3,281,599	\$ 3,235,307	\$ 3,354,177	\$ 3,229,614	\$ 3,384,784	\$ 3,298,300	\$ 3,271,133	\$ 3,334,641	\$ 3,524,580	\$ 3,524,580	\$ 3,524,580	\$ 3,524,580	\$ 3,524,580	\$ 3,524,580	\$ 3,524,580	\$ 3,524,580	\$ 3,524,580	\$ 3,524,580
27	- \$/MWh	\$ 40.75	\$ 48.99	\$ 52.90	\$ 52.09	\$ 53.81	\$ 51.79	\$ 54.12	\$ 52.57	\$ 51.84	\$ 52.77	\$ 55.40	\$ 55.40	\$ 55.40	\$ 55.40	\$ 55.40	\$ 55.40	\$ 55.40	\$ 55.40	\$ 55.40	\$ 55.40
28																					
29	Bundled Transmission																				
30	- \$1,000	\$ 712,780	\$ 889,001	\$ 1,017,101	\$ 1,078,821	\$ 1,168,845	\$ 1,285,817	\$ 1,444,089	\$ 1,616,099	\$ 1,637,586	\$ 1,655,358	\$ 1,678,441	\$ 1,702,236	\$ 1,727,379	\$ 1,748,509	\$ 1,771,745	\$ 1,782,200	\$ 1,794,604	\$ 1,768,566	\$ 1,780,868	\$ 1,785,691
31																					
32	Non-PSCR Customer Sales Adjustment																				
33	- GWh	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919
34	- \$1,000	\$ 45,917	\$ 45,927	\$ 47,084	\$ 48,769	\$ 48,712	\$ 47,559	\$ 45,401	\$ 45,569	\$ 44,359	\$ 44,661	\$ 45,738	\$ 45,738	\$ 45,738	\$ 45,738	\$ 45,738	\$ 45,738	\$ 45,738	\$ 45,738	\$ 45,738	\$ 45,738
35																					
36	Transmission Adjustment																				
37	- GWh	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919	919
38	- \$1,000	\$ 11,642	\$ 13,211	\$ 15,064	\$ 15,959	\$ 17,227	\$ 18,943	\$ 21,211	\$ 23,664	\$ 23,842	\$ 24,066	\$ 24,238	\$ 24,581	\$ 24,944	\$ 25,249	\$ 25,585	\$ 25,736	\$ 25,915	\$ 25,539	\$ 25,717	\$ 25,786
39																					
40	PSCR Fuel & Purchased Power																				
41	- GWh	55,330	60,900	61,110	61,186	61,415	61,440	61,627	61,822	62,182	62,273	62,700	62,700	62,700	62,700	62,700	62,700	62,700	62,700	62,700	62,700
42	- \$1,000	\$ 2,947,244	\$ 3,858,228	\$ 4,236,551	\$ 4,249,401	\$ 4,457,083	\$ 4,448,928	\$ 4,762,261	\$ 4,845,166	\$ 4,840,518	\$ 4,921,273	\$ 5,133,045	\$ 5,156,497	\$ 5,181,276	\$ 5,202,102	\$ 5,225,002	\$ 5,235,306	\$ 5,247,530	\$ 5,221,869	\$ 5,233,993	\$ 5,238,747
43	- \$/MWh	\$ 53.27	\$ 63.35	\$ 69.33	\$ 69.45	\$ 72.57	\$ 72.41	\$ 77.28	\$ 78.37	\$ 77.84	\$ 79.03	\$ 81.87	\$ 82.24	\$ 82.64	\$ 82.97	\$ 83.33	\$ 83.50	\$ 83.69	\$ 83.28	\$ 83.48	\$ 83.55

Line No.	(a) Description	(b) 2028	(c) 2029	(d) 2030	(e) 2031	(f) 2032	(g) 2033	(h) 2034	(i) 2035	(j) 2036	(k) 2037	(l) 2038	(m) 2039	(n) 2040	(o) 2041	(p) 2042	(q) 2043	(r) 2044	(s) 2045	(t) 2046	(u) 2047
1	MISO WHOLESALE PURCHASES & SALES																				
2	MISO Wholesale Purchases																				
3	- GWh	6,677	15,939	14,750	11,314	9,918	5,728	7,215	5,383	6,153	5,516	6,856	6,856	6,856	6,856	6,856	6,856	6,856	6,856	6,856	
4	- \$1,000	\$ 251,198	\$ 658,210	\$ 589,868	\$ 462,815	\$ 406,608	\$ 242,529	\$ 319,214	\$ 223,477	\$ 191,612	\$ 195,236	\$ 262,756	\$ 262,756	\$ 262,756	\$ 262,756	\$ 262,756	\$ 262,756	\$ 262,756	\$ 262,756	\$ 262,756	
5	- \$/MWh	\$ 37.62	\$ 41.29	\$ 39.99	\$ 40.91	\$ 41.00	\$ 42.34	\$ 44.24	\$ 41.51	\$ 31.14	\$ 35.39	\$ 38.32	\$ 38.32	\$ 38.32	\$ 38.32	\$ 38.32	\$ 38.32	\$ 38.32	\$ 38.32	\$ 38.32	
6																					
7	MISO Wholesale Sales																				
8	- GWh	2,726	873	1,343	2,857	3,624	5,727	4,939	6,758	7,688	7,849	6,670	6,670	6,670	6,670	6,670	6,670	6,670	6,670	6,670	
9	- \$1,000	\$ 153,768	\$ 57,824	\$ 101,435	\$ 179,169	\$ 211,542	\$ 282,375	\$ 216,233	\$ 307,345	\$ 405,582	\$ 398,206	\$ 350,126	\$ 350,126	\$ 350,126	\$ 350,126	\$ 350,126	\$ 350,126	\$ 350,126	\$ 350,126	\$ 350,126	
10	- \$/MWh	\$ 56.42	\$ 66.25	\$ 75.54	\$ 62.71	\$ 58.37	\$ 49.31	\$ 43.78	\$ 45.48	\$ 52.76	\$ 50.73	\$ 52.50	\$ 52.50	\$ 52.50	\$ 52.50	\$ 52.50	\$ 52.50	\$ 52.50	\$ 52.50	\$ 52.50	
11																					
12	MISO Market Expenses (excluding Sch 16 & 17) - \$1,000	\$ 78,735	\$ 67,630	\$ 63,624	\$ 65,632	\$ 64,636	\$ 65,138	\$ 64,892	\$ 65,023	\$ 64,971	\$ 65,005	\$ 65,001	\$ 65,001	\$ 65,001	\$ 65,001	\$ 65,001	\$ 65,001	\$ 65,001	\$ 65,001	\$ 65,001	
13																					
14	NET MISO PURCHASES & SALES																				
15	- GWh	3,951	15,067	13,407	8,456	6,294	2	2,275	(1,375)	(1,535)	(2,333)	187	187	187	187	187	187	187	187	187	
16	- \$1,000	\$ 176,165	\$ 668,016	\$ 552,058	\$ 349,278	\$ 259,702	\$ 25,292	\$ 167,873	\$ (18,844)	\$ (148,999)	\$ (137,965)	\$ (22,370)	\$ (22,370)	\$ (22,370)	\$ (22,370)	\$ (22,370)	\$ (22,370)	\$ (22,370)	\$ (22,370)	\$ (22,370)	
17	- \$/MWh	\$ 44.59	\$ 44.34	\$ 41.18	\$ 41.30	\$ 41.26	\$ 15,295.43	\$ 73.78	\$ 13.71	\$ 97.08	\$ 59.13	\$ (119.77)	\$ (119.77)	\$ (119.77)	\$ (119.77)	\$ (119.77)	\$ (119.77)	\$ (119.77)	\$ (119.77)	\$ (119.77)	
18																					
19	P.A. 295 RENEWABLE PURCHASES																				
20	Renewable Energy Build																				
21	Wind																				
22	- GWh	3,957	3,943	3,943	4,377	4,931	5,454	5,992	8,267	10,991	11,478	11,481	11,481	11,481	11,481	11,481	11,481	11,481	11,481	11,481	
23	- \$1,000	\$ 338,079	\$ 345,520	\$ 353,434	\$ 385,508	\$ 425,443	\$ 463,266	\$ 503,244	\$ 643,301	\$ 812,408	\$ 850,132	\$ 860,463	\$ 860,463	\$ 860,463	\$ 860,463	\$ 860,463	\$ 860,463	\$ 860,463	\$ 860,463	\$ 860,463	
24	- \$/MWh	\$ 85.44	\$ 87.63	\$ 89.64	\$ 88.07	\$ 86.27	\$ 84.94	\$ 83.98	\$ 77.82	\$ 73.92	\$ 74.07	\$ 74.95	\$ 74.95	\$ 74.95	\$ 74.95	\$ 74.95	\$ 74.95	\$ 74.95	\$ 74.95	\$ 74.95	
25																					
26	Solar																				
27	- GWh	6,664	8,492	11,694	15,392	18,688	20,121	21,563	21,628	21,769	21,708	21,777	21,777	21,777	21,777	21,777	21,777	21,777	21,777	21,777	
28	- \$1,000	\$ 447,031	\$ 570,624	\$ 752,313	\$ 918,309	\$ 1,102,962	\$ 1,185,963	\$ 1,265,281	\$ 1,270,009	\$ 1,277,579	\$ 1,274,637	\$ 1,278,518	\$ 1,278,518	\$ 1,278,518	\$ 1,278,518	\$ 1,278,518	\$ 1,278,518	\$ 1,278,518	\$ 1,278,518	\$ 1,278,518	
29	- \$/MWh	\$ 67.08	\$ 67.20	\$ 64.34	\$ 59.66	\$ 59.02	\$ 58.94	\$ 58.68	\$ 58.72	\$ 58.69	\$ 58.72	\$ 58.71	\$ 58.71	\$ 58.71	\$ 58.71	\$ 58.71	\$ 58.71	\$ 58.71	\$ 58.71	\$ 58.71	\$ 58.71
30																					
31	Renewable Energy PPA																				
32	Wind																				
33	- GWh	1,771	2,308	2,846	2,950	2,961	2,950	2,950	2,950	2,961	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	2,950	
34	- \$1,000	\$ 113,257	\$ 145,480	\$ 177,565	\$ 183,770	\$ 184,442	\$ 183,770	\$ 183,770	\$ 183,770	\$ 184,434	\$ 183,727	\$ 183,770	\$ 183,770	\$ 183,770	\$ 183,770	\$ 183,770	\$ 183,770	\$ 183,770	\$ 183,770	\$ 183,770	
35	- \$/MWh	\$ 63.95	\$ 63.04	\$ 62.39	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29	\$ 62.29
36																					
37	Landfill Gas / Biomass																				
38	- GWh	166	165	165	165	166	165	165	165	166	165	165	165	165	165	165	165	165	165	165	
39	- \$1,000	\$ 16,395	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,395	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,394	\$ 16,347	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,350	\$ 16,350	
40	- \$/MWh	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02	\$ 99.02
41																					
42	Solar																				
43	- GWh	2,124	2,693	3,179	3,211	3,216	3,211	3,211	3,211	3,215	3,209	3,211	3,211	3,211	3,211	3,211	3,211	3,211	3,211	3,211	
44	- \$1,000	\$ 142,098	\$ 186,958	\$ 225,578	\$ 231,145	\$ 234,490	\$ 236,827	\$ 238,005	\$ 238,568	\$ 239,186	\$ 239,000	\$ 239,395	\$ 239,395	\$ 239,395	\$ 239,395	\$ 239,395	\$ 239,395	\$ 239,395	\$ 239,395	\$ 239,395	
45	- \$/MWh	\$ 66.89	\$ 69.43	\$ 70.96	\$ 71.99	\$ 72.92	\$ 73.76	\$ 74.13	\$ 74.31	\$ 74.39	\$ 74.48	\$ 74.56	\$ 74.56	\$ 74.56	\$ 74.56	\$ 74.56	\$ 74.56	\$ 74.56	\$ 74.56	\$ 74.56	\$ 74.56
46																					
47	TOTAL RENEWABLE ENERGY PURCHASES																				
48	- GWh	14,682	17,600	21,827	26,096	29,961	31,901	33,861	36,221	39,101	39,510	39,583	39,583	39,583	39,583	39,583	39,583	39,583	39,583	39,583	
49	- \$1,000	\$ 1,056,860	\$ 1,264,932	\$ 1,525,239	\$ 1,735,082	\$ 1,963,732	\$ 2,086,176	\$ 2,206,650	\$ 2,351,998	\$ 2,530,001	\$ 2,563,844	\$ 2,578,496	\$ 2,578,496	\$ 2,578,496	\$ 2,578,496	\$ 2,578,496	\$ 2,578,496	\$ 2,578,496	\$ 2,578,496	\$ 2,578,496	
50	- \$/MWh	\$ 71.98	\$ 71.87	\$ 69.88	\$ 66.49	\$ 65.54	\$ 65.39	\$ 65.13	\$ 64.93	\$ 64.70	\$ 64.89	\$ 65.14	\$ 65.14	\$ 65.14	\$ 65.14	\$ 65.14	\$ 65.14	\$ 65.14	\$ 65.14	\$ 65.14	\$ 65.14
51																					
52	OTHER																				
53																					
54	Capacity ¹																				
55	- \$1,000	\$ 3,537	\$ (1,817)	\$ 52,448	\$ 9,779	\$ 21,826	\$ 10,874	\$ 63,679	\$ 32,772	\$ (43,305)	\$ (46,835)	\$ 4,465	\$ 4,465	\$ 4,465	\$ 4,465	\$ 4,465	\$ 4,465	\$ 4,465	\$ 4,465	\$ 4,465	
56																					
57	Demand Response Customer Capacity Expenses - \$1,000	\$ 14,935	\$ 17,132	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	\$ 16,829	
58																					
59	ESR Tolling Agreements																				
60	- MW	435	435	435	435	435	435	435	435	435	435	435	435	435	435	435	435	435	435	435	
61	- \$1,000	\$ 6,743	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	\$ 80,910	
62	- \$/kW-mnth	\$ 1.29	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	\$ 15.50	
63																					
64	PURPA/PA2																				
65	- GWh	307	307	307	307	307	307	307	307	307	306	307	307	307	307	307	307	307	307	307	
66	- \$1,000	\$ 21,346	\$ 21,713	\$ 22,147	\$ 22,590	\$ 23,105	\$ 23,503	\$ 23,973	\$ 24,452	\$ 25,009	\$ 25,437	\$ 25,949	\$ 25,949	\$ 25,949	\$ 25,949	\$ 25,949	\$ 25,949	\$ 25,949	\$ 25,949	\$ 25,949	
67	- \$/MWh	\$ 69.45	\$ 70.83	\$ 72.25	\$ 73.70	\$ 75.17	\$ 76.67	\$ 78.21	\$ 79.77	\$ 81.37	\$ 8										

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	
			2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	Source:	
1	Power Supply Costs (adjusted for R10, DB in buy through & third party sales)	\$000s	\$2,787,939	\$3,273,380	\$3,631,363	\$3,680,518	\$3,903,252	\$4,068,958	\$4,357,424	\$4,416,063	\$4,336,208	\$4,395,421	\$4,602,422	\$4,627,856	\$4,654,769	\$4,678,038	\$4,703,100	\$4,714,070	\$4,726,804	\$4,707,379	\$4,719,553	\$4,726,943	Exh- A-7 line 43	
2	Net System Requirement (adjusted for R10, DB in buythrough)	GWh	52,777	52,893	53,103	53,179	53,386	53,433	53,620	53,815	54,153	54,267	54,693	54,693	54,693	54,693	54,693	54,693	54,693	54,693	54,693	54,693	54,693	Exh- A-7 line 42
3	Unit Cost of Power Supply	Mills/kWh	52.82	61.89	68.38	69.21	73.11	76.15	81.26	82.06	80.07	81.00	84.15	84.61	85.11	85.53	85.99	86.19	86.42	86.07	86.29	86.43	line 3 + line 4	
4	Base Unit Cost	Mills/kWh	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	U-21534: Exh A-13, Sch C4, line 1	
5	Unit Cost Above (Below) Base	Mills/kWh	21.56	30.63	37.12	37.95	41.85	44.89	50.00	50.80	48.81	49.74	52.89	53.35	53.85	54.27	54.73	54.93	55.16	54.81	55.03	55.17	line 5 - line 6	
6	Loss Multiplier		1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	U-21534 A-13, C4.1 line 6	
7	Final PSCR Factor	Mills/kWh	23.22	32.98	39.98	40.87	45.07	48.34	53.85	54.71	52.57	53.56	56.96	57.46	57.99	58.45	58.94	59.16	59.41	59.02	59.26	59.41	line 7 * line 8	

Line No.	(a) Description	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)	
			2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	Source:	
1	Power Supply Costs (adjusted for R10, DB in buy through & third party sales)		\$2,947,244	\$3,858,228	\$4,236,551	\$4,249,401	\$4,457,083	\$4,448,928	\$4,762,261	\$4,845,166	\$4,840,518	\$4,921,273	\$5,133,045	\$5,156,497	\$5,181,276	\$5,202,102	\$5,225,002	\$5,235,306	\$5,247,530	\$5,221,869	\$5,233,993	\$5,238,747	Exh- A-9 line 43	
2	Net System Requirement (adjusted for R10, DB in buythrough)	GWh	55,330	60,900	61,110	61,186	61,415	61,440	61,627	61,822	62,182	62,273	62,700	62,700	62,700	62,700	62,700	62,700	62,700	62,700	62,700	62,700	62,700	Exh- A-9 line 42
3	Unit Cost of Power Supply	Mills/kWh	53.27	63.35	69.33	69.45	72.57	72.41	77.28	78.37	77.84	79.03	81.87	82.24	82.64	82.97	83.33	83.50	83.69	83.28	83.48	83.55	line 3 + line 4	
4	Base Unit Cost	Mills/kWh	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	31.26	U-21534: Exh A-13, Sch C4, line 1	
5	Unit Cost Above (Below) Base	Mills/kWh	22.01	32.09	38.07	38.19	41.31	41.15	46.02	47.11	46.58	47.77	50.61	50.98	51.38	51.71	52.07	52.24	52.43	52.02	52.22	52.29	line 5 - line 6	
6	Loss Multiplier		1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	1.077	U-21534 A-13, C4.1 line 6	
7	Final PSCR Factor	Mills/kWh	23.70	34.56	40.99	41.13	44.49	44.32	49.55	50.74	50.17	51.44	54.50	54.90	55.33	55.68	56.08	56.25	56.46	56.02	56.23	56.31	line 7 * line 8	

Line No.	(a) Description	(b)	(c) 2028	(d) 2029	(e) 2030	(f) 2031	(g) 2032	(h) 2033	(i) 2034	(j) 2035	(k) 2036	(l) 2037	(m) 2038	(n) 2039	(o) 2040	(p) 2041	(q) 2042	(r) 2043	(s) 2044	(t) 2045	(u) 2046	(v) 2047	(w) Source:	
1	Power Supply Costs (adjusted for R10, D8 in buy through & third party sales)		\$ 159,305	\$ 584,849	\$ 605,189	\$ 568,883	\$ 553,831	\$ 379,971	\$ 404,837	\$ 429,104	\$ 504,310	\$ 525,852	\$ 530,623	\$ 528,640	\$ 526,507	\$ 524,064	\$ 521,901	\$ 521,236	\$ 520,727	\$ 514,489	\$ 514,440	\$ 511,804	Exh A-11 line 1 minus Exh A-12 line 1	
2	Net System Requirement (adjusted for R10, D8 in buythrough)	GWh	2,553	8,007	8,007	8,007	8,029	8,007	8,007	8,007	8,029	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007	8,007	Exh A-11 line 2 minus Exh A-12 line 2
3	Unit Cost of Power Supply	Mills/kWh	0.44	1.47	0.94	0.24	(0.54)	(3.74)	(3.99)	(3.69)	(2.23)	(1.97)	(2.28)	(2.37)	(2.47)	(2.56)	(2.66)	(2.69)	(2.73)	(2.79)	(2.81)	(2.87)	Exh A-11 line 3 minus Exh A-12 line 3	
4	Base Unit Cost	Mills/kWh	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	Exh A-11 line 4 minus Exh A-12 line 4	
5	Unit Cost Above (Below) Base	Mills/kWh	0.44	1.47	0.94	0.24	(0.54)	(3.74)	(3.99)	(3.69)	(2.23)	(1.97)	(2.28)	(2.37)	(2.47)	(2.56)	(2.66)	(2.69)	(2.73)	(2.79)	(2.81)	(2.87)	Exh A-11 line 5 minus Exh A-12 line 5	
6	Loss Multiplier		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Exh A-11 line 6 minus Exh A-12 line 6	
7	Final PSCR Factor	Mills/kWh	0.48	1.58	1.02	0.26	(0.58)	(4.03)	(4.30)	(3.97)	(2.40)	(2.12)	(2.46)	(2.56)	(2.66)	(2.76)	(2.86)	(2.90)	(2.94)	(3.00)	(3.03)	(3.10)	Exh A-11 line 7 minus Exh A-12 line 7	

EXHIBIT A-14

Intentionally Left Blank

Line	(a)	(ac)	(ad)	(ae)	(af)	(ag)	(ah)	(ai)	(aj)	(ak)	(al)	(am)	(an)	(ao)
1						2059	2060	2061						
2					Solar End of Life	500	700	400						
3					% of total	31%	44%	25%						
4					Jan 1 % Remaining	100%	69%	25%						
5														
6														
7														
Proxy CCGT w/CCS														
8 CCGT Revenue Requirement		\$ 172,378	\$ 167,020	\$ 161,851	\$ 156,682	\$ 151,513	\$ 146,344	\$ 141,175	\$ 136,006	\$ 130,837	\$ 125,668	\$ 120,500	\$ 115,331	\$ 110,162
9 CCS Revenue Requirement		\$ 198,930	\$ 195,649	\$ 192,485	\$ 189,321	\$ 186,157	\$ 182,992	\$ 179,828	\$ 176,664	\$ 173,499	\$ 170,335	\$ 167,171	\$ 164,007	\$ 160,842
10 Nominal Cost		\$ 371,308	\$ 362,669	\$ 354,336	\$ 346,003	\$ 337,669	\$ 329,336	\$ 321,003	\$ 312,670	\$ 304,337	\$ 296,004	\$ 287,670	\$ 279,337	\$ 271,004
11 Energy Value		\$ 166,276	\$ 171,265	\$ 176,403	\$ 181,695	\$ 187,146	\$ 192,760	\$ 198,543	\$ 204,499	\$ 210,634	\$ 216,953	\$ 223,462	\$ 230,166	\$ 237,070
12 Capacity Revenue		\$ 67,767	\$ 69,800	\$ 71,894	\$ 74,051	\$ 76,272	\$ 78,560	\$ 80,917	\$ 83,345	\$ 85,845	\$ 88,420	\$ 91,073	\$ 93,805	\$ 96,619
13 Total Wholesale Value CCGT w/CCS		\$ 234,043	\$ 241,065	\$ 248,296	\$ 255,745	\$ 263,418	\$ 271,320	\$ 279,460	\$ 287,844	\$ 296,479	\$ 305,373	\$ 314,535	\$ 323,971	\$ 333,690
Solar														
14 Energy Value		\$ 106,609	\$ 109,807	\$ 113,101	\$ 116,494	\$ 119,989	\$ 84,967	\$ 21,879						
15 Capacity Revenue		\$ 6,116	\$ 6,299	\$ 6,488	\$ 6,683	\$ 6,883	\$ 4,874	\$ 1,255						
16 Total Solar Revenue		\$ 112,724	\$ 116,106	\$ 119,589	\$ 123,177	\$ 126,872	\$ 89,841	\$ 23,134						
576 MW Storage Alternative														
17 Storage Revenue Requirement		\$ 204,063	\$ 203,574	\$ 202,872	\$ 201,945	\$ 200,780	\$ 199,363	\$ 197,680	\$ 195,717	\$ 193,458	\$ 190,887	\$ 187,988	\$ 184,743	\$ 181,135
18 Energy Value		\$ 55,370	\$ 57,032	\$ 58,742	\$ 60,505	\$ 62,320	\$ 64,189	\$ 66,115	\$ 68,099	\$ 70,142	\$ 72,246	\$ 74,413	\$ 76,646	\$ 78,945
19 Capacity Revenue		\$ 70,081	\$ 72,183	\$ 74,349	\$ 76,579	\$ 78,876	\$ 81,243	\$ 83,680	\$ 86,190	\$ 88,776	\$ 91,439	\$ 94,183	\$ 97,008	\$ 99,918
20 Total Wholesale Value Storage		\$ 125,451	\$ 129,215	\$ 133,091	\$ 137,084	\$ 141,196	\$ 145,432	\$ 149,795	\$ 154,289	\$ 158,918	\$ 163,685	\$ 168,596	\$ 173,654	\$ 178,863

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF JUSTIN J. W. BROOKS

Line
No.

1 **Q1. What is your name, business address and by whom are you employed?**

2 A1. My name is Justin Jeffrey Whitaker Brooks. My business address is: 3000
3 Riverchase Galleria, Suite 3 575, Hoover, AL 35244. I am employed by
4 PowerGEM, as a Project Lead. PowerGEM is a software and consulting firm that
5 provides expertise in numerous areas including resource planning and resource
6 adequacy to utilities across the United States.

7

8 **Q2. On whose behalf are you testifying?**

9 A2. I am testifying on behalf of DTE Electric Company (DTE Electric or the Company).
10

11 **Q3. What is your educational background?**

12 A3. I graduated from North Carolina State University with a Bachelor of Science in
13 Nuclear Engineering. In addition, I received a Master of Science from Virginia
14 Commonwealth University in Mechanical and Nuclear Engineering.

15

16 **Q4. What work experience do you have?**

17 A4. In 2012, I joined Newport News Shipbuilding where I performed various duties
18 across numerous naval platforms related to radiation shielding and the safe
19 engineering and conduct of radiological work. In 2017, I joined the Naval Nuclear
20 Laboratory where I performed various duties related to the engineering of safety
21 systems in support of the Naval Nuclear Propulsion Program. In 2019, I joined
22 Duke Energy where I developed and led the in-house resource adequacy analysis
23 program for all three company jurisdictions using PowerGEM's Strategic Energy
24 and Risk Valuation Model (SERVM). In this role, I conducted analysis in support

Line
No.

1 of the 2021, 2022, and 2023 Duke Energy Carolinas and Duke Energy Progress
2 Integrated Resource Plans for North and South Carolina.

3

4 **Q5. Do you hold any certifications or are you a member of any professional**
5 **organizations?**

6 A5. I am a registered professional engineer in North Carolina.

7

8 **Q6. What are your current duties and responsibilities?**

9 A6. As a Project Lead with PowerGEM, I am responsible for managing the SERVUM
10 product and both managing and conducting resource adequacy studies for utility
11 clients.

12

13 **Q7. Have you previously sponsored testimony before the Michigan Public Service**
14 **Commission (MPSC)?**

15 A7. No. I have not appeared before the MPSC.

16

17 **Q8. Please provide a summary of your and your firm's expertise in performing**
18 **this type of analysis.**

19 A8. I have performed and supervised resource adequacy and capacity accreditation
20 studies for various clients over the past six years both with Duke Energy and
21 PowerGEM. In addition, I have been involved with various industry task groups
22 such as the Electric Power Research Institute's "Resource Adequacy for a
23 Decarbonized Future" project, Energy Systems Integration Group's "Redefining
24 Resource Adequacy" taskforce, the SERC Reliability Corporation's Resource
25 Adequacy Working Group, and the North American Electric Reliability

Line
No.

1 Corporation Probabilistic Assessment Working Group. PowerGEM¹ has
2 performed resource adequacy and capacity accreditation analysis for various
3 entities across the country for over 20 years. A non-exhaustive list includes utilities
4 such as the Company, Ameren, Associated Electric Cooperative, Central Louisiana
5 Electric Co-Op, Dominion Energy South Carolina, Duke Energy Carolinas, Duke
6 Energy Progress, Entergy, Georgia System Operations Corporation, Louisville Gas
7 & Electric, Santee Cooper, Southern Company, and the Tennessee Valley
8 Authority. Some of the Independent System Operator and Regional Transmission
9 Organizations include Alberta Electric System Operator (AESO), Electric
10 Reliability Council of Texas (ERCOT), Midwest Independent System Operator
11 (MISO), and the Southwest Power Pool (SPP).

¹ PowerGEM acquired Astrapé Consulting in 2024

Line
No.

1 **Purpose of Testimony**

2 **Q9. What is the purpose of your testimony?**

3 A9. The purpose of my testimony is to explain the results of the resource adequacy
4 analysis performed at the Company’s request in years 2029 and 2033 to support the
5 addition of the Customer’s (Google LLC) load to the DTE Electric system.

6

7 **Q10. Are you sponsoring any exhibits in this proceeding?**

8 A10. Yes. I am sponsoring the following exhibits:

9	<u>Exhibit</u>	<u>Description</u>
10	A-3	Justin Brooks Curriculum Vitale
11	A-4	DTE Electric Resource Adequacy Analysis

12

13 **Q11. Were these exhibits prepared by you or under your direction?**

14 A11. Yes, they were.

15

16 **Resource Adequacy Analysis**

17 **Q12. What is resource adequacy?**

18 A12. Resource adequacy is the ability of the electric system to meet the energy needs of
19 electricity consumers. This means having sufficient resources to meet projected
20 electric demand².

21

22 **Q13. How does MISO ensure resource adequacy requirements?**

23 A13. MISO, under its Federal Energy Regulatory Commission (FERC) approved tariff,
24 has resource adequacy requirements to ensure adequate resources are available to

² <https://www.ferc.gov/reliability-explainer>

Line
No.

1 meet demand. Load Serving Entities must comply with the MISO resource
2 adequacy requirements.

3

4 **Q14. How does the Company demonstrate resource adequacy per the MISO tariff?**

5 A14. MISO establishes a Planning Reserve Margin (PRM), which is defined as the
6 amount of capacity above the expected weather-normalized peak demand necessary
7 to meet the electric industry's commonly used criteria of potentially experiencing
8 a single day containing at least one hour with firm load shed every ten years. The
9 PRM is added to the Company's coincident peak demand to calculate its Planning
10 Reserve Margin Requirements (PRMR). The Company demonstrates resource
11 adequacy by ensuring it has adequate resources to meet or exceed the PRMR.

12

13 **Q15. How will the Customer's load impact the Company's PRMR?**

14 A15. The Customer's load will increase the Company's PRMR. As the Customer's load
15 increases to the max load of approximately 1 GW, the Company's coincident peak
16 demand and PRMR will also increase.

17

18 **Q16. How will the Company meet the increased PRMR?**

19 A16. The Company will meet the increased PRMR through the deployment of zonal
20 resource credits (ZRC), renewable resources and energy storage under the Clean
21 Capacity Accelerator Agreement (CCAA), as well as demand response as
22 described by Witness Burgdorf. Adding additional capacity resources ensures
23 that the Company will have sufficient capacity to meet MISO's resource
24 adequacy requirements.

Line
No.

1 **Q17. How does the resource adequacy study you performed differ from how the**
2 **PRMR is determined?**

3 A17. The resource adequacy study that I performed is designed to evaluate whether the
4 output of the complex capacity expansion modeling process meets the specified
5 level of resource adequacy. To do this, I evaluated the DTE Electric system using
6 PowerGEM's SERVUM.

7
8 **Q18. What metric is used to evaluate whether a resource portfolio is resource**
9 **adequate?**

10 A18. The standard metric used to evaluate resource adequacy of a resource portfolio is
11 Loss of Load Expectation (LOLE).

12

13 **Q19. What is LOLE?**

14 A19. LOLE is the expected number of days in a year when the utility will not have
15 enough energy from its resources to meet load and will have a firm load shed event.
16 It is the most commonly used resource adequacy criteria in the United States. The
17 Company's threshold for LOLE is specified by MISO Tariff Module E-1³ to be one
18 day with one or more hours of firm load shed every ten years due to a shortage of
19 generation capacity. This is more commonly referred to as either 0.1 LOLE or "one
20 day in ten".

21

22 **Q20. Can you describe the differences between capacity expansion modeling and**
23 **resource adequacy modeling?**

³ https://docs.misoenergy.org/miso12-legalcontent/Module_E-1_-_Resource_Adequacy.pdf

Line
No.

1 A20. Capacity expansion modeling and resource adequacy modeling serve different but
2 complementary purposes in long-term planning. Capacity expansion modeling is a
3 deterministic analysis that identifies least-cost portfolios to meet a utility's
4 forecasted peak demand plus the required PRM over long term time horizons.
5 Capacity expansion modeling typically assumes normal weather conditions,
6 expected load growth and average generator performance. Because it is designed
7 to optimize under normal conditions, capacity expansion modeling does not capture
8 operational risks that occur in high impact, low probability events.

9
10 Resource adequacy modeling, on the other hand, is a probabilistic type of analysis.
11 Using the SERVVM tool, it stochastically stress tests the proposed resource
12 portfolios from the capacity expansion model in future study years to ensure that
13 the portfolios will meet the resource adequacy criteria, which in this analysis is 0.1
14 LOLE. SERVVM generates a large distribution of future scenarios to ensure a
15 representative sample from which to assess whether the DTE Electric system is
16 adequate. This type of modeling incorporates variations and risks such as:

- 17 (1) Extreme weather and its impact on both load and resources
- 18 (2) Economic load forecast uncertainty
- 19 (3) Generator performance uncertainty

20

21 Additionally, resource adequacy modeling is highly data and computing intensive,
22 running it every year throughout a long study horizon would be time-consuming and
23 provide limited incremental value. The best practice is to focus on key years defined
24 by major changes in the load and/or generation fleet.

Line
No.

1 **Q21. Can you describe the SERVM Model used in the resource adequacy analysis?**

2 A21. Yes. SERVM is a production cost model designed to analyze the capabilities of an
3 electric system during a variety of conditions over thousands of scenarios. It
4 chronologically simulates the economic commitment and dispatch of a system
5 calculating economic and reliability metrics for each scenario.

6

7 **Q22. Can you describe the framework for the resource adequacy analysis you**
8 **performed?**

9 A22. Yes. The Company requested evaluation of two key study years 2029 and 2033, as
10 described by Witness Burgdorf. As part of the evaluation, MISO Local Resource
11 Zones (LRZs) 1, 2, 3, 4, 5, 6, and the non-Company portion of LRZ7 were included
12 in the analysis in addition to the DTE Electric system. For this analysis, I evaluated
13 the DTE Electric system against weather from 1980 through 2023, five levels of
14 economic load forecast uncertainty (-4%, -2%, 0%, 2%, and 4%), and fifty
15 stochastic evaluations of generator performance. All told, 11,000 yearly scenarios,
16 at an hourly resolution, were evaluated for each portfolio, for each study year. The
17 resulting probabilistic weighted average, or expected value, is the “final” result of
18 the analysis.

19

20 **Q23. What is the result of the 2029 resource adequacy analysis?**

21 A23. As shown in Exhibit A-4, assuming the resources included in the CCAA as well as
22 demand response in 2029 as discussed by Witness Burgdorf, the plan is resource
23 adequate with a LOLE of 0.102 event-day per year.

24

25 **Q24. What was your approach for modeling resources in 2033?**

Line
No.

1 A24. I evaluated the DTE Electric system as provided by the Company with the DR and
2 ZRCs expiring by June 1, 2033.

3

4 **Q25. What is the result of the 2033 resource adequacy analysis?**

5 A25. This produced a LOLE for the Company of 0.238 event-day per year which does
6 not meet the 0.1 threshold (Exhibit A-4). To address this deficit, perfect capacity
7 was added until the system reached 0.1 event-day per year LOLE.

8

9 **Q26. What is the definition of “perfect capacity” and what did the SERV
10 modeling identify as the perfect capacity need?**

11 A26. Perfect capacity (sometimes referred to as PCAP) is defined as capacity with no
12 outages. Perfect capacity helps planners compare very different technologies on a
13 common basis, determine how much new capacity is needed to maintain resource
14 adequacy (such as 0.1 LOLE), and understand how resource mixes affect the
15 probability of outages. The modeling identified a need of 677 MW of perfect
16 capacity to bring the DTE Electric system back to 0.1 event-day per year LOLE.

17

18 **Q27. Did the Company revise their proposed plan to account for this inadequacy?**

19 A27. Yes. The Company provided a revised build plan that contained additional capacity
20 as described by Witness Burgdorf. This revised build plan was then evaluated in
21 SERV.

22

23 **Q28. What was the result of the 2033 resource adequacy analysis with the revised
24 build plan?**

Line
No.

1 A28. The Companies revised build plan is resource adequate with a LOLE of 0.093
2 event-day per year (Exhibit A-4).
3

4 **Q29. Does this complete your direct testimony?**

5 A29. Yes.

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

EXHIBITS

JUSTIN J. W. BROOKS



Justin J. W. Brooks, P.E.

Project Lead

jbrooks@power-gem.com | Charlotte, NC | <https://www.linkedin.com/in/justinbrookspowergem/>

PROFESSIONAL SUMMARY

Mr. Brooks has fourteen years of experience in resource adequacy analysis and nuclear engineering. Areas of expertise include physical reliability studies, capacity accreditation methodologies, production cost modeling, utility integrated resource planning (IRP), and software development for resource adequacy applications. As a Project Lead with PowerGEM, Mr. Brooks leads reliability and resource adequacy studies for utility clients and manages the SERVM software development team. Prior to joining PowerGEM, Mr. Brooks served as a Lead Quantitative Analyst at Duke Energy and began his career in the naval nuclear propulsion program at Newport News Shipbuilding and the Naval Nuclear Laboratory. Mr. Brooks is a licensed Professional Engineer, holds an M.S. in Mechanical and Nuclear Engineering from Virginia Commonwealth University, and a B.S. in Nuclear Engineering from North Carolina State University.

WORK EXPERIENCE

Project Lead

April 2024 - Present

PowerGEM, Charlotte, NC

- Manage the SERVM Software Development Team
- Manage and perform Resource Adequacy Analysis for large scale utilities

Lead Quantitative Analyst

October 2019 – April 2024

Duke Energy, Charlotte, NC

- Lead analyst for physical reliability analysis for all Duke jurisdictions. Develop and run in-house and third-party models, input tooling, and output tooling.
- Assisted with writing testimony and discovery requests for regulatory proceedings. Authored portions of various Integrated Resource Plans.
- Served on the Southeast Reliability Corporation (SERC) Resource Adequacy Working Group (RAWG) supporting ProbA studies.

Senior Nuclear Engineer

April 2017 - September 2019

Naval Nuclear Laboratory, Pittsburgh, PA

- Lead Nuclear Safety Engineer for Federal Project 20-D-931 (KL Fuel Development Laboratory).
- Nuclear Safety Engineer supporting naval spent fuel.

Engineer Nuclear II

May 2017 – April 2017

Newport News Shipbuilding, Newport News, VA

- Worked in several different business areas across multiple platforms (Aircraft Carrier, Submarine, and Training Prototype).
- Lead Radiation Shielding Engineer: Managed all aspects of the temporary radiation shielding program for Overhaul Engineering including design and installation across multiple platforms.



- Underhull Tank Entry: Lead Engineer for preliminary tank access including development of multiple temporary systems and mock-up structures. Managed cost, schedule, and developed engineering products for concurrent job scopes.

REPORTS & WHITE PAPERS

"Wide-Area Resource Adequacy Assessments. Probabilistic Planning for Interconnected Grids." Prepared for Energy Systems Integration Group. 2025.

"Duke Energy Carolinas and Duke Energy Progress Effective Load Carrying Capability (ELCC) Report." Prepared for Duke Energy. 2025.

"New Resource Adequacy Criteria for the Energy Transition. Modernizing Reliability Requirements." Prepared for Energy Systems Integration Group. 2024.

EDUCATION

M.S. in Mechanical and Nuclear Engineering

December 2015

Virginia Commonwealth University, Richmond, VA

B.S. in Nuclear Engineering

May 2012

North Carolina State University, Raleigh, NC

SKILLS

Technical Skills: SERVM, PowerSIMM, Python, C#, MATLAB, Autodesk Suite

Industry Knowledge: Resource Adequacy, Capacity Accreditation, Integrated Resource Planning

Soft Skills: Employee Engagement, Project Management, Vendor Relations, Technical Writing

CERTIFICATIONS & LICENSES

- Professional Engineer License Number 051456–NCBELS, 2020



Date, 02 March 2026

As requested, PowerGEM has performed a resource adequacy analysis of the DTE Electric (DTE) system in future years 2029 and 2033. This analysis evaluated the proposed build plans created by DTE in support of the Customer 2 Data Center and was conducted with DTE being interconnected to the Midcontinent Independent System Operator (MISO) system. This interconnected system was stochastically simulated in PowerGEMs proprietary Strategic Energy and Risk Valuation Model (SERVM). For each proposed build plan a total of 11,000 scenarios at an hourly resolution considering uncertainty in weather, economic load growth, and generator performance were evaluated.

To be found resource adequate, the system needed to demonstrate that its Loss of Load Expectation (LOLE), measured in units of event-day per year, meets or exceeds the commonly used threshold of one day in ten years or 0.1 LOLE. The results of the analysis were:

Year	LOLE [event-day per year]	Result
2029	0.102	Pass
2033	0.238	Fail

To rectify the resource adequacy problem identified in 2033, 677 MW of perfect capacity were required to bring the system back to the threshold of 0.1 LOLE. DTE provided a revised 2033 build plan with a placeholder firm capacity resource for 2033. The results of the revised build plan were:

Year	LOLE [event-day per year]	Result
2033	0.093	Pass

Which satisfied the one day in ten years resource adequacy threshold.

Sincerely,

/s/

Justin J. W. Brooks, P.E.
Project Lead

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of)
DTE ELECTRIC COMPANY)
for Approval of Special Contracts)
and for other relief)

Case No. U-22058

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
AARON WILLIS

DTE ELECTRIC COMPANY
QUALIFICATIONS AND DIRECT TESTIMONY OF AARON WILLIS

Line
No.

1 **Q1. What is your name, business address and by whom are you employed?**

2 A1. My name is Aaron Willis (he/him/his). My business address is One Energy Plaza,
3 Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC,
4 a subsidiary of DTE Energy Company (DTE Energy), as Director, Regulatory
5 Affairs.

6

7 **Q2. On whose behalf are you testifying?**

8 A2. I am testifying on behalf of DTE Electric Company (DTE Electric or Company).

9

10 **Q3. What is your educational background?**

11 A3. I received a Bachelor of Arts in Political Science from the University of Michigan,
12 a Master's in Environmental Management from the Yale School of Forestry and
13 Environmental Studies, and a Master's in Business Administration from the
14 University of Maryland.

15

16 **Q4. What is your work experience?**

17 A4. In 2009, I was employed by the US Army Corps of Engineers, Institute for Water
18 Resources as Social Scientist supporting enforcement of the Clean Water Act and
19 engagement with domestic and international partners on a variety of water
20 resources issues. In 2015, I was employed by Booz Allen Hamilton in their energy
21 practice, providing support to commercial and federal clients on a variety of energy
22 matters.

Line
No.

1 In 2017, I began my employment with DTE Energy as an Associate in Corporate
2 Strategy. In this role, I supported key operational and strategic work across the
3 Company. I was promoted to Senior Associate in 2019 and transitioned to
4 Corporate Development, where I supported the Company's financial strategy. In
5 2020, I accepted a position in Regulatory Affairs supporting the Company's state
6 regulatory strategy and engagement with the Michigan Public Service Commission
7 (MPSC or Commission), MPSC Staff, and Michigan energy stakeholders. In 2021,
8 I became Manager, Regulatory Economics, with responsibilities including the
9 management of regulatory activities relative to DTE Electric's rate strategy,
10 pricing, and load research. In 2024, I was promoted to Director, Regulatory Affairs.

11

12 **Q5. What are your current duties and responsibilities?**

13 A5. My responsibilities include the management of regulatory activities relative to DTE
14 Electric's rate strategy, regulatory mechanisms, pricing, revenue requirements, cost
15 of service, and load research.

16

17 **Q6. Have you previously sponsored testimony before the Michigan Public Service**
18 **Commission?**

19 A6. Yes. I have sponsored testimony in the following cases:

- 20 • U-21163 XL High Load Factor Rate
- 21 • U-20836 DTE Electric 2022 General Rate Case
- 22 • U-21193 DTE Electric 2022 Integrated Resource Plan
- 23 • U-21306 Rider No. 16 Transition
- 24 • U-21338 DTE Electric 2023 Securitization
- 25 • U-21297 DTE Electric 2023 General Rate Case

Line
No.

- 1 • U-18091 DTE Electric 2024 PURPA Case
- 2 • U-21534 DTE Electric 2024 General Rate Case
- 3 • U-21860 DTE Electric 2025 General Rate Case
- 4 • U-21909 DTE Electric Performance Based Ratemaking Mechanism

Line
No.

1 **Purpose of Testimony**

2 **Q7. What is the purpose of your testimony in this proceeding?**

3 A7. The purpose of my testimony is to describe the customer benefit generated by the
4 contracts executed between the Company and Google LLC (the Customer) and
5 explained by Witness Foley. I will explain the Company's methodology for
6 calculating customer benefit and the input information used in the calculation.

7

8 **Q8. Are you sponsoring any exhibits in this proceeding?**

9 A8. Yes. I am sponsoring the following exhibits:

- 10 • Exhibit A-19 – Customer Benefit
- 11 • Exhibit A-20 – Base Sales Benefit

12

13 **Q9. Is this transaction beneficial to all other customers?**

14 A9. Yes. Based on the Company's best information, this transaction is expected to
15 generate an estimated \$1.7 billion of benefit for other customers, clearing the
16 threshold established by the Commission in Case No. U-21859. The Commission's
17 November 6th, 2025, Order in that case set a test that Consumers Energy
18 "demonstrate[s] that costs caused by the interconnecting large load customer to be
19 served under the tariff are not being paid for by other customers". This testimony
20 demonstrates the Company's expectation of positive benefits for all other
21 customers, and that the combined revenues and avoided costs exceed the costs
22 cause by the Customer over the term of the contract. Said differently, costs will not
23 be paid by other customers.

Line
No.

1 **Q10. What is the Company's approach to calculating customer benefits of the**
2 **special contracts?**

3 A10. The contracts described by Witness Foley each generate certain additional costs
4 and certain benefits (cost reductions or avoided costs) to other customers. For
5 example, the Primary Supply Agreement (PSA) results in additional sales that the
6 Customer is committing to bring to the system; these sales create downward
7 pressure on base rates. Similarly, the Clean Capacity Accelerator Agreement
8 (CCAA) governs how the Customer will directly support certain storage and
9 renewable assets as well as capacity contracts; the structure of the CCAA
10 (described by Witness Foley) generates additional benefits to other customers.
11 Future generation resources (modeled here using a Combined Cycle Gas Turbine
12 (CCGT) with Carbon Capture and Sequestration (CCS) as a proxy) introduce
13 additional costs.

14
15 The Company's objective in calculating the benefits of the contracts is to account
16 for 1) each category of benefit/cost such as those above, and 2) model those cost
17 changes using applicable regulatory structures and processes. The sum of the
18 inputs, including beneficial inputs such as the impact of incremental sales and
19 incremental costs such as new assets, reflects the net customer impact in each year.
20 The approach established by the Company to assess the Customer impact is
21 designed to capture all benefit and cost changes and utilize existing methods. The
22 net of this analysis is \$1.7 billion of estimated benefit to the Company's other
23 customers over the term of the PSA and CCAA.

Line
No.

1 **Q11. How is the Company supporting the calculations appearing within Exhibit A-**
2 **19?**

3 A11. Each of the cost and benefit categories assessed by the Company has testimony and
4 quantitative support, which explain the calculations and the basis for them. Across
5 the Exhibit, negative values reflect benefits and positive values reflect costs.

6 • Base Sales Benefit – this is described below in my testimony and appears
7 on Line 2 of Exhibit A-19.

8 • Incremental Power Supply Cost Recovery (PSCR) – Witness Burgdorf
9 sponsors the estimated changes to PSCR costs from the addition of the
10 Customer’s load, including, for example, incremental transmission costs,
11 changes in PSCR sales, and renewable compliance. This also includes the
12 avoided cost of reducing 250 MW of renewable compliance build as
13 discussed by Witness Bilyeu. Using this information, Witness Burgdorf
14 develops net changes in power supply costs to customers. The net
15 (benefit)/cost is found on Line 4 of Exhibit A-19.

16 • Other Non-Fuel and Purchased Power O&M – Witness Burgdorf sponsors
17 the modeled other O&M costs. These costs are found on Line 6 of Exhibit
18 A-19.

19 • Proxy CCGT Revenue Requirement – Witness Burgdorf sponsors the plant
20 capital and O&M cost assumptions and an associated revenue requirement.
21 This cost is found on Line 8 of Exhibit A-19

22 • CCS Revenue Requirement – Witness Burgdorf sponsors the CCS capital
23 and O&M cost assumptions and an associated revenue requirement,
24 including applicable tax credits. This cost is found on Line 10 of Exhibit A-
25 19

Line
No.

- 1 • Benefit of Storage Pull Ahead – The CCAA¹ contract described by Witness
- 2 Foley includes up to 480 MW of storage being directly supported by the
- 3 Customer². As described by Witness Burgdorf’s testimony in Section I, the
- 4 storage assets were removed from the base build plan, generating an
- 5 avoided cost benefit to existing customers. This benefit is found on Line 12
- 6 of Exhibit A-19.
- 7 • Total (Benefit)/Cost to Customers – This is the sum of the preceding items
- 8 and is found on Line 14 of Exhibit A-19.

9

10 **Q12. What are the total benefits of the special contracts?**

11 A12. The total benefit to other customers from the contracts is estimated to be \$1.7 billion
12 from 2028 through the conclusion of the contract in 2047. The detailed build up by
13 year can be found in Exhibit A-19. The total benefits by component over the
14 contract life is found on col (v) lines 2-12 and replicated below:

15	• Base Sales Benefit	\$4.85B benefit
16	• PSCR ³	\$2.31B benefit
17	• Other Non-F&PP O&M	\$0.02B cost
18	• Proxy CCGT	\$4.17B cost
19	• CCS direct cost	\$2.43B cost
20	• <u>Storage Pull Ahead</u>	<u>\$1.16B benefit</u>
21	• Total	\$1.70B benefit

¹ The CCAA payment structure is described by Witness Foley

² The Company modeled 450 MW of CCAA storage, however it may build up to 480 MW of storage under the CCAA. Incremental storage deployment beyond 450 MW would generate additional customer benefits.

³ This includes the avoided cost benefit of reducing renewable compliance build by 250 MW as described by Witnesses Bilyeu and Burgdorf

Line
No.

1 **Q13. How did you calculate the “base sales benefit” in Exhibit A-20?**

2 A13. The base sales benefit utilizes the Company’s standard cost of service (COS) model
3 as approved in Case No. U-21534 (updated for additional sales as approved in Case
4 No. U-21990) and evaluates the impact of the Customer’s load. As utilized here,
5 the model output is the net change in the revenue deficiency (sufficiency). The
6 analysis incorporated the incremental revenues and incremental base power supply
7 expenses associated with serving the Customer —items typically addressed in an
8 electric rate case—without modifying any underlying COS methods or
9 assumptions. The analysis assumes the underlying load is at full ramp of 1000 MW
10 and a 90% load factor. The difference between the revenue deficiency (sufficiency)
11 calculated without the Customer load and the revenue deficiency calculated with
12 the Customer load represents the benefit to all customers. In this instance, the
13 calculation yields a revenue sufficiency – the addition of the load and additional
14 base power supply expenses yields a benefit to other customers.

15

16 **Q14. Does the base sales benefit include any changes to rate base or other costs?**

17 A14. No. Additional rate base costs, benefits, and other costs are identified separately in
18 Exhibit A-19.

19

20 **Q15. Is the method for calculating base sales consistent with how the Company
21 develops the revenue requirement within COS in rate cases?**

22 A15. Yes. First, I calculated the Customer’s present revenues, based on assumed Rate
23 Schedule D11 (transmission voltage) service, and the incremental base power
24 supply costs attributable to its load, consistent with the treatment such items would
25 receive in a rate case. Income taxes were then calculated on the incremental pretax

Line
No.

1 net income, and the incremental income deficiency was grossed up using the
2 revenue multiplier approved in Case No. U-21534. The revenue multiplier is used
3 to convert between after-tax income deficiency/(sufficiency) and the pre-tax
4 revenue requirement. These results were incorporated into the COS model. To
5 complete the analysis, updates were made to (i) sales and present revenues by class,
6 (ii) customer counts where applicable, and (iii) load schedules such that the data
7 center's load is reflected in the production and distribution allocators. The COS
8 analysis then determined the updated revenue deficiency/(sufficiency). The
9 sufficiency is the difference with and without the incremental Customer load.

10

11 **Q16. Can you explain the results of the base sales analysis that you performed?**

12 A16. After incorporating the incremental revenues, base power supply expenses⁴, taxes,
13 and updated load schedules, the model was rerun to determine the revenue
14 deficiency/(sufficiency) with the Customer's load included. This value was then
15 compared to the revenue deficiency/(sufficiency) without the Customer's load. The
16 difference represents the modeled net benefit that would be realized in a rate case
17 cost of service study. A lower revenue deficiency (or higher sufficiency) in the
18 "with Customer" case indicates that the Customer's incremental revenues exceed
19 the incremental costs included in this COS analysis, resulting in a benefit that would
20 flow through to all customers in an electric rate case. The "Customer Study Results"
21 tab of Exhibit A-20 summarizes this calculation.

⁴ Consistent with the Company's standard rate case fuel and purchased power calculations and shown on tab "Adjust A-13 C4" of Exhibit A-20

Line
No.

1 **Q17. How does the single year analysis account for the full contract period?**

2 A17. As described above, the COS is premised on the U-21534 Ordered COS. The
3 “Customer Study Results” tab, line 30, column (l) of Exhibit A-20 shows a
4 sufficiency (i.e. a net benefit) of \$194.7 million. This is assumed to be a 2025
5 nominal value. The values for years beyond 2026 are calculated as follows:

- 6 • 2026 and 2027 are excluded as the Customer will not be served in 2026 and
7 has de minimis load in 2027
- 8 • All years 2028 – 2047 assume an underlying growth of Rate Schedule D11
9 of 1.5%, compounding annually from a 2025 basis
- 10 • 2028 sales are estimated to be approximately 43% of the estimated full ramp
11 sales based on the Customer’s ramp schedule. This is found on line 33,
12 column (b) of the tab
- 13 • 2029 is the first year in which the Customer sales are assumed in full for the
14 calendar year. This is found on line 33, column (c) of the tab
- 15 • For all years beyond 2029, they are inflated at 1.5% with no other
16 adjustments

17
18 **Q18. Does the Customer provide benefit through the nuclear surcharge?**

19 A18. Yes. The nuclear surcharge revenue requirement approved in Case No. U-21534 is
20 \$40.1 million and is recovered volumetrically. Considering the additional Customer
21 sales, this generates a benefit of \$5.0 million per year (or \$2.4 million in 2028 at
22 lower sales). This is reflected in Exhibit A-20 on the “Customer Study Results” tab,
23 line 34.

Line
No.

1 **Q19. How are incremental power supply costs considered in this analysis?**

2 A19. As described more extensively by Witness Burgdorf, there are various changes to
3 cost and load assumptions that occur within the PSCR process. These include the
4 addition of the Customer load when calculating the PSCR factor, and the
5 consideration of additional fuel and purchased power costs, renewable costs or
6 benefits, and transmission costs. The with and without calculation of the PSCR
7 factor is a critical input to understanding overall customer impacts. It appropriately
8 captures the incremental costs the Customer brings to the PSCR while accounting
9 for the benefits of spreading existing fixed costs (for transmission and renewable
10 build) across additional sales. Witness Burgdorf describes the specifics of the inputs
11 and calculations in his testimony.

12

13 **Q20. Does this conclude your testimony?**

14 A20. Yes.

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	
		U-21534 Order Adjusted				Customer Study COS				Change												
		Prod	Dist	Total		Prod	Dist	Total		Prod	Dist	Total										
1 Rate Base		8,707,728	13,326,332	22,034,060		8,708,781	13,325,280	22,034,060		1,052	(1,052)	(0)										
Revenues:																						
2 Revenue From Electric Sales		3,623,008	2,290,630	5,913,638		4,081,718	2,297,354	6,379,072		458,710	6,725	465,434										
3 D13 Present Revenue		10,496	566	11,062		10,496	566	11,062		-	-	-										
4 Misc Revenue		34,977	80,359	115,336		35,414	79,922	115,336		437	(437)	(0)										
5 Total Adjusted Revenues		3,668,481	2,371,555	6,040,036		4,127,628	2,377,843	6,505,470		459,146	6,288	465,434										
Expenses:																						
6 Fuel		1,113,403	-	1,113,403		1,273,165	-	1,273,165		159,762	-	159,762										
7 Purchased Power		569,180	-	569,180		673,773	-	673,773		104,593	-	104,593										
8 O & M Expense		512,885	641,851	1,154,736		512,885	641,851	1,154,736		-	-	(0)										
9 Depreciation		508,902	741,663	1,250,565		508,902	741,663	1,250,565		-	-	0										
10 Other (Reg Assets, etc)		-	-	-		-	-	-		-	-	-										
11 Remove Reg Assets		-	-	-		-	-	-		-	-	-										
12 Accretion of Loss/ Gain on Sale		-	-	-		-	-	-		-	-	-										
13 Other Taxes		121,801	266,636	388,436		121,801	266,636	388,436		-	-	(0)										
14 Income Taxes		150,422	120,904	271,327		193,885	129,200	323,084		43,462	8,295	51,758										
15 Amortizations		-	-	-		-	-	-		-	-	-										
16 Total Expenses		2,976,593	1,771,054	4,747,647		3,284,410	1,779,349	5,063,760		307,818	8,295	316,113										
17 Net Oper Income		691,888	600,501	1,292,389		843,217	598,493	1,441,711		151,329	(2,007)	149,321										
18 AFUDC & Other		56,690	1,182	57,872		56,690	1,182	57,872		-	-	-										
19 Net Adjustments		854	1,400	2,254		854	1,400	2,254		-	-	-										
20 Adj Net Oper Income		749,432	603,083	1,352,515		900,761	601,076	1,501,837		151,329	(2,007)	149,321										
21 Rate of Return		8.61%	4.53%	6.14%		10.34%	4.51%	6.14%														
22 Return @ 5.68653727512958 %		495,168	757,807	1,252,975		495,228	757,747	1,252,975		60	(60)	(0)										
23 Income Deficiency		(254,264)	154,724	(99,540)		(405,533)	156,671	(248,862)		(151,269)	1,948	(149,321)										
24 Base Revenue Def / (Sufficiency)		(343,164)	208,821	(134,343)		(547,321)	211,449	(335,872)		(204,158)	2,628	(201,529)										
25 Tree Trim Surge Rev Req (Dist Only)		-	11,695	11,695		-	11,695	11,695		-	-	-										
26 Monroe Reg Asset Rev Req (Prod Only)		137,505	-	137,505		137,505	-	137,505		-	-	-										
27 Base Rev Def/ (Sufficiency) w Tree Trim Surge & Monroe		(205,658)	220,516	14,858		(409,816)	223,145	(186,671)		(204,158)	2,628	(201,529)										
28 Less: D13 Incremental Revenues		(278)	27	(251)		(278)	27	(251)		-	-	-										
29 R10 Tax Gross-Up Adjustment (Prod Only)		-	-	(0)		0	-	0		0	-	0										
30 Total Revenue Def/ (Sufficiency)		<u>(205,380)</u>	<u>220,489</u>	<u>15,109</u>		<u>(409,538)</u>	<u>223,117</u>	<u>(186,421)</u>		<u>(204,158)</u>	<u>2,628</u>	<u>(201,529)</u>										
31 Total Base Revenue Requirement		3,417,628	2,511,119	5,928,746		3,672,180	2,520,472	6,192,651		254,552	9,353	263,905										
32 Year		2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	
33 Base Sufficiency		(90,616)	(213,896)	(217,104)	(220,361)	(223,666)	(227,021)	(230,427)	(233,883)	(237,391)	(240,952)	(244,567)	(248,235)	(251,959)	(255,738)	(259,574)	(263,468)	(267,420)	(271,431)	(275,502)	(279,635)	
34 Nuclear Surcharge		(2,171)	(5,049)	(5,049)	(5,049)	(5,049)	(5,049)	(5,049)	(5,049)	(5,049)	(5,049)	(5,049)	(5,049)	(5,049)	(5,049)	(5,049)	(5,049)	(5,049)	(5,049)	(5,049)	(5,049)	
35 Base Sales Benefit		(92,787)	(218,945)	(222,154)	(225,410)	(228,716)	(232,071)	(235,476)	(238,933)	(242,441)	(246,002)	(249,616)	(253,284)	(257,008)	(260,787)	(264,623)	(268,517)	(272,469)	(276,480)	(280,552)	(284,684)	