APPENDIX K: EXISTING POWER SUPPLY

In this Appendix K, Minnesota Power provides the Company's current list of exiting energy conversion facilities and the current generation supply map. Please see Minnesota Power's 2015 Plan, Appendix C, Existing Power Supply for more detailed information related to each resource.

Existing Energy Conversion Facilities[1]

Bison 1—81.8 MW (retirement planned by end of 2018)

Bison 2—105 MW (retirement planned by end of 2018)

Bison 3—105 MW

Bison 4—204.8 MW

Hydro Operations—114.6 MW

- St. Louis River System—85.6 MW
  - Knife Falls Hydro Electric Station—1.9 MW
  - Scanlon Hydro Electric Station—1.4 MW
  - Thomson Hydro Electric Station—71.3 MW
  - Fond du Lac Hydro Electric Station—11.0 MW
- Winton Hydro Electric Station—4.0 MW
- Prairie River Hydro Electric Station—0.5 MW
- Mississippi River System—24.5 MW
  - Little Falls Hydro Electric Station—4.4 MW
  - Blanchard Hydro Electric Station—16.5 MW
  - Sylvan Hydro Electric Station—1.9 MW
  - Pillager Hydro Electric Station—1.7 MW

Hibbard Energy Center—54.2 MW (summer), 47.2 MW (winter)

Boswell Energy Center Units 1 and 2—138 MW

Boswell Energy Center Unit 3—350.5 MW

Boswell Energy Center Unit 4—585 MW (468 MW Minnesota Power capacity)

Laskin Energy Center Units 1 and 2—110 MW (natural gas)

Taconite Harbor Energy Center Units 1 and 2—150 MW (currently idled)

[1] Nameplate capacity.

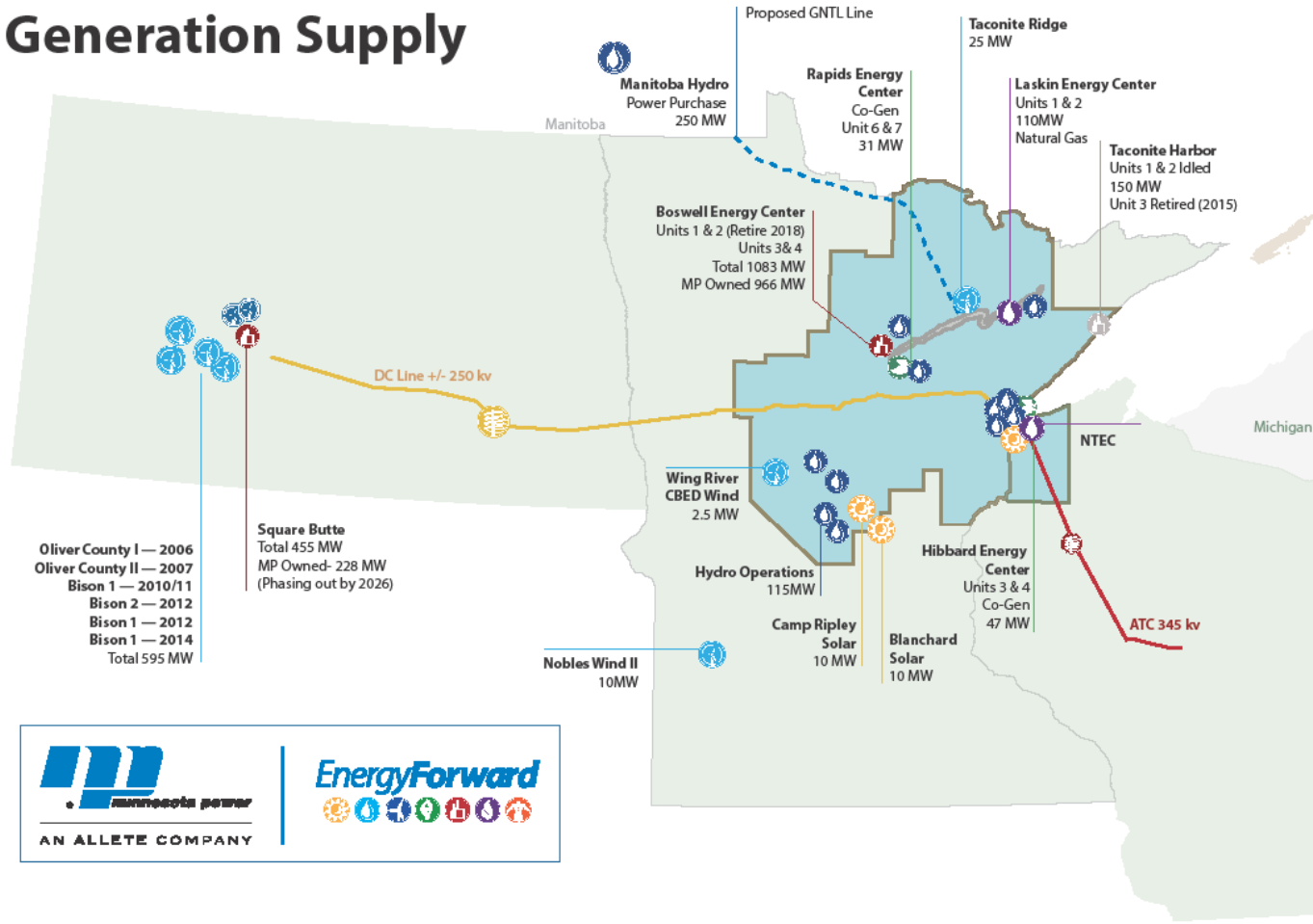
Taconite Ridge Wind Energy Center—25 MW

Camp Ripley Solar Facility—10 MW

(Non-regulated) Rapids Energy Center—30.8 MW

Purchases

- Square Butte—Young 2—100 MW in 2017
- Oliver County Wind Energy Centers I and II–98.6 MW
- Wing River Wind–2.5 MW
- Manitoba Hydro–50 MW
- Ontario Hydro–100 MW (capacity only)


Generation Supply
Proposed GNTL Line
Taconite Ridge
25 MW
Manitoba Hydro
Power Purchase
250 MW
Rapids Energy
Center
Co-Gen
Unit 6 & 7
31 MW
Laskin Energy Center
Units 1 & 2
110MW
Natural Gas
Taconite Harbor
Units 1 & 2 Idled
150 MW
Unit 3 Retired (2015)
Manitoba
Boswell Energy Center
Units 1 & 2 (Retire 2018)
Units 3& 4
Total 1083 MW
MP Owned 966 MW
DC Line +/- 250 kv
Michigan
NTEC
Wing River
CBED Wind
2.5 MW
Hydro Operations
115MW
Hibbard Energy
Center
Units 3 & 4
Co-Gen
47 MW
ATC 345 kv
Camp Ripley
Solar
10 MW
Blanchard
Solar
10 MW
Nobles Wind II
10MW
Square Butte
Total 455 MW
MP Owned- 228 MW
(Phasing out by 2026)
Oliver County I — 2006
Oliver County II — 2007
Bison 1 — 2010/11
Bison 2 — 2012
Bison 1 — 2012
Bison 1 — 2014
Total 595 MW
minnesota power
AN ALLETE COMPANY
EnergyForward

Appendix L: Large Customer Demand Response Request for Proposals

Request for Proposals

for

Up to 300 MW of Large Customer Demand Response Resources

issued by
Minnesota Power

Issue Date: August 5, 2016
Proposals Due: September 26, 2016

Complete Information on this RFP can be found at:

http://RFP.mnpower.com

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1.0 BACKGROUND

Minnesota Power (MP), a division of ALLETE, Inc., is seeking power supply proposals for up to a nominal 300 MW of demand response products located at a customer site where load is served by MP under the Large Power or Large Light and Power Service Schedule and the demand is greater than five (5) MW, beginning in the 2019 to 2023 timeframe. This request is part of MP's broader evaluation process that considers the costs and characteristics of several different power supply types (e.g., wind, solar, natural gas, demand response, and distributed generation) to optimize the mix of resources to meet all customer needs. MP's current resource strategy calls for a diversified mix of resources to meet customers' needs reliably and cost effectively in an environmentally responsible manner.

MP seeks cost-effective demand response resources that utilize the capability of MP's large industrial customers to curtail their load for electric system emergencies or market economics and provide capacity that is accreditable under current Midcontinent Independent System Operator (MISO) Resource Adequacy rules. MP seeks two types of demand response products: 1) MP System Capacity and 2) Scheduled Economic Curtailment Energy. These products are defined further is sections 2.0. The bidder must be an existing MP customer on the Large Power or Large Light and Power Service Schedule and have the capability to curtail load thru an automated process. Proposals must reflect the cost and characteristics of the demand response resource to curtail load. Proposals must offer an initial contract term of 10 years. Agreements are contingent upon Minnesota Public Utilities Commission (MPUC) approval and may require associated modifications to Electric Service Agreements also subject to MPUC approval.

All proposals must be received by the contact designated in Section 4.3 by the Proposal Submittal Deadline date shown in Section 4.1. MP reserves the right in its sole discretion to modify this schedule for any reason.

MP will not be submitting a demand response proposal into this Request for Proposal (RFP). In connection with this RFP, MP has retained the services of an independent third party consultant (Sedway Consulting, Inc.) to work with MP in the quantitative evaluation of all proposals. However, MP will make the final decision (subject to MPUC review, as applicable) in MP's sole discretion.

* * * * *

2.0 PRODUCTS SOLICITED

In this RFP MP is soliciting offers for two types of demand response products described here. MP will consider other demand response products offered by qualified bidders, although MP's preference is for the demand response products solicited for in this RFP. The bidders must designate which demand response product type is being offered in Exhibit B – Demand Response Data.

2.1 Product 1: MP System Capacity

MP System Capacity product is a demand response resource that is available for energy curtailment events during MISO system emergencies or MP local system emergencies. The capacity will be accredited in MISO as a "Load Modifying Resource (LMR) – Demand Resource" resource and must meet all requirements for this type of capacity resource per MISO Resource Adequacy Business Practice Manual and MISO Module E Resource Adequacy Tariff[1].

2.2 Product 2: Scheduled Economic Curtailment Energy

Scheduled Economic Curtailment Energy product must meet the characteristics of "Product 1: MP System Capacity" and be available for economic energy curtailment events determined by market energy prices and the sole discretion of the company. The economic load curtailment events will be limited to 200, 400 or 800 hours per year. The bidder must identify in Exhibit B: Demand Response Data if the offer is for 200, 400 or 800 hours of curtailments per year. MP has sole discretion to call on this curtailable energy for the benefit of all customers.

3.0 ELIGIBLE PROPOSALS – MINIMUM REQUIREMENTS

Proposals must meet the general minimum eligibility requirements described below. MP will screen all proposals for compliance with these requirements. Proposals that fail to meet one or more of the general minimum eligibility requirements may be disqualified from further consideration.

3.1 Capacity

Offers must provide MISO accreditable capacity of no less than 1 MW and up to a maximum of 300 MW. The proposal must offer capacity that is accreditable (including Zonal Resource Credits located in Local Resource Zone 1) under current MISO Resource Adequacy rules. MP is willing to work with bidders on accrediting this capacity with MISO per the Resource Adequacy rules.

Per MISO Resource Adequacy rules the accredited capacity value is based on the available demand response during historical MISO system peaks. For the bidders benefit included in Exhibit B: Demand Response Data are the dates and times of MISO's system peaks. The Customer's historical demand during MISO peak hours is available upon request.

3.2 Available Period

The product must be delivered in the 2019 to 2023 timeframe. The term for all contracts must be for 10 years.

[1] The MISO Business Practice Manual for Resource Adequacy (#11) is located here https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

3.3 Participant Requirements

The bidder must be a MP retail customer currently on the Large Power or Large Light and Power Service Schedule and have a demand greater than 5 MW. If bidder is a customer participating directly in one of MP's current demand response programs, this does not prevent the bidder from participating in this RFP. Although, bidders cannot commit the same MW's of demand response to multiple programs or process offerings.

3.4 Location Requirements

The curtailable load must be located at a customer site within MP's service territory that is served under either the Large Power or Large Light and Power Service Schedule.

3.5 Environmental

Proposal must provide any environmental attributes associated with curtailing energy under Product 2.

3.6 Firm Pricing

All pricing should reflect those costs (to the extent applicable) at the time of submittal. The cost of installing load control equipment or curtailing load under provisions in "Product 2 – Scheduled Economic Curtailment Energy" shall be the responsibility of the respondent and must be included in the proposed pricing. Respondent shall be responsible for all operational related costs, penalties, and charges assessed by MISO.

Proposals must include pricing that is firm and not subject to any revisions during MP's evaluation and negotiation process. Bidder may propose escalation rates that are either fixed or, if appropriate and defensible, annually indexed to publicly-published indices acceptable to MP; however, the formulaic adjustment of indexed prices must be clearly described in the proposal and the formulaic mechanism itself may not be subject to revision during MP's evaluation and negotiation process. All pricing should be provided in Exhibit B and must be in United States dollars and not subject to currency exchange rate adjustment. The proposal must be signed by an officer of the bidding firm who is duly authorized to commit the firm to carry out the demand response proposal should MP accept the proposal. All prices must be firm and binding through May 31, 2017

3.7 Credit Rating

A bidder must have a credit rating for its senior unsecured debt of **BBB** or higher (for Standard & Poor's) or **Baa2** or higher (for Moody's). If a bidder is unrated or does not meet this minimum credit rating requirement, the bidder must demonstrate the capability to supply performance assurance in the form of a corporate guarantor that meets the requirement, a letter of credit and/or cash. The amount of performance assurance shall be no less than $5/kW of the proposed capacity of the proposal. This performance assurance will remain in place from contract execution through the term of the contract unless otherwise negotiated based upon the expected financial exposure related to the bid.

3.8 Statement of Material Exceptions

Proposals must provide the bidder's material exceptions to MP's Demand Response Partial Term Sheet (Exhibit C & D) included with this package.

3.9 Offer Submission

MP will only consider offers that meet the Proposal Submission Deadline set forth in the RFP schedule in Section 4.1.

3.10 Legal Certifications

A bidder must certify that:

1. There are no pending legal or civil actions that would impair the bidder's ability to perform its obligations under the proposed PPA;

2. the bidder has not directly or indirectly induced or solicited any other respondent to submit a false or sham proposal;

3. the bidder has not solicited or induced any other person, firm, or corporation to refrain from submitting a proposal; and

4. the bidder has not sought by collusion to obtain any advantage over any other respondent.

* * * * *

4.0 SCHEDULE, COMMUNICATION AND RFP INSTRUCTIONS

4.1 Overview of Process

The schedule below represents MP's expected time-line for conducting this demand response resource solicitation. MP reserves the right to modify this schedule as circumstances warrant and/or as MP deems appropriate.

MP RFP Schedule

Event	Anticipated Date
Release of RFP	August 5, 2016
Informational Session	10:00 am to 12:00 pm on August 15, 2016 at Minnesota Power General Office Building in Room 140[2]
Proposal Submittal Deadline	**5:00 pm CST on September 26, 2016**
Proposal Evaluation	September 26 to October 14, 2016
Negotiations with Selected Bidders	November – December 2016
Application for Regulatory Approval	January 2017

If you plan to participate in the informational session please RSVP to MPLargeCustomerDR-RFP@mnpower.com or MPCo-GenRFP@mnpower.com. A WebEx option will be available for bidders that would like to participate in the informational session remotely. Please indicate in your RSVP if you plan to attend in person or via the WebEx. Additional information on the WebEx will be provided prior to the session.

After proposals are submitted, Sedway Consulting will review and quantitatively evaluate all conforming proposals. An MP e-mail address (MPLargeCustomerDR-RFP@mnpower.com) has been set up to collect all communications and questions from potential respondents as well as a web site (http://RFP.MNPower.com) to download the RFP and Exhibits and provide uniform communications, including updates and other details as may be provided throughout the bidding process.

Proposals will be opened in private by Sedway Consulting on a confidential basis. One original copy of each proposal will be retained by Sedway Consulting for a review and comprehensive quantitative evaluation and one original copy of each proposal will be retained by MP for a comprehensive qualitative evaluation.

Each respondent should expect to receive a confirmation email from Sedway Consulting that his/her offer submission has been received. If a confirmation email is not received within 24 hours following the Offer Submission Deadline, a respondent should contact the independent evaluator at: Alan.Taylor@sedwayconsulting.com or (303) 581-4172.

Proposals will be reviewed by Sedway Consulting for completeness and offers that do not include the information requirements of this RFP may be notified by Sedway Consulting and allowed to cure the deficiency. During the evaluation process, respondents may be contacted for additional data or clarifications by Sedway Consulting.

[2] The Minnesota Power General Office Building is located at 30 W. Superior St., Duluth, Minnesota 55802

4.2 Exhibits

Respondents to this RFP are required to sign **Exhibit A: Non-disclosure Agreement (NDA)** in its present form.

Respondents to this RFP area also required to complete **Exhibit B: Demand Response Data**

Respondents to the RFP who are offering Product 1 are required to provide written exceptions to **Exhibit C: Product 1**

Respondents to the RFP who are offering Product 2 are required to provide written exceptions to **Exhibit D: Product 2**

All correspondence concerning the submittal process for this RFP must be sent via e-mail to MPLargeCustomerDR-RFP@mnpower.com with Sedway Consulting copied at Alan.Taylor@sedwayconsulting.com.

Individual questions submitted by a respondent to MP and Sedway Consulting before the submittal deadline will be answered and responses sent back via email to the respondent as soon as practical. Responses to frequently asked or broadly applicable questions may be placed on the RFP Website for the benefit of all respondents, with any identifying information redacted from the question.

4.3 Deadline and Method for Submitting Proposals

All proposals submitted in response to this RFP must be received by MP and Sedway Consulting at the email addresses below no later than the Proposal Submittal Deadline shown in Section 4.1. Sedway Consulting and MP will not evaluate proposals as part of this RFP process if submitted after this date and time. MP does not anticipate an opportunity in the schedule for respondents to refresh or update their pricing before the final selection(s) are made (if any). Multiple proposals submitted by the same respondent must be identified separately. Financial statements, annual reports, and other large documents should be referenced via a web site address.

Respondents shall email an electronic copy of its proposal to MPLargeCustomerDR-RFP@mnpower.com with Sedway Consulting copied at Alan.Taylor@sedwayconsulting.com.

Each proposal must contain the following:

1. Each proposal must contain the following:
    a. Exhibit A: NDA
    b. Exhibit B: DR Data
    c. Additional materials that address the requirements of the RFP
2. Do not send any files in compressed formats, such as .zip.
3. Respondents should undertake efforts to avoid excessively large emails/attachments; in any case, individual email size must be less than 10 MB. If the emailed information exceeds this limit, then respondents should break their submission into multiple emails.

* * * * *

5.0 PROPOSAL ORGANIZATION

The proposal must include an executive summary, proposal limitations, relevant company data and experience, the technical proposal, along with the appropriate Exhibits. Some information may not be known at the time proposals are due. However, partial information and estimates are better than nothing at all, so respondents are encouraged to submit as much information as possible.

5.1 Executive Summary

Please provide a one page executive summary of the proposal in the form of a cover letter. Include the demand response location, age or load control capability status, size, the primary contact's name, email, and phone number, and an overview of the major features of the proposal. The Executive Summary must be signed by an officer of the respondent who is duly authorized to commit the firm to carry out the proposed demand response transaction should MP accept the proposal (this does not have to be the primary contact). A Table of Contents should be the first page and immediately precede the Executive Summary.

5.2 Proposal Limitations

Please describe in reasonable detail any existing regulatory, legal, economic, operational, or systematic conditions that might affect the respondent's ability to deliver capacity and curtailable energy as offered.

5.3 Company Data, Financing Plan, and Experience

Please include information on the respondent's corporate structure (including identification of any parent companies), the project's financing plan (if applicable), the respondent's most recent credit rating, quarterly report containing unaudited consolidated financial statements that is signed and verified by an authorized officer of respondent attesting to its accuracy, a copy of respondent's annual report for the prior three years containing audited consolidated financial statements and a summary of respondent's relevant experience. Please describe any current litigation or environmental fines from the last three years that could potentially affect the demand response proposal. All financial statements, annual reports and other large documents may be referenced via a website address.

Please provide a list of programs/products with a brief description of the experience as it relates to participating in demand response.

5.4 Confidentiality

Note that any portion of a bidder's proposal that the bidder deems to be confidential must be clearly marked. MP and its consultants will take reasonable precautions to maintain the confidentiality of such information. However, MP is rate regulated by the MPUC; bidders must recognize that their confidential information may have to be shared with regulatory agencies and provided in MPUC regulatory proceedings as well as other regulatory or legal proceedings. MP will employ reasonable efforts to ensure that such confidential information is not publicly disclosed in such proceedings but can give no guarantees of such protection.

5.5 Technical Proposal

Proposals shall include a detailed technical description of proposed demand response product. Please review the technical description provided in this section such that it matches up with the technical and

cost information provided in the Exhibit. The technical description shall include, but not be limited to the following items as known and applicable:

1. Size and location
2. Customer service account number
3. Product type
4. Capacity pricing ($/Zonal Resource Credit-Month)
5. Delivery date and term
6. Development and implementation schedule Gantt chart (if new load controls are required)
7. Equipment controlled (including MW loading)
8. Full description of load control technology (e.g. automation capabilities)
9. Description of operating flexibility (Product 2 only)
10. Scheduling process and flexibility (notifying MP the demand response available each day)
11. Discuss any other owners and the load control rights/preference arrangements
12. “Best Practices” operation and maintenance
13. Capacity size options between 1 – 300 MW
14. Statement of Exceptions to MP’s Demand Response Partial Term Sheet.

* * * * *

6.0 PROPOSAL EVALUATION AND CONTRACT NEGOTIATIONS

6.1 Initial Proposal Review

An initial review of the bids will be performed by Sedway Consulting. Proposals will be reviewed for completeness and proposals that do not meet or include the information requirements of this RFP may be notified and allowed to cure the deficiencies. Respondents may also be contacted for additional data or clarifications by Sedway Consulting. In general, more certain information and development progress is better than less certain or unknown information.

6.2 Proposal Quantitative Evaluation

Sedway Consulting will quantitatively evaluate all conforming proposals' ability to meet both capacity and energy needs and the corresponding costs. During the quantitative evaluation process, Sedway Consulting may or may not choose to initiate more detailed clarification discussions and a more thorough quantitative evaluation with one or more respondents. Discussions with a respondent shall in no way be construed as commencing contract negotiations.

6.3 Proposal Qualitative Evaluation

MP will evaluate and consider both the Quantitative Evaluation developed by Sedway Consulting and the qualitative aspects of all conforming proposals' ability to meet both capacity and energy needs. In general, more certain information and development progress is better than less certain or unknown information.

In evaluating Proposals, MP may generally consider the following criteria (in no particular order and without limiting consideration of other factors):

1. Sedway Consulting's Quantitative Evaluation
2. Price certainty, price volatility, and risk of price increases
3. Integration into MP's system
4. General location of the demand response
5. Respondent's demand response experience as it relates to utility demand response programs or products (in and outside MISO)
6. Respondent's or Guarantor's financial condition and creditworthiness
7. Operating flexibility including capability to meet performance requirements per MISO Resource Adequacy rules, MISO Demand Response Rules and MP's Demand Response Partial Term Sheet
8. Implementation schedule for load control equipment (if applicable)
9. Load control systems
10. Other owners and load control rights/preference
11. Current litigation

12. Tax treatment and impact on MP's balance sheet
13. Age, remaining life of operations
14. Capacity size options/limits from 1 – 300 MW and future option to expand
15. Overall completeness, clarity, and quality of the Proposal
16. Compliance of proposals with the specifications and requirements described in the RFP
17. Other data as may be requested prior to commencing further discussions
18. Exceptions to MP's Demand Response Partial Term Sheets

6.4 Contract Negotiations

Based on the Quantitative Evaluation and Qualitative Evaluation, MP may or may not select candidates for further discussions. MP will contact any selected respondent in writing to confirm interest in commencing contract negotiations. All PPA negotiations will use MP's Demand Response Partial Term Sheet(s) as a starting point. MP's commencement of and participation in negotiations shall not be construed as a commitment to execute a contract. If a contract is negotiated, it will not be effective unless and until it is fully executed with the receipt of all required regulatory approvals.

* * * * *

7.0 RESERVATION OF RIGHTS

Nothing contained in this RFP shall be construed to require or obligate Minnesota Power to select any proposals or limit the ability of Minnesota Power to reject all proposals in its sole and exclusive discretion. Minnesota Power further reserves the right to withdraw and terminate this RFP at any time prior to the submittal deadline, selection of bids or execution of a contract. All contracts will be contingent on MPUC approval.

All proposals submitted to Minnesota Power pursuant to this RFP shall become the exclusive property of Minnesota Power and may be used for any reasonable purpose by Minnesota Power. Minnesota Power and Sedway Consulting shall consider materials provided by respondent in response to this RFP to be confidential only if such materials are clearly designated as "Confidential." Respondents should be aware that their proposal, even if marked “Confidential”, may be subject to discovery and disclosure in regulatory or judicial proceedings that may or may not be initiated by Minnesota Power. Respondents may be required to justify the requested confidential treatment under the provisions of a protective order issued in such proceedings. If required by an order of an agency or court of competent jurisdiction, Minnesota Power may produce the material in response to such order without prior consultation with the respondent.

Request for Proposals

for

Up to 300 MW of Capacity and Energy from Customer Co-Generation

issued by
Minnesota Power

Issue Date: August 5, 2016
Proposals Due: September 26, 2016

Complete Information on this RFP can be found at:

http://RFP.mnpower.com

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1.0 BACKGROUND

Minnesota Power (MP), a division of ALLETE, Inc., has issued this Request for Proposals (RFP) and is seeking power supply proposals for up to a nominal 300 MW of capacity and unit-contingent energy from a co-generation facility owned and located at Minnesota Power retail customer currently served under the Large Power or Large Light and Power Service Schedule and the customer demand is greater than five (5) MW, beginning in the 2019 to 2023 timeframe. This request is part of MP's broader evaluation process that considers the costs and characteristics of several different power supply types (e.g., wind, solar, natural gas, demand response, and distributed generation) to optimize the mix of resources to meet customer needs. MP's current resource strategy calls for a diversified mix of resources to meet all customers' needs reliably and cost effectively in an environmentally responsible manner.

MP seeks cost-effective customer co-generation resources that utilize the efficiencies of locating generation where customer load exist and provide capacity that is accreditable under current Midcontinent Independent System Operator (MISO) Resource Adequacy rules[1]. The bidder must be an existing MP customer and the co-generation project must be owned by an existing MP customer and comply with terms in existing Electric Service Agreement (ESA). Proposals must reflect the cost and characteristics of the Customer co-generation resource. Proposals must offer an initial contract term for a minimum of 20 years. Agreements are contingent upon Minnesota Public Utilities Commission (MPUC) approval and may require associated modifications to Electric Service Agreements also subject to MPUC approval.

Proposals must reflect all of the costs and characteristics of the resource delivered to MP's load zone.

All proposals must be received by the contact designated in Section 3.3 by the Proposal Submittal Deadline date shown in Section 3.1. MP reserves the right in its sole discretion to modify this schedule for any reason.

MP will not be submitting a Customer co-generation proposal into this Request for Proposal (RFP). In connection with this RFP, MP has retained the services of an independent third party consultant (Sedway Consulting, Inc.) to work with MP in the quantitative evaluation of all proposals. However, MP will make the final decision (subject to MPUC review, as applicable) in MP's sole discretion.

* * * * *

[1] The MISO Business Practice Manual for Resource Adequacy (#11) is located here https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

2.0 ELIGIBLE PROPOSALS – MINIMUM REQUIREMENTS

Proposals must meet the general minimum eligibility requirements described below. MP will screen all proposals for compliance with these requirements. Proposals that fail to meet one or more of the general minimum eligibility requirements may be disqualified from further consideration.

2.1 Eligible Power Supply Requirements

1. Offers must be eligible to provide MISO accredited or accreditable capacity (including Zonal Resource Credits for Local Resource Zone 1) and energy of no less than 1 MW and up to a maximum of 300 MW of Summer and Winter capacity, be available to start delivery in the 2019 to 2023 timeframe, and be owned by a current MP service customer with demand greater than 5 MW,

2. Offers must be based on a non-intermittent, firm resource with an availability guarantee per the Customer Sited Customer Co-Generation Partial Term Sheet.

3. Offers must demonstrate delivery of capacity and energy to the MP load node (currently MISO MP.MP CPNode).

2.2 Eligible Project Structures

Minnesota Power will consider the following proposal types:

1. Power Purchase Agreements (“PPA”)

2. Tolling Agreements (“TA”)

3. Asset Purchase

The term for all contracts must be for a minimum of 20 years and the bidder may provide MP an option to purchase a portion or the entire facility after 10, 15 or 20 years at net book value.

2.3 Participant Requirements

The bidder must be a MP retail service customer currently on a Large Power or Large Light & Power Service Schedule and have a demand greater than 5 MW.

2.4 Locational Requirements

The customer co-generation project must be located within MP service territory at a customer site that is served under either the Large Power or Large Light and Power Service Schedule, interconnected to either the MP owned distribution or transmission system and capable to serve customer load at the site.

2.5 Power Delivery Requirements

All proposals must demonstrate firm delivery of capacity to the Minnesota Power load node (as determined by MISO or MP), currently MP.MP. The cost of obtaining firm transmission service or interconnecting to the MP distribution system, and any interconnection equipment shall be the responsibility of the respondent and must be included in the proposed pricing. Respondent shall be responsible for all operational related costs, penalties, and charges assessed by MISO. MP is available to assist in coordinating the actual interconnection process with MISO and MP.

One of the goals of this RFP is to determine the overall cost to MP's retail customers of the selected resource(s), recognizing that the cost of interconnection and delivery of power from the chosen resource(s) to MP's native load is an element of cost that must be taken into account. Network upgrade costs (Including cost at the distribution and transmission level) that are assessed to the project will be the responsibility of the respondent. All pricing should reflect those costs (to the extent applicable) at the time of submittal. To the extent that network or distribution upgrades are required as a consequence of adding the proposed project to the MISO transmission system or the MP distribution system, the network upgrade costs will be included in Minnesota Power's economical evaluation of the proposal.

2.6 Fuel Transportation Service

Offers for natural gas-fired customer co-generation resources must be served through firm transportation service by at least one major natural gas pipeline. For each pipeline the proposal must indicate the most applicable fuel pricing hub(s), pipeline tariffs and receipt points, negotiated rates, reservation rates, any local distribution company (LDC) charges, backup fuel capability, and any other fuel-related cost (as applicable). For evaluation purposes, the evaluation team plans to use the same fundamental fuel price forecast for estimates of natural gas commodity pricing for each bid.

The natural gas must be supplied at a rate, compression, and pressure sufficient to run the facility at full output (including duct firing and any other capacity enhancements) on a continuous basis and still comply with all operating requirements of the pipeline or LDC system.

For natural gas pipeline capacity, provide appropriate transportation details including the Maximum Daily Transportation Quantity and any other terms, conditions, or limits necessary for Minnesota Power to understand the deliverability of fuel and total cost of firm gas transportation. If an existing facility has existing firm pipeline contracts, the main terms of these contracts should be provided with the proposal if the respondent wishes to transfer these contracts to Minnesota Power. This information must be provided in Exhibit B: PPA/TA Data and/or Exhibit C: Asset Purchase Data and/or Exhibit D: New Build Cost Buildup (as available and applicable).

For non-natural gas fired customer co-generation (e.g. biomass) offers the bidder must provide a firm plan for fuel procurement that includes fuel availability, demonstration the fuel is a proven technology, delivered cost to site, storage capability on site, fuel handling equipment required, upgrades and cost associated for delivery method(s) (e.g. new rail spur) and contract arrangements for fuel delivery. If an existing facility, please include current fuel procurement plan, fuel delivery contracts, delivered fuel cost for the past five years, and a description of any events in the past five years where the bidder was unable to procure fuel for the facility.

2.7 Environmental

The customer co-generation resource must be in compliance with all applicable environmental rules and regulations.

To the extent applicable, all environmental attributes, including emission reduction credits and/or allowances, related to the power being purchased should be conveyed to MP. This includes, but is not limited to, any and all credits in any form (emissions credits, offsets, financial credits, renewable energy credits, etc.) or baseline emissions associated with both known and unknown pollutants, including but not limited to SO2, NOx, Hg, and CO2. Any and all environmental liabilities, including compliance with known and future or unknown regulations or laws will be the sole responsibility of the generation producer/PPA seller.

For Asset Purchase proposals, the Seller will retain all pre-closing and known future environmental liabilities and obligations associated with the real and personal property transferred with or as part of a Sale of the Plant. This includes both on and off-site liabilities. The Buyer will assume all post-closing environmental liabilities and obligations.

2.8 Firm Pricing

Proposals must include pricing that is firm and not subject to any revisions during Minnesota Power's evaluation and negotiation process. Bidders may propose escalation rates that are either fixed or, if appropriate and defensible annually indexed to the Gross Domestic Product Implicit Price Deflator (GDPIPD). Such indexing is not acceptable for demand or capital pricing but for elements of a bidders pricing proposal that will be impacted by the GDPIPD. The GDPIPD will be adjusted annually as published by the U.S. Department of Commerce, Bureau of Economic Analysis. Formulaic mechanisms will not be subject to revisions during MP's evaluation and negotiation process.

All pricing should be provided in Exhibit B and/or Exhibit C and/or Exhibit D in terms of US dollars as of the date the term of the contract begins and not subject to a currency exchange rate adjustment. All PPA/TA information should be provided in Exhibit B: PPA/TA Data, all Asset Purchase information should be provided in Exhibit C: Asset Purchase Data and a cost buildup for new build projects should be provided in Exhibit D: New Build Cost Buildup (all data as available and applicable). Any and all environmental liabilities, including compliance with known and future or unknown regulations or laws will be the liability and sole responsibility of the generation producer/PPA Seller. Minnesota Power will receive all associated allowances or credits, if any. Seller agrees to transfer any Financial Transmission Rights or Auction Revenue Rights associated with the asset to the Buyer (if applicable).

Respondents are strongly encouraged to provide their 'best and final' pricing with their initial submittal. Minnesota Power does not anticipate an opportunity in the schedule for respondents to refresh or update their pricing before the final selection(s) are made (if any). Respondents Proposal and pricing shall remain valid until May 31, 2017.

2.9 Credit Rating

A bidder must have a credit rating for its senior unsecured debt of **BBB** or higher (for Standard & Poor's) or **Baa2** or higher (for Moody's). If a bidder is unrated or does not meet this minimum credit rating requirement, the bidder must demonstrate the capability to supply performance assurance in the form of a corporate guarantor that meets the requirement, a letter of credit and/or cash. The amount of performance assurance shall be no less than $100/kW of the proposed capacity of the proposal. This performance assurance will remain in place from contract execution through the term of the contract unless otherwise negotiated based upon the expected financial exposure related to the bid.

2.10 Statement of Material Exceptions

Proposals must provide the bidder's material exceptions to MP's Customer Co-Generation Partial Term Sheet included with this package.

2.11 Legal Certifications

A bidder must certify that:

1. There are no pending legal or civil actions that would impair the bidder's ability to perform its obligations under the proposed PPA;

2. the bidder has not directly or indirectly induced or solicited any other respondent to submit a false or sham proposal;

3. the bidder has not solicited or induced any other person, firm, or corporation to refrain from submitting a proposal; and

4. the bidder has not sought by collusion to obtain any advantage over any other respondent.

* * * * *

3.0 SCHEDULE AND RFP INSTRUCTIONS

3.1 Overview of Process

The schedule below represents MP's expected time-line for conducting this resource solicitation. MP reserves the right to modify this schedule as circumstances warrant and/or as MP deems appropriate.

Minnesota Power RFP Schedule

Event	Anticipated Date
Release of RFP	August 5, 2016
Informational Session	10:00 am to 12:00 pm on August 15, 2016 at Minnesota Power General Office Building in Room 140[2]
Proposal Submittal Deadline	**5:00 pm CST on September 26, 2016**
Proposal Evaluation	September 26 to October 14, 2016
Negotiations with Selected Bidders	November - December 2016
Application for Regulatory Approval	January 2017

If you plan to participate in the informational session please RSVP to MPLargeCustomerDR-RFP@mnpower.com or MPCo-GenRFP@mnpower.com. A WebEx option will be available for bidders that would like to participate in the informational session remotely. Please indicate in your RSVP if you plan to attend in person or via the WebEx. Additional information on the WebEx will be provided prior to the session.

After proposals are submitted, Sedway Consulting will review and quantitatively evaluate all conforming proposals. An MP e-mail address (MPCo-GenRFP@mnpower.com) has been set up to collect all communications and questions from potential respondents as well as a web site (http://RFP.MNPower.com) to download the RFP and Exhibits and provide uniform communications, including updates and other details as may be provided throughout the bidding process.

Proposals will be opened in private by Sedway Consulting on a confidential basis. One original copy of each proposal will be retained by Sedway Consulting for a review and comprehensive quantitative evaluation and one original copy of each proposal will be retained by Minnesota Power for a comprehensive qualitative evaluation.

Each respondent should expect to receive a confirmation email from Sedway Consulting that his/her offer submission has been received. If a confirmation email is not received within 24 hours following the Offer Submission Deadline, a respondent should contact the independent evaluator at: Alan.Taylor@sedwayconsulting.com or (303) 581-4172.

Proposals will be reviewed by Sedway Consulting for completeness and offers that do not include the information requirements of this RFP may be notified by Sedway Consulting and allowed to cure the deficiency. During the evaluation process, respondents may be contacted for additional data or clarifications by Sedway Consulting.

[2] The Minnesota Power General Office Building is located at 30 W. Superior St., Duluth, Minnesota 55802

3.2 Exhibits

Respondents to this RFP are required to sign **Exhibit A: Non-disclosure Agreement (NDA)** in its present form.

Respondents to this RFP area also required to complete **Exhibit B: PPA/TA Data** and/or **Exhibit C: Asset Purchase Data** and/or **Exhibit D: New Build Cost Buildup** (as available and applicable).

Respondents to this RFP are required to complete **Exhibit E: General Information** (as applicable).

Respondents to the RFP are required to provide written exceptions to **Exhibit F: Customer Co-Generation Partial Term Sheet**

All correspondence concerning the submittal process for this RFP must be sent via e-mail to MPCo-GenRFP@mnpower.com with Sedway Consulting copied at Alan.Taylor@sedwayconsulting.com.

Individual questions submitted by a respondent to MP and Sedway Consulting before the submittal deadline will be answered and responses sent back via email to the respondent as soon as practical. Responses to frequently asked or broadly applicable questions may be placed on the RFP Website for the benefit of all respondents, with any identifying information redacted from the question.

3.3 Deadline and Method for Submitting Proposals

All proposals submitted in response to this RFP must be received by MP and Sedway Consulting at the email addresses below no later than the Proposal Submittal Deadline shown in Section 3.1. Sedway Consulting and Minnesota Power will not evaluate proposals as part of this RFP process if submitted after this date and time. Minnesota Power does not anticipate an opportunity in the schedule for respondents to refresh or update their pricing before the final selection(s) are made (if any). Multiple proposals submitted by the same respondent must be identified separately. Financial statements, annual reports, and other large documents should be referenced via a web site address.

Respondents shall email an electronic copy of its proposal to MPCo-GenRFP@mnpower.com with Sedway Consulting copied at Alan.Taylor@sedwayconsulting.com.

1. Each Proposal must contain the following:

    a. A signed **Exhibit A: Non-disclosure Agreement (NDA)** in its present form

    b. **Exhibit B: PPA/TA Data** and/or **Exhibit C: Asset Purchase Data** and/or **Exhibit D: New Build Cost Buildup** (as applicable)

    c. **Exhibit E: General Information**

    d. Additional materials that address the requirements of the RFP

2. Do not send any files in compressed formats, such as .zip.

3. Respondents should undertake efforts to avoid excessively large emails/attachments; in any case, individual email size must be less than 10 MB. If the emailed information exceeds this limit, then respondents should break their submission into multiple emails.

* * * * *

4.0 PROPOSAL ORGANIZATION

The proposal must include an executive summary, proposal limitations, relevant company data and experience, the technical proposal, along with the appropriate Exhibits. Some information may not be known at the time proposals are due. However, partial information and estimates are better than nothing at all, so respondents are encouraged to submit as much information as possible.

4.1 Executive Summary

Please provide a one page executive summary of the proposal in the form of a cover letter. Include the facility's location, age or development status, size, the primary contact's name, email, and phone number, and an overview of the major features of the proposal. The Executive Summary must be signed by an officer of the respondent who is duly authorized to commit the firm to carry out the proposed power supply transaction should Minnesota Power accept the proposal (this does not have to be the primary contact). A Table of Contents should be the first page and immediately precede the Executive Summary.

4.2 Proposal Limitations

Please describe in reasonable detail any existing regulatory, legal, economic, operational, or systematic conditions that might affect the respondent's ability to deliver capacity and energy as offered.

4.3 Company Data, Financing Plan, and Experience

Please include information on the respondent's corporate structure (including identification of any parent companies), the project's financing plan, the respondent's most recent credit rating, quarterly report containing unaudited consolidated financial statements that is signed and verified by an authorized officer of respondent attesting to its accuracy, a copy of respondent's annual report for the prior three years containing audited consolidated financial statements and a summary of respondent's relevant experience. Please describe any current litigation or environmental fines from the last three years that could potentially affect the facility or its operation. All financial statements, annual reports and other large documents may be referenced via a web site address.

Proposals shall include a list of projects with a brief description of Respondent's experience in the areas of development, financing, permitting, ownership, construction, and operation of all utility-scale and customer co-generation scale power generation facilities.

Please provide a list of projects with a brief description of the experience as it relates to utility-scale and customer co-generation scale power generation.

Please provide a list of projects with a brief description of the Operator's experience as it relates to utility-scale and customer co-generation scale power generation (in and outside MISO).

4.4 Technical Proposal

Proposals shall include a detailed technical description of proposed Project. Please review the technical description provided in this section such that it matches up with the technical and cost information provided in the Exhibits. The technical description shall include, but not be limited to the following items as known and applicable:

1. Project name, size, and location

2. Customer service account number

3. Commercial operation date and expected facility life

4. Development and construction schedule Gantt chart (if new)

5. Site characteristics including zoning, site control, site map (white and aerial backgrounds), and any potential environmental or other sensitive issues

6. Description of all the permits needed and plan to acquiring those permits including timing and any expected contingencies or local consultants required

7. Site layout (white background)

8. Community Outreach Plan and evidence of community support

9. Labor source (preference is the use of local prevailing wage for labor cost; if a respondent is willing to commit to this, the respondent's proposal should clearly state that commitment)

10. Full description of proposed technology, reliability, redundancies, automatic generation control, engineering and design status (e.g. FEP-1, FEP-2, PDR, etc), operating capabilities, and heat rate efficiencies

11. List of other equipment including auxiliary boiler, energy storage, evaporative cooling, chillers, and duct firing

12. Description of emission control equipment and any ASTM studies

13. Natural gas supply, availability and firm transportation arrangements, backup fuel capability and characteristics if applicable

14. Non-natural gas supply, availability and transportation arrangements, backup fuel capability and characteristics if applicable

15. Full description of the interconnection and firm transmission, deliverability to the delivery point, the overall risk to the transmission or distribution systems, and estimated network upgrade costs (see below)

16. Description of operating flexibility including start times (hot/warm/cold) and ramp rates, minimum down time, minimum output, heat rates at less than full capacity, reactive power, voltage regulation, frequency control, other potential ancillary services, different operational modes, and the current market for those ancillary services

17. Scheduling process and flexibility

18. Environmental, emission and/or any other operating constraints

19. Water supply, usage and discharge

20. Schedule of major maintenance

21. Key terms of a Long-term Service Agreement (LTSA)

22. Key features and terms for Original Equipment Manufacturer spare parts and Long-term Parts Agreement (as applicable)

23. Description of control systems and building enclosure

24. Discuss any other owners and the dispatch rights/preference arrangements

25. An allowance for multiple offers into MISO markets

26. "Best Practices" construction, operation, and maintenance

27. May provide an option to purchase after year 15 or 20 at net book value

28. Other future options and/or the capability to expand

29. Capacity size options between 1 – 300 MW

30. Statement of exceptions to MP's Customer Co-Generation Partial Term Sheet

Any fuel "formula" provided must be in sufficient detail for Sedway Consulting and Minnesota Power to understand all the formula components for estimation of the total cost of fuel (and backup fuel), in $/MMBtu, for the Delivery Term (See Exhibit B and C).

For natural gas-fired customer co-generation facilities, firm gas transportation is to be provided by the respondent and the pertinent details on the firm gas transportation arrangement. If firm gas transportation is not indicated, then the respondent should explain the reason. Details should include maximum daily quantity transportation volume, and any transportation demand rate information necessary to understand the total cost of firm gas transportation on a monthly and annual basis.

Describe the transmission and interconnection arrangements and any transmission service required for delivery of capacity to MP's native load. Respondents will have the responsibility to secure and provide all firm transmission services necessary for firm delivery of capacity to the Minnesota Power MISO load node, MP.MP, however MP will assist in coordinating the actual interconnection process with MISO or MP.

For Purchase Power Agreement and Tolling Agreements, specific operational information and pricing should be provided as indicated in Exhibit B: PPA/TA Data, all asset purchase proposals shall provide the specific information requested in Exhibit C: Asset Purchase Data, and all new build projects shall provide the specific information requested in Exhibit D: New Build Cost Buildup; (as available and applicable). All respondents to this RFP are required to complete Exhibit E: General Information (as applicable).

* * * * *

5.0 PROPOSAL EVALUATION AND CONTRACT NEGOTIATIONS

5.1 Initial Proposal Review

An initial review of the bids will be performed by Sedway Consulting. Proposals will be reviewed for completeness and proposals that do not meet or include the information requirements of this RFP may be notified and allowed to cure the deficiencies. Respondents may also be contacted for additional data or clarifications by Sedway Consulting. In general, more certain information and development progress is better than less certain or unknown information.

5.2 Proposal Quantitative Evaluation

Sedway Consulting will quantitatively evaluate all conforming proposals' ability to meet both capacity and energy needs and the corresponding costs. During the quantitative evaluation process, Sedway Consulting may or may not choose to initiate more detailed clarification discussions and a more thorough quantitative evaluation with one or more respondents. Discussions with a respondent shall in no way be construed as commencing contract negotiations.

5.3 Proposal Qualitative Evaluation

Minnesota Power will evaluate and consider both the Quantitative Evaluation developed by Sedway Consulting and the qualitative aspects of all conforming proposals' ability to meet both capacity and energy needs. In general, more certain information and development progress is better than less certain or unknown information.

In evaluating Proposals, Minnesota Power may generally consider the following criteria (in no particular order and without limiting consideration of other factors):

1. Sedway Consulting's Quantitative Evaluation
2. Price certainty, price volatility, and risk of price increases
3. Integration into Minnesota Power's system
4. General location of the facility
5. Capability to serve customer load directly
6. Co-generation capability
7. Site characteristics including zoning, permits required, and any potential environmental issues or other sensitive issues
8. Site control
9. Respondent's development, financing, construction, operating, maintenance, and ownership experience as it relates to utility-scale power generation or customer co-generation
10. EPC contractor's experience as it relates to utility-scale power generation or customer co-generation (if applicable)

11. Operator's experience as it relates to utility-scale power generation or customer co-generation (in and outside MISO)

12. Respondent's or Guarantor's financial condition and creditworthiness

13. Transmission or distribution interconnection, deliverability to the delivery point, congestion, losses, and overall risk of transmission

14. Fuel supply and firm transportation arrangements

15. Operating flexibility including fast start times (hot/warm/cold) and higher ramp rates, minimum down time, minimum output, major maintenance, more efficient heat rates at less than full capacity, reactive power, voltage regulation, frequency control, scheduling flexibility, different operational modes, other potential ancillary services, and the current market for ancillary services

16. Construction schedule

17. Water supply, usage and discharge

18. Status of engineering and design (e.g. FEP-1, FEP-2, PDR, etc.)

19. Other power equipment enhancements including an auxiliary boiler, energy storage, evaporative cooling, chillers, and duct firing

20. Emission control equipment and emission rates

21. Quantity and complexity of network upgrades required (network upgrade costs will be included in quantitative evaluation of the proposal)

22. Labor source (preference is the use of local prevailing wage for labor cost; if a respondent is willing to commit to this, the respondent's proposal should clearly state that commitment)

23. Schedule of major maintenance

24. Long-term Service Agreement

25. Original Equipment Manufacturer spare parts and Long-term Parts Agreement

26. Control systems

27. Other owners and dispatch rights/preference, allowance for multiple offers into MISO

28. "Best practices" or similar construction, operation, and maintenance

29. Environmental and any other operating constraints

30. Technology, engineering design, redundancy, and overall reliability

31. Backup fuel capability (if applicable)

32. Current litigation

33. Community support
34. Tax treatment and impact on Minnesota Power's balance sheet
35. Age, remaining life, and term
36. Capacity size options/limits from 1 – 300 MW and future option to expand
37. Overall completeness, clarity, and quality of the Proposal
38. Compliance of proposals with the specifications and requirements described in the RFP
39. Other data as may be requested prior to commencing further discussions
40. Exceptions to MP's Customer Co-Generation Partial Term Sheet

5.4 Contract Negotiations

Based on the Quantitative Evaluation and Qualitative Evaluation, Minnesota Power may or may not select candidates for further discussions. Minnesota Power will contact any selected respondent in writing to confirm interest in commencing contract negotiations. All PPA negotiations will use Minnesota Power's standard PPA as a starting point. Minnesota Power's commencement of and participation in negotiations shall not be construed as a commitment to execute a contract. If a contract is negotiated, it will not be effective unless and until it is fully executed with the receipt of all required regulatory approvals.

* * * * *

6.0 RESERVATION OF RIGHTS

Nothing contained in this RFP shall be construed to require or obligate MP to select any proposals or limit the ability of MP to reject all proposals in its sole and exclusive discretion. MP further reserves the right to withdraw and terminate this RFP at any time prior to the submittal deadline, selection of bids or execution of a contract. All contracts will be contingent on MPUC approval.

All proposals submitted to MP pursuant to this RFP shall become the exclusive property of MP and may be used for any reasonable purpose by MP. MP and Sedway Consulting shall consider materials provided by respondent in response to this RFP to be confidential only if such materials are clearly designated as "Confidential." Respondents should be aware that their proposal, even if marked “Confidential”, may be subject to discovery and disclosure in regulatory or judicial proceedings that may or may not be initiated by MP. Respondents may be required to justify the requested confidential treatment under the provisions of a protective order issued in such proceedings. If required by an order of an agency or court of competent jurisdiction, MP may produce the material in response to such order without prior consultation with the respondent.

4401 Fair Lakes Court
Fairfax, VA 22033 USA
Phone: 1.703.818.9100
www.paceglobal.com

Appendix N: Pace Global 2017 Independent Resource Analysis

2017 Independent Resource Analysis

Prepared for:

Minnesota Power

July 25, 2017

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EXHIBITS

EXECUTIVE SUMMARY

Pace Global was retained to perform an independent, risk based resource analysis for Minnesota Power to rigorously assess the merits of Nemadji Trail Energy Center (NTEC) 1X1 natural gas combined cycle project and wind, solar and natural gas peaking supply additions (the "Energy*Forward* Resource Package" or "EFRP") relative to other reasonable supply technologies that are available. The analysis was designed to assess Minnesota Power's options, including the EFRP, to best meet objectives of providing for its long-term electricity needs in a reliable, cost competitive, and flexible manner under a wide variety of market, regulatory, and economic conditions over the Study Period (2018-2034). This analysis determined the recommended resource portfolio that best balances the various and sometimes competing resource planning objectives over a wide range of possible future conditions.

Pace Global adhered to the same approach that it has used successfully for utilities over the past decade in evaluating and selecting among alternative portfolios. This approach has been coined "Risk Integrated Resource Planning" and has been accepted by utilities, managements, stakeholder groups and public utility commissions across the U.S. This same approach was used several years ago in assessing Minnesota Power's Boswell Unit 4 scrubber investment decision. The approach considers several steps:

1. Identify objectives and assign metrics to each objective
2. Select portfolios for consideration (screening or regulatory requirements)
3. Develop probability distributions for each of the key inputs (load, fuel costs, emission costs, capital costs)
4. Select 200 scenarios by sampling from the probability distributions of inputs
5. Test each portfolio against a robust range and combinations of future markets conditions
6. Develop a balanced scorecard that compares each portfolio against each critical metric
7. Select the recommended portfolio that best balances competing objectives over a range of futures

METRICS

Metrics defined at the onset of the analysis that reflect Minnesota Power's planning goals were used to compare the portfolios in this analysis. These metrics are summarized in Exhibit 1.

Exhibit 1: Minnesota Power Portfolio Objectives

Category	Objective	Metric
Cost	Minimize power supply costs and rate increases	Total portfolio cost measured as the mean NPV of total portfolio cost
Risk / Rate Stability	Improve rate stability/manage risks to ratepayers	High cost exposure measured as the 95th percentile NPV of total portfolio cost
		Portfolio diversity measured as the number of technology/supply options offering over five percent of generation needs
		Environmental regulatory risk measured as the NPV of portfolio emissions cost
Market Exposure	Adaptable portfolio to take advantage of but not be adversely impacted by market exposure	Reliance on market sales (GWh)
		Share of hours where must take energy exceeds load (%)
Cost Exposure	Reliable power supply with appropriate level of capital and fuel market exposure	Capital share of total portfolio cost (%)
		Fuel share of total portfolio cost (%)

Source: Pace Global and Minnesota Power

PORTFOLIOS

Portfolios considered reflect Minnesota Power's current supply including existing assets and bilateral contracts and planned or modeled retirement dates (i.e. a generator's book life) and contract expirations. Additionally, power purchase agreements from Minnesota Power's 2016 competitive solicitation process for wind and solar supplies, including 250MW of new wind and 10MW of new solar were included in all portfolios. Load projections were consistent across all portfolios. The candidate portfolios considered the EFRP compared to other supply alternatives that meet all renewable targets, including the regulatory requirement to evaluate an option where renewable generation is used to meet 50% or 75% of incremental demand needed over the Study Period. The candidate portfolios include:

- **EFRP** – Portfolio supply over the Study Period is met with 250MW share of natural gas combined cycle capacity from the NTEC Project as well as some additional natural gas peaking capacity late in the Study Period to meet growing capacity needs.
- **Portfolio 1, 75% Wind** – Portfolio supply over the Study Period is met with significant new wind additions to meet capacity needs as well as around 160MW of natural gas fired peaking capacity. This portfolio includes 1,700MW of new wind builds with wind generation accounting for around 75% of incremental demand over the longer term. This scenario was developed to comply with Minn. Stat. §216B.2422, subd. 2.
- **Portfolio 2, 50% Wind** – Portfolio supply over the Study Period is primarily met with significant new wind additions to meet capacity needs as well as around 240MW natural gas fired peaking capacity. This portfolio includes 1,100MW of new wind builds with wind generation accounting for

around 50% of incremental demand over the longer term. This scenario was developed to comply with Minn. Stat. §216B.2422, subd. 2.

- **Portfolio 3, Battery and Wind** – Portfolio supply over the Study Period is met with significant new wind additions to meet capacity needs as well as 210MW of batteries. This portfolio includes 1,100MW of new wind builds with wind generation accounting for around 50% of incremental demand over the longer term.
- **Portfolio 4, Natural Gas Peaking** – Portfolio supply over the Study Period is met with new natural gas fired peaking capacity. This portfolio includes 440MW of new natural gas fired peaking capacity.

STOCHASTIC INPUTS

Pace Global's analysis considered the risk of alternate market conditions over the Study Period using stochastic distributions of the values of key market drivers around a mean or expected value. Distributions around the mean or expected values were constructed for the following inputs (the construction is shown in the body of this report).

- Fuel costs – distributions around expected natural gas and coal commodity prices
- Load – distribution around expected MISO regional load
- Cost of new entry – distributions around the expected capital costs of new build units, as well as longer term builds outside from supplies already contracted
- Emission costs – distributions around the expected cost of emission allowances including a cost of carbon and allowance prices for sulfur dioxide ("SO2") and nitrous oxides ("NOx") emissions under the Cross State Air Pollution Rule ("CSAPR").

Across the 200 scenarios (stochastic iterations) run for this analysis, different combinations of future market conditions drive different market prices, dispatch of plants in the region, new build and MISO regional retirement decisions and ultimately costs of Minnesota Power's alternative portfolios. The risk analysis is a robust approach to not only gauge the expected performance and costs of each portfolio but also consider alternate future market conditions and their associated risks.

PREFERRED RESOURCE PORTFOLIO

Using the metrics defined at the onset of the analysis, Pace Global determined the EFRP to be the preferred resource portfolio for Minnesota Power customers.

The risk analysis determined the EFRP to be the lowest cost portfolio both under expected market conditions and the lowest cost under worst case (extremely high cost market) conditions. Portfolios 1, 2 and 3 that assumed significant new wind builds limit exposure to changing fuel costs but have a great deal of surplus energy in the later years due to the significant wind capacity additions. This would require Minnesota Power to sell its excess energy on the open market exposing it to significant market price risk. It is Pace Global's view that over time, exposure to selling into a weak future market is more risky than purchasing power from the market in a high priced market in MISO. As more and more renewables enter the market we do not see a strongly strengthening market for power over time, rather declining average prices with more volatility tied to the output of non-dispatchable resources. The addition of the combined cycle capacity in the EFRP would provide Minnesota Power the flexibility to generate when the wind resources are not available and take advantage of opportunistic market conditions or self-supply with limited additional environmental impact relative to the other portfolios.

Exhibit 2: Balanced Scorecard of Risk Based Portfolio Analysis

Portfolios Study Period: 2018-2034	Cost	Risk/ Rate Stability			Market Exposure		Cost Exposure		All-in
	Mean Portfolio Cost NPV ($B)	High Cost Exposure 95th Percentile NPV ($B)	Diversity (# tech-nologies supplying >5% generation)	Envt. Regulatory Risk ($M)	Reliance on Market Sales (GWh)	% Hours Must Take Energy Exceeds Load (%)	Capital Share of Total Portfolio Cost (%)	Fuel Share of Total Portfolio Cost (%)	Overall Ranking
EFRP	$5.66	$5.97	5	$106.7	0.44	0.4%	42%	20%	
P-1 – 75% Wind	$5.97	$6.20	3	$106.2	21.0	71%	51%	18%	
P-2 – 50% Wind	$5.84	$6.08	4	$106.4	7.7	46%	48%	18%	
P-3 – Battery	$5.89	$6.14	4	$106.4	7.2	47%	48%	18%	
P-4 – Gas Peaking	$5.66	$5.98	4	$106.9	0.11	0.4%	42%	19%	

Note: Cost rankings reflect green for optimal condition and those within 1 percent, yellow for 1% to 5%, and red for conditions more than 5 percent from the optimal condition.

Source: Pace Global

Exhibit 2 shows an overall summary of how each portfolio performed against each of the metrics. Color coding was used for ease of reference to reflect the relative ranking of each portfolio on each metric. In the color coding, the portfolio that performed best in that metric was given a green color. Depending on how close the results were, those portfolios performing somewhat worse were given a yellow color and if there was a substantial difference between those and the worst performers, they were given a red color.

Relative to the 75% wind portfolio (P1), the EFRP across all 200 iterations on average (i) is lower cost by over 5 percent, (ii) is almost 4 percent lower in cost in its worst case outcome; (iii) has more technologies providing at least 5% of generation requirements; (iv) relies 20% less on market sales; (v) has must take energy resources exceeding load less than 1 percent of the time; and (vi) is less capital intensive. On the downside, it relies on market purchases more than the P1 75% wind portfolio, although the combined cycle unit allows for the flexibility to generate or take advantage of the market, and has a 2 percent higher fuel cost component. The same conclusion can be reached relative to the P2 50% wind and the P3 battery scenarios, though the aggregate benefits are to a slightly lesser degree.

From a cost and rate stability standpoint, the EFRP with the NTEC combined cycle unit has very similar costs to the P4 natural gas combustion turbine option. The EFRP has the benefit of lower reliance on market purchases relative to P4 as the peaking units are largely capacity only resources, generating on average 3 percent while the NTEC project demonstrated an average utilization of 45 percent in the analysis. NTEC provides Minnesota Power the ability to opportunistically take advantage of favorable market opportunities with the flexibility to provide significant generation at a much lower heat rate and emission profile relative to market to serve load.

INTRODUCTION

In its 2015 Integrated Resource Plan ("2015 IRP"), Minnesota Power outlines its strategy for moving away from a coal-based supply mix to a more balanced and diverse energy portfolio known as Energy*Forward*. In its Energy*Forward* strategy, Minnesota Power aims to achieve a balanced mix with a third of supply sourced from environmentally compliant coal and the balance from renewables and renewable enabling sources like natural gas over the long term. Actions under this strategy have already been implemented including the retirement of Clay Boswell coal fired units 1 and 2 in 2018 and the development of the Great Northern Transmission Line which will bring emission free hydroelectric generation to Minnesota Power's supply mix starting in 2020. Options to further advance the Energy*Forward* strategy are now being considered.

Minnesota Power has the option to participate in the Nemadji Trail Energy Center ("NTEC") project that provides a unique opportunity to bring additional natural gas generation into its supply mix and by partnering with another utility, take advantage of economies of scale. Further, adding combined cycle technology into Minnesota Power's portfolio is a way to economically help to manage the intermittency of the additional wind and solar resources in the portfolio. The Energy*Forward* Resource Package ("EFRP") assessed in this independent resource analysis considers a 250MW share of NTEC along with wind, solar, and natural gas peaking to supply mid- and long-term future energy and capacity needs anticipated at this time.

MOTIVATING QUESTIONS

Pace Global's Risk-Integrated Resource Planning ("RIRP") analysis was designed to assess merits of the candidate portfolios and in doing so consider key challenges that Minnesota Power will face over the planning horizon. The resource planning analysis considers Minnesota Power's planning principles which are:

1. Diversity – A power supply mix that cost-effectively manages risks in environmental regulation, fuel cost and generation technology.
2. Flexibility – A power supply adaptable to industry changes and fleet transitions.
3. Reduce Carbon Emissions – Effectively reduce the carbon emissions of the power supply while managing customer costs.
4. Efficiency – A reliable power supply that serves customer needs with the appropriate level of capital investment.

Considering these principles and the portfolio decisions at hand, Pace Global's analysis addresses the following key planning questions.

- What are the best new supply options to meet Minnesota Power's goals over time?
- Which of the bids recently received for solar and wind should be part of Minnesota Power's future portfolio?
- Should Minnesota Power participate in the proposed jointly owned NTEC combined cycle project or backfill with all renewable technologies?
- What additional opportunities exist for other cost-effective peaking natural gas technologies?

- What storage options could be economically attractive alternatives to peaking facilities?

EVALUATION PROCESS

Like most electric utilities, Minnesota Power has to make resource decisions under a great deal of uncertainty. A resource decision that meets all objectives when judged only under current or best guess forecasted conditions may prove to be a future financial burden on the utility over time if the forecasts are incorrect. Fuel market volatility, capital cost uncertainty, load uncertainty, emission regulations, and regulatory changes will all affect how a resource portfolio performs throughout its operational life. Understanding the range of potential market volatility and the severity of impending regulatory changes on alternative generation portfolios is crucial to making sound portfolio choices.

For Minnesota Power, the least expensive resource addition may not be the best if it also exposes customers to severe market volatility or negative effects associated with impending regulatory change. The tradeoffs between costs, risks, reliability, operational responsiveness and flexibility, environmental stewardship, and other utility objectives need to be quantified for each portfolio and need to inform the selection of the portfolio that will perform best according to those objectives the utility ranks as its highest priorities. The Pace Global RIRP methodology addresses all above important questions through a highly structured process that consisted of the following steps:

1. Identify overall objectives and metrics
2. Formulate candidate portfolios
3. Perform stochastic risk analysis of five portfolios to identify the Preferred Resource Portfolio
    - Provide stochastic distributions for key variables
    - Perform risk analysis for the candidate portfolios
4. Define conclusions and recommendations

The major steps listed above are presented in subsequent sections in this report.

THE ENERGY*FORWARD* RESOURCE PACKAGE

The EFRP would meet Minnesota Power's future energy needs and the state Solar Energy Standard with additional wind, solar, participation in the NTEC combined cycle generation facility, as well as additional natural gas fired peaking capacity late in the Study Period. The renewable additions would include in the near-term, 10MW of solar and 250MW of wind from competitive bids resulting from Minnesota Power's 2016 RFPs. Longer term, an additional 10MW of solar would be included in the portfolio to ensure that Minnesota Power complies with the state Solar Energy Standard requirements.

The NTEC project is a 1x1 natural gas fired generating facility to be located in Douglas County, Wisconsin. NTEC is a 525MW project, of which Minnesota Power would secure 250MW under a capacity dedication agreement with South Shore Energy, LLC, a subsidiary of ALLETE, Inc. formed for the purpose of owning 50 percent of NTEC. The project is scheduled to enter commercial operation at the end of 2024. Additional supply needs anticipated over the Study Period would be met with 110MW of natural gas-fired peaking capacity in the early 2030s.

MINNESOTA POWER ENERGY SITUATION ASSESSMENT

MINNESOTA POWER'S SUPPLY PROFILE

Minnesota Power's current resource mix will serve projected load and cover MISO's UCAP reserve requirement of 7.8 percent above peak demand for the very near term. The retirement of Clay Boswell coal units at the end of 2018 will drive a net short capacity position as early as 2019. Short term purchase agreements will cover some of this supply need. Supply in the form of the purchase agreement from Manitoba Hydro will begin in 2020, covering some of the mid-term short position. However, the projected growth in Minnesota Power's peak load and the decrease in power taken from the Milton R. Young 2 unit will continue to drive the need for additional supply; both capacity and energy resources will be needed.

At this time, close to half of the load Minnesota Power serves is industrial customers. This is noteworthy for two reasons. First, the shape of load served is relatively flat because a large share of these industrial customers operates 24 hours per day and 7 days per week. This is also noteworthy in that large blocks of demand can be added or removed as industrial customers expand or close operations.

This section presents the current supply and demand situation for Minnesota Power as well as some key changes in the supply mix expected at this time and assumed in this analysis.

GENERATION FACILITIES AND POWER PURCHASE CONTRACTS

As a load serving entity, Minnesota Power has a mix of generation assets with a total peak capacity of around 1,480MW. Exhibit 3 outlines Minnesota Power's existing supply resources. They can be summarized as follows:

- **Baseload coal-fired generating units** – This capacity includes the ownership of the Clay Boswell units 1 through 4 and partial share of Milton R. Young unit 2. Clay Boswell units 1 and 2 will come offline at the end of 2018 and Minnesota Power's capacity from Milton R. Young unit 2 will continue to decline and phase out completely by the end of 2025.
- **Natural gas-fired peaking units** – This capacity includes the full ownership of Laskin units 1 and 2. This analysis assumes that these units will cease operation at the end of 2030.
- **Wind** – Minnesota Power owns wind generating facilities including Bison 1 through 4 in North Dakota and Taconite Ridge in Minnesota and has long-term power purchase agreements for Oliver 1 and 2 in North Dakota. The Oliver purchase agreement will terminate at the end of 2032 with Oliver 1 terminating year end 2031 and Oliver 2 at the end of 2032, and is not assumed to be renewed in this analysis.
- **Biomass** – This capacity includes Hibbard units 3 and 4. This analysis assumes that these units will cease operations by the end of 2029.
- **Hydroelectric** – This capacity included two hydro generating resources; Thomson and Run of River facilities.
- **Solar** – Minnesota Power currently has two solar facilities that are recognized as a capacity resource for the summer peak. These are Camp Ripley and the Community Solar Garden in Duluth.
- **Demand-side capacity resources** – This capacity is primarily large power interruptible demand response capacity, as well as commercial and residential demand response and customer sited capacity.
- **Purchased capacity contracts** – Minnesota Power has several short term contracts and one long-term contract to purchase capacity as well as some capacity sale contracts. The net capacity

from purchases is included in Exhibit 3 below.

Exhibit 3: Minnesota Power Existing Supply Resources Summary

Resource Type	Units	Capacity 2018 / 2034 (MISO Accredited - UCAP)
Coal	Clay Boswell 1 & 2 Clay Boswell 3 & 4 Milton R. Young Unit 2	1,018MW / 783MW
Gas	Laskin 1 & 2 peaking units	81MW / 0MW
Wind*	Bison 1 – 4 Taconite Ridge Oliver 1 & 2	93MW / 75MW
Hydro	Thomson Run of River Hydro	107MW / 107MW
Biomass	Hibbard 3 & 4	45MW / 0MW
Solar*	Camp Ripley Community Solar Garden	0MW / 7MW (summer credit only)
Demand Side Resources	Customer sited capacity DSM – large power interruptible	259MW / 186MW
Firm Purchases and Sales	Several short-term capacity only and energy and capacity purchase and sale agreements Manitoba Hydro energy and capacity purchase	32MW / 250MW

*Note wind nameplate capacity totals 621MW in 2018 and 522MW in 2034 and solar nameplate capacity totals 13MW in 2034.

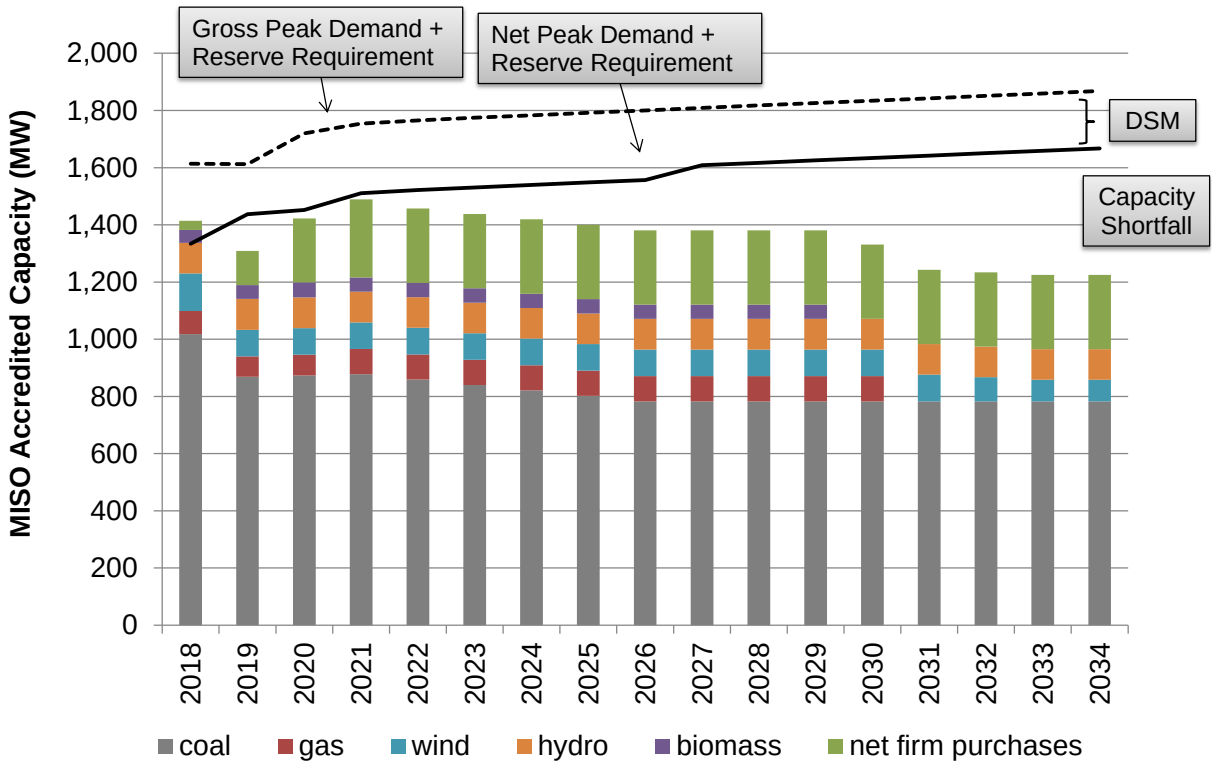
Source: Minnesota Power, Pace Global.

SUPPLY AND DEMAND BALANCE

Minnesota Power's load is projected to increase over the forecast period. Steady load growth coupled with planned unit retirements and contract expirations drive a net short position of the portfolio based on existing resources in the near term. Minnesota Power's base portfolio is net short capacity starting in 2019 following the retirement of Clay Boswell units 1 and 2. After this point the shortfall levels off somewhat as some firm capacity sales agreements expire and the 250MW purchase with Manitoba Hydro begins. Over time, the shortfall steadily increases through 2034 when, based on the current supply

resources and projected load growth, the shortfall would be 442MW. Exhibit 4 presents the current portfolio capacity relative to expected peak load. Load is presented as gross peak demand including reserve requirements and also as net peak load. The net peak load also includes reserve requirement but accounts for the capacity provided by demand side programs based on current projections.

Exhibit 4: Minnesota Power Existing Supply Resources vs. Projected Peak Load



Note: Base portfolio depicted reflects winter accredited capacity. Minnesota Power's base portfolio includes about 7MW of summer accredited capacity.

Source: Minnesota Power, Pace Global.

Status quo conditions (i.e., relying on market purchases to fill the capacity shortage) involve significant risk throughout the planning horizon due to high market exposure and a low reserve margin. As such, Minnesota Power is considering what decisions need to be made at this time to ensure that capacity and energy needs are met in the coming years as existing capacity resources cease and load growth continues.

MINNESOTA POWER RESOURCE OBJECTIVES AND METRICS

To properly evaluate resource decisions, planning objectives were defined at the onset of the resource analysis. A consensus was developed around the preferred resource portfolio by selecting the portfolio that best met the planning objectives over a wide range of regulatory and market outcomes. Metrics for each planning objective were created to form a basis for comparing different portfolios.

Even with the appropriate metrics identified for each planning objective, the tradeoffs associated with resource decisions represent the biggest challenge for resource planning. Exhibit 5 displays the competing objectives, identified as priorities. As is shown, focus on any one objective can move the resource portfolio away from focus on the others. A wide range of metrics were used to rank portfolios for each objective, to evaluate the tradeoffs associated with different portfolio options and, ultimately, arrive at a resource portfolio that balances many competing goals.

Exhibit 5: Minnesota Power Portfolio Objectives and Metrics

Category	Objective	Metric
Cost	Minimize power supply costs and rate increases	Total portfolio cost measured as the mean NPV of total portfolio cost
Risk / Rate Stability	Improve rate stability/manage risks to ratepayers	High cost exposure measured as the 95th percentile NPV of total portfolio cost
		Portfolio diversity measured as the number of technology/supply options offering over five percent of generation needs
		Environmental regulatory risk measured as the NPV of portfolio emissions cost
Market Exposure	Adaptable portfolio to take advantage of but not be adversely impacted by market exposure	Reliance on market sales (GWh)
		Share of hours where must take energy exceeds load (%)
Cost Exposure	Reliable power supply with appropriate level of capital and fuel market exposure	Capital share of total portfolio cost (%)
		Fuel share of total portfolio cost (%)

Source: Pace Global and Minnesota Power

COST OBJECTIVE

Preserve Competitive Rates

Preserving competitive rates is a common objective for utilities. In Minnesota Power's case, one of the primary objectives is to select the lowest-cost supply options and, therefore, minimize the rate impact on the customers. Pace Global used portfolio cost minimization as a proxy for maintaining competitive rates.

For comparative purposes, different portfolio options were evaluated based on the total net present value of all generation-related costs associated with serving Minnesota Power's load (in millions of dollars). The cost metric included the variable cost of generation, fixed costs, executed contracts costs, capital cost investments, and the cost of net market transactions (purchases minus sales).

RISK OBJECTIVES

Maintain Stable Rates (High Cost Exposure)

Rate stability can be measured by different metrics. For this analysis, portfolios were evaluated against statistically derived distributions on key market drivers like natural gas prices, coal prices, energy demand, carbon prices, power market prices, and capital costs. Rather than recording portfolio costs under one set of assumptions, Pace Global measured costs under a distribution of the key assumptions drivers. In this context, portfolios were evaluated based on the high, 95-percent confidence band, of these costs. This represented a metric of the portfolio cost under the most unfavorable expected market conditions.

Portfolio Diversity

Minnesota Power has implemented a strategy to move away from a coal dominant portfolio to a more balanced portfolio. One of the four planning goals is to diversify and have a power supply mix that cost-effectively manages risks of environmental regulation, fuel cost and generation technology. Minnesota Power's goal is to move to one third coal and the balance of its portfolio from renewables and sources facilitating renewables like natural gas to meet it load. Reliably serving customers was considered in terms of the reliance on a variety of generation supply type across the different portfolios. Overreliance on fewer energy technologies to supply most of its energy needs constitutes a risk as different market conditions will favor different generation types and value is placed on a balanced portfolio in this analysis. This is particularly a consideration for non-dispatchable technologies like wind where the resource output could vary notably over the course of a day and on a day to day basis. The number of sources / technologies contributing a significant share of Minnesota Power's load, defined as greater than 5 percent of total generation needs, was the metric identified to compare portfolio diversity to quantify this risk.

Environmental Regulatory Risk

Minnesota Power is obligated to comply with the state's renewable energy standard (RES) requiring that 25 percent of retail electric sales are supplied from eligible renewable sources, including wind, small hydroelectric facilities and biomass. Further, the state Solar Energy Standard requires that 1.5 percent of retail sales from investor owned utilities are supplied from solar by 2020. Due to its long term commitment to wind and other renewable technologies, Minnesota Power is already meeting the 25 percent requirement. Additional solar capacity will be needed to meet the Solar Energy Standard which was accounted for in all portfolios considered.

An increasing concern regarding global climate change has put specific emphasis on the carbon emissions associated with different power generating resource options. The potential advent of regulation and costs associated with CO_2 emissions constitutes a major risk for fossil plant owners. Pace Global's risk analysis considers a wide range of future carbon pricing levels as well as emission prices for SO_2 and NO_x emissions under the Cross State Air Pollution Rule. With this context in mind, the emissions cost for the various portfolios was the metric selected to consider environmental impact and associated risk for the comparison.

MARKET EXPOSURE

Reliance on Market Sales

Intermittent renewables that contribute significant generation relative to the capacity that is accredited under MISO for meeting reserve needs have the potential to place Minnesota Power in a net long energy position and, as a result, be reliant on selling excess energy to the market in the future. Pace Global finds the risk of being reliant on the market for a large amount of excess sales to be significant, particularly in soft market conditions. The total market sales from 2025 to 2034, the time when the portfolios begin to diversify from one another to the end of the Study Period, was used as the metric to quantify each portfolio's reliance on market sales.

Reliance on Must Run Resources

The impact of "must run" resources is considered under different daily and seasonal production and demand conditions. This metric is informative in better understanding the predominance of hours of the day where a portfolio's must run energy may be exceeding load, for example in off peak hours. This impact was quantified in the metric, share of hours (2025-2034) where must take energy exceeded load. Must take resources were defined as wind, solar, coal running at minimum capacity and energy from the Manitoba Hydro long-term firm purchase contract.

For each hour of the Study Period simulated in the risk analysis, the share of load met by these must take resources in the portfolio was calculated. The metric reflects the percentage of hours where the generation from must take resources exceed the corresponding hourly load for all years where the portfolios diversify, 2025 to 2034. Noting that other dispatchable resources are available to meet load when the wind is not available, it is important to have a balance of these resources.

COST EXPOSURE

Capital Cost Exposure

Minnesota Power has a planning goal of a reliable power supply that serves customer needs with the appropriate level of capital investment. Capital, including investment in new generation as well as fixed maintenance costs of operating assets for each portfolio, was the metric used to compare the capital exposure for the portfolios.

Fuel Cost Exposure

As fuel costs are likely to experience volatility over the forecast horizon, fuel cost exposure measured as the percentage of portfolio cost from fuel for each portfolio, was assessed as a metric to compare the exposure of the portfolios to fuel costs.

CANDIDATE PORTFOLIOS

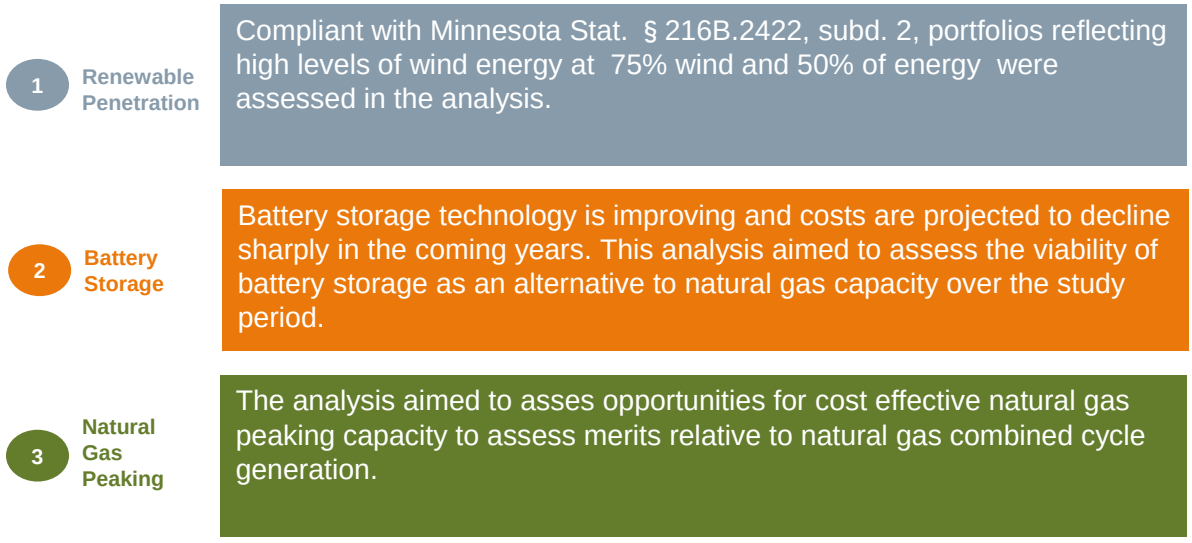
PORTFOLIO CONSTRUCTION AND CONSIDERATIONS

In addition to the EFRP, portfolios were constructed to reflect reasonable alternative supply options based on technologies that are available and economic. All portfolios reflected the following:

- No additional changes to Minnesota Power's existing generation resources and contracts were assumed. Planned unit retirement and contract terms and expiration dates were reflected in all portfolios.
- Compliance with the Minnesota RES and Solar Energy Standard was met in all portfolios.
- All portfolios included additional renewable supply from the 2016 solicitations for wind and solar, including a 250MW long-term wind purchase agreement beginning in 2020 and a 10MW solar purchase agreement starting in 2019. Another 12MW solar purchase agreement starting in 2025 was assumed to ensure compliance with the Minnesota Solar Energy Standard.
- Maintain reasonable tolerance to MISO reserve margin requirements, assuming that up to 50MW of capacity could be procured from the market in any given year of the Study Period.

Accounting for these factors, portfolios were constructed to assess the following considerations for Minnesota Power's future supply mix.

Exhibit 6: Summary of Key Drivers in Portfolio Construction and Screening



Source: Pace Global

The goal of the portfolio development process was to identify technically feasible and commercially viable generation resources that could be used as building blocks in constructing portfolios. For this reason, the portfolio development process focused on resource options that could meet Minnesota Power's new generation resource requirements, including size of the new generation resource, which is informed by

factors including load profile, capacity accredited by MISO, existing resources retirement, and PPA expiration, etc. In portfolios reflecting high penetrations of wind, flexible resources were paired to complement the non-dispatchable nature of wind.

Technologies considered included a combination of dispatchable fossil-fueled generation resources including NTEC as well as combustion turbines ("CTs"), and reciprocating engines. For renewables, in addition to a section of the most competitive bids from Minnesota Power's recent renewable RFP process included in all portfolios, longer term builds for wind were incorporated to meet reserve margins. Battery storage technologies were also considered in one portfolio with high wind penetration levels.

CANDIDATE PORTFOLIOS FOR STOCHASTIC ANALYSIS

The five candidate portfolios constructed for the analysis are summarized in Exhibit 7. These portfolios reflect the EFRP and reasonable alternative technology options to compare against. Each of these portfolios was evaluated in the stochastic analysis.

Exhibit 7: Candidate Portfolios for Stochastic Analysis

	EFRP	(P-1) 75% Wind	(P-2) 50% Wind	(P-3) Battery	(P-4) Gas Peaking
2018-2024	Retirement Retire Boswell 1 & 2 Phase out Young 2 New MHEB 250MW 10 MW Solar (SES) Wind PPA 250MW (RFP)	Retirement Retire Boswell 1 & 2 Phase out Young 2 New MHEB 250MW 10 MW Solar (SES) Wind PPA 250MW (RFP)	Retirement Retire Boswell 1 & 2 Phase out Young 2 New MHEB 250MW 10 MW Solar (SES) Wind PPA 250MW (RFP)	Retirement Retire Boswell 1 & 2 Phase out Young 2 New MHEB 250MW 10 MW Solar (SES) Wind PPA 250MW (RFP)	Retirement Retire Boswell 1 & 2 Phase out Young 2 New MHEB 250MW 10 MW Solar (SES) Wind PPA 250MW (RFP)
2025-2034	Retirement Hibbard 3&4 Laskin 1&2 New NTEC 250MW Solar 12MW (SES) Gas CT 110MW	Retirement Hibbard 3&4 Laskin 1&2 New Wind 1,700MW Solar 12MW (SES) RICE 162MW	Retirement Hibbard 3&4 Laskin 1&2 New Wind 1,100MW Solar 12MW (SES) RICE 252MW	Retirement Hibbard 3&4 Laskin 1&2 New Wind 1,150MW Solar 12MW (SES) Li-I Battery 210MW	Retirement Hibbard 3&4 Laskin 1&2 New Solar 12MW (SES) Gas CT 440MW

Source: Pace Global

Minnesota Power's location offers access to high quality wind resources in Minnesota and in North and South Dakota. This analysis considered the impact of incorporating wind supply in portfolios in various accessible regions to diversify the wind assets and expected production. The impact of significant additional wind generation in the Minnesota Power portfolio as well in the MISO region was assessed.

STOCHASTIC RISK ASSESSMENT OF CANDIDATE PORTFOLIOS

Pace Global performed a stochastic risk assessment of the candidate portfolios to quantify the performance and cost under a probabilistic range of future market conditions. An overview of the stochastic inputs to the analysis and results of the risk assessment are presented below.

STOCHASTIC INPUT DEVELOPMENT

Stochastic inputs used in the risk integrated resource planning process were based on a combination of historic volatility and expectations for future market trends. Pace Global's market insight was used to develop a view on future market trends; statistical and modeling tools were then employed to quantify the uncertainty around the expected trends and evaluate the performance of each portfolio under different uncertainties. The stochastic analyses required that uncertainties in these forecasts be determined. The effects of the load, fuel prices, CO_2 prices, and capital costs uncertainty on the portfolios were quantified over the study horizon under 200 different simulations.

Stochastic Inputs

Pace Global developed distributions of other key inputs to represent the probability of occurrence over a range of outcomes. Below are some of the key drivers of the stochastic analysis, with detailed inputs presented in Appendix B: Key Market Drivers.

- Load: MISO Regional Load was considered across a range to analyze impacts of alternate load growth outcomes.
- Capital Costs: Capital cost uncertainty was evaluated by defining stochastic bands around the capital costs of each resource addition in the portfolio for each year of the Study Period, based on historical commodity cost volatility and breakdowns of capital costs for different generating technologies.
- Natural Gas Prices: Natural gas price projections were developed according to primary supply and demand drivers that influence domestic production costs as well as international market dynamics.
- Emission Price Projections: CO_2 price projections were developed according to expectations for state and federal policy and regulations. Allowance price distributions for SO_2 and NO_x under the Cross State Air Pollution Rule were also a stochastic input to the analysis.
- Coal Price Projections in the Region: Coal price projections were developed according to primary supply and demand drivers.

STOCHASTIC ASSESSMENT RESULTS

The results of the stochastic analysis were aggregated and quantified as the predetermined metrics to compare the portfolios. Exhibit 8 presents total portfolio costs indicative of the expected cost, represented by the mean of the 200 iterations, the high bound cost, represented by the 95th percentile of all iterations.

Exhibit 8: Summary of NPV Portfolio Cost and Risk, 2018 - 2034 (2016$B)

	EFRP	(P-1) 75% Wind	(P-2) 50% Wind	(P-3) Battery	(P-4) Gas Peaking
Mean Cost	$5.66	$5.97	$5.84	$5.89	$5.66
95% Cost	$5.97	$6.20	$6.08	$6.14	$5.98

Source: Pace Global

Mean portfolio cost by components included in the objective metrics are presented in Exhibit 9 along with the share of total portfolio cost the individual components comprise. Because the coal generation from units in the portfolio is relatively constant across portfolios, the relative fuel costs and environmental costs are also largely consistent across all portfolios. The capital associated with significant wind builds in Portfolios 1, 2 and 3 show a notable increase in the capital costs of these portfolios and respective share of total portfolio cost.

Exhibit 9: NPV Portfolio Cost by Component (2016$B) and Share of Total Cost (%)

	EFRP	(P-1) 75% Wind	(P-2) 50% Wind	(P-3) Battery	(P-4) Gas Peaking
Capital	$2.38	$3.06	$2.77	$2.81	$2.36
	42.1%	51.3%	47.5%	47.7%	41.7%
Fuel	$1.15	$1.07	$1.08	$1.07	$1.08
	20%	18%	18%	18%	19%
Environmental	$0.107	$0.106	$0.106	$0.106	$0.107
	1.9%	1.8%	1.8%	1.8%	1.9%

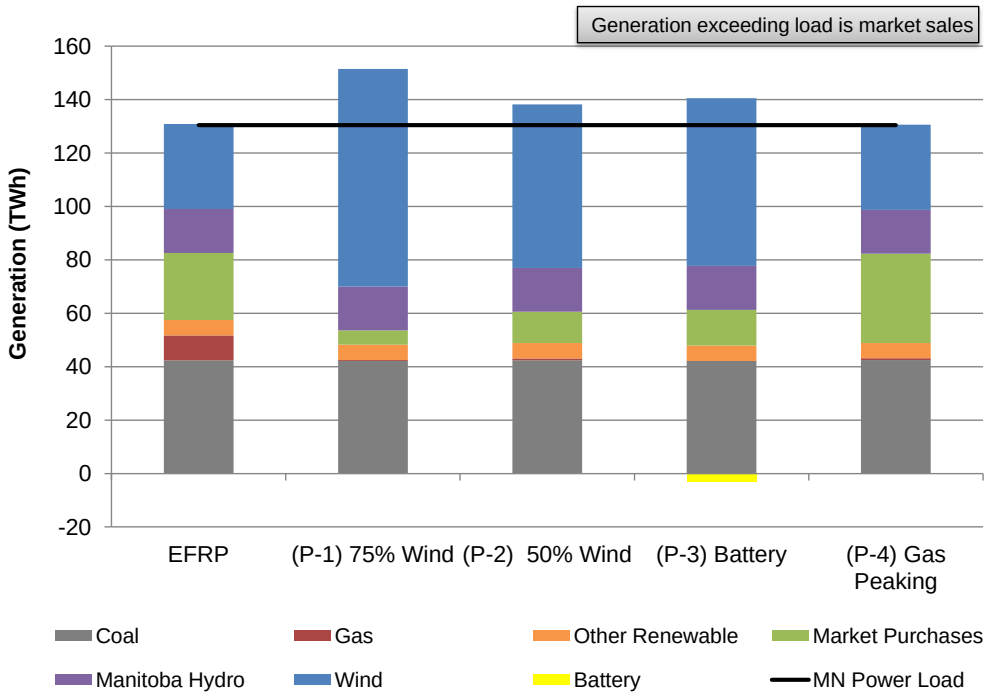
Source: Pace Global

Generation by source for each portfolio is presented in Exhibit 10. The generation is aggregated for the years after which the portfolios differentiate, starting in 2025 and extend through the end of the Study

Period. As noted, the consistent market conditions result in similar levels of coal generation across all portfolios. Despite the prominent levels of natural gas capacity in several portfolios, the EFRP is the only portfolio that ultimately offers a significant amount of generation from natural gas from the NTEC project. The 250MW NTEC unit exhibits an average capacity factor of 45 percent once operational. For comparison purposes, the natural gas peaking units in Portfolio 4 have a combined capacity of 440MW, but operate at a capacity factor of only about 2.5 percent on average, offering only minimal generation to the portfolio other than in exceptionally high cost market conditions, limiting the flexibility that these units offer to the portfolio.

The contribution of wind to the total energy mix varies significantly across portfolios, with wind accounting for up to 80 percent of load in the later years of the Study Period in Portfolio 1 (75% wind), ultimately resulting in net excess energy production and reliance on the market to sell this energy. This reliance on the market is viewed as a risk to these portfolios noting that the excess energy production most often occurs during low-cost, off peak hours of the day that could result in Minnesota Power selling at a loss. The battery storage capability in Portfolio 3 results in net negative generation due to the losses associated with charging and discharging the battery.

Exhibit 10: Total Portfolio Generation by Source Type (2025 – 2034)



Source: Pace Global

It is important to assess how must take energy, like wind and solar as well as coal running at minimums and firm purchase agreements, vary throughout the day relative to load and not just in aggregate. Daily and seasonal changes in wind and solar production along with hourly load changes have the potential to place Minnesota Power in a net long position from these must take energy resources alone in select

hours of the day. The share of must take resources, defined as (1) wind, (2) solar, (3) coal running at minimum capacity, and (4) the Manitoba Hydro firm purchase energy, relative to load on an hourly basis over the Study Period was calculated. This metric accounts for the volume and timing of the production of must take energy relative to the load throughout the day. Exhibit 11 presents this metric on average over the time period 2025 to 2034. On average, must take energy resources exceed Minnesota Power's hourly load in Portfolio 1, 71 percent of the time and slightly under 50 percent of the time for Portfolios 2 and 3. Over these years of the Study Period, must take energy exceeds Minnesota Power's hourly load less than half of one percent of the time in the EFRP and in Portfolio 4. The EFRP and Portfolio 4 portfolios would be less reliant on selling or "dumping" excess energy, particularly in low-priced off-peak hours of the day.

Exhibit 11: Share of Hours Must Take Energy Exceeds Hourly Load (2025-2034)

	EFRP	(P-1) 75% Wind	(P-2) 50% Wind	(P-3) Battery	(P-4) Gas Peaking
Average 2025-2034	**0.4%**	**71%**	**46%**	**47%**	**0.4%**

Source: Pace Global

CONCLUSIONS AND RECOMMENDATIONS

Using the metrics defined at the onset of the analysis, Pace Global's risk analysis determined the EFRP to be the preferred resource portfolio for Minnesota Power customers.

Expected Cost - The risk analysis resulted in the EFRP demonstrating the lowest mean portfolio cost of the candidate portfolios assessed. This indicates that under expected market conditions, the EFRP would be the lowest cost portfolio option for Minnesota Power. Portfolio 4, Natural Gas Peaking, resulted in a very similar cost profile under expected market conditions, although higher risk profile at higher natural gas prices.

Cost Risk – The EFRP also demonstrated the lowest cost risk, in the event of high cost market conditions. This cost risk was measured as the cost of the 95th percentile distribution of portfolio costs from the risk analysis. This indicates that under the most severe cost market conditions, the EFRP would still be expected to be the lowest cost portfolio option for Minnesota Power.

Portfolio Diversity – The EFRP offers the most diverse portfolio in terms of the number of significant generating sources. The presence of the combined cycle unit not only offers capacity to the portfolio but an energy source allowing Minnesota Power to opportunistically take advantage of favorable market opportunities with the flexibility to provide significant generation at a much lower heat rate and emission profile relative to market to serve load at competitive costs. The combined cycle unit is available at times when the wind is not.

Environmental Regulatory Risk – Because the coal capacity and expected generation from coal in the portfolio was relatively constant across all portfolios, the environmental regulatory risk was also found to be relatively consistent across portfolios. The EFRP would have slightly greater environmental costs due to the additional natural gas generation, however, these costs were less than one percent different from the lowest ranking portfolio and therefore all portfolios were assigned the same ranking for this metric.

Reliance on Market Sales – The EFRP showed a low risk in terms of reliance on sales of excess energy to the market. Portfolio 4 had a lower reliance on market sales, however, conversely this portfolio was more reliant on market purchases as the natural gas peaking capacity included in the portfolio offered only minimal energy to serve load.

Must-Take Resource Share of Load – The EFRP and Portfolio 4 had must take energy resources contributing to a reasonable share of load at all hours of the day. The wind heavy portfolios had high levels of must take energy resources that resulted in these sources exceeding load in many hours of the day over the Study Period.

Capital Share of Total Portfolio Cost – The EFRP (along with Portfolio 4) have the lowest capital investment required relative to the other portfolios that incorporate significant capacity of wind and dispatchable resources and storage.

Fuel Share of Total Portfolio Cost – The EFRP does have greater exposure to fuel costs and market relative to the other portfolios. However, this additional exposure should be mitigated as the combined

cycle unit also offers the ability to opportunistically purchase from the market in times of unfavorable market pricing.

Exhibit 12 shows relative ranking of the candidate portfolios based on Minnesota Power's key portfolio planning objectives and respective metrics. Accounting for all metrics, Pace Global's analysis finds the EFRP to be the preferred resource portfolio.

Exhibit 12: Balanced Scorecard of Risk Based Portfolio Analysis

Portfolios Study Period: 2018-2034	Cost	Risk/ Rate Stability			Market Exposure		Cost Exposure		All-in
	Mean Portfolio Cost NPV ($B)	High Cost Exposure 95th Percentile NPV ($B)	Diversity (# tech-nologies supplying >5% generation)	Envt. Regulatory Risk ($M)	Reliance on Market Sales (GWh)	% Hours Must Take Energy Exceeds Load (%)	Capital Share of Total Portfolio Cost (%)	Fuel Share of Total Portfolio Cost (%)	Overall Ranking
EFRP	$5.66	$5.97	5	$106.7	0.44	0.4%	42%	20%	
P-1 – 75% Wind	$5.97	$6.20	3	$106.2	21.0	71%	51%	18%	
P-2 – 50% Wind	$5.84	$6.08	4	$106.4	7.7	46%	48%	18%	
P-3 – Battery	$5.89	$6.14	4	$106.4	7.2	47%	48%	18%	
P-4 – Gas Peaking	$5.66	$5.98	4	$106.9	0.11	0.4%	42%	19%	

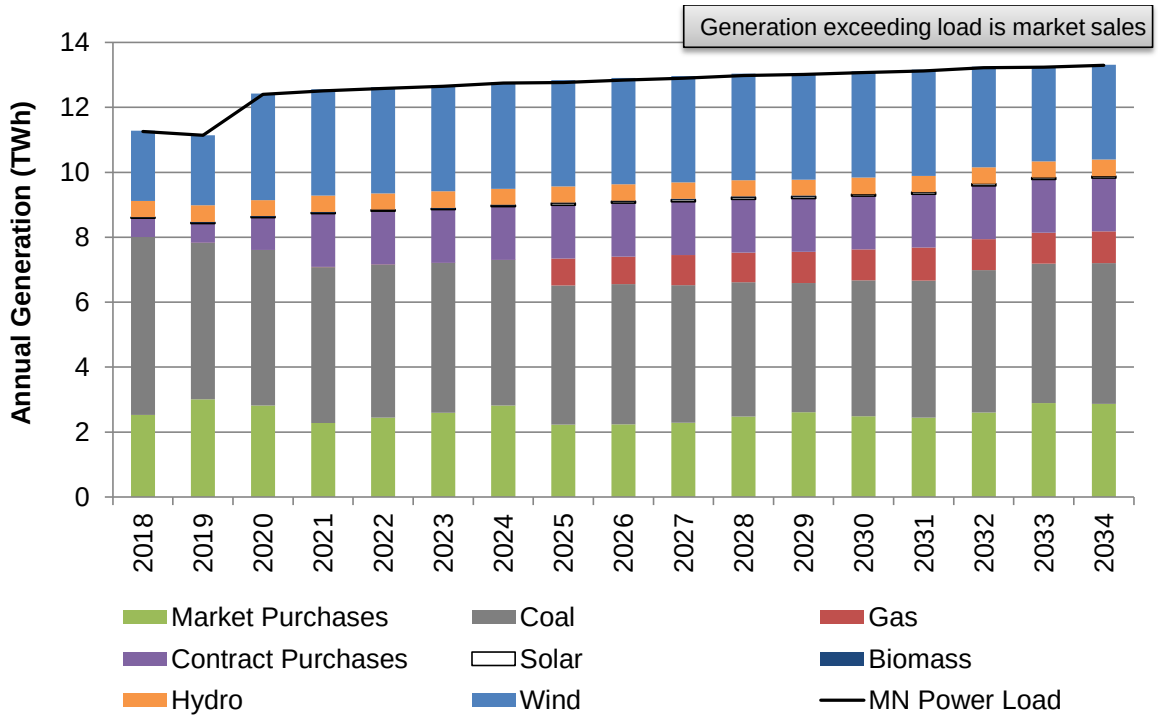
Note: Cost rankings reflect green for optimal condition and those within 1 percent, yellow for 1% to 5%, and red for conditions more than 5 percent from the optimal condition.

Source: Pace Global

APPENDIX A: CANDIDATE PORTFOLIO PROFILES

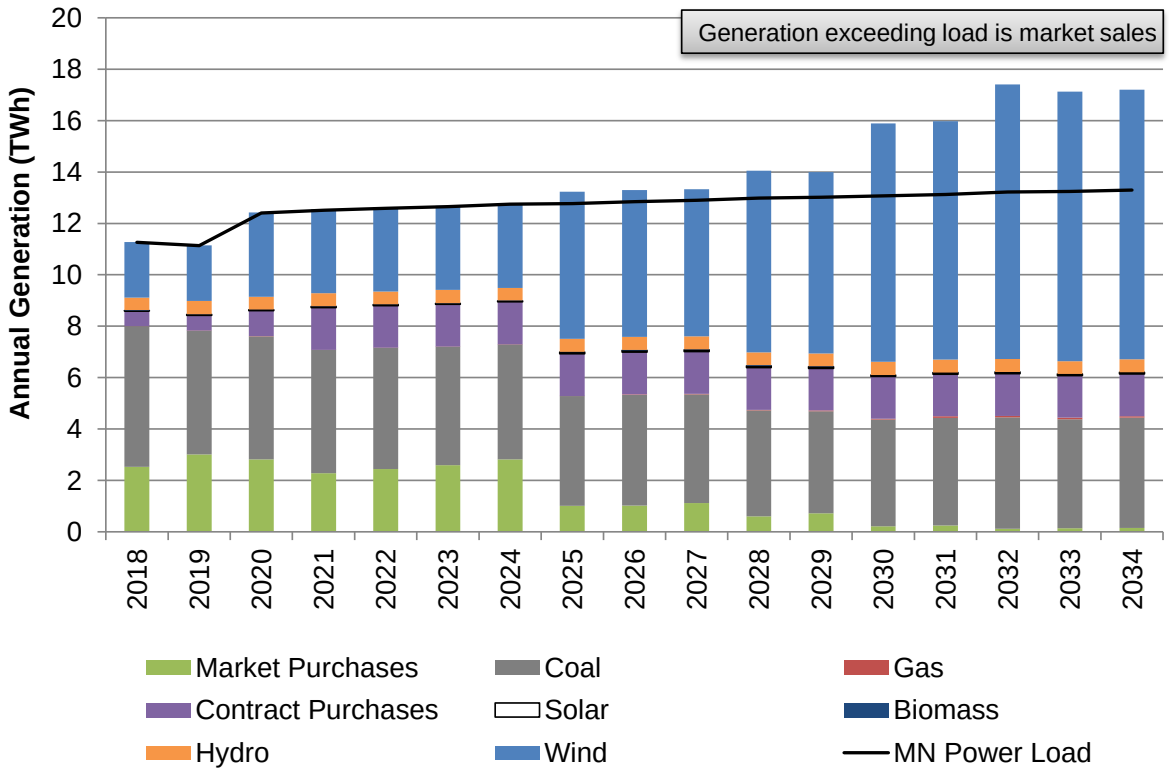
Annual summaries of average generation by source for all portfolios from the risk analysis are presented below.

Exhibit 13: EFRP – Annual Generation by Source Type (2018-2034)



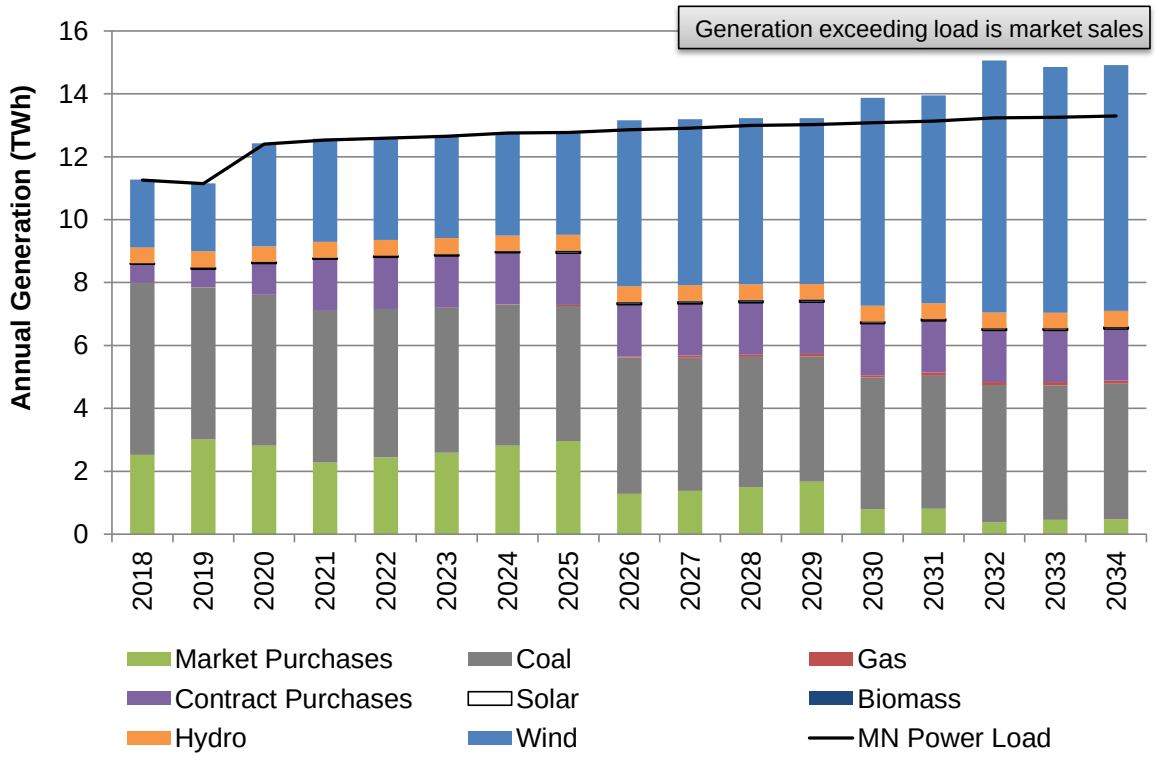
Source: Pace Global

Exhibit 14: Portfolio 1, 75% Wind – Annual Generation by Source Type (2018-2034)



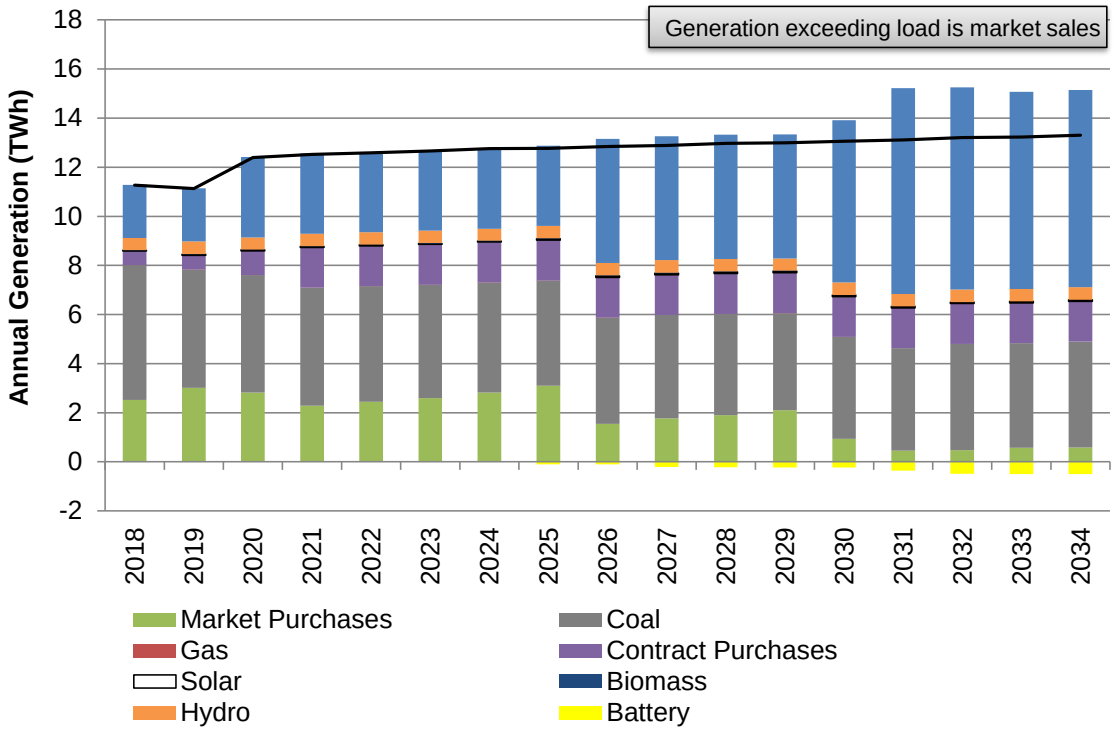
Source: Pace Global

Exhibit 15: Portfolio 2, 50% Wind – Annual Generation by Source Type (2018-2034)



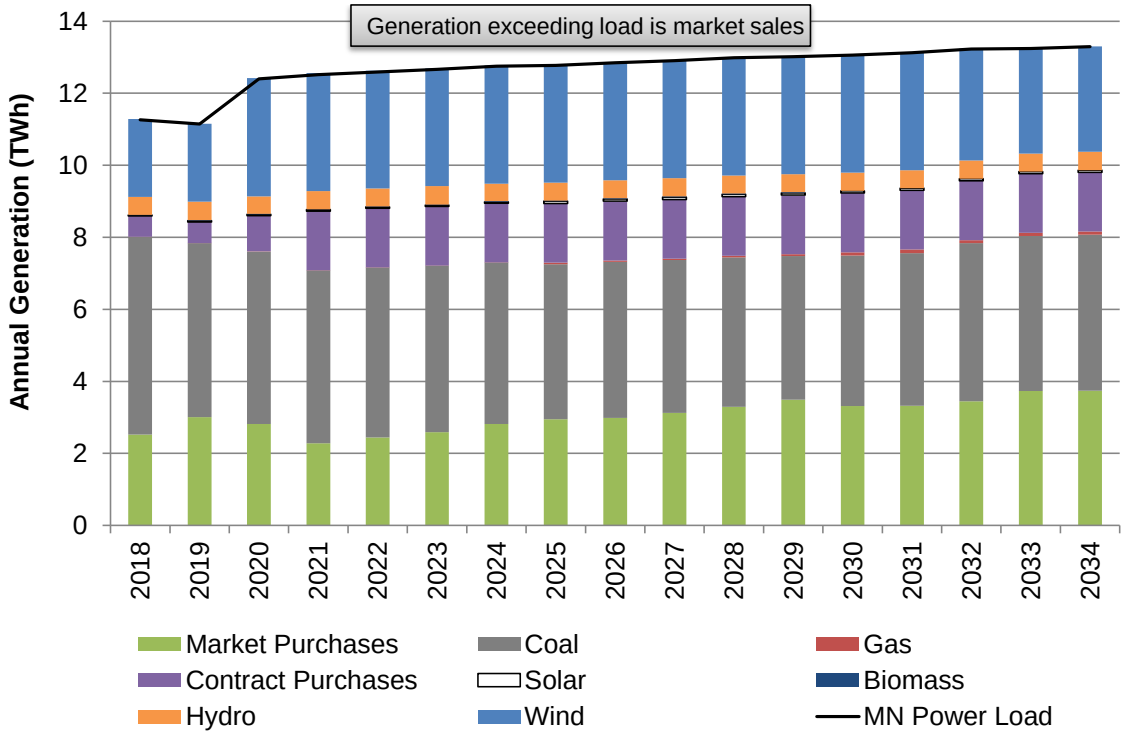
Source: Pace Global

Exhibit 16: Portfolio 3, Battery – Annual Generation by Source Type (2018-2034)



Source: Pace Global

Exhibit 17: Portfolio 4, Gas Peaking – Annual Generation by Source Type (2018-2034)



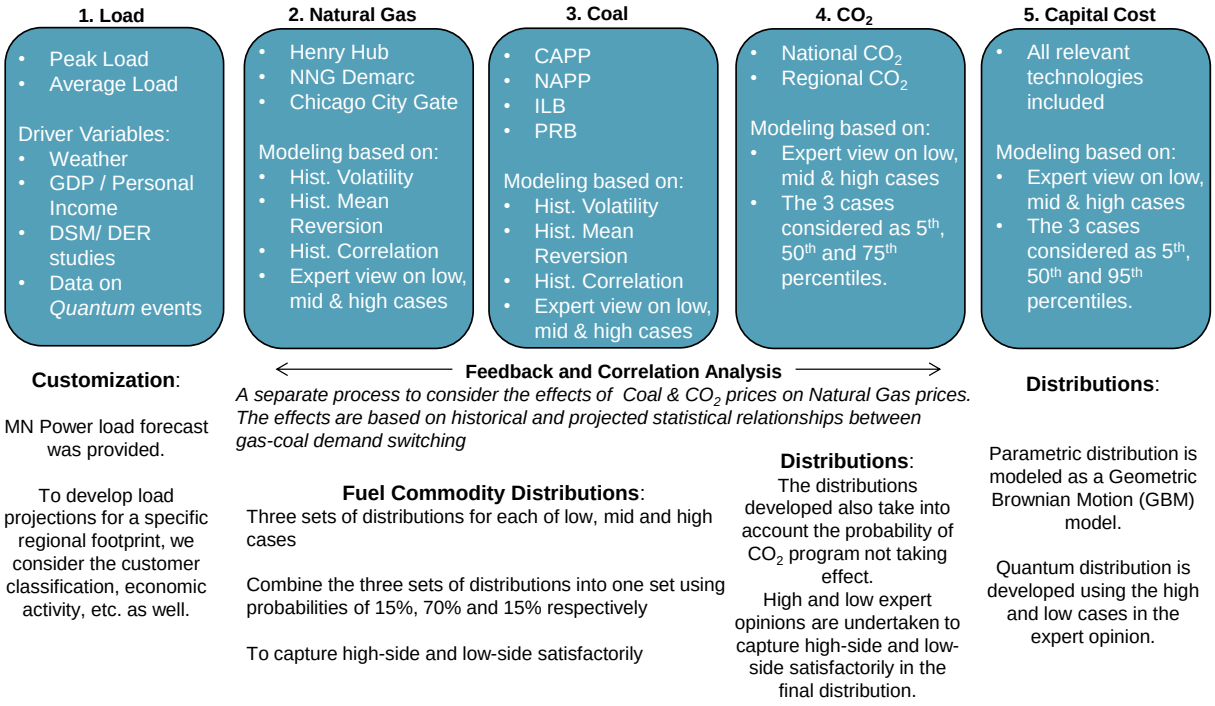
Source: Pace Global

APPENDIX B: KEY MARKET DRIVERS

STOCHASTIC INPUTS

Distributions for key market drivers included in the risk analysis are presented in this section. Pace Global develops stochastic inputs for key market drivers. These drivers differ for the different inputs which are summarized below.

Exhibit 18: Stochastic Inputs and Relevant Drivers



Source: Pace Global

Capital Cost Projections

Pace Global develops equipment performance and cost forecasts for over thirty technologies in the power generation industry. These technologies include aero and frame natural gas fired power plants (40-1,000MW), renewable generation facilities (solar, wind and hydro) plus other technologies such as storage and nuclear power plants. Specifically, Pace Global provides assumptions on All-in Capital Expenses ("CapEx"), Variable Operation & Maintenance costs ("VOM"), Fixed Operation & Maintenance costs ("FOM"), Capacity, Heat Rate and Construction Time. Definitions of CapEx, VOM and FOM are below.

- CapEx ($/kW) includes all EPC costs (equipment, material, and labor), Owners Costs (land, gas interconnection, site transmission, and assorted development costs and fees) and Interest During Construction ("IDC") costs.

- VOM ($/MWh) includes consumable materials, water treatment chemicals, and minor online turbine maintenance. VOM does not include fuel costs.
- FOM ($/kW) includes plant operating and maintenance labor, minor and major maintenance costs sometimes encapsulated in Long-Term Service Agreements (LTSAs), and other plant specific costs like insurance and property tax.

Pace Global's assumptions for technology new builds included in the portfolio analysis and new builds in the broader MISO market assumed the parameters included in Exhibit 19.

Exhibit 19: New Resource Technology Parameters – National Average

Technology	Advanced CC 2x1	Conventional CT - Fr.	Conventional CT - Aero., Lg	RICE - NG	Utility Solar PV - Fixed	Onshore Wind	Batteries - Li-ion
Fuel	Nat. Gas.	Nat. Gas.	Nat. Gas.	Nat. Gas.	Sun	Wind	All
Construction Time (Yrs)	3	2	2	2	2	3	1
Size (MW)	857	220	102	102	50+	> 20	1 MW, 4 hrs
Heat Rate, HHV (Btu/kWh)	6,555	9,862	8,994	8,218	-	-	-
All-in Capex, Avg. (2016$/ kW)	1,019	817	1,221	1,274	1,449	1,866	2,612
VOM ($/MWh)	2.90	3.37	4.85	5.88	-	3.75	1.40
FOM ($/kW-yr)	8.36	11.36	11.46	16.80	18.56	32.49	26.73

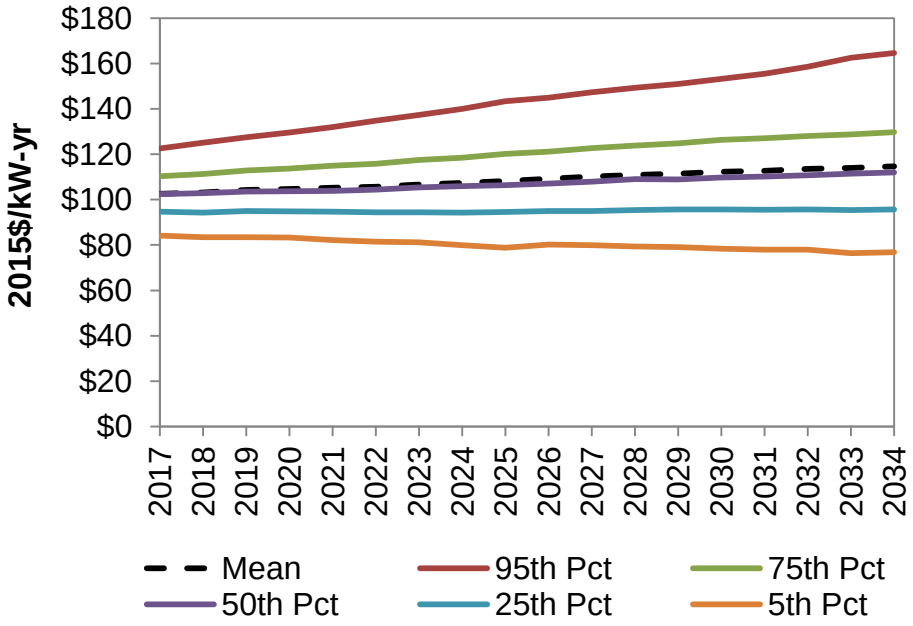
Source: Pace Global.

Pace Global maintains a database of all applicable studies, projects, and announcements that include over fifty public and confidential client sources. All sources in the database are within three years of the present to maintain up-to-date assumptions. Pace Global screens each source for equipment type, model, project scope and location to develop qualified samples. These qualified samples are then modified using variables including location adjustments, inflation adjustments and owner's interest rate to develop comparable national samples. Pace Global then uses statistical analysis from the comparable national samples and expert opinion to determine likely cost ranges for each technology.

The technology database provides the foundation for our technology performance and costs forecasts. To develop longer term cost projections, Pace Global considers a number of factors, including the recent and expected rates of technological improvements for existing technologies and new technologies that are under development. Pace Global also considers the history of technology transition from one model to the next, as exemplified by "F class" and "G/H/J class" gas turbines. Stochastic Distributions for technologies included in the analysis are presented in Exhibit 20 through Exhibit 24.

Advanced 2x1 CC technology is relatively new technology that has not developed a full fleet of projects. EPC costs including construction, commissioning and testing are projected decline as more projects are implemented in the future. However, increasing fuel costs over the forecast period result in slightly increasing levelized costs over the Study Period.

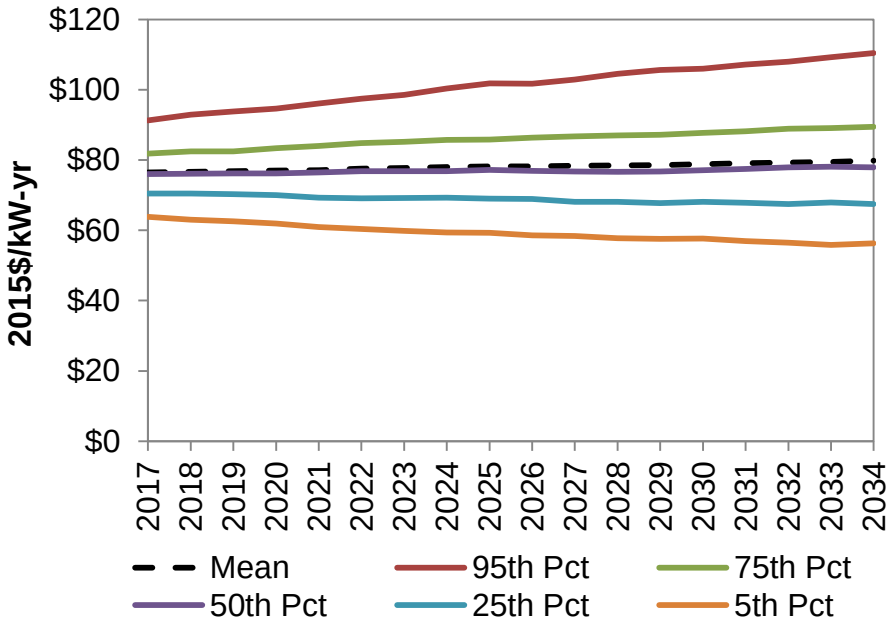
Exhibit 20: Advanced Natural Gas Combined Cycle Levelized Cost Probability Bands



Source: Pace Global

Conventional Frame CT technology has a fleet of existing projects and is considered mature technology. Labor costs are expected to increase steadily which results in a slight increase in capital costs over time. The impacts of slightly increasing fuel costs over the Study Period are less prevalent in the in the levelized cost for the CT technologies due to the expected lower utilization of these technologies relative to the CC.

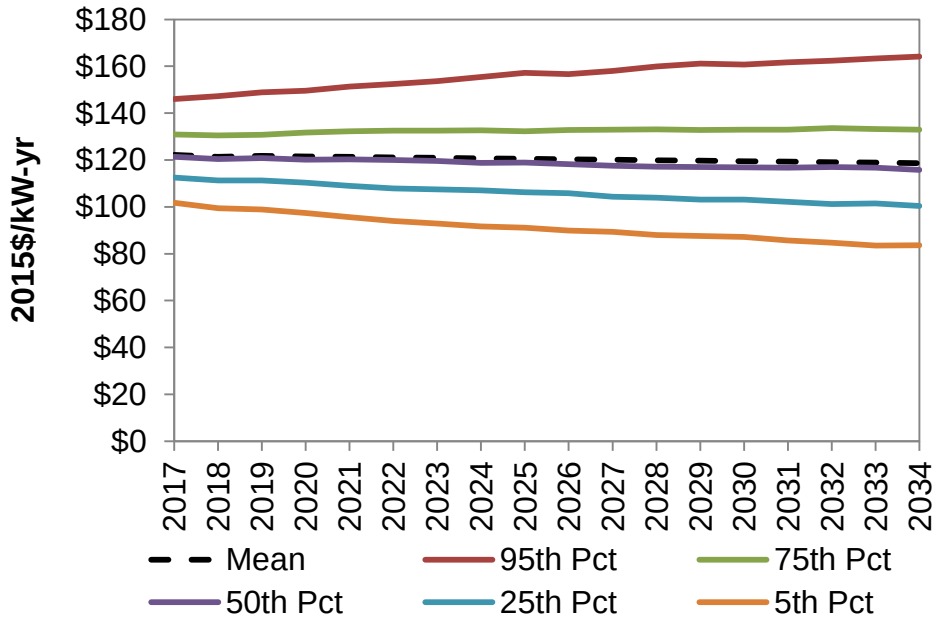
Exhibit 21: Conventional Frame Combustion Turbine Levelized Cost Probability Bands



Source: Pace Global

Reciprocating Internal Combustion Engine (RICE) technology has a fleet of existing projects and is considered mature technology. However, more original equipment manufacturers are licensing their equipment overseas for reduced manufacturing cost. This along with future battery technology advancements creating a more competitive market for fast ramping, small peaking units, capital costs are expected to decline overtime.

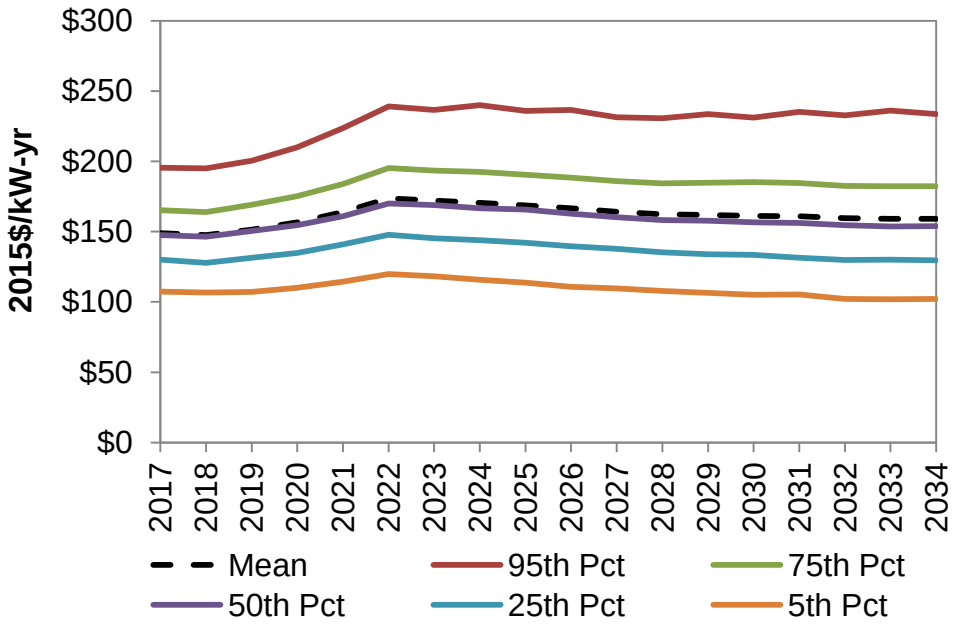
Exhibit 22: Reciprocating Engine Levelized Cost Probability Bands



Source: Pace Global

Onshore Wind technology has seen recent declines in capital costs since the large volume of turbines manufactured per project enables fast learning curves for reducing cost. Increasing hub heights will help wind turbines capture higher wind speeds to reduce costs per kW. The levelized costs reflect the phase out of the Production Tax Credit over the next several years, resulting in increasing all-in costs in the near term as projects are no longer able to realize the full credit in the future.

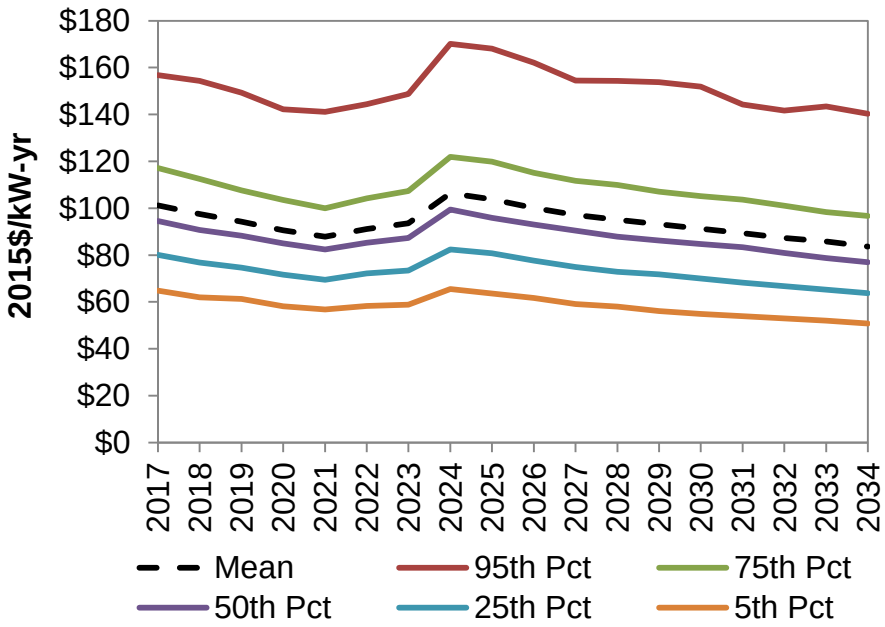
Exhibit 23: Onshore Wind Levelized Cost Probability Bands



Source: Pace Global

Solar photovoltaic installed costs have declined notably over the past several years due to economies of scale with the large volume of panels manufactured enabling fast learning curves for reducing costs. As the solar market grows and becomes more competitive (i.e. multi-axis panels) competition and reductions in balance of plant costs are expected to result in additional capital cost declines. The levelized cost will see increases through 2024 despite declining capital costs due to the phase down of the Investment Tax Credit.

Exhibit 24: Solar PV (Fixed-Axis) Levelized Cost Probability Bands



Source: Pace Global

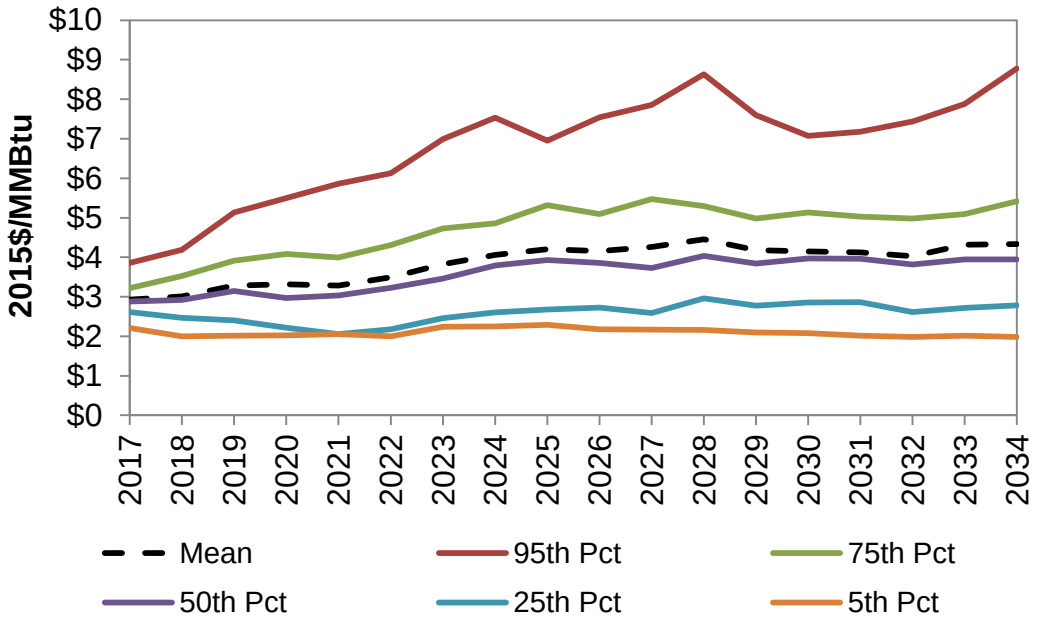
Natural Gas Prices

Pace Global's view of natural gas prices shown in Exhibit 13 is based on a fundamental view of supply, demand, and infrastructure. For context, natural gas markets in the U.S. have been in an oversupply environment due to the onset of shale gas production since approximately 2008, which has driven down natural gas prices at the benchmark Henry Hub. Since the end of 2014, natural gas prices have been near historical lows (concurrent with a downturn in oil prices), averaging just $2.65 per MMBtu since January 2015 but dipping below $1.50 per MMBtu. While producers have weathered the down market relatively well, through forward-hedging and high-grading their production to core areas, the unsustainably low prices caused producers to cut back on drilling and investment. Overall U.S. natural gas production levels began to decline beginning in 2015, even as demand continued to grow. The production decline only began to reverse recently at the beginning of 2017 as the supply/demand balance began to tighten, propelling Henry Hub prices to climb above $3.00 per MMBtu.

The short-term outlook for U.S. natural gas markets sees a resumption of growth in shale gas production helping to keep natural gas prices near to or below $3.00 per MMBtu for the next 2-3 years, particularly as recent increases in price incentivize new drilling. In addition, inventories of drilled-but-uncompleted wells, which can typically be completed for ~70 percent of the cost of a new well, remain relatively high. However, the overall trend continues of natural gas production growth shifting toward the Northeast while new incremental export demand (in the form of liquefied natural gas exports and pipeline exports to Mexico) grows in the Gulf Coast region. This paradigm shift of demand and supply growing in different regions will put upward price pressure on the benchmark

Henry Hub, allowing prices to rise incrementally to a more sustainable long-term level of $4.00 per MMBtu.

Exhibit 25: Henry Hub Price Probability Bands



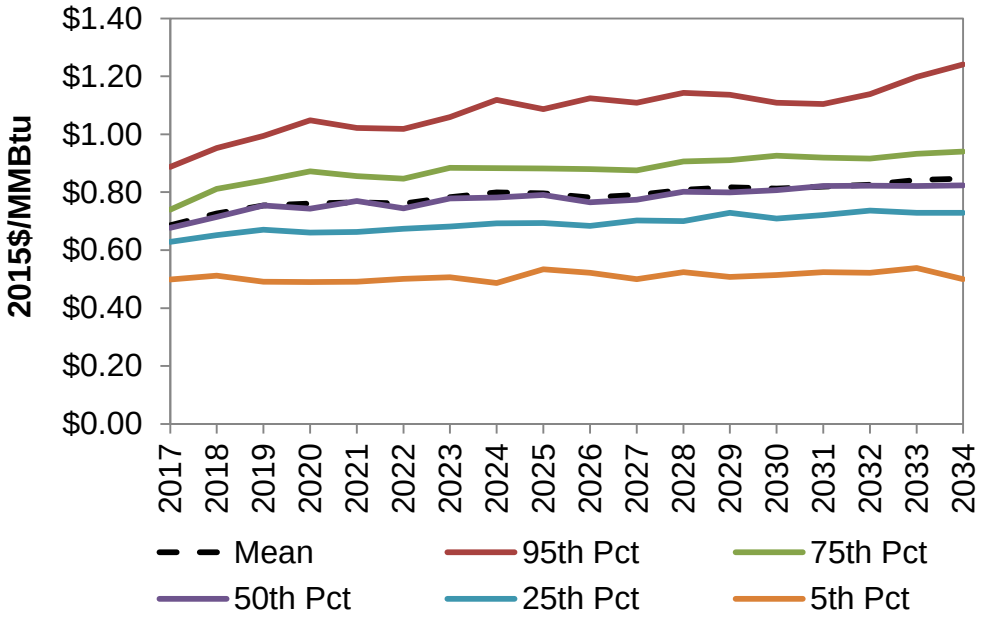
Source: Pace Global

Coal Prices

Pace Global assesses basin-level market fundamentals and develops projections based on current market forward signals and expected market trends. Coal's share of national power generation fell from 50 percent in 2008 to just over 30 percent in 2016. As a result, prices have fallen as producers in major supply regions have reined in production to right size to current market conditions.

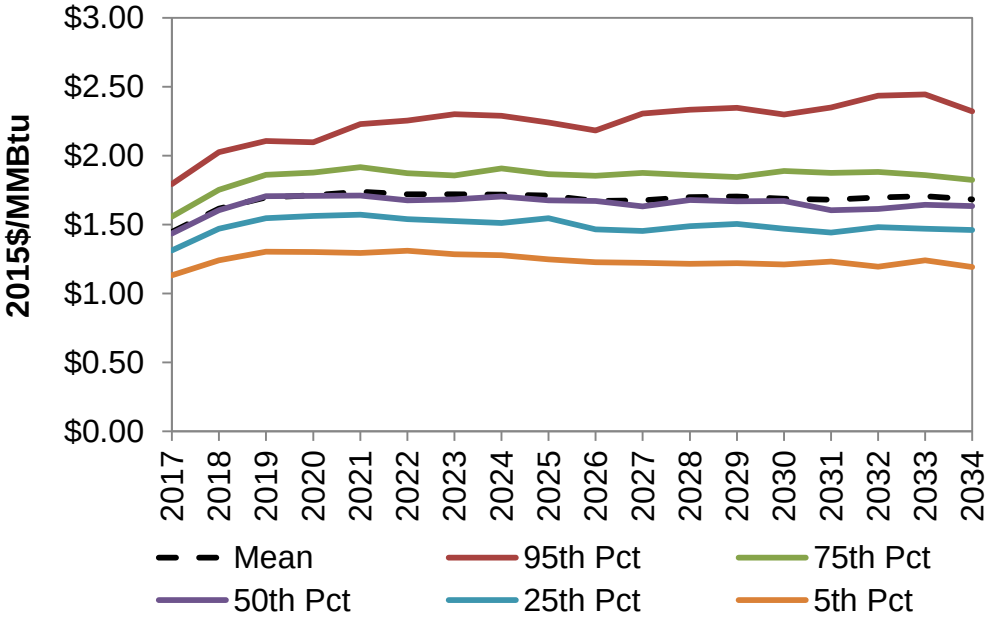
For PRB coal, prices are expected to increase gradually in real dollars due to increases in mining costs due to reserve depletion as shown in Exhibit 26. Coal commodity pricing out of the Illinois Basin are expected to remain relatively flat over the forecast period as new large underground mines are expected to not experience significant impacts of reserve depletion in this relatively newer supply region (Exhibit 27).

Exhibit 26: PRB Basin Price Probability Bands



Source: Pace Global

Exhibit 27: ILB Basin Price Probability Bands



Source: Pace Global

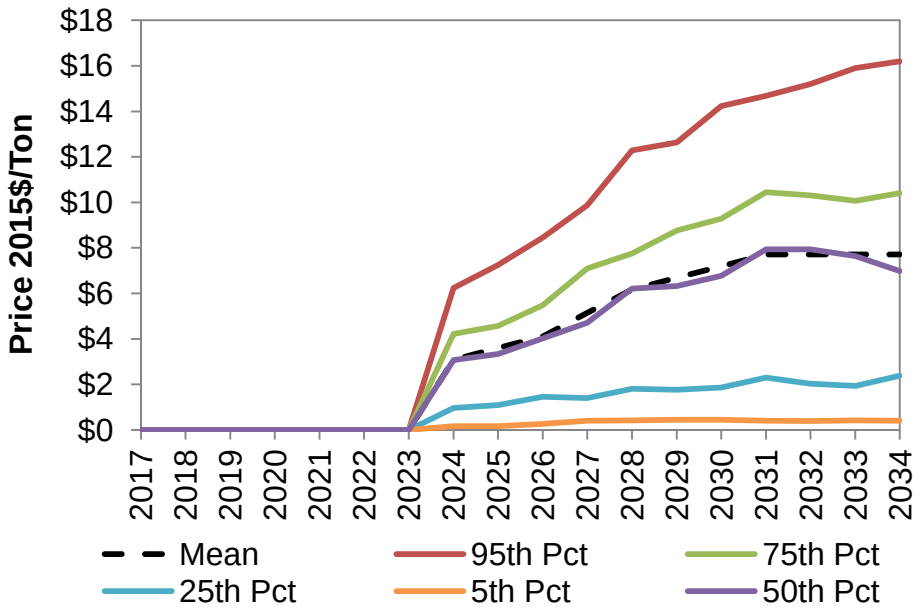
Pace Global projects delivered coal prices for use in its power market simulations by adding forecasted transportation costs to regional FOB basin-level forecasts. In developing plant-level coal price forecasts, Pace Global examines the coal purchasing characteristics of each coal-fired power plant, as well as the overall market for steam coal in order to project delivered coal costs. Pace Global reviews Form EIA-923 data on coal deliveries to each of the facilities as reported in the Energy Velocity database. Trends in the applicable transportation markets are then reviewed and used to develop escalation rates by mode of transportation - primarily rail, barge, and truck.

CO_2 Prices

There is a great deal of uncertainty at this time over the future of the Clean Power Plan (CPP) or any subsequent federal regulation covering the CO_2 emissions from existing power generators. In February of 2016, the Supreme Court imposed a stay on the CPP while the courts consider the legal challenges to the rule. This effectively put the schedule and implementation of CPP in abeyance. Further, the Trump Administration opposes the CPP and is expected to follow through with action to withdrawal the rule in its current form in the near future.

Despite these uncertainties, Pace Global projects a national carbon price to become effective in 2024, covering emissions from large existing coal and natural gas combined cycle power generators in the U.S. At this time, Pace Global projects our reference case carbon price assuming that most states opt into a federal, mass-based trading scheme to meet goals in line with reductions called for under the CPP in aggregate. The distribution of carbon prices included in this analysis is included in Exhibit 28.

Exhibit 28: Carbon Compliance Cost Probability Bands

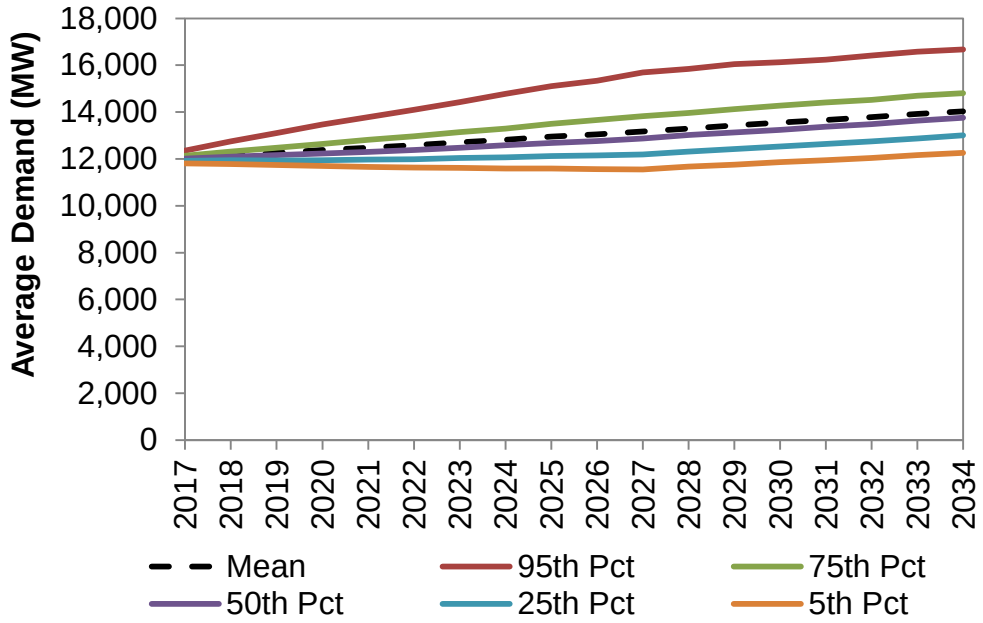


Source: Pace Global

MISO Load

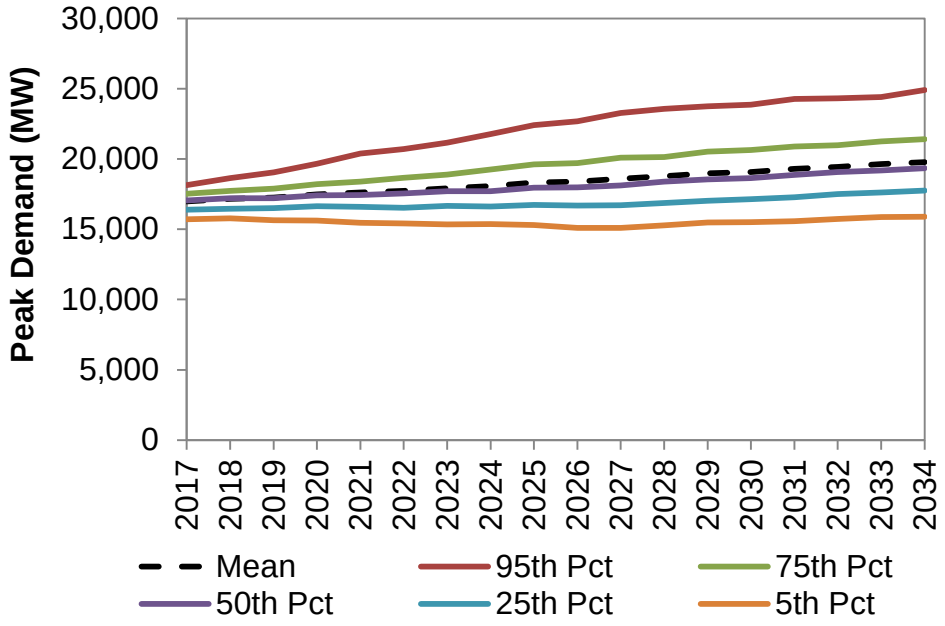
MISO average and peak load distributions included in the analysis are presented in Exhibit 29 and Exhibit 30.

Exhibit 29: Average Load Probability Bands – MISO Load Zone 1



Source: Pace Global

Exhibit 30: Peak Load Probability Bands – MISO Load Zone 1

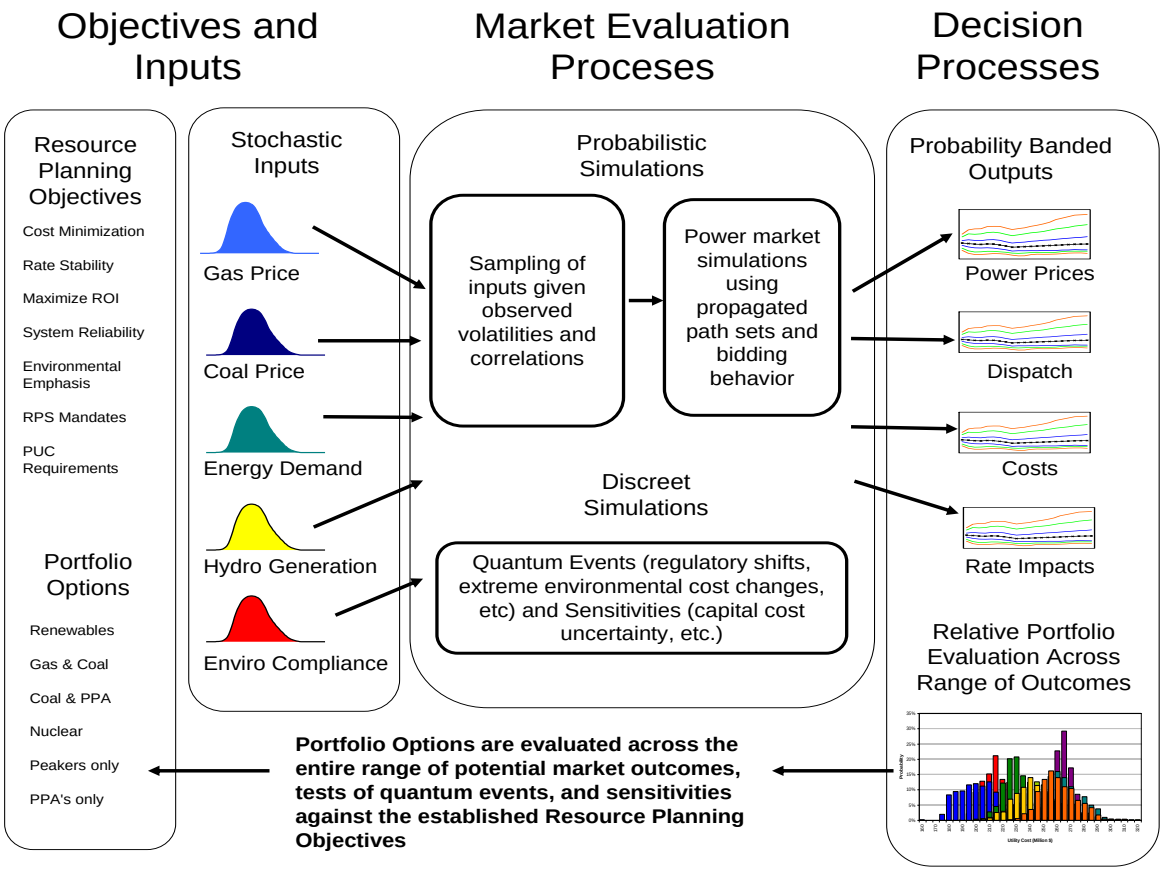


Source: Pace Global

APPENDIX C: MODEL OVERVIEW

A high level overview of Pace Global's RIRP process is shown in Exhibit 31.

Exhibit 31: Risk Integrated Resource Planning Process Overview



Objectives and Inputs

The Pace Global RIRP process includes a sophisticated, integrated set of models, systems and protocols. Objectives defined upfront define the metrics used to evaluate portfolios. Portfolios are developed from feasible combinations of existing assets, resource additions (local and remote), buy options, build options, contractual, demand side and energy efficiency options, all considering transmission and other constraints, that can be used to meet or adjust load.

Once the objectives, metrics and portfolio options are established, Pace Global begins the process of developing the reference case assumptions and characterizations of key risks and uncertainties. Stochastic inputs typically fuel prices, demand levels, capital and generation costs, and environmental

compliance costs. Pace Global uses a combination of historical market volatility and forecasts and uncertainty distributions that are developed from our market-based models of regional system loads, natural gas, coal, oil and power for this purpose. Combined with quantum scenarios and game changing events identified with the client, these probabilistic inputs will produce a broad range of potential market outcomes against which to compare all candidate portfolio options.

Market Modeling

Pace Global's tools fully integrate risk assessment into long-term energy and resource planning. The core component of our risk analysis system is the AURORAxmp® power dispatch and market price model, developed by EPIS and used extensively in the western U.S. AURORAxmp® has been adapted for our risk analysis simulations and it combines the best features of the other software packages used for resource planning. Some key features of AURORAxmp® are:

- A dispatch algorithm similar to other production costing models;
- A unique bidding structure that simulates market incentives for investing in plants that can cause over or under building of assets. This feature provides a distinct advantage over equilibrium models, as power markets are rarely in equilibrium;
- An ability to characterize market volatility and uncertainty in stochastic distribution representations for all fuels and the price movement correlations among these inputs;
- An ability to conduct Monte Carlo simulations generated from these distributions to generate power dispatch and market price simulations;
- Direct links to nodal transmission models for accurate representations of LMP/nodal pricing and transmission congestion;
- Accurate modeling of SO_2, NO_X, and carbon emission rate and emissions costs;
- Integrated evaluation of multiple portfolios in the context of one integrated model; and
- Easy downloads to graphics packages for representing inputs and results in easy to follow and understandable graphics.

Pace Global simulates the generation market prices and plant dispatch for a relevant market area over the range of inputs established in the Objectives and Inputs stage using its power dispatch model (AURORAxmp®). This model is a sophisticated market dispatch model that has every generating station (including its characteristics, regulatory requirements and transmission links) in the United States. Inputs to the model include operating cost and performance parameters, fuel options and costs and environmental costs and parameters. The model takes distributions for key stochastic inputs so that multiple simulations can be run. By running the simulations hundreds of times using combinations of probabilistic inputs in a Monte Carlo-like fashion, Pace Global is able to capture the uncertainty inherent in energy markets and determine how each portfolio will perform under a myriad of potential future energy states. Whether gas prices are higher or lower than expected, under wet or dry conditions, with hot summers or cool summers, and all combinations, this analysis shows how each of the candidate portfolios will dispatch, how much each technology option will cost to run, and how this range of operational possibilities will impact the decision metrics, or objectives of the resource portfolio.

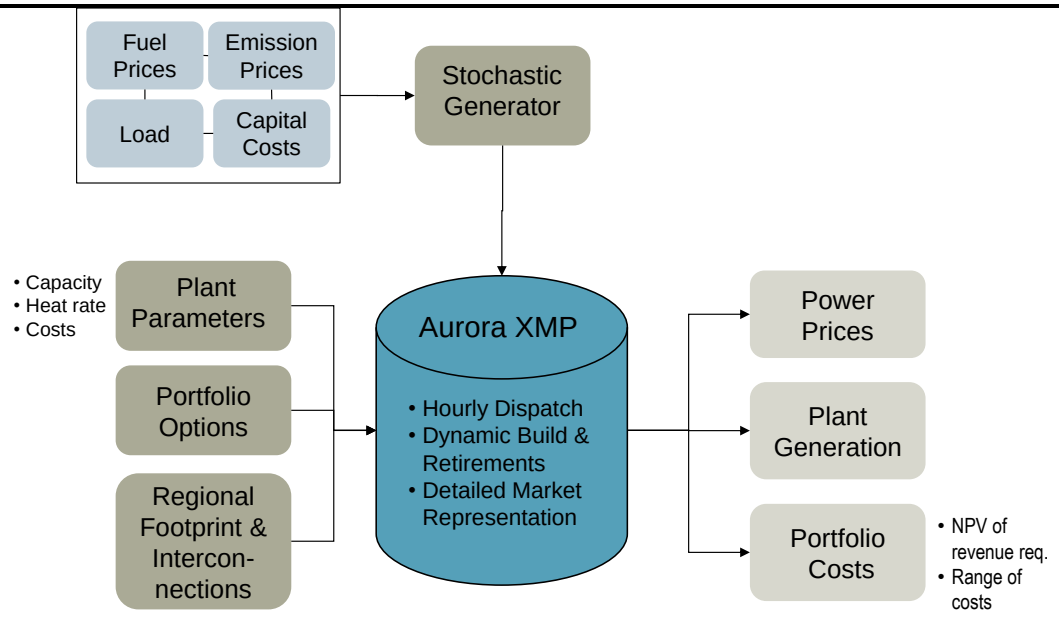
Pace Global's Integrated Approach with Aurora

Pace Global deploys AURORAxmp®to simulate the economic dispatch of power plants within a competitive framework. Representations of hourly regional demand profiles and plant-level supply characteristics are included, as well as detailed assessments on the fundamental drivers of power plant dispatch within each relevant market area. Key components of our methodology include:

- **Load Forecast:** Pace Global independently develops regional load forecasts (with stochastic uncertainty bands) based on the historic relationship between economic drivers, weather, and load.
- **Regional Fuel/Emission Projections:** Pace Global develops independent projections of fuel and emission pricing inputs (with stochastic uncertainty bands) based on the fundamental drivers of each market and a comprehensive review of regulatory environments.
- **Renewable Generation Profiles:** Pace Global analyzes the historic generation of renewable technologies throughout its modeling regions in order to characterize renewable generation profiles.
- **Portfolio Tracking Module**: Your entire portfolio options can be built within the modeling framework, inclusive of all plant parameters and associated fixed and variable costs to account for full interaction with the MISO market.
- **Bidding Function:** Pace Global's market simulations incorporate bidding behavior and scarcity premiums in our dispatch algorithm. Each region's bidding function is based on hourly analyses of the historic relationship between prices and reserve margins.
- **Dynamic Capacity Expansion:** Gas-fired, wind, and solar capacity expansions are built dynamically when observed margins reach a specified threshold.

A summary of the methodology with key inputs, algorithms, and outputs is shown in Exhibit 32.

Exhibit 32: Pace Global Market Analysis Methodology



Source: Pace Global.

Dynamic Build Capacity Expansion

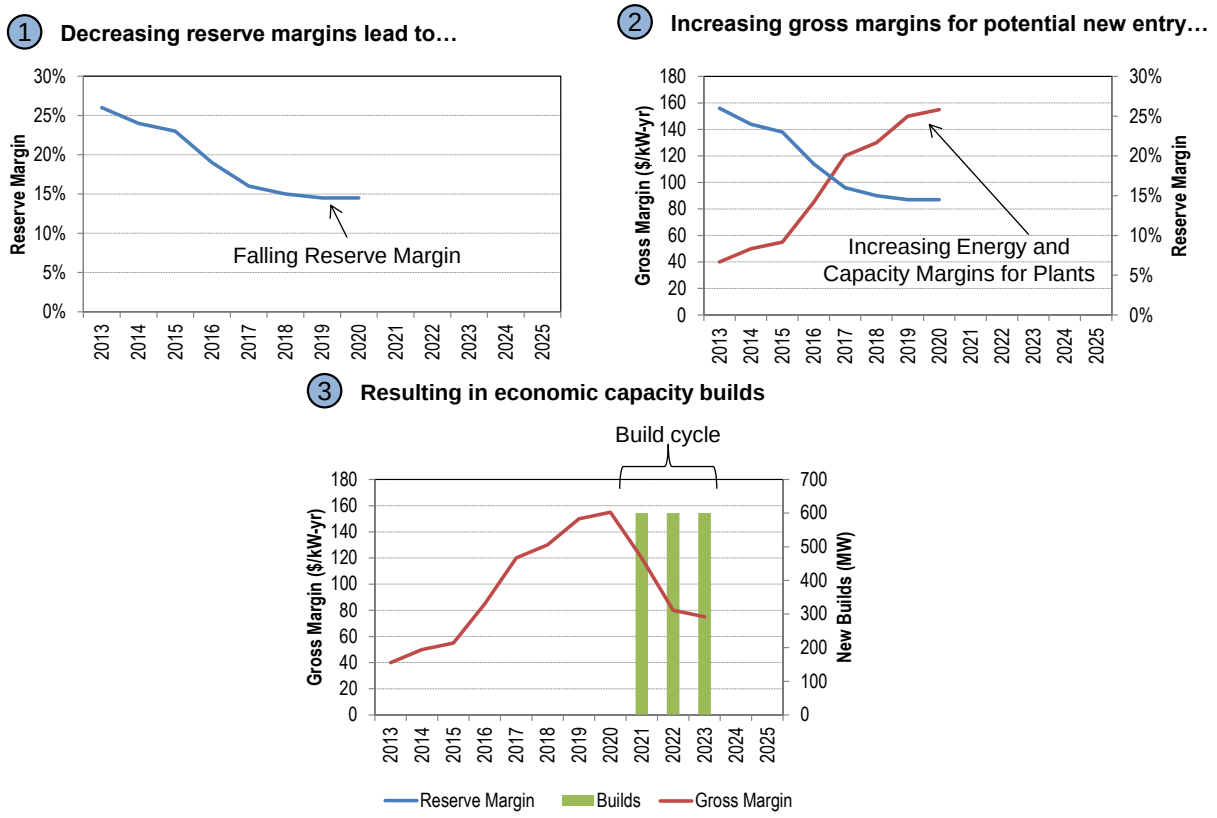
Pace Global incorporates the dynamic simulation of additional economic capacity in our long term analyses. With this approach, incremental expansion is expected when economic conditions provide a sufficient rate of return for new units. Where net energy and capacity revenues together justify build of a new unit on the basis of a historic trend, a new unit is built. Sustained positive returns, generally stimulated by falling reserve margins and rising prices are expected to lead to capacity additions. The magnitude of the capacity expansion depends on the achieved Return on Investment (ROI) specific to the type of generating plant.

Pace Global's dynamic build logic is illustrated in Exhibit 33. This graphic illustrates how new capacity enters the market according to economic signals – these units are shown under the legend Economic Expansion (the units labeled Additional Expansion reflect announced units or units built on the basis of RPS or reliability requirements). For example, following an expected widening in system reserve margins over the period to 2009-2011, the system is expected to tighten during the 2011-2014 timeframe. In this example, we project that rising margins in the period 2011-2014 will send a signal causing a new plant to come online around the 2015 time frame.

Following a temporary capacity glut, rising plant margins during the 2015-2018 period are unlikely enough to provide an unequivocal signal to new plant developers. In this case, a full build Task is not supported until the period from 2023-2026. From 2021, declining plant margins set in, reflecting the overbuild cycle.

The dynamic expansion methodology is currently applied to incremental natural gas-fired combined cycles, natural gas-fired peakers, wind, and solar builds in the region, and is employed across all iterations of analysis. This allows all market simulations to incorporate the reactive behavior observed in the market to periods of sustained margins.

Exhibit 33: Dynamic Build Simulation Logic



Source: Pace Global.

Decision Processes

Finally, Pace Global synthesizes all of the market analysis data into a coherent decision framework. For example, if rate stability is identified as a key objective of the resource portfolio, Pace Global will provide the analysis results that display how each portfolio affects rates across the entire range of potential market outcomes, identifying the efficient frontier of cost and risk minimization options that allows for more intuitive and informed decision making.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Appendix O: Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2016 Wind Resource Solicitation

Sedway Consulting, Inc.

INDEPENDENT EVALUATION REPORT
FOR MINNESOTA POWER COMPANY'S
2016 WIND RESOURCE SOLICITATION

Submitted by:

Alan S. Taylor
Sedway Consulting, Inc.
Boulder, Colorado

June 6, 2017

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Introduction and Background

On July 27, 2016, Minnesota Power Company (MP) issued a Request for Proposals (RFP) for up to 300 MW of power supplies from wind projects to capture the benefits of the Federal Production Tax Credit for customers and comply with a Minnesota Public Utilities Commission directive associated with the utility's 2016 Integrated Resource Plan (IRP). Sedway Consulting, Inc. (Sedway Consulting) was retained by MP to oversee this solicitation for new wind resources and provide an independent evaluation of all proposals. This report provides an assessment of MP's wind resource solicitation from the initial phase of the solicitation (i.e., the issuance of the RFP) through the execution of a final contract for providing energy from the least-cost wind resource for MP's customers.

Sedway Consulting undertook the following tasks as part of this engagement:

- Reviewed and commented on the Resource Request document before the solicitation was launched,
- Participated in MP planning calls/meetings to establish the screening procedures and evaluation methodologies that would be employed in the review and evaluation of all proposals,
- Acquired and archived all important evaluation parameters and market price assumptions prior to bid opening, for use in Sedway Consulting's proprietary evaluation model,
- Independently reviewed all proposals and compiled levelized contract prices and net costs for the ranking of proposals,
- Participated in MP calls/meetings to discuss proposal review results,
- Participated in an on-site meeting to discuss Sedway Consulting's evaluation results and determine an appropriate short list of projects/bidders,
- Reviewed contract redlines and monitored negotiations with shortlisted bidders, and
- Participated in debriefing calls with those bidders who were not shortlisted (and who requested a call).

Sedway Consulting was provided access to all necessary materials and meetings and was able to perform its own evaluation of all of the proposals. Sedway Consulting conferred with MP in periodic calls/meetings to discuss proposal clarification, disqualification, and evaluation decisions.

Overview of Conclusions

Sedway Consulting developed an economic ranking of all proposals based on their $/MWh net costs, assessed the qualitative risks and benefits associated with the top-ranked proposals, presented the results to MP and discussed the selection of an appropriate short list of projects and counterparties with whom to commence negotiations. Sedway Consulting concludes that MP conducted fair and appropriate negotiations with those counterparties. Of those projects that were shortlisted, Tenaska's Nobles 2 proposal was the most cost-effective (i.e., lowest $/MWh net cost). That project will be a new 250 MW wind resource in Nobles and Murray Counties, Minnesota, with an expected commercial operation date of December 31, 2019. Sedway Consulting concludes that MP made the appropriate selection decisions in its solicitation and concurs with the decision to secure wind energy deliveries through the execution of the Nobles 2 Power Partners LLC power purchase agreement for the proposed 20 year term.

This Independent Evaluation Report has a confidential appendix that includes a description of each proposal and an overview of the evaluation results and sensitivity analyses. This material is being afforded confidential treatment to protect participants from having their project pricing and operational information provided to their competitors. Also, MP's customers could be harmed if too much information was made publicly available, allowing some participants to game future solicitations rather than delivering the best renewable projects at the lowest possible prices.

Activities Prior to the Receipt of Proposals

Sedway Consulting had provided independent evaluation services in previous MP wind RFPs and was thus quite familiar with MP's evaluation processes and available planning assumptions. Prior to the receipt of proposals, Sedway Consulting requested and incorporated MP's latest market price forecasts into Sedway Consulting's evaluation model. Sedway Consulting requested MP to provide as much information as possible prior to the receipt of proposals. This, in essence, allowed Sedway Consulting to lock down and archive the basic evaluation parameters for the process. Such information included forecasts of regional market energy prices,[1] cost of capital components, discount rate, and historical locational marginal pricing (LMP) information. These assumptions were incorporated into Sedway Consulting's own evaluation model and formed the basis for independently assessing the benefits and costs of resources that were bid into MP's solicitation.

[1] In past MP wind solicitations, Sedway Consulting has also ascribed a value to the capacity of proposed wind resources. In consultation with MP, it was decided that such capacity valuation was not necessary in the current evaluation in that it was dependent on MISO capacity accreditation rules that may change, was likely to be quite similar across all wind projects (and thus would not be a differentiating benefit), and might be inappropriately influenced by bidder-supplied generation profiles.

Receipt and Evaluation of Proposals

On September 9, 2016, MP and Sedway Consulting received a significant number of proposals in its wind resource solicitation. Submissions were made via email. Both MP and Sedway Consulting reviewed the submitted proposals during September 2016, periodically discussing proposal deficiencies and requests to specific bidders for supplemental information.

The evaluation process entailed a general review of all proposals and the calculation and ranking of levelized energy prices for all proposed options. Instances where proposals were found to be non-compliant or incomplete, bidders were notified and given an opportunity to supplement their proposal materials. The evaluation team focused more of its efforts on the higher-ranked proposals, performing a thorough qualitative assessment of those proposals that appeared to have the best quantitative value for MP's customers. Concurrent with that qualitative analysis, Sedway Consulting undertook the modeling of all proposals to assess their energy benefits; specifically, Sedway Consulting performed detailed modeling to determine each proposal's net cost (described below). Although the levelized price ranking provided a good approximation of how project economics might compare, an assessment of the offers' generation profiles and the energy benefits associated with those profiles provided a comprehensive comparison.

Description of Sedway Consulting's Detailed Evaluation Process

The detailed economic evaluation entailed modeling the bids in Sedway Consulting's Renewable Bid Evaluation Model (RBEM) – a spreadsheet-based tool that determined a proposal's net cost by calculating the present value of the project's costs and subtracting the present value of a proposed facility's hourly energy benefits. The costs in the net cost calculation included contract payments for delivered energy and an imputed debt cost[2] for power purchase agreements (PPA). Energy benefits were the product of the expected hourly generation of a facility and a forecast of hourly $/MWh energy market prices over the term of the contract. For those offers that did not provide for delivery to the MP.MP MISO node, a sensitivity analysis was performed to assess the impact of LMP differentials between the proposed delivery point and the MP.MP node. Sedway Consulting's evaluation model normalized the net cost by dividing it by the present value of a project's expected energy deliveries, thereby yielding a $/MWh levelized net cost. In some of Sedway Consulting's past renewable project analyses, this $/MWh net cost has been a positive number and reflects the premium that a utility must pay for renewable energy relative to "brown" power – the more positive the number, the greater the renewable premium. In the case of MP's 2016 wind solicitation, all of the top-ranked

[2] Imputed debt (or debt equivalence) costs are associated with a rebalancing of a utility's debt and equity ratios in light of credit rating agencies' policies that view PPAs as being partially equivalent to debt obligations.

proposals had negative net costs. This may be attributable to the fact that the current wind industry is in a highly competitive phase and wind turbine costs have been declining. Developers appear to be willing to provide wind projects at lower prices than has been the case in the past. Also, the federal renewable Production Tax Credit (PTC) for wind projects will expire for any facilities that are not under construction by December 31, 2019. The extension of that PTC is in question, given the federal government's budget deficits. Thus, many developers are probably eager to commence construction on wind projects as fast as possible, even at low prices. In any case, MP received proposals that were clearly cost-effective, relative to expected energy market prices.

The response to MP's 2016 wind resource solicitation was quite robust: 35 project proposals[3] were submitted. A summary of the projects is depicted in Table A-1 in Confidential Appendix A.

As noted above, Sedway Consulting performed a detailed levelized net cost analysis of all proposals. The results of Sedway Consulting's analysis are depicted in Table A-2 in Confidential Appendix A. The table includes each PPA/project's expected capacity, proposed duration, the $/MWh levelized net cost, and the levelized $/MWh components of that net cost.

Shortlisting of Proposals and Negotiation of Contracts

On October 17, 2016, Sedway Consulting met with MP personnel from various departments and presented the results of its analysis. After discussing the results, it was decided that a key subset of the top-ranked projects should be shortlisted, as described further in Confidential Appendix A. Negotiations commenced with the counterparties that proposed these projects and continued through the spring of 2017. One of those shortlisted projects was the Tenaska Nobles 2 proposal. Sedway Consulting concurred with MP's decision to make a final selection of that project and execute the Tenaska Nobles 2 contract. The other shortlisted proposals had higher net costs and other attributes that made them less attractive for meeting MP's resource needs, as described further in Confidential Appendix A.

Conclusion

Sedway Consulting was provided access to all necessary materials and meetings and was able to perform its own detailed evaluation of the proposals received in MP's 2016 wind resource RFP.

Sedway Consulting monitored the back-and-forth email traffic between MP and the wind resource bidders and believes that MP treated all bidders consistently and fairly. Sedway

[3] Many of these project proposals included mutually-exclusive options (e.g., flat versus escalating pricing, different terms); thus, there were many more distinct offers.

Consulting also monitored the negotiation process and believes that MP treated the shortlisted counterparties consistently and fairly.

Sedway Consulting believes that MP selected the best wind project for meeting its IRP requirements.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

CONFIDENTIAL
Appendix A
Offer Description and Evaluation Results

This has been designated as non-public in its entirety, as the document includes a summary of the terms of the proposals received in response to Minnesota Power's RFP for wind resource projects and the independent evaluation of those proposals. This information derives independent economic value from not being generally known to, or readily ascertainable by, others who could obtain economic advantage from its disclosure or use and thus constitutes information Minnesota Power considers to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b).

This Appendix A of the Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2016 Wind Resource Solicitation was prepared June 6, 2017, by Alan S. Taylor, Sedway Consulting, Inc.

APPENDIX P: REQUEST FOR PROPOSALS FOR WIND RESOURCE

Request for Proposals
For
Wind Resource

issued by

Minnesota Power
30 West Superior Street
Duluth, Minnesota 55802
www.mnpower.com

Released: July 27, 2016

Complete information on this RFP can be found at:
http://RFP.mnpower.com

TABLE OF CONTENTS

1.0 BACKGROUND

Minnesota Power (MP), a division of ALLETE, Inc., is seeking power supply proposals for up to 300 MW of wind generation, including Community-Based Energy Development (C-BED). This request is part of MP's broader evaluation process that considers the costs and characteristics of different power supply types (e.g., wind, solar, natural gas, demand response, and distributed generation) to optimize the mix of resources to meet customer needs. MP's current resource strategy calls for a diversified mix of resources to meet customers' needs reliably and cost effectively in an environmentally responsible manner.

MP seeks cost-effective wind resources that utilize the Federal Production Tax Credit. Proposals must offer capacity that is accreditable under current Midcontinent Independent System Operator (MISO) resource adequacy rules in MISO Local Resource Zone 1. Proposals must reflect the cost and characteristics of the resource delivered to MP's load zone. Proposals must offer an initial contract term of 20 years or longer. Purchase agreements are contingent upon Minnesota Public Utilities Commission (MPUC) approval.

Proposals must be received by MP (described in Section 5.1) by the Proposal Submission Deadline shown in Section 3.0. MP reserves the right in its sole discretion to modify this schedule for any reason.

MP will not be submitting a self-build wind resource proposal into this Request for Proposals (RFP). In connection with this RFP, MP has retained the services of an independent third party evaluator (Sedway Consulting, Inc.) to work with MP in the evaluation of all proposals. However, MP will make the final decision (subject to MPUC review and approval, as applicable) in MP's sole discretion.

2.0 ELIGIBLE PROPOSALS/MINIMUM REQUIREMENTS

Proposals must meet the general minimum eligibility requirements described below. MP will screen all proposals for compliance with these requirements. Proposals that fail to meet one or more of these requirements may be disqualified from further consideration.

2.1 Nameplate Capacity

Proposals must offer wind generation supplies with a nameplate capacity of no greater than a nominal 300 MW.

2.2 Proven and Commercially-Available Technology

Proposals must offer capacity and energy that will be generated from proven and commercially-available wind technology. A proposal must include information on at least one project using the stated technology.

2.3 Commercial Operation Date

Proposals must offer wind generation supplies with commercial operation dates anytime between January 1, 2018 and December 31, 2020.

2.4 Capacity Accreditation

Proposals must offer capacity that is accreditable under current MISO resource adequacy rules in MISO Local Resource Zone 1.

2.5 Environmental Attributes

Proposals must provide the environmental attributes (e.g., renewable energy credits and carbon-free attributes) associated with the generation of wind energy from the project.

2.6 Power Delivery Requirements

Network upgrade costs that are assessed to the project shall be the responsibility of the bidder and must be included in the bidder's proposed pricing. The bidder shall identify in Exhibit B the interconnection and network upgrade costs included in their proposed pricing.

The cost of obtaining firm transmission service, any interconnection equipment, congestion costs, and losses up to the point of delivery shall be the responsibility of the bidder and must be included in the bidder's proposed pricing. The bidder shall be responsible for all operational related costs, penalties, and charges assessed by MISO. See Transmission Delivery Plan (Item 5) in Section 5.2, Proposal Content, for additional information. MP has a preference for proposals that provide for firm transmission service with delivery to MP's MISO load node, currently MP.MP.

One of the goals of this RFP is to determine the overall cost to MP's retail customers of the selected resource(s). MP's economic evaluation of the proposal will take into account the cost of interconnection and delivery of power from the proposed resource to MP's native load.

NOTE: MP has an approved interconnection with MISO for a 100 MW (nominal) wind generating facility connecting to the Tri-County Substation in southeast Mercer County, North Dakota. This interconnection can be made available for this RFP to bidders with viable projects in that area. If interested, contact MP for details (refer to Section 4.0 for communication details).

2.7 Contract Term

Proposals must offer an initial contract term of at least 20 years. Proposals may also include option(s) for MP to purchase of the facility after at least 10 years.

2.8 Firm, Binding Prices

Proposals must include pricing that is firm and not subject to any revisions during MP's evaluation and negotiation process. Bidder's may propose escalation rates that are either fixed or, if appropriate and defensible, annually indexed to publicly-published indices acceptable to MP; however, the formulaic adjustment of indexed prices must be clearly described in the proposal and the formulaic mechanism itself may not be subject to revision during MP's evaluation and negotiation process. All prices must be in United States dollars and not subject to currency exchange rate adjustment. The proposal must be signed by an officer of the bidding firm who is duly authorized to commit the firm to carry out the power supply proposal should MP accept the proposal. All prices must be firm and binding through May 31, 2017.

2.9 Statement of Material Exceptions

Proposals must provide the bidder's material exceptions to MP's Model Wind Power Purchase Agreement.

2.10 Credit Rating

A bidder must have a credit rating for its senior unsecured debt of **BBB** or higher (for Standard & Poor's) or **Baa2** or higher (for Moody's). If a bidder is unrated or does not meet this minimum credit rating requirement, the bidder may provide credit support from a corporate guarantor that meets the requirement. Alternatively, if a bidder is unrated or does not meet the above minimum credit rating requirement and the bidder does not provide credit support from a suitable corporate guarantor, the bidder must certify and state in its proposal that, if selected, it will provide to MP within two weeks of short list notification cash or a letter of commitment from an acceptable bank for $5/kW of the proposed capacity of the project in the form of an irrevocable letter of credit.

2.11 Legal Certifications

A bidder must certify that:

1. there are no pending legal or civil actions that would impair the bidder's ability to perform its obligations under the proposed PPA,

2. the bidder has not directly or indirectly induced or solicited any other respondent to submit a false or sham proposal,

3. the bidder has not solicited or induced any other person, firm, or corporation to refrain from submitting a proposal, and

4. the bidder has not sought by collusion to obtain any advantage over any other respondent.

2.12 Proposal Submission Deadline

To be eligible for consideration, a proposal must be received by MP as described in Section 5.1 by the Proposal Submission Deadline shown in Section 3.0.

2.13 Additional Eligibility Considerations

Proposals must include sufficient information to allow MP to evaluate an offer. Section 5.2 (Proposal Content) includes further instructions on what must be included in a proposal. Proposals that are deficient or incomplete may be rejected by MP.

3.0 SCHEDULE

Table 1 represents MP's expected timeline for conducting this resource request. MP reserves the right to modify this schedule as circumstances warrant and/or as MP deems appropriate.

Table 1: Schedule/Timeline	
Event	**Anticipated Date**
Release of RFP	July 27, 2016
Proposal Submission Deadline	**September 7, 2016, 4:00 p.m. (CDT)**
Proposal Evaluation	September 8 to October 14, 2016
Negotiations with Selected Bidder(s)	November - December 2016
Application for Regulatory Approval	January 2017

4.0 COMMUNICATION WITH MP

Website http://RFP.mnpower.com has been created for downloading the RFP and Exhibits and to provide uniform communications, including updates and other details as may be provided throughout the bidding process.

All communications and questions from potential respondents regarding the RFP shall be submitted in written form and sent via e-mail to MPWindRFP@mnpower.com with the Independent Evaluator copied at: Alan.Taylor@sedwayconsulting.com.

Phone inquiries and verbal conversations with respondents regarding this RFP are not permitted before the submittal deadline. Individual questions submitted by a respondent to MP before the submittal deadline will be answered and responses sent back via email to the respondent as soon as practical. Responses to frequently asked or broadly applicable questions may be placed on the RFP Website for the benefit of all respondents, with any identifying information redacted.

5.0 PROPOSAL SUBMISSION

5.1 Proposal Submission Requirements

All proposals submitted in response to this RFP must be received by MP and the Independent Evaluator at the email addresses below no later than the Proposal Submission Deadline shown in Section 3.0. MP will not evaluate proposals as part of this RFP process if submitted after this date and time. MP does not anticipate an opportunity in the schedule for respondents to refresh or update their pricing before the final selection(s) are made.

Respondents shall email an electronic copy of its proposal to MPWindRFP@mnpower.com with the Independent Evaluator copied at: Alan.Taylor@sedwayconsulting.com.

1. Each proposal must contain the following:
    a. Exhibit A: Energy Generation Profile (in Excel form)

b. Exhibit B: PPA Pricing (in Excel form)
c. Additional materials that address the requirements of the RFP

2. Do not send any files in compressed formats, such as .zip.
3. Respondents should undertake efforts to avoid excessively large emails/attachments; in any case, individual email size must be less than 10 MB. If the emailed information exceeds this limit, then respondents should break their submission into multiple emails.
4. Financial statements, annual reports, and other large documents should be referenced via a website address.
5. Multiple proposals by the same respondent must be identified separately.

5.2 Proposal Content

Bidders must submit the following information:

1. **Project team experience.** Bidders must describe the experience of the principal members of the project team. For existing projects, proposals must include information on who will be responsible for on-going operations and maintenance (O&M). For new projects, in addition to the O&M issues, proposals must also include information on who will be responsible for design, siting, permitting, financing, and construction of the facility. Each member that will lead key aspects of the project should have experience in leading those tasks on previous projects that are similar to the proposed project. Proposals must include descriptions of these previous projects for each key team member and references who may be contacted by MP's evaluation team.

2. **Bidder's financial status.** Proposals must include the bidder's (or guarantor's, if applicable) most recent audited annual report and any 10Q filings since the period covered in the annual report. If such report and filings are not available, the bidder should note this and provide unaudited financials for the last three fiscal years. All financial statements, annual reports, and other large documents may be referenced via a website address.

3. **Project schedule and current status.** For new projects, proposals must include a project schedule that shows the expected commencement, duration, and completion of all significant project development tasks. If some of the tasks are already underway, the bidder should describe the current status of those tasks. Note that specific major project milestones will be the responsibility of the bidder and will be incorporated into the PPA should the bidder's offer be selected by MP.

4. **Siting plan**. For new projects, bidders must describe the status of the site for the proposed project (i.e., whether or not the bidder owns or is leasing the land, has the land under option for purchase or lease, the current zoning of the land, and any rezoning actions, if applicable). The bidder must provide a map of the proposed project site and surrounding territory and indicate the expected point of interconnection. The bidder must indicate whether there are any sensitive attributes

(e.g., residential dwellings, wetlands, state/national parks or wildlife preserves, eagles, endangered or threatened species, cultural or archeological landmarks) on or near the site and, if within one mile, note their proximity to the site. The bidder must provide proof that local community authorities have been notified of the bidder's intention to develop the proposed project and indicate the degree of acceptance by the local community. The bidder should describe any plans for community education and outreach concerning the proposed project, including outreach to non-participating landowners. C-BED proposals will be considered pursuant to the requirements of Minn. Stat. § 216B.1612.

5. **Transmission delivery plan.** If the project is not or will not be in MP's control area, the bidder must provide a transmission delivery plan that demonstrates that the project's output will be deliverable to MP's MISO load node (MP.MP). The bidder shall identify the project's interconnection status and include the applicable MISO queue number(s). The bidder must state all assumptions or actualities concerning the availability and cost of the delivery plan and/or other delivery expenses between the source and MP's MISO load node. Specifically, the bidder must indicate what cost assumptions have been incorporated into the proposed pricing, including those for curtailment, congestion and losses. MP reserves the right, in MP's sole discretion, to reject any proposals that do not adequately address the delivery of the project's output to MP's MISO load node.

   NOTE: Bidders will be required to demonstrate within 30 days of being notified of being on MP's Resource Request short list that the delivery plan, if applicable to the bidder's proposal, can with reasonable certainty be secured.

6. **Permitting plan.** For new projects (or for existing projects with significant on-going permitting requirements), bidders should describe the permits that they will need to secure for the facility's development and discuss their plans for acquiring those permits including timing and any expected contingencies that would need to be included in a PPA.

7. **Financing plan.** For new projects, bidders should describe their plans for acquiring the necessary funds for developing and operating their projects. Such plans should include a discussion of the project's legal ownership structure, whether there will be a guarantor standing behind any specific financial obligations, the expected percentage of debt and equity capital that the bidder has committed to secure, and the identity and credit rating of firms that are likely to provide such financing. If available, letters of interest or letters of commitment from such firms should be provided.

8. **Design and construction plan.** For new projects, bidders should provide information on what firm(s) will be involved with the design and construction of the facility and describe any relevant issues that may positively or negatively influence the project's design and construction. MP has a preference for the use of local prevailing wage for labor cost. The qualitative evaluation will take into

account whether the proposal includes a written commitment to paying local prevailing wages.

9. **Resource supply plan.** Bidders should provide hourly estimates of net generation for an average day of each month (24 hours of estimates for each of 12 months). Such bidders should also provide supporting information (e.g., wind turbine power curve, production data, expected degradation over time, description of data-gathering and data-synthesizing processes) that would allow MP to understand how the hourly generation estimates were derived. Additional hourly net generation and other performance information may be requested by MP from bidders that are shortlisted.

10. **O&M plan.** Proposals should include a discussion of the bidder's O&M plan and what firm(s) would provide such services.

11. **Scheduling.** Bidders must describe how they will provide accurate forecast information to MP for scheduling the unit into MISO if the generation will be scheduled by MP.

12. **Statement of Exceptions to MP's PPA.** As noted in Section 2.9, each bidder must review MP's Model Wind PPA and document all material exceptions to the terms and conditions that are relevant to the bidder's proposed resource and that the bidder wishes to take in substantiating the fundamental terms and conditions of its power supply offer.

13. **Proposal Limitations.** Please describe in reasonable detail any existing regulatory, legal, economic, operational, or systematic conditions that might affect the respondent's ability to deliver capacity and energy as offered.

5.3 Confidentiality

Note that any portion of a bidder's proposal that the bidder deems to be confidential must be clearly marked. MP and its consultants will take reasonable precautions to maintain the confidentiality of such information. However, MP is rate regulated by the MPUC; bidders must recognize that their confidential information may have to be shared with regulatory agencies and provided in MPUC regulatory proceedings as well as other regulatory or legal proceedings. MP will employ reasonable efforts to ensure that such confidential information is not publicly disclosed in such proceedings but can give no guarantees of such protection.

6.0 EVALUATION PROCESS

MP's evaluation of power supply proposals will involve the following steps:

1. Screening for completeness and compliance with minimum eligibility requirements
2. Preliminary and detailed economic assessment
3. Non-economic/risk assessment
4. Selection of short list
5. Further due diligence
6. Final selection

Note: MP reserves the right to eliminate any or all proposals during any of these steps. Any proposal advancing any one or more steps does not create any entitlement or reasonable expectation that the proposal will ultimately achieve a PPA. All obligations between MP and a bidder relating to a proposal will be governed by an executed and effective PPA for which all negotiated conditions precedent have been satisfied.

6.1 Screening for completeness/compliance with minimum eligibility requirements

MP's evaluation team will perform an initial screening of each proposal to ensure that the proposal is complete and complies with the Resource Request's minimum eligibility requirements. Proposals with substantial deficiencies will be rejected. For proposals with marginal deficiencies, MP may request that the bidder promptly provide missing information or appropriate clarifications; failure to provide such information may result in a proposal being rejected. All proposals that are deemed to be reasonably complete and compliant will be passed to the economic and non-economic/risk assessment steps.

6.2 Preliminary and detailed economic assessment

MP may perform a preliminary economic screening analysis to identify proposals that are clearly uneconomic and thus do not warrant further detailed evaluation. If performed, such an analysis will involve the use of resource evaluation spreadsheets to review and rank the proposals based on pricing and operational information from the proposal.

The evaluated cost of each proposal will be determined by considering the price under the proposed PPA, the estimated value of energy and capacity from the project based on the project's energy production profile and projected locational marginal prices (LMPs) at the delivery point, and a quantification of the financial costs to MP of rating agencies' treatment of long-term PPA payment obligations as imputed debt. Project costs will be present-valued and/or levelized back to a base year.

6.3 Non-economic/risk assessment

In parallel with the economic assessment, MP's evaluation team will also assess each resource's or portfolio's non-economic characteristics and risks. Such analysis will involve a qualitative consideration of such issues as:

- Bidder's project team experience and financial strength,
- Feasibility of schedule and current status,
- Status of site control, zoning, and local acceptance,
- Interconnection complexities,
- Transmission delivery complexities,
- Size of resource relative to MP's overall resource need of up to 300 MW (particularly applicable to relatively new technologies and/or development teams with little experience or financial strength),
- Likelihood of permitting,
- Environmental impacts,
- Likelihood of getting financed,
- Quality of design and construction plan,
- Assessment of acceptable wind technology,
- Quality of O&M plan,
- Ability to provide MP timely and accurate information to schedule the unit into the MISO market, and
- Exceptions taken to MP's PPA.

MP's evaluation team will rank the potential power supply portfolios by levelized total system cost and supplement each portfolio's place in the ranking with a qualitative assessment of the above risks in developing a final set of resources that will be recommended for inclusion on a short list.

6.4 Additional due diligence

Bidders of shortlisted projects will be notified and face-to-face meetings and/or conference calls will be held to perform additional due diligence. Such meetings or calls will provide both MP and the bidder an opportunity to identify and clarify any remaining uncertainties that would complicate the finalization of a PPA or the development of the project. Following this process, MP will select one or more finalist projects that, in total, are sufficient to meet MP's customer needs.

7.0 RESERVATION OF RIGHTS

MP makes the following reservations in undertaking this power supply solicitation:

1. MP reserves the right to modify or withdraw this Resource Request.

2. MP reserves the right to reject any and all responses to this Resource Request.

3. MP's Resource Request does not equate to an offer to purchase any capacity and energy.

4. All proposal preparation costs must be borne by the bidder.

5. Proposals will not be returned to the bidders.

6. MP may select proposals that total more or less than the stated need.

7. MP may accept a proposal that is not the lowest cost proposal(s).

8. MP may seek clarification from bidders and may request additional information from bidders beyond that which is specifically identified in the Resource Request.

9. MP reserves the right to waive bidder noncompliance with any aspect of its Resource Request.

10. MP may conduct negotiations with selected bidders and may terminate negotiations at any time.

11. Any and all decisions are conditioned on the approval of MP's management and Board of Directors as well as all required regulatory and other approvals.

12. MP reserves the right to modify or supplement this Resource Request at any time during this process. Any such modifications or supplements shall become part of this process and shall be addressed as part of any proposal submitted.

APPENDIX Q: REQUEST FOR PROPOSALS FOR SOLAR RESOURCE

Request for Proposals
For
Solar Resource

issued by

Minnesota Power
30 West Superior Street
Duluth, Minnesota 55802
www.mnpower.com

Released: August 4, 2016

Complete information on this RFP can be found at:
http://RFP.mnpower.com

TABLE OF CONTENTS

1.0 BACKGROUND

Minnesota Power (MP), a division of ALLETE, Inc., is seeking power supply proposals for 1MW to 300 MW of solar generation, including Community-Based Energy Development (C-BED). This request is part of MP's broader evaluation process that considers the costs and characteristics of different power supply types (e.g., wind, solar, natural gas, demand response, and distributed generation) to optimize the mix of resources to meet customer needs. MP's current resource strategy calls for a diversified mix of resources to meet customers' needs reliably and cost effectively in an environmentally responsible manner.

MP seeks cost-effective solar resources that utilize the Federal Tax Credit. Proposals must offer capacity that is accreditable under current Midcontinent Independent System Operator (MISO) resource adequacy rules in MISO Local Resource Zone 1. Proposals must reflect the cost and characteristics of the resource delivered to MP's load zone. Proposals must offer an initial contract term of 20 years or longer. Purchase agreements are contingent upon Minnesota Public Utilities Commission (MPUC) approval.

Proposals must be received by MP (described in Section 5.1) by the Proposal Submission Deadline shown in Section 3.0. MP reserves the right in its sole discretion to modify this schedule for any reason.

In combination and/or in competition with submitted resource proposals, MP intends to consider self-build resource alternatives as potential power supplies to meet its customers' solar resource needs. In connection with this RFP, MP has retained the services of an independent third party evaluator (Sedway Consulting, Inc.) to work with MP in the evaluation of all proposals. MP will make the final decision (subject to MPUC review and approval, as applicable) in MP's sole discretion.

2.0 ELIGIBLE PROPOSALS/MINIMUM REQUIREMENTS

Proposals must meet the general minimum eligibility requirements described below. MP will screen all proposals for compliance with these requirements. Proposals that fail to meet one or more of these requirements may be disqualified from further consideration.

2.1 Nameplate Capacity

Proposals must offer solar generation supplies with a nameplate capacity of between 1MW and not exceeding 300MW.

2.2 Proven and Commercially-Available Technology

Proposals must offer capacity and energy that will be generated from proven and commercially-available solar technology

2.3 Commercial Operation Date (COD)

Proposals must offer solar generation supplies with commercial operation dates anytime between January 1, 2018 and December 31, 2022.

2.4 Capacity Accreditation

Proposals must offer capacity that is accreditable under current MISO resource adequacy rules in MISO Local Resource Zone 1.

2.5 Environmental Attributes

Proposals must provide all environmental attributes (e.g., renewable energy credits and carbon-free attributes, other) associated with the generation of solar energy from the project.

2.6 Power Delivery Requirements

Network upgrade costs that are assessed to the project shall be the responsibility of the bidder and must be included in the bidder's proposed pricing. The bidder shall identify in Attachment A the interconnection and network upgrade costs included in their proposed pricing.

The cost of obtaining firm transmission service, any interconnection equipment, upgrades, studies, congestion costs, and losses up to the point of delivery shall be the responsibility of the bidder and must be included in the bidder's proposed pricing. The bidder shall be responsible for all operational related costs, penalties, and charges assessed by MISO. See Transmission Delivery Plan (Item 5) in Section 5.2, Proposal Content, for additional information. MP has a preference for proposals that provide for firm transmission service with delivery to MP's MISO load node, currently MP.MP and a further preference for projects connected to the MP distribution system.

One of the goals of this RFP is to determine the overall cost to MP's retail customers of the selected resource(s). MP's economic evaluation of the proposal will take into account the cost of interconnection and delivery of power from the proposed resource to MP's native load.

2.7 Contract Term

Proposals must offer an initial contract term of at least 20 years. Proposals may also include option(s) for MP to purchase the facility after a period of 10 years.

2.8 Firm, Binding Prices

Proposals must include pricing that is firm and not subject to any revisions during MP's evaluation and negotiation process. Bidder's may propose escalation rates that are either fixed or, if appropriate and defensible, annually indexed to publicly-published indices acceptable to MP; however, the formulaic adjustment of indexed prices must be clearly described in the proposal and the formulaic mechanism itself may not be subject to revision during MP's evaluation and negotiation process. All prices must be in United States dollars and not subject to currency exchange rate adjustment. The proposal must be signed by an officer of the bidding firm who is duly authorized to commit the firm to carry out the power supply proposal should MP accept the proposal. All prices must be firm and binding through May 31, 2017.

2.9 Statement of Material Exceptions

Proposals must provide the bidder's material exceptions to MP's Model Solar Power Purchase Agreement.

2.10 Credit Rating

A bidder must have a credit rating for its senior unsecured debt of **BBB** or higher (for Standard & Poor's) or **Baa2** or higher (for Moody's). If a bidder is unrated or does not meet this minimum credit rating requirement, the bidder may provide credit support from a corporate guarantor that meets the requirement. Alternatively, if a bidder is unrated or does not meet the above minimum credit rating requirement and the bidder does not provide credit support from a suitable corporate guarantor, the bidder must certify and state in its proposal that, if selected, it will provide to MP within two weeks of short list notification cash or a letter of commitment from an acceptable bank for $5/kW of the proposed capacity of the project in the form of an irrevocable letter of credit.

2.11 Legal Certifications

A bidder must certify that:

1. there are no pending legal or civil actions that would impair the bidder's ability to perform its obligations under the proposed PPA,

2. the bidder has not directly or indirectly induced or solicited any other respondent to submit a false or sham proposal,

3. the bidder has not solicited or induced any other person, firm, or corporation to refrain from submitting a proposal, and

4. the bidder has not sought by collusion to obtain any advantage over any other respondent.

2.12 Proposal Submission Deadline

To be eligible for consideration, a proposal must be received by MP as described in Section 5.1 by the Proposal Submission Deadline shown in Section 3.0.

2.13 Additional Eligibility Considerations

Proposals must include sufficient information to allow MP to evaluate an offer. Section 5.2 (Proposal Content) includes further instructions on what must be included in a proposal. Proposals that are deficient or incomplete may be rejected by MP.

3.0 SCHEDULE

Table 1 represents MP's expected timeline for conducting this resource request. MP reserves the right to modify this schedule as circumstances warrant and/or as MP deems appropriate.

Table 1: Schedule/Timeline

Event	**Anticipated Date**
Release of RFP	August 4, 2016
Proposal Submission Deadline	**September 14, 2016, 4:00 p.m. (CDT)**
Proposal Evaluation	September 15 to October 14, 2016
Negotiations with Selected Bidder(s)	November - December 2016
Application for Regulatory Approval	January 2017

4.0 COMMUNICATION WITH MP

Website http://RFP.mnpower.com has been created for downloading the RFP and Attachments and to provide uniform communications, including updates and other details as may be provided throughout the bidding process.

All communications and questions from potential respondents regarding the RFP shall be submitted in written form and sent via e-mail to SolarRFP@mnpower.com with the Independent Evaluator copied at: Alan.Taylor@sedwayconsulting.com.

Phone inquiries and verbal conversations with respondents regarding this RFP are not permitted before the submittal deadline. Individual questions submitted by a respondent to MP before the submittal deadline will be answered and responses sent back via email to the respondent as soon as practical. Responses to frequently asked or broadly applicable questions may be placed on the RFP Website for the benefit of all respondents, with any identifying information redacted.

5.0 PROPOSAL SUBMISSION

5.1 Proposal Submission Requirements

All proposals submitted in response to this RFP must be received by MP and the Independent Evaluator at the email addresses below no later than the Proposal Submission Deadline shown in Section 3.0. MP will not evaluate proposals as part of this RFP process if submitted after this date and time. MP does not anticipate an opportunity in the schedule for respondents to refresh or update their pricing before the final selection(s) are made.

Respondents shall email an electronic copy of its proposal to SolarRFP@mnpower.com with the Independent Evaluator copied at: Alan.Taylor@sedwayconsulting.com.

1. Each proposal must contain the following:
    a. Attachment A: Generation Profile and Pricing (in Excel form)
    b. Attachment B: MP Model PPA for Solar RFP
    c. Attachment C: Bidder Questionnaire
    d. Additional materials that address the requirements of the RFP
2. Do not send any files in compressed formats, such as .zip.
3. Respondents should undertake efforts to avoid excessively large emails/attachments; in any case, individual email size must be less than 10 MB. If the emailed information exceeds this limit, then respondents should break their submission into multiple emails.
4. Financial statements, annual reports, and other large documents should be referenced via a website address.
5. Multiple proposals by the same respondent must be identified separately.

5.2 Proposal Content

Bidders must submit the following information:

1. **Project team experience.** Bidders must describe the experience of the principal members of the project team. For existing projects, proposals must include information on who will be responsible for on-going operations and maintenance (O&M). For new projects, in addition to the O&M issues, proposals must also include information on who will be responsible for design, siting, permitting, financing, and construction of the facility. Each member that will lead key aspects of the project should have experience in leading those tasks on previous projects that are similar to the proposed project. Proposals must include descriptions of these previous projects for each key team member and references who may be contacted by MP's evaluation team.

2. **Bidder's financial status.** Proposals must include the bidder's (or guarantor's, if applicable) most recent audited annual report and any 10Q filings since the period covered in the annual report. If such report and filings are not available, the bidder should note this and provide unaudited financials for the last three fiscal years. All financial statements, annual reports, and other large documents may be referenced via a website address.

3. **Project schedule and current status.** For new projects, proposals must include a project schedule that shows the expected commencement, duration, and completion of all significant project development tasks. If some of the tasks are already underway, the bidder should describe the current status of those tasks. Note that specific major project milestones will be the responsibility of the bidder and will be incorporated into the PPA should the bidder's offer be selected by MP.

4. **Siting plan**. For new projects, bidders must describe the status of the site for the proposed project (i.e., whether or not the bidder owns or is leasing the land, has the land under option for purchase or lease, the current zoning of the land, and any rezoning actions, if applicable). The bidder must provide a map of the proposed project site and surrounding territory and indicate the expected point of interconnection. The bidder must indicate whether there are any sensitive attributes (e.g., residential dwellings, wetlands, state/national parks or wildlife preserves, eagles, endangered or threatened species, cultural or archeological landmarks) on or near the site and, if within one mile, note their proximity to the site. The bidder must provide proof that local community authorities have been notified of the bidder's intention to develop the proposed project and indicate the degree of acceptance by the local community. The bidder should describe any plans for community education and outreach concerning the proposed project, including outreach to non-participating landowners. C-BED proposals will be considered pursuant to the requirements of Minn. Stat. § 216B.1612.

5. **Transmission delivery plan.** If the project is not or will not be in MP's control area, the bidder must provide a transmission delivery plan that demonstrates that the project's output will be deliverable to MP's MISO load node (MP.MP). The bidder shall identify the project's interconnection status and include the applicable MISO queue number(s). The bidder must state all assumptions or actualities concerning the availability and cost of the delivery plan and/or other delivery expenses between the source and MP's MISO load node. Specifically, the bidder must indicate what cost assumptions have been incorporated into the proposed pricing, including those for curtailment, congestion and losses. MP reserves the right, in MP's sole discretion, to reject any proposals that do not adequately address the delivery of the project's output to MP's MISO load node.

6. **Distribution Interconnection Plan. Bidder shall follow Minnesota Power standard interconnection procedures as outlined in http://www.mnpower.com/CustomerService/DistributedGeneration?section=CS for projects connected to the Minnesota Power distribution system.**

   NOTE: Bidders will be required to demonstrate within 30 days of being notified of being on MP's Resource Request short list that the delivery plan, if applicable to the bidder's proposal, can with reasonable certainty be secured.

7. **Permitting plan.** For new projects (or for existing projects with significant on-going permitting requirements), bidders should describe the permits that they will need to secure for the facility's development and discuss their plans for acquiring those permits including timing and any expected contingencies that would need to be included in a PPA.

8. **Financing plan.** For new projects, bidders should describe their plans for acquiring the necessary funds for developing and operating their projects. Such plans should include a discussion of the project's legal ownership structure, whether there will be a guarantor standing behind any specific financial obligations, the expected percentage of debt and equity capital that the bidder has committed to secure, and the identity and credit rating of firms that are likely to provide such financing. If available, letters of interest or letters of commitment from such firms should be provided.

9. **Design and construction plan.** For new projects, bidders should provide information on what firm(s) will be involved with the design and construction of the facility and describe any relevant issues that may positively or negatively influence the project's design and construction. MP has a preference for the use of local prevailing wage for labor cost. The qualitative evaluation will take into account whether the proposal includes a written commitment to paying local prevailing wages.

10. **Resource supply plan.** Bidders should provide hourly estimates of net generation for an average day of each month (typical hours of estimates for each of 12 months). Such bidders should also provide supporting information (e.g., PV modeling data and parameters, production data, expected degradation over time, description of data-gathering and data-synthesizing processes) that would allow MP to understand how the hourly generation estimates were derived. Additional hourly net generation and other performance information may be requested by MP from bidders that are shortlisted.

11. **O&M plan.** Proposals should include a discussion of the bidder's O&M plan and what firm(s) would provide such services.

12. **Scheduling.** Bidders must describe how they will provide accurate forecast information to MP for scheduling the facility into MISO if the generation will be scheduled by MP.

13. **Statement of Exceptions to MP's PPA.** As noted in Section 2.9, each bidder must review MP's Model Solar PPA and document all material exceptions to the terms and conditions that are relevant to the bidder's proposed resource and that the bidder wishes to take in substantiating the fundamental terms and conditions of its power supply offer.

14. **Proposal Limitations.** Please describe in reasonable detail any existing regulatory, legal, economic, operational, or systematic conditions that might affect the respondent's ability to deliver capacity and energy as offered.

5.3 Confidentiality

Note that any portion of a bidder's proposal that the bidder deems to be confidential must be clearly marked. MP and its consultants will take reasonable precautions to maintain the confidentiality of such information. However, MP is rate regulated by the MPUC; bidders must recognize that their confidential information may have to be shared with regulatory agencies and provided in MPUC regulatory proceedings as well as other regulatory or legal proceedings. MP will employ reasonable efforts to ensure that such confidential information is not publicly disclosed in such proceedings but can give no guarantees of such protection.

6.0 EVALUATION PROCESS

MP's evaluation of power supply proposals will involve the following steps:

1. Screening for completeness and compliance with minimum eligibility requirements
2. Preliminary and detailed economic assessment

3. Non-economic/risk assessment
4. Selection of short list
5. Further due diligence
6. Final selection

Note: MP reserves the right to eliminate any or all proposals during any of these steps. Any proposal advancing any one or more steps does not create any entitlement or reasonable expectation that the proposal will ultimately achieve a PPA. All obligations between MP and a bidder relating to a proposal will be governed by an executed and effective PPA for which all negotiated conditions precedent have been satisfied.

6.1 Screening for completeness/compliance with minimum eligibility requirements

MP's evaluation team will perform an initial screening of each proposal to ensure that the proposal is complete and complies with the Resource Request's minimum eligibility requirements. Proposals with substantial deficiencies will be rejected. For proposals with marginal deficiencies, MP may request that the bidder promptly provide missing information or appropriate clarifications; failure to provide such information may result in a proposal being rejected. All proposals that are deemed to be reasonably complete and compliant will be passed to the economic and non-economic/risk assessment steps.

6.2 Preliminary and detailed economic assessment

MP may perform a preliminary economic screening analysis to identify proposals that are clearly uneconomic and thus do not warrant further detailed evaluation. If performed, such an analysis will involve the use of resource evaluation spreadsheets to review and rank the proposals based on pricing and operational information from the proposal.

The evaluated cost of each proposal will be determined by considering the price under the proposed PPA, the estimated value of energy and capacity from the project based on the project's energy production profile and projected locational marginal prices (LMPs) at the delivery point, and a quantification of the financial costs to MP of rating agencies' treatment of long-term PPA payment obligations as imputed debt. Project costs will be present-valued and/or levelized back to a base year.

6.3 Non-economic/risk assessment

In parallel with the economic assessment, MP's evaluation team will also assess each resource's or portfolio's non-economic characteristics and risks. Such analysis will involve a qualitative consideration of such issues as:

- Bidder's project team experience and financial strength,
- Feasibility of schedule and current status,

- Status of site control, zoning, and local acceptance,
- Interconnection complexities,
- Transmission delivery complexities,
- Size of resource relative to MP's overall resource need of 1MW to 300 MW (particularly applicable to relatively new technologies and/or development teams with little experience or financial strength),
- Likelihood of permitting,
- Environmental impacts,
- Likelihood of getting financed,
- Quality of design and construction plan,
- Assessment of acceptable photovoltaic solar technology,
- Quality of O&M plan,
- Ability to provide MP timely and accurate information to schedule the unit into the MISO market, and
- Exceptions taken to MP's Model Solar PPA.

MP's evaluation team will rank the potential power supply portfolios by levelized total system cost and supplement each portfolio's place in the ranking with a qualitative assessment of the above risks in developing a final set of resources that will be recommended for inclusion on a short list.

6.4 Additional due diligence

Bidders of shortlisted projects will be notified and face-to-face meetings and/or conference calls will be held to perform additional due diligence. Such meetings or calls will provide both MP and the bidder an opportunity to identify and clarify any remaining uncertainties that would complicate the finalization of a PPA or the development of the project. Following this process, MP will select one or more finalist projects that, in total, are sufficient to meet MP's customer needs.

7.0 RESERVATION OF RIGHTS

MP makes the following reservations in undertaking this power supply solicitation:

1. MP reserves the right to modify or withdraw this Resource Request.

2. MP reserves the right to reject any and all responses to this Resource Request.

3. MP's Resource Request does not equate to an offer to purchase any capacity and energy.

4. All proposal preparation costs must be borne by the bidder.

5. Proposals will not be returned to the bidders.

6. MP may accept a proposal that is not the lowest cost proposal(s).

7. MP may seek clarification from bidders and may request additional information from bidders beyond that which is specifically identified in the Resource Request.

8. MP reserves the right to waive bidder noncompliance with any aspect of its Resource Request.

9. MP may conduct negotiations with selected bidders and may terminate negotiations at any time.

10. Any and all decisions are conditioned on the approval of MP's management and Board of Directors as well as all required regulatory and other approvals.

11. MP reserves the right to modify or supplement this Resource Request at any time during this process. Any such modifications or supplements shall become part of this process and shall be addressed as part of any proposal submitted.

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Appendix R: Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2016 Solar Resource Solicitation

Sedway Consulting, Inc.

INDEPENDENT EVALUATION REPORT
FOR MINNESOTA POWER COMPANY'S
2016 SOLAR RESOURCE SOLICITATION

Submitted by:

Alan S. Taylor
Sedway Consulting, Inc.
Boulder, Colorado

July 10, 2017

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Introduction and Background

On August 4, 2016, Minnesota Power Company (MP) issued a Request for Proposals (RFP) for up to 300 MW of power supplies from solar projects to capture the benefits of the Federal Production Tax Credit for customers and comply with a Minnesota Public Utilities Commission directive associated with the utility's 2016 Integrated Resource Plan (IRP). Sedway Consulting, Inc. (Sedway Consulting) was retained by MP to oversee this solicitation for new solar resources and provide an independent evaluation of all proposals. This report provides an assessment of MP's solar resource solicitation from the initial phase of the solicitation (i.e., the issuance of the RFP) through the development of a final short list of bidders/projects with whom MP commenced negotiations and ultimately executed a final contract with the best option.

Sedway Consulting undertook the following tasks as part of this engagement:

- Reviewed and commented on the Resource Request document before the solicitation was launched,
- Participated in MP planning calls/meetings to establish the screening procedures and evaluation methodologies that would be employed in the review and evaluation of all proposals,
- Acquired and archived all important evaluation parameters and market price assumptions prior to bid opening, for use in Sedway Consulting's proprietary evaluation model,
- Received (via email) and independently reviewed all proposals, compiling levelized contract prices and net costs for the ranking of proposals,
- Participated in MP calls/meetings to discuss proposal review results,
- Participated in an on-site meeting to discuss Sedway Consulting's evaluation results and determine an appropriate preliminary short list of projects/bidders,
- Conferred with MP regarding its RFP modeling results and the utility's conclusion that no solar resources were cost-effective at the proposed prices (but that a small solar project may be worth pursuing),
- Made recommendations on solicitation refinements and additional requests for best-and-final offers (BAFO) associated with the projects on the preliminary short list,
- Participated in debriefing calls with those bidders who were not shortlisted (and who requested a call), and
- Performed a final evaluation of BAFOs and participated in final selection calls with MP.

Sedway Consulting was provided access to all necessary materials and meetings and was able to perform its own evaluation of all of the proposals. Sedway Consulting conferred with MP in periodic calls/meetings to discuss proposal clarification, disqualification, and evaluation decisions.

Overview of Conclusions

Sedway Consulting developed an economic ranking of all proposals based on their $/MWh net costs, assessed the qualitative risks and benefits associated with the top-ranked proposals, presented the results to MP and discussed the selection of an appropriate short list of projects and counterparties with whom to commence negotiations. Of those projects that were shortlisted, Cypress Creek Renewable's Blanchard proposal was the most cost-effective (i.e., lowest $/MWh net cost of the best-and-final offers). That project will be a new 10 MW-AC solar photovoltaic (PV) resource near Royalton, Minnesota, with an expected commercial operation date of June 30, 2020. Sedway Consulting concludes that MP made the appropriate selection decisions in its solicitation and concurs with the decision to secure solar energy deliveries through the execution of Cypress Creek Renewable's Blanchard Solar LLC power purchase agreement for the proposed 25 year term.

This Independent Evaluation Report has a confidential appendix that includes a description of each proposal and an overview of the evaluation results and sensitivity analyses. This material is being afforded confidential treatment to protect participants from having their project pricing and operational information provided to their competitors. Also, MP's customers could be harmed if too much information was made publicly available, allowing some participants to game future solicitations rather than delivering the best renewable projects at the lowest possible prices.

Activities Prior to the Receipt of Proposals

Sedway Consulting had provided independent evaluation services in previous MP solar RFPs and was thus quite familiar with MP's evaluation processes and available planning assumptions. Prior to the receipt of proposals, Sedway Consulting requested and incorporated MP's latest market price forecasts into Sedway Consulting's evaluation model. Sedway Consulting requested MP to provide as much information as possible prior to the receipt of proposals. This, in essence, allowed Sedway Consulting to lock down and archive the basic evaluation parameters for the process. Such information included forecasts of regional market energy prices,[1] cost of capital components, and discount rate. These assumptions were incorporated into Sedway Consulting's own

[1] In past MP solar solicitations, Sedway Consulting has also ascribed values to the capacity of proposed solar resources and potential solar renewable energy credits (RECs). In consultation with MP, it was decided that such capacity and REC valuations were not necessary in the current evaluation in that they were dependent on MISO capacity accreditation rules that may change, were likely to be similar across all solar projects (and thus would not represent differentiating benefits), and/or might be inappropriately influenced by bidder-supplied generation profiles.

evaluation model and formed the basis for independently assessing the benefits and costs of resources that were bid into MP's solicitation.

Receipt and Evaluation of Proposals

On September 14, 2016, MP and Sedway Consulting received a significant number of proposals in the utility's solar resource solicitation. Submissions were made via email. Both MP and Sedway Consulting reviewed the submitted proposals during September and early October 2016, periodically discussing proposal deficiencies and requests to specific bidders for supplemental information.

The evaluation process entailed a general review of all proposals and the calculation and ranking of levelized energy prices for all proposed options. Instances where proposals were found to be non-compliant or incomplete, bidders were notified and given an opportunity to supplement their proposal materials. The evaluation team focused more of its efforts on the higher-ranked proposals, performing a thorough qualitative assessment of those proposals that appeared to have the best quantitative value for MP's customers. In addition, Sedway Consulting worked with an MP transmission interconnection subject matter expert to investigate (and clarify with questions to the bidders, when necessary) the feasibility, status, and potential benefits or drawbacks of the proposed points of interconnection for the top-ranked projects. Concurrent with that qualitative analysis, Sedway Consulting undertook the modeling of all proposals to assess their energy benefits; specifically, Sedway Consulting performed detailed modeling to determine each proposal's net cost (described below). Although the levelized price ranking provided a good approximation of how project economics might compare, an assessment of the offers' generation profiles and the energy benefits associated with those profiles provided a comprehensive comparison.

Description of Sedway Consulting's Detailed Evaluation Process

The detailed economic evaluation entailed modeling the bids in Sedway Consulting's Renewable Bid Evaluation Model (RBEM) – a spreadsheet-based tool that determined a proposal's net cost by calculating the present value of the project's costs and subtracting the present value of a proposed facility's hourly energy benefits. The costs in the net cost calculation included contract payments for delivered energy and an imputed debt cost[2] for power purchase agreements (PPA). Energy benefits were the product of the expected hourly generation of a facility and a forecast of hourly $/MWh energy market prices over the term of the contract. Sedway Consulting's evaluation model normalized the net cost by dividing it by the present value of a project's expected energy deliveries, thereby yielding a $/MWh levelized net cost. As a positive number, this $/MWh net cost reflects

[2] Imputed debt (or debt equivalence) costs are associated with a rebalancing of a utility's debt and equity ratios in light of credit rating agencies' policies that view PPAs as being partially equivalent to debt obligations.

the premium that a utility must pay for renewable energy relative to "brown" power – the more positive the number, the greater the renewable premium.

The response to MP's 2016 solar resource solicitation was quite robust: 70 project proposals[3] were submitted. A summary of the projects is depicted in Table A-1 in Confidential Appendix A.

As noted above, Sedway Consulting performed a detailed levelized net cost analysis of all proposals. The results of Sedway Consulting's analysis are depicted in Table A-2 in Confidential Appendix A. The table includes each PPA/project's expected capacity, proposed duration, the $/MWh levelized net cost, and the levelized $/MWh components of that net cost.

Shortlisting of Proposals

On October 17, 2016, Sedway Consulting met with MP personnel from various departments and presented the results of its analysis. In discussing the evaluation and selection process with MP, it had been decided that the projects and associated evaluation results should be separated into three size groups:

- projects with capacities that were 25 MW or less,
- projects with capacities in the 26 MW to 74 MW range, and
- projects that were 75 MW and greater.

This was done to facilitate MP's IRP modeling efforts. It was recognized that it would be impractical for MP to model all of the solicitation's responses in its IRP process. Instead, the utility wished to identify the best projects (i.e., lowest net cost and risk) within some general size ranges and model those to see what MP's optimal resource portfolio might include.

After discussing Sedway Consulting's results, it was decided that a key subset of the top-ranked projects in each size group would be preliminarily shortlisted, as described further in Confidential Appendix A. MP used the pricing and characteristics from these top-ranked projects/PPAs of varying sizes in its IRP model and determined that no solar resources were justified in the utility's optimal least-cost resource portfolio at the proposed prices. That said, MP has a state solar energy requirement that it source 1.5% of its retail sales, net of exclusions, from solar resources by 2020, with a compliance strategy to procure or develop at least 20 MW of utility-scale solar resources by 2020. Currently, the utility has a 10 MW solar PV project that was recently completed at the Minnesota Army National Guard's Camp Ripley facility near Little Falls, Minnesota. Thus, MP recognized that it had a remaining 10 MW need which could be filled with a project from the current RFP or future RFPs. Given that there are enhanced federal

[3] Many of these project proposals included mutually-exclusive options (e.g., flat versus escalating pricing, different terms); thus, there were many more distinct offers.

Investment Tax Credit (ITC) benefits for solar resources that will begin declining in 2020 and whose legislative extension is uncertain, MP decided to procure the 10 MW of solar resource(s) from the current RFP's responses. MP and Sedway Consulting thus focused on-going evaluation efforts on projects in the smaller size range.

Several bidders had contacted MP and Sedway Consulting during the evaluation process and noted that technology costs had declined and they could improve their bid pricing. In all such cases, MP and Sedway Consulting made it clear to such bidders that unsolicited, "one-off" repricing of proposals would not be entertained. However, given the results of the preliminary shortlisting analysis and the decision to focus on smaller projects, MP and Sedway Consulting agreed that it would be appropriate to return to a sizable portion of the top-ranked bidders with projects in the 25 MW and smaller category and afford them all the opportunity to reprice their proposals and scale down any that were greater than 10 MW. All other bidders would be released from further consideration. In addition, for those bidders who had submitted multiple offers in the small category, it was decided that MP should provide direction on which projects were no longer under consideration if the site/transmission interconnection analyses had indicated that the projects were not ones that MP would select.

On November 17, 2016, MP notified all bidders of their projects' status. A reasonably large number of bidders with small projects were retained and offered the opportunity to reprice (and resize, if necessary), thereby ensuring adequate competition for the final evaluation. This final set of bidders was requested to provide revised prices by December 1, 2016.

Sedway Consulting performed an analysis of the final offers, sought some clarifications on a few, and conferred with MP in December, 2016 and early January, 2017 to select a final short list of bidders/projects with whom MP should commence negotiations. That final short list included enough bidders to protect against the possibility of failed negotiations with the best project. MP notified all remaining bidders of their status on January 6, 2017. None of the finalists were affiliates or MP self-build counterparties, so MP proceeded with the negotiation process without further involvement from Sedway Consulting.

On June 7, 2017, MP executed a PPA with Blanchard Solar, LLC for all of the output form a new 10 MW solar PV facility that will be developed near Royalton, Minnesota. That PPA represents the project and pricing that was at the top of Sedway Consulting's final evaluation ranking.

Conclusion

Sedway Consulting was provided access to all necessary materials and meetings and was able to perform its own detailed evaluation of the proposals received in MP's 2016 solar resource RFP.

Sedway Consulting monitored the back-and-forth email traffic between MP and the solar resource bidders and believes that MP treated all bidders consistently and fairly.

Sedway Consulting believes that MP selected the best solar project for meeting its IRP requirements.

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Appendix A
Offer Description and Evaluation Results

This has been designated as non-public in its entirety, as the document includes a summary of the terms of the proposals received in response to Minnesota Power's RFP for solar resource projects and the independent evaluation of those proposals. This information derives independent economic value from not being generally known to, or readily ascertainable by, others who could obtain economic advantage from its disclosure or use and thus constitutes information Minnesota Power considers to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b).

This Appendix A of the Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2016 Solar Resource Solicitation was prepared July 10, 2017, by Alan S. Taylor, Sedway Consulting, Inc.

APPENDIX S: SUMMARY OF MINNESOTA POWER'S INTERCONNECTION PROCESS

Minnesota Power follows a robust interconnection process to ensure that interconnecting generators can safely operate while maintaining reliable service for all customers. The framework for the interconnection process was created by industry stakeholders and approved by the Minnesota Public Utilities Commission.

The interconnection process begins with an application from a customer or developer and must contain a completed Generation Interconnection Application and payment of the application fee. The Generation Interconnection Application contains information including, but not limited to, a one-line diagram, the overall site plan of the installation, and the proposed schedule of installation. Upon receipt of the application, Minnesota Power performs a preliminary review of the information for accuracy and completeness. It is at this point, the base screening criteria is applied and it is determined if the installation will require further engineering study.

Following the completion of engineering studies (if necessary), Minnesota Power provides construction estimates, comments on the proposed schedule, determines a payment schedule for Minnesota Power work, identifies any special protection requirements for the installation, and identifies monitoring and control requirements of the site. The applicant then moves into the detailed design stage of the process and provides Minnesota Power with information such as a final schedule, detailed one-line diagrams, detailed site plan, detailed equipment specifications, and a proposed testing schedule. Minnesota Power reviews the final detailed design and upon approval the necessary equipment is ordered by Minnesota Power and the Applicant to facilitate construction. Final acceptance testing is performed to ensure safe and reliable operation of the new generator installation.

APPENDIX T: SUMMARY OF MISO'S GENERATOR INTERCONNECTION PROCESS

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The Midcontinent Independent System Operator, Inc. ("MISO") Generator Interconnection Process is governed under Attachment X of the MISO Tariff and further refined through their Business Practices Manual (BPM-015: Generator Interconnection Business Practice Manual). The application process and study calendar are posted publicly on MISO's website and were used to determine the dates for the August 2017 study cycle.

MISO Generator Interconnection Queue Process Outline
The MISO Generator Interconnection Process is divided into three phases. Each phase is described at a high level below (see Figure 1).

- Pre-Queue
- Application Review
- Definitive Planning

The Pre-Queue phase is optional and means "Interconnection Customer outreach and education effort undertaken prior to the submission of the Interconnection Request" (MISO Tariff, Attachment X). This phase includes activities such as: MISO led informational sessions, customer requested ad hoc meetings, and customer review of contour maps.

During the application screening/review, MISO will review the customers' interconnection application and work with the Interconnection Customer to verify the information submitted and clarify any ambiguity. The application must be submitted at least 45 calendar days prior to the "on-time" scheduled start of the Definitive Planning Phase (DPP) in order to proceed into DPP Phase 1.

An Interconnection Customer enters DPP Phase 1 by submitting the M2 milestone payment and D3 study deposit at least 45 Calendar Days prior to the "on-time" scheduled start of the DPP. The generator interconnection process is divided into four segments: DPP Phases 1 through 3 and the Generator Interconnection Agreement (GIA) Phase.

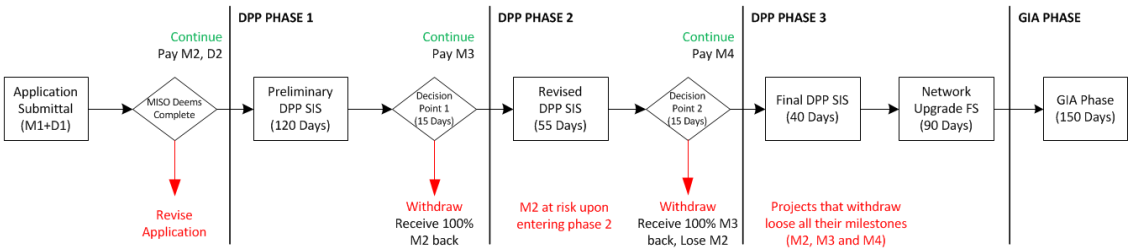
During DPP Phases 1 and 2 MISO performs a complete System Impact Study (SIS) to identify any transmission system issues caused by interconnecting the proposed generation. Following each SIS, MISO prepares a cost estimate for each project summarizing the expected cost to interconnect. Once MISO provides the individual cost estimate to each Interconnection Customer (IC), the customer has 15 business days to withdraw from the generator interconnection process or provide an additional cash milestone payment to continue.

Following the decision point at the end of DPP Phase 2 MISO will perform a final SIS. This final study group includes only those generation projects that have decided to complete the final step to obtain an interconnection agreement. At this stage MISO also works with the regional Transmission Owners (TOs) to develop an engineered cost estimate for all the transmission system Network Upgrades required to interconnect the proposed generation. The individual cost

estimates provided at the end of DPP Phase 3 are included in the Generator Interconnection Agreement (GIA) and form the basis for expected interconnection costs.

The GIA Phase begins immediately following the completion of the individual Network Upgrade cost estimates. During the GIA Phase, MISO works with the regional TOs and the individual ICs to develop agreements regarding funding of the network upgrade projects identified in the final SIS, the timeline for transmission system Network Upgrades, and operational timelines and parameters for the generation facility. The complete set of terms developed becomes part of the final GIA that is filed with FERC.

Figure 1: MISO Generator Interconnection Process



Estimated Timeline for the August 2017 DPP Cycle

The August 2017 DPP Cycle was originally scheduled to begin during the first week in August 2017. However, due to significant backlog in processing interconnection requests in the upper Midwest, MISO is currently projecting that they will deviate from the original start date. This delay means that the new expected start date for DPP Phase 1 is now sometime in late May 2018.

Milestone Payments and Study Costs

To enter the generator interconnection process, the IC must submit a completed application (M1 milestone), a $5,000[1] non-refundable application deposit (D1), and a $530,000 System Impact Study deposit (D2) which covers the costs of performing the System Impact Studies. The D1 deposit is non-refundable while any unused portion of the D2 deposit is refundable under certain conditions.

Once the application is deemed complete, and assuming the Interconnection Customer decides to proceed to the Definitive Planning Phase, the IC (South Shore Energy) must then submit a $2,246,000 Definitive Planning Phase Entry Milestone Deposit (M2) which will be held as a deposit toward future network upgrade costs during the DPP Process. The total M2 milestone payment is calculated at $4,000/MW or $2,246,000 for the proposed 561.5 MW combined cycle plant.

[1] On June 7, 2017, South Shore Energy submitted a revised DPP application for MISO Project J732. With that application the D1, D2 and M2 milestone payment requirements were satisfied.

Milestones M3 and M4 are variable based on the estimated costs for the Network Upgrades that are identified during Phases 2 and 3 of the Definitive Planning Phase respectively. The equations for each are:

- M3 = (10% of Network Upgrades) – M2
- M4 = (20% of Network Upgrades) – M3 – M2

Milestone Payments (M2, M3, and/or M4) are refundable as long as certain conditions are met. These are covered in more detail in the "Withdrawal Options" section below. Per the MISO Tariff, if M2, M3, and M4 are paid in cash, MISO will transfer that cash to the affected Transmission Owner(s) to satisfy the Initial Payment after the LGIA is signed. However, the exact value of the Initial Payment may differ from the funds that are available so additional expenditures or refund (to the Project) may be necessary. An estimate of these payments is provided in Table 1 below.

South Shore Energy will get updates as the Project (J732) moves through the MISO process.

Table 1: Estimate of Definitive Planning Process Payments (Assuming a 561.5 MW Plant)

Description	Low Estimate	High Estimate
Application Fee (D1)	$5,000[2]	$5,000[2]
Definitive Planning Phase Study Funding Deposit (D2)	$530,000[3]	$530,000[3]
Definitive Planning Entry Milestone Payment (M2)	$2,246,000[4]	$2,246,000[4] **[TRADE SECRET DATA BEGINS…**
Milestone Payment to Proceed to Phase II (M3)	$0	
Milestone Payment to Proceed to Phase III (M4)	$0	
Total (estimated)	**$2,735,000**	**…TRADE SECRET DATA ENDS]**

Withdrawal Options

There are multiple withdrawal options in the MISO generator interconnection process and these are outlined below.

[2] Non-refundable
[3] Partially refundable, but specific conditions must be met.
[4] Calculated as a flat fee of $4,000/MW.
[5] For the purposes of estimating costs **[TRADE SECRET DATA BEGINS… …TRADE SECRET DATA ENDS]** was used as a benchmark for Network Upgrade costs. This value was determined by the NTEC Project Team as the level at which the project remains feasible. Any value above this amount would be reevaluated and discussed between the partners.

Penalty-Free

Under the currently approved Generator Interconnection Process (effective January 4, 2017) there are two options for withdrawal without penalty. They are:

- At Decision Point 1, following the completion of the preliminary SIS, if the IC withdraws at this decision point the M2 payment is fully refunded, but the IC forfeits $5,000 application fee (D1).
- At the time of the Network Upgrade Facility Study if MISO Network Upgrade costs increase from Phase III results by 25% AND $10k/MW.

However, if FERC approves the revisions submitted with the compliance filing on March 31, 2017, then the IC can withdraw their project from the queue without penalty in the following circumstances:

- At Decision Point 2 if the MISO Network Upgrade costs between Phase I and Phase II increase by 25% AND $10k/MW.
- At Decision Point 2 if Affected System Network Upgrade costs between Phase I and Phase II increase by 30% AND $10k/MW.
- Following completion of the final SIS (during Phase III) if MISO Network Upgrade costs between Phase II and Phase III increase by 25% AND $10k/MW due to study error.
- Following completion of the final SIS (during Phase III) if MISO Network Upgrade costs between Phase II and Phase III increase by 35% AND $15k/MW.
- Following the completion of the final SIS (during Phase III) if Affected System Network Upgrade costs between Phase II and Phase III increase by 40% AND $15k/MW.
- Following completion of the final SIS (during Phase III) if MISO Network Upgrade costs between Phase I and Phase III increase by 50% AND $20k/MW.
- Following the completion of the final SIS (during Phase III) if Affected System Network Upgrade costs between Phase I and Phase III increase by 55% AND $20k/MW.

With Penalty

An IC can withdraw from the interconnection process at any time, but risks forfeiting all of some of their milestone payments. As shown in Figure 1:

- If the IC withdraws at Decision Point 2 for any reason, the M2 milestone payment is forfeited, but the M3 milestone payment is refunded.
- If the IC withdraws at any point after Decision Point 2 for a reason other than those described above, they forfeit all M2, M3, and M4 milestone Payments.

Conditional LGIA

There is potential for the NTEC project to receive a Conditional LGIA for a period of time before receiving a final LGIA. A project is deemed conditional if all conditions listed in the GIA Appendix A10 are not met. The A10 list will contain all directly assigned Network Upgrades associated with the project, as well as MTEP upgrades not yet in service on which the project has an impact, based on a defined set of criteria. Additionally, if there are Network Upgrades assigned to previous DPP groups needed for voltage and stability related issues, those upgrades will be included in all subsequent groups' A10 list until constructed.

Projects with a Conditional LGIA are subject to the Annual ERIS Evaluation and Annual Interim Deliverability Study. This study determines the available levels of ERIS and NRIS for the project based on actual network topology for the following Resource Adequacy Planning Year. Until all conditions are met in the A10 list, available ERIS and NRIS levels may vary between 0% and 100% of requested amount. After construction of all projects in the A10 list, the project will no longer need to participate in this study and will be allocated the full amount of ERIS and NRIS as granted in the DPP study.

APPENDIX U: REQUEST FOR PROPOSALS FOR UP TO 400 MW OF CAPACITY AND ENERGY

Request for Proposals

for

Up to 400 MW of Capacity and Energy

issued by

Minnesota Power

Issue Date: October 15, 2015
Proposals Due: January 7, 2016
Version 2: Updated December 15, 2015

Complete Information on this RFP can be found at:

http://RFP.mnpower.com

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1.0 BACKGROUND

Minnesota Power (MP), a division of ALLETE, Inc., has issued this Request for Proposals (RFP) and is seeking power supply proposals for up to a nominal 400 MW of natural gas-fired capacity and unit-contingent energy, beginning in the 2022 to 2024 timeframe.

Minnesota Power's resource strategy calls for a more balanced and flexible fleet of generation resources with the capability to meet customers' needs reliably and cost effectively in an environmentally responsible manner while still managing the inherent variability of the business cycles that affect large industrial customers.

The 2015 Integrated Resource Plan (IRP) that was recently filed with the Minnesota Public Utilities Commission (MPUC) indicates the need for a large, efficient natural gas-fired generating facility in the 2021 to 2024 timeframe. The IRP is designed to provide Minnesota Power customers with a safe, reliable, and affordable power supply while also reducing emissions. A natural gas combined cycle resource provides an efficient, less carbon-intensive option than MP's existing thermal generation portfolio to support the reliability of the company's power supply by increasing low-cost dispatchable energy and decreasing emissions.

Proposals must reflect all of the costs and characteristics of the resource delivered to MP's load zone and accept the curtailment, congestion and losses for delivery to MP's MISO load node. All potential agreements may be subject to MPUC approval.

All proposals must be received by the contact designated in Section 3.3 by the Proposal Submittal Deadline date shown in Section 3.1. MP reserves the right in its sole discretion to modify this schedule for any reason.

In combination and/or in competition with submitted resource proposals, MP intends to consider self-build natural gas-fired resource alternatives as potential power supplies to meet its resource needs. In connection with this RFP, MP has retained the services of an independent third party consultant (Sedway Consulting, Inc.) to work with MP in the quantitative evaluation of all proposals and self-build resources. However, MP will make the final decision (subject to MPUC review, as applicable) in MP's sole discretion.

* * * * *

2.0 ELIGIBLE PROPOSALS – MINIMUM REQUIREMENTS

Proposals must meet the general minimum eligibility requirements described below. MP will screen all proposals for compliance with these requirements. Proposals that fail to meet one or more of the general minimum eligibility requirements may be disqualified from further consideration.

2.1 Eligible Power Supply Requirements

1. Offers must provide MISO accredited or accreditable capacity (including Zonal Resource Credits) of no less than 200 MW and up to a maximum of 400 MW of Summer and/or Winter capacity, be available to start delivery in the 2022 to 2024 timeframe, and be operated by a MISO market participant,

2. Offers must be based on a natural gas-fired, non-intermittent, firm resource with an availability guarantee of no less than 96% for the summer months (June through August) and winter months (December through February), and 75% for the remaining shoulder months.

3. Offers must deliver capacity and energy to the MP load zone (currently at the MISO MP.MP CPNode)

2.2 Eligible Project Structures

Minnesota Power will consider the following proposal types:

1. Power Purchase Agreements (“PPA”)

2. Tolling Agreements (“TA”)

3. Asset Purchase

4. Self-build Generation

The term for all contracts must be for a minimum of 20 years with an option to purchase the facility after 20 years at net book value. MP also has a preference for options for purchase at years 10 to 15.

2.3 Power Delivery Requirements

All proposals must provide for firm transmission service with delivery to the Minnesota Power load node (as determined by MISO), currently MP.MP. The cost of obtaining firm transmission service, any interconnection equipment, congestion costs, and losses up to the point of delivery shall be the responsibility of the respondent and must be included in the proposed pricing. Respondent shall be responsible for all operational related costs, penalties, and charges assessed by MISO.

One of the goals of this RFP is to determine the overall cost to MP's retail customers of the selected resource(s), recognizing that the cost of interconnection and delivery of power from the chosen resource(s) to MP's native load is an element of cost that must be taken into account. Network upgrade costs that are assessed to the project will be the responsibility of the respondent. Bidders will also be responsible for procuring transmission service and any associated third-party transmission costs needed to deliver power from the project to the Minnesota Power load zone. All pricing should reflect those costs (to the extent applicable) at the time of submittal. To the extent that network upgrades are required as a

consequence of adding the proposed project to the MISO transmission system, the network upgrade costs will be included in Minnesota Power's economical evaluation of the proposal.

2.4 Firm Fuel Transportation Service

Gas-fired generation resources must be served through firm transportation service by at least one major natural gas pipeline. For each pipeline the proposal must indicate the most applicable fuel pricing hub(s), pipeline tariffs and receipt points, negotiated rates, reservation rates, any local distribution company (LDC) charges, backup fuel capability, and any other fuel-related cost (as applicable). For evaluation purposes, the evaluation team plans to use the same fundamental fuel price forecast for estimates of natural gas commodity pricing for each bid.

The natural gas must be supplied at a rate, compression, and pressure sufficient to run the facility at full output (including duct firing and any other capacity enhancements) on a continuous basis and still comply with all operating requirements of the pipeline or LDC system.

For natural gas pipeline capacity, provide appropriate transportation details including the Maximum Daily Transportation Quantity and any other terms, conditions, or limits necessary for Minnesota Power to understand the deliverability of fuel and total cost of firm gas transportation. If an existing facility has existing firm pipeline contracts, the main terms of these contracts should be provided with the proposal if the respondent wishes to transfer these contracts to Minnesota Power. This information must be provided in Exhibit C: PPA/TA Data and/or Exhibit D: Asset Purchase Data and/or Exhibit E: New Build Cost Buildup (as available and applicable).

2.5 Environmental

The gas-fired resource must be in compliance with all applicable environmental rules and regulations.

To the extent applicable, all environmental attributes, including emission reduction credits and/or allowances, related to the power being purchased should be conveyed to MP. This includes, but is not limited to, any and all credits in any form (emissions credits, offsets, financial credits, etc.) or baseline emissions associated with both known and unknown pollutants, including but not limited to SO2, NOx, Hg, and CO2. Any and all environmental liabilities, including compliance with known and future or unknown regulations or laws will be the sole responsibility of the generation producer/PPA seller.

For Asset Purchase proposals, the Seller will retain all pre-closing and known future environmental liabilities and obligations associated with the real and personal property transferred with or as part of a Sale of the Plant. This includes both on and off-site liabilities. The Buyer will assume all post-closing environmental liabilities and obligations.

2.6 Firm Pricing

Proposals must include pricing that is firm and not subject to any revisions during Minnesota Power's evaluation and negotiation process. Bidders may propose escalation rates that are either fixed or, if appropriate and defensible annually indexed to the Gross Domestic Product Implicit Price Deflator (GDPIPD). Such indexing is not acceptable for demand or capital pricing but for elements of a bidders pricing proposal that will be impacted by the GDPIPD. The GDPIPD will be adjusted annually as published by the U.S. Department of Commerce, Bureau of Economic Analysis. Formulaic mechanisms will not be subject to revisions during MP's evaluation and negotiation process.

All pricing should be provided in Exhibit C and/or Exhibit D and/or Exhibit E in terms of US dollars as of the date the term of the contract begins and not subject to a currency exchange rate adjustment. All PPA/TA information should be provided in Exhibit C: PPA/TA Data, all Asset Purchase information should be provided in Exhibit D: Asset Purchase Data, and a cost buildup for new build projects should be provided in Exhibit E: New Build Cost Buildup; (all data as available and applicable). Any and all environmental liabilities, including compliance with known and future or unknown regulations or laws will be the liability and sole responsibility of the generation producer/PPA Seller. Minnesota Power will receive all associated allowances or credits, if any. Seller agrees to transfer any Financial Transmission Rights or Auction Revenue Rights associated with the asset to the Buyer.

Respondents are strongly encouraged to provide their 'best and final' pricing with their initial submittal. Minnesota Power does not anticipate an opportunity in the schedule for respondents to refresh or update their pricing before the final selection(s) are made (if any). Respondents Proposal and pricing shall remain valid until October 31, 2016.

2.7 Credit Rating

A bidder must have a credit rating for its senior unsecured debt of **BBB** or higher (for Standard & Poor's) or **Baa2** or higher (for Moody's). If a bidder is unrated or does not meet this minimum credit rating requirement, the bidder must demonstrate the capability to supply performance assurance in the form of a corporate guarantor that meets the requirement, a letter of credit and/or cash. The amount of performance assurance shall be no less than $100/kW of the proposed capacity of the proposal. This performance assurance will remain in place from contract execution through the term of the contract unless otherwise negotiated based upon the expected financial exposure related to the bid.

2.8 Legal Certifications

A bidder must certify that:

1. There are no pending legal or civil actions that would impair the bidder's ability to perform its obligations under the proposed PPA;

2. the bidder has not directly or indirectly induced or solicited any other respondent to submit a false or sham proposal;

3. the bidder has not solicited or induced any other person, firm, or corporation to refrain from submitting a proposal; and

4. the bidder has not sought by collusion to obtain any advantage over any other respondent.

* * * * *

3.0 SCHEDULE AND RFP INSTRUCTIONS

3.1 Overview of Process

The schedule below represents MP's expected time-line for conducting this resource solicitation. MP reserves the right to modify this schedule as circumstances warrant and/or as MP deems appropriate.

Minnesota Power RFP Schedule

Event	Anticipated Date
Release of RFP	October 15, 2015
Notice of Intent to Bid Due	November 16, 2015
Proposal Submittal Deadline	**5:00 pm CST on January 7, 2016**
Selection of Bid(s)	February 15, 2016
Complete Negotiations	Second Quarter 2016

After proposals are submitted, Sedway Consulting will review and quantitatively evaluate all conforming proposals. An MP e-mail address (MPGasRFP@mnpower.com) has been set up to collect all communications and questions from potential respondents as well as a web site (http://RFP.MNPower.com) to download the RFP and Exhibits and provide uniform communications, including updates and other details as may be provided throughout the bidding process. Phone calls and verbal conversations with respondents regarding this RFP are not permitted before the submittal date.

Proposals will be opened in private by Sedway Consulting on a confidential basis. One original copy of each proposal will be retained by Sedway Consulting for a review and comprehensive quantitative evaluation and one original copy of each proposal will be retained by Minnesota Power for a comprehensive qualitative evaluation.

Each respondent should expect to receive a confirmation email from Sedway Consulting that his/her offer submission has been received. If a confirmation email is not received within 24 hours following the Offer Submission Deadline, a respondent should contact the independent evaluator at: Alan.Taylor@sedwayconsulting.com or (303) 581-4172.

Proposals will be reviewed by Sedway Consulting for completeness and offers that do not include the information requirements of this RFP may be notified by Sedway Consulting and allowed to cure the deficiency. During the evaluation process, respondents may be contacted for additional data or clarifications by Sedway Consulting.

3.2 Exhibits

Respondents to this RFP are encouraged to fill out and sign **Exhibit A: Notice of Intent to Bid**.

Respondents to this RFP are required to sign **Exhibit B: Non-disclosure Agreement (NDA)** in its present form.

Respondents to this RFP area also required to complete **Exhibit C: PPA/TA Data** and/or **Exhibit D: Asset Purchase Data** and/or **Exhibit E: New Build Cost Buildup** (as available and applicable).

Respondents to this RFP are required to complete **Exhibit F: General Information** (as applicable).

All correspondence concerning the submittal process for this RFP must be sent via e-mail to MPGasRFP@mnpower.com.

Phone inquiries regarding this RFP will not be entertained before the submittal deadline. Individual questions submitted by a respondent to MP and Sedway Consulting before the submittal deadline will be answered and responses sent back via email to the respondent as soon as practical. Responses to frequently asked or broadly applicable questions may be placed on the RFP Website for the benefit of all respondents, with any identifying information redacted from the question.

3.3 Deadline and Method for Submitting Proposals

All proposals submitted in response to this RFP must be received by MP at the address below no later than the Proposal Submittal Deadline shown in Section 3.1. Sedway Consulting and Minnesota Power will not evaluate proposals as part of this RFP process if submitted after this date and time. Minnesota Power does not anticipate an opportunity in the schedule for respondents to refresh or update their pricing before the final selection(s) are made (if any). Multiple proposals submitted by the same respondent must be identified separately. Financial statements, annual reports, and other large documents should be referenced via a web site address. Each proposal must contain the following:

1. A signed **Exhibit B: Non-disclosure Agreement (NDA)** in its present form

2. Three hard copies of each proposal

3. A flash drive with:

    a. **Exhibit C: PPA/TA Data** and/or **Exhibit D: Asset Purchase Data** and/or **Exhibit E: New Build Cost Buildup** (as applicable)

    b. **Exhibit F: General Information**

    c. A PDF file of the entire proposal

All proposals should be sent to the address below:

Minnesota Power
Attn: 2015 Gas-Fired RFP Response /Eric Palmer
30 W. Superior St.
Duluth, MN 55802

* * * * *

4.0 PROPOSAL ORGANIZATION

The proposal must include an executive summary, proposal limitations, relevant company data and experience, the technical proposal, along with the appropriate Exhibits. Some information may not be known at the time proposals are due. However, partial information and estimates are better than nothing at all, so respondents are encouraged to submit as much information as possible.

4.1 Executive Summary

Please provide a one page executive summary of the proposal in the form of a cover letter. Include the facility's location, age or development status, size, the primary contact's name, email, and phone number, and an overview of the major features of the proposal. The Executive Summary must be signed by an officer of the respondent who is duly authorized to commit the firm to carry out the proposed power supply transaction should Minnesota Power accept the proposal (this does not have to be the primary contact). A Table of Contents should be the first page and immediately precede the Executive Summary.

4.2 Proposal Limitations

Please describe in reasonable detail any existing regulatory, legal, economic, operational, or systematic conditions that might affect the respondent's ability to deliver capacity and energy as offered.

4.3 Company Data, Financing Plan, and Experience

Please include information on the respondent's corporate structure (including identification of any parent companies), the project's financing plan, the respondent's most recent credit rating, quarterly report containing unaudited consolidated financial statements that is signed and verified by an authorized officer of respondent attesting to its accuracy, a copy of respondent's annual report for the prior three years containing audited consolidated financial statements and a summary of respondent's relevant experience. Please describe any current litigation or environmental fines from the last three years that could potentially affect the facility or its operation. All financial statements, annual reports and other large documents may be referenced via a web site address.

Proposals shall include a list of projects with a brief description of Respondent's experience in the areas of development, financing, permitting, ownership, construction, and operation of all utility-scale power generation facilities.

Please provide a list of projects with a brief description of the experience as it relates to utility-scale power generation.

Please provide a list of projects with a brief description of the Operator's experience as it relates to utility-scale power generation (in and outside MISO).

4.4 Technical Proposal

Proposals shall include a detailed technical description of proposed Project. Please review the technical description provided in this section such that it matches up with the technical and cost information provided in the Exhibits. The technical description shall include, but not be limited to the following items as known and applicable:

1. Project name, size, and location

2. Commercial operation date and expected facility life

3. Development and construction schedule Gantt chart (if new)

4. Site characteristics including zoning, site control, site map (white and aerial backgrounds), and any potential environmental or other sensitive issues

5. Description of all the permits needed and plan to acquiring those permits including timing and any expected contingencies or local consultants required

6. Site layout (white background)

7. Community Outreach Plan and evidence of community support

8. Labor source (preference is the use of local prevailing wage for labor cost; if a respondent is willing to commit to this, the respondent's proposal should clearly state that commitment)

9. Full description of proposed technology, reliability, redundancies, automatic generation control, engineering and design status (e.g. FEP-1, FEP-2, PDR, etc), operating capabilities, and heat rate efficiencies

10. List of other equipment including auxiliary boiler, energy storage, evaporative cooling, chillers, and duct firing

11. Description of emission control equipment and any ASTM studies

12. Natural gas supply and firm transportation arrangements, backup fuel capability and characteristics if applicable

13. Full description of the interconnection and firm transmission, deliverability to the delivery point, congestion, losses, the overall risk of transmission, and estimated network upgrade costs (see below)

14. Description of operating flexibility including start times (hot/warm/cold) and ramp rates, minimum down time, minimum output, heat rates at less than full capacity, reactive power, voltage regulation, frequency control, other potential ancillary services, different operational modes, and the current market for those ancillary services

15. Scheduling process and flexibility

16. Environmental, emission and/or any other operating constraints

17. Water supply, usage and discharge

18. Schedule of major maintenance

19. Key terms of a Long-term Service Agreement (LTSA)

20. Key features and terms for Original Equipment Manufacturer spare parts and Long-term Parts Agreement (as applicable)

21. Description of control systems and building enclosure

22. Discuss any other owners and the dispatch rights/preference arrangements

23. An allowance for multiple offers into MISO markets

24. “Best Practices” construction, operation, and maintenance

25. An option to purchase after year 20 at net book value

26. Other future options and/or the capability to expand

27. Capacity size options between 200 – 400 MW

Any fuel “formula” provided must be in sufficient detail for Sedway Consulting and Minnesota Power to understand all the formula components for estimation of the total cost of fuel (and backup fuel), in $/MMBtu, for the Delivery Term (See Exhibit C and D).

Firm gas transportation is to be provided by the respondent and the pertinent details on the firm gas transportation arrangement. If firm gas transportation is not indicated, then the respondent should explain the reason. Details should include maximum daily quantity transportation volume, and any transportation demand rate information necessary to understand the total cost of firm gas transportation on a monthly and annual basis.

Describe the firm transmission arrangements including all transmission providers involved and the transmission services provided (terms and any ancillary services required and appropriate congestion cost). Respondents will have the responsibility to secure and provide all firm transmission services necessary for firm delivery of capacity to the Minnesota Power MISO load node, MP.MP.

For Purchase Power Agreement and Tolling Agreements, specific operational information and pricing should be provided as indicated in Exhibit C: PPA/TA Data, all asset purchase proposals shall provide the specific information requested in Exhibit D: Asset Purchase Data, and all new build projects shall provide the specific information requested in Exhibit E: New Build Cost Buildup; (as available and applicable). All respondents to this RFP are required to complete Exhibit F: General Information (as applicable).

* * * * *

5.0 PROPOSAL EVALUATION AND CONTRACT NEGOTIATIONS

5.1 Initial Proposal Review

An initial review of the bids will be performed by Sedway Consulting. Proposals will be reviewed for completeness and proposals that do not meet or include the information requirements of this RFP may be notified and allowed to cure the deficiencies. Respondents may also be contacted for additional data or clarifications by Sedway Consulting. In general, more certain information and development progress is better than less certain or unknown information.

5.2 Proposal Quantitative Evaluation

Sedway Consulting will quantitatively evaluate all conforming proposals' ability to meet both capacity and energy needs and the corresponding costs. During the quantitative evaluation process, Sedway Consulting may or may not choose to initiate more detailed clarification discussions and a more thorough quantitative evaluation with one or more respondents. Discussions with a respondent shall in no way be construed as commencing contract negotiations.

5.3 Proposal Qualitative Evaluation

Minnesota Power will evaluate and consider both the Quantitative Evaluation developed by Sedway Consulting and the qualitative aspects of all conforming proposals' ability to meet both capacity and energy needs. In general, more certain information and development progress is better than less certain or unknown information.

In evaluating Proposals, Minnesota Power may generally consider the following criteria (in no particular order and without limiting consideration of other factors):

1. Sedway Consulting's Quantitative Evaluation
2. Price certainty, price volatility, and risk of price increases
3. Integration into Minnesota Power's system
4. General location of the facility
5. Site characteristics including zoning, permits required, and any potential environmental issues or other sensitive issues
6. Site control
7. Respondent's development, financing, construction, operating, maintenance, and ownership experience as it relates to utility-scale power generation
8. EPC contractor's experience as it relates to utility-scale power generation (if applicable)
9. Operator's experience as it relates to utility-scale power generation (in and outside MISO)
10. Respondent's or Guarantor's financial condition and creditworthiness
11. Transmission interconnection, deliverability to the delivery point, congestion, losses, and overall risk of transmission

12. Natural gas supply and firm transportation arrangements

13. Operating flexibility including fast start times (hot/warm/cold) and higher ramp rates, minimum down time, minimum output, major maintenance, more efficient heat rates at less than full capacity, reactive power, voltage regulation, frequency control, scheduling flexibility, different operational modes, other potential ancillary services, and the current market for ancillary services

14. Construction schedule

15. Water supply, usage and discharge

16. Status of engineering and design (e.g. FEP-1, FEP-2, PDR, etc.)

17. Other power equipment enhancements including an auxiliary boiler, energy storage, evaporative cooling, chillers, and duct firing

18. Emission control equipment and emission rates

19. Quantity and complexity of network upgrades required (network upgrade costs will be included in quantitative evaluation of the proposal)

20. Labor source (preference is the use of local prevailing wage for labor cost; if a respondent is willing to commit to this, the respondent's proposal should clearly state that commitment)

21. Schedule of major maintenance

22. Long-term Service Agreement

23. Original Equipment Manufacturer spare parts and Long-term Parts Agreement

24. Control systems

25. Other owners and dispatch rights/preference, allowance for multiple offers into MISO

26. “Best practices” or similar construction, operation, and maintenance

27. Environmental and any other operating constraints

28. Technology, engineering design, redundancy, and overall reliability

29. Backup fuel capability

30. Current litigation

31. Community support

32. Tax treatment and impact on Minnesota Power’s balance sheet

33. An option to purchase after year 20 at price based on net book value (preference for options for purchase at years 10 to 15)

34. Age, remaining life, and term

35. Capacity size options/limits from 200 – 400 MW and future option to expand

36. Overall completeness, clarity, and quality of the Proposal

37. Compliance of proposals with the specifications and requirements described in the RFP

38. Other data as may be requested prior to commencing further discussions

5.4 Contract Negotiations

Based on the Quantitative Evaluation and Qualitative Evaluation, Minnesota Power may or may not select candidates for further discussions. Minnesota Power will contact any selected respondent in writing to confirm interest in commencing contract negotiations. All PPA negotiations will use Minnesota Power's standard PPA as a starting point. Minnesota Power's commencement of and participation in negotiations shall not be construed as a commitment to execute a contract. If a contract is negotiated, it will not be effective unless and until it is fully executed with the receipt of all required regulatory approvals.

* * * * *

6.0 RESERVATION OF RIGHTS

Nothing contained in this RFP shall be construed to require or obligate Minnesota Power to select any proposals or limit the ability of Minnesota Power to reject all proposals in its sole and exclusive discretion. Minnesota Power further reserves the right to withdraw and terminate this RFP at any time prior to the submittal deadline, selection of bids or execution of a contract. All contracts will be contingent on MPUC approval.

All proposals submitted to Minnesota Power pursuant to this RFP shall become the exclusive property of Minnesota Power and may be used for any reasonable purpose by Minnesota Power. Minnesota Power and Sedway Consulting shall consider materials provided by respondent in response to this RFP to be confidential only if such materials are clearly designated as "Confidential." Respondents should be aware that their proposal, even if marked “Confidential”, may be subject to discovery and disclosure in regulatory or judicial proceedings that may or may not be initiated by Minnesota Power. Respondents may be required to justify the requested confidential treatment under the provisions of a protective order issued in such proceedings. If required by an order of an agency or court of competent jurisdiction, Minnesota Power may produce the material in response to such order without prior consultation with the respondent.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

Appendix V: Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2015 Gas-Fired Resource Solicitation

Sedway Consulting, Inc.

INDEPENDENT EVALUATION REPORT FOR MINNESOTA POWER COMPANY'S 2015 GAS-FIRED RESOURCE SOLICITATION

Submitted by:

Alan S. Taylor
Sedway Consulting, Inc.
Boulder, Colorado

June 30, 2017

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Introduction and Background

On October 15, 2015, Minnesota Power Company (MP) issued a Request for Proposals (RFP) for up to 400 MW of dispatchable natural-gas-fired capacity and associated unit-contingent energy. Proposals ultimately[1] were due by January 7, 2016 and entailed the bidder's development, ownership, and operation of an eligible project, with all of the facility's generation to be sold to MP over a long-term agreement. MP anticipated that it would receive a proposal from an affiliate. To ensure fair and consistent treatment of all bidders, MP retained Sedway Consulting, Inc. (Sedway Consulting) to oversee the RFP process and provide an independent evaluation of all bids. This report provides Sedway Consulting's assessment of MP's 2015 Gas Resource solicitation from the initial phase of the solicitation (i.e., the issuance of the RFP) through the determination and selection of the least-cost project for MP's customers.

Sedway Consulting undertook the following tasks as part of this engagement:

- Reviewed and commented on the RFP document before the solicitation was launched,
- Discussed with MP the separation of bidding and evaluation functions at MP,
- Reviewed and assisted with developing answers to bidder questions that were submitted after the release of the RFP and ultimately posted for all bidders to see,
- Participated in MP planning calls/meetings to establish the procedures and evaluation methodologies that would be employed by Sedway Consulting in its review and evaluation of all proposals,
- Acquired and archived all important evaluation parameters and market price assumptions prior to bid opening, for use in Sedway Consulting's proprietary evaluation models,
- Conducted the bid opening process and retained a hard copy and an electronic copy of each submitted proposal,
- Independently reviewed and evaluated all proposals,
- Assisted in developing and issuing clarification questions and transaction parameters to bidders to ensure that all proposals were clear, complete, and based on consistent PPA assumptions,
- Monitored all RFP-related email communications with bidders,
- Reviewed and incorporated where appropriate additional cost information (e.g., firm gas transportation costs, transmission costs) developed by MP's subject matter experts or other outside consultants,

[1] The RFP initially stated that the bid submission deadline was January 5, 2016, but that was later extended to give bidders more time and avoid complications with the New Year's holiday/long weekend.

- Participated in the decision process for developing a short list of projects and counterparties with whom MP should commence preliminary negotiations,
- Participated in debriefing calls with bidders who were not shortlisted,
- Monitored preliminary negotiation calls with shortlisted bidders, and
- Participated in the final selection decision-making process.

Sedway Consulting was provided access to all necessary materials and meetings and was able to perform its own evaluation of all proposals. Sedway Consulting reviewed MP's RFP, market price assumptions, revenue requirement assumptions, and communications with bidders. Sedway Consulting performed its own evaluation of proposals and participated in periodic calls to discuss proposal clarification, disqualification, and evaluation decisions.

Overview of Conclusions

Sedway Consulting concluded that MP's affiliate South Shore project was more cost-effective than any of the other PPA proposals received in the utility's 2015 Gas Resource solicitation. Sedway Consulting concluded that MP made the appropriate selection and rejection decisions in its 2015 Gas Resource solicitation.

This Independent Evaluation Report has a confidential appendix that describes each PPA proposal and provides an overview of the evaluation results and sensitivity analyses. This material is being afforded confidential treatment to protect participants from having their project pricing and operational information provided to their competitors. Also, MP's customers could be harmed if too much information was made publicly available, allowing some participants to game future solicitations rather than delivering the best projects at the lowest possible prices.

Design of RFP and Evaluation Process

MP's RFP required bidders to provide PPA pricing for a minimum term of 20 years, with an option for MP to purchase the facility at year 20 for net book value. In addition, MP stated a preference for having buy-out options at the end of years 10 and 15. With these buy-out options, if it so chose, MP would have the ability to purchase the facility and terminate any remaining portion of a PPA at those earlier buy-out dates.

Prior to the opening of proposals, Sedway Consulting participated in calls and exchanged emails with MP's evaluation personnel to learn about and incorporate MP's latest market price forecasts into Sedway Consulting's evaluation process. Sedway Consulting requested MP to provide as much information as possible prior to the receipt of proposals. This, in essence, allowed Sedway Consulting to lock down and archive the basic evaluation parameters for the process. Such information included cost of capital

components, discount rate, revenue requirement assumptions, and a set of proxy bid evaluation results from MP's detailed dispatch model (RTSim) that were used to calibrate Sedway Consulting's Revenue Requirements Model (RRM) and Response Surface Model (RSM). These assumptions were incorporated into Sedway Consulting's own evaluation models and formed the basis for independently assessing the benefits and costs of the bids that were submitted into MP's solicitation. This allowed Sedway Consulting to perform an entirely independent evaluation of all bids, using its own models to determine each offer's expected capacity-related costs and energy-related benefits without any further input from MP.

Revenue Requirements Model (RRM)

Sedway Consulting's RRM is a spreadsheet-based tool that calculates annual revenue requirements associated with generation or transmission capital investments. Model inputs include:

- In-service-year capital investment
- Book life
- Tax life
- Capital structure
- Common equity, preferred equity, and debt rates
- Effective tax rate
- Insurance rate
- Property tax rate,
- Decommissioning expense (if any), and
- Additional financial parameters.[2]

In the evaluation of the options proposed in MP's Gas RFP, Sedway Consulting used the RRM to calculate fixed charge rates for transmission investments and cross-check estimates for generation-related annual revenue requirements. However, the primary evaluation tool was the RSM.

Response Surface Model (RSM)

Sedway Consulting's RSM is a power supply evaluation tool that uses the following information for each offer:

- Capacity (summer and winter)
- Commencement and expiration dates for power deliveries
- Capacity pricing
- Fuel pricing and locational adders

[2] Such parameters may include differing depreciation structures, bonus depreciation, production tax credits, and investment tax credits.

- Heat rates
- Firm gas transportation cost assumptions
- Variable O&M pricing
- Start-up costs and fuel requirements
- Forced outage rates
- Planned maintenance hours
- Attributable transmission capital costs.

All of the above information (if applicable) can be specified for any number of operating modes for any offer (e.g., base combined-cycle, duct-fired, power augmentation, etc.).

The RSM is a spreadsheet-based tool that was calibrated to approximate the economic costs and benefits of each offer, based on the assumptions and representation of the regional electricity and natural gas markets in RTSim, MP's detailed production cost model. The RSM calculated each offer's monthly fixed costs and energy-related benefits,[3] and developed a net levelized cost of each option, expressed in $/kW-month.

RSM and Net Levelized Cost Ranking

The economic information for all proposals was input into Sedway Consulting's RSM – a power supply evaluation tool that was calibrated to approximate the impact of each proposal on MP's system production costs. The RSM calculated each option's annual fixed costs and variable dispatch costs, estimated the production cost impacts of each option, accounted for capacity replacement costs for all proposed contracts that expired before the end of the study period, and developed a ranking of all options. That ranking was based on the net levelized fixed price of each option, expressed in $/kW-month.

An option's net cost was a combination of fixed and variable cost factors. On the fixed cost side, the RSM calculated annual fixed costs associated with capacity payments, fixed O&M costs, debt equivalence costs, transmission revenue requirements, and firm gas transportation costs. These annual total fixed costs were discounted and converted into an equivalent levelized fixed price, expressed in $/kW-month. This was done by taking the present value of the stream of costs and dividing it by the present value of the kW-months of capacity associated with the option.

On the variable cost side, the RSM first developed a variable dispatch charge (in $/MWh) for each option for each month. This charge was calculated by multiplying the option's heat rate by the applicable monthly fuel index price (plus volumetric firm gas transportation charges, where appropriate), and adding the variable O&M charge. A bid's start charges were calculated as the sum of the proposed $/turbine-start charge (multiplied by the number of turbines where appropriate) and the mmBtu/start fuel requirements multiplied by the fuel index price. Because start charges had been factored

[3] All offers' energy benefits were calculated relative to a common benchmark – specifically a gas-fired reference resource with a heat rate of 8,500 Btu/kWh.

into the RSM's surface results during the proxy bid calibration process, the RSM incorporated both the variable dispatch charge and start costs for each bid in its determination of the expected production cost benefits for each bid. The RSM estimated the energy benefits and production costs of each bid for each month by interpolating between total production costs that were extracted from the set of calibration runs from MP's detailed evaluation model that, as noted earlier, had been structured by Sedway Consulting and executed prior to the receipt of the offers. A bid's production cost savings were calculated as the difference between the estimated MP system production costs for that bid and the estimated MP system production costs for a high-heat-rate reference unit (with a 8,500 Btu/kWh heat rate).

The RSM then converted these production cost savings into a levelized $/kW-month value, using the same arithmetic process that was performed with the annual fixed costs. This conversion normalized the production cost savings (i.e., accounted for the different amounts of capacity provided by each offer) and yielded a value that could be netted with the levelized fixed price in calculating each offer's levelized net cost. The offers were ranked on this levelized net cost, from lowest to highest. The top-ranked offers had the lowest net costs, representing those options with the lowest fixed costs, or the greatest production cost savings, or a good combination of both.

Filler Resource

As was mentioned earlier, the RSM accounted for the costs of replacing capacity for all proposed contracts that expired before the end of the study period (2052). This was done by "filling in" for the lost capacity at the end of each proposal's term of service. This allowed for a side-by-side comparison of the value of proposals that had varying contract durations. Also, the RSM had been calibrated with runs that assumed that a proxy proposed resource would provide its capacity for the entire duration of the study period. Thus, it was necessary to continue a proposal's capacity throughout the entire period so as to maintain consistent and sufficient reserve margins. In effect, by supplementing each short-term proposal with a filler resource for the later years, the RSM was simulating what MP would have to do when a proposed transaction expired – acquire or develop an amount of replacement capacity equal to that expired resource.

As the basis for cost assumptions for the filler resource, Sedway Consulting performed an initial RSM analysis without a filler resource, identified the top three highest-ranked offers, and blended the fixed costs of these best offers into an escalating[4] trend-line of $/kW-month fixed costs that had the same net present value as these three best offers combined. Similarly, an annual trend-line of production cost savings was developed by

[4] Escalating at 2% per year, in line with the evaluation's inflation assumption. Most power purchase proposals tend to have flat or escalating capacity charges, presumably reflecting expectations that general inflation will increase the costs of constructing new facilities in the future. Sedway Consulting therefore structured the filler's profile of fixed costs to match what is generally seen in the marketplace. This meant that the filler's first year's fixed costs were the lowest, with each year thereafter escalating at 2%.

averaging the three offers. With these forecasts in place, the RSM was then able to estimate the net costs associated with a filler resource for any time periods after which an offer's proposed delivery period had ended. The RSM scaled the replacement capacity to exactly equal the size of the expiring proposal resource. Thus, all proposals enjoyed the benefit of being replaced at the end of their terms with a resource that exhibited the operating efficiencies and economy-of-scale benefits of the top three offers.

Additional Cost Parameters

The following additional cost parameters were included in the evaluation analysis:

- Debt equivalence
- Firm gas transportation charges
- Transmission-related revenue requirements

Debt Equivalence. Rating agencies view some portion of a utility's capacity payment obligations to a power provider as the equivalent of debt on the utility's balance sheet. If a utility does not rebalance its capital structure by issuing stock, this debt equivalence can negatively impact a utility's financial ratios and cause rating agencies to downgrade their opinion of the utility's creditworthiness. This can increase the utility's cost of borrowing.

For the debt equivalence and associated imputed debt calculations, Sedway Consulting used a methodology that has been employed by Standard & Poor's Ratings Services (S&P). In their determination of a utility's credit rating, S&P (and, in a similar fashion, other credit rating agencies) uses this methodology to calculate an equivalent amount of imputed debt that is associated with contracts with fixed payment obligations. Sedway Consulting then calculated the annual financial costs to MP's customers of rebalancing the utility's capital structure to offset the additional imputed debt associated with each PPA offer and included such costs in that offer's evaluation results.

Firm gas transportation. All gas-fired proposals were modeled with firm gas transportation costs. Sedway Consulting used each proposed resource's operating parameters (e.g., heat rates, capacities) to determine a Maximum Daily Quantity (MDQ) of firm gas that would need to be contracted to ensure that MP had a reliable resource for its supply portfolio. In consultation with MP, Sedway Consulting used appropriate assumptions for the likely long-term firm gas transportation tariff rates for the pipeline(s) that would likely provide gas to each proposed facility. The monthly reservation charges for this firm gas transportation service were then added to each proposal's costs.

Transmission-related revenue requirements. With a large addition of new generation to a utility or regional transmission system, several portions of the transmission grid may need to be reinforced. This can entail the construction of new circuits or the reconductoring and upgrading of existing transmission lines. In instances where transmission studies had been performed, Sedway Consulting relied on estimates for the costs of such network upgrades from those studies. Where information was not readily

available, Sedway Consulting worked with MP to have an outside transmission expert perform preliminary studies for top-ranked offers.

Sensitivities

MP and Sedway Consulting conferred about two key evaluation elements – transmission costs and CO2 regulation costs – and decided that it would be helpful to develop four sets of results for the decision-making process. Those four rankings would be derived from results that either included or excluded transmission costs and CO2 regulation costs. The "with" and "without" CO2 regulation cost results required the calibration of two different RSMs to capture the different impacts on energy benefits and dispatch. The "with" and "without" transmission cost sensitivities simply entailed the inclusion/exclusion of these fixed costs.

Receipt and Evaluation of Proposals

On January 7, 2016, MP and Sedway Consulting received submissions of a number of proposals in the utility's solicitation. Sedway Consulting performed its analysis of the submitted proposals during early 2016, periodically discussing proposal deficiencies and preliminary results with MP.

One critical factor in the evaluation was the recognition that recent Federal Energy Regulatory Commission (FERC) decisions[5] issued after the RFP was released made it problematic for MP to count capacity associated with resources located outside of the Midwest Independent Transmission System Operator's (MISO) Local Resource Zone (LRZ) 1 (i.e., the zone MP's service territory is in) toward the utility's resource adequacy capacity requirements. Counting capacity from resources outside of LRZ 1 would be dependent on the utility's Local Clearing Requirements (LCR) that would be determined through MISO's annual Resource Adequacy process. Thus, the long-term availability of Zonal Resource Credits and these LCRs would be uncertain, and a minimum amount of import capacity would need to be reserved for renewable purchases that MP had already procured. Thus, the FERC decisions created a strong preference for any new capacity procured through MP's 2015 Gas RFP to be in MISO LRZ 1. Even if bidders of resources outside of LRZ 1 offered to make MP financially whole for any cost differences or penalties associated with the auctions, such financial compensation would not address actual operating reliability issues should those arise. Thus, even though all proposed gas-fired resources were evaluated, projects outside of LRZ 1 were considered to be quite risky, and the focus of the evaluation was on LRZ 1 resources.

[5] The most recent FERC decision was: 2015-11-20 153 FERC 61230 Docket No ER11-4081-002.

Shortlisting and Negotiation

On February 15, 2016 and February 19, 2016, Sedway Consulting and MP held preliminary and final shortlisting calls, respectively – reviewing the four sets of results and rankings for the with and without transmission costs and CO2 regulation costs sensitivities. The decision was made for MP to move ahead with preliminary negotiations with two counterparties – one of which was South Shore Energy, LLC, a wholly-owned subsidiary of ALLETE and thus an affiliate of MP.

The results of Sedway Consulting's analysis are depicted in Confidential Appendix A and indicated that the South Shore offer(s) had the lowest net cost of LRZ 1 resources under all scenarios. That confidential appendix includes each PPA/project's net cost under the four scenarios and the components of that net cost.

As noted above, Sedway Consulting calculated debt equivalence costs for all of the proposals. MP anticipates that a PPA executed with an affiliate may be viewed by the credit rating agencies as contributing no net debt equivalent obligations for ALLETE, its parent company and the entity that is rated by the credit rating agencies. To be conservative, Sedway Consulting did not adopt this conclusion and instead assumed that the South Shore proposals would have debt equivalence costs associate with them. Sedway Consulting used the same methodology and assumptions for developing the South Shore debt equivalence cost estimates as was used with all of the other bids.

During March and April of 2016, Sedway Consulting monitored the preliminary negotiations that MP conducted with the two shortlisted bidders. Both bidders were provided feedback and given opportunities to improve their proposals. Sedway Consulting concluded that MP treated both bidders fairly and consistently.

Finalist Selection

On April 28, 2016, Sedway Consulting and MP reviewed the latest evaluation results for the two shortlisted bidders' proposals and confirmed that the South Shore proposal(s) represented the lower cost and best offers that MP should move forward with.

Negotiations between MP and South Shore proceeded through the remainder of 2016, without Sedway Consulting's involvement. During that time, MP revised its load forecast and concluded that its need for a gas-fired resource was less than had been envisioned when its 2015 Gas RFP had been released (namely, no less than 200 MW and up to a maximum of 400 MW of capacity in the 2022 to 2024 timeframe). MP notified Sedway Consulting on December 19, 2016 that it was approaching South Shore for a revised CC offer in line with a new capacity need of 150 MW with an in-service date of 2024. On February 27, 2017, South Shore provided to Sedway Consulting and MP a pair of revised offers in response to MP's request. Neither was for 150 MW, and both included capacity pricing that was higher than the shortlisted offers. Sedway Consulting evaluated the revised South Shore offers and concluded that, although the capacity

pricing had been increased, they still were economically superior to the other shortlisted bidder's offers.

Ultimately, MP determined that it needed more capacity than had been the view at the end of 2016 and selected the higher capacity proposal – which was for 250 MW with an in-service date of December 1, 2024.

Sedway Consulting's analysis and sensitivities concluded that the South Shore offers were the most economical bids from the utility's 2015 Gas RFP. Sedway Consulting concurred with MP's decision to move ahead with final negotiations on this project. The other proposals received in the solicitation had prices and associated operational costs that were too high to make them competitive with the South Shore project, as described further in Confidential Appendix A. In addition, Sedway Consulting found that the final revised offer from South Shore represented the best option for meeting MP's revised needs.

Conclusion

Sedway Consulting was provided access to all necessary materials and meetings and was able to perform its own evaluation of the PPA proposals.

Sedway Consulting monitored the back-and-forth email traffic and final calls between MP and the bidders and believes that MP treated all bidders consistently and fairly.

Sedway Consulting believes that MP's selection of the revised South Shore offer was appropriate and that offer represented the most economic transaction structure for meeting the utility's revised capacity needs.

PUBLIC DOCUMENT
TRADE SECRET DATA EXCISED

CONFIDENTIAL
Appendix A
Offer Description and Economic Evaluation Results

This has been designated as non-public in its entirety, as the document includes a summary of the terms of the proposals received in response to Minnesota Power's RFP for gas-fired resource projects and the independent economic evaluation of those proposals. This information derives independent economic value from not being generally known to, or readily ascertainable by, others who could obtain economic advantage from its disclosure or use and thus constitutes information Minnesota Power considers to be trade secret, as defined by Minn. Stat. § 13.37, subd. 1(b).

This Appendix A of the Sedway Consulting Independent Evaluation Report for Minnesota Power Company's 2015 Gas-Fired Resource Solicitation was prepared June 30, 2017, by Alan S. Taylor, Sedway Consulting, Inc.

Appendix W: Combined Cycle Site Selection Study

Combined Cycle Site Selection Study

Minnesota Power

Project No. 74366

February 2014

Combined Cycle Site Selection Study

prepared for

Minnesota Power
Duluth, Minnesota

February 2014

Project No. 74366

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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1.0 EXECUTIVE SUMMARY

This report chapter presents an executive summary of the Combined Cycle Site Selection Study (Study). The Study was completed by Burns & McDonnell Engineering Company, Inc. (BMcD) for Minnesota Power Company (MP), a subsidiary of ALLETE Inc. The objectives, site selection methodology, and results of the Study are described in the following sections.

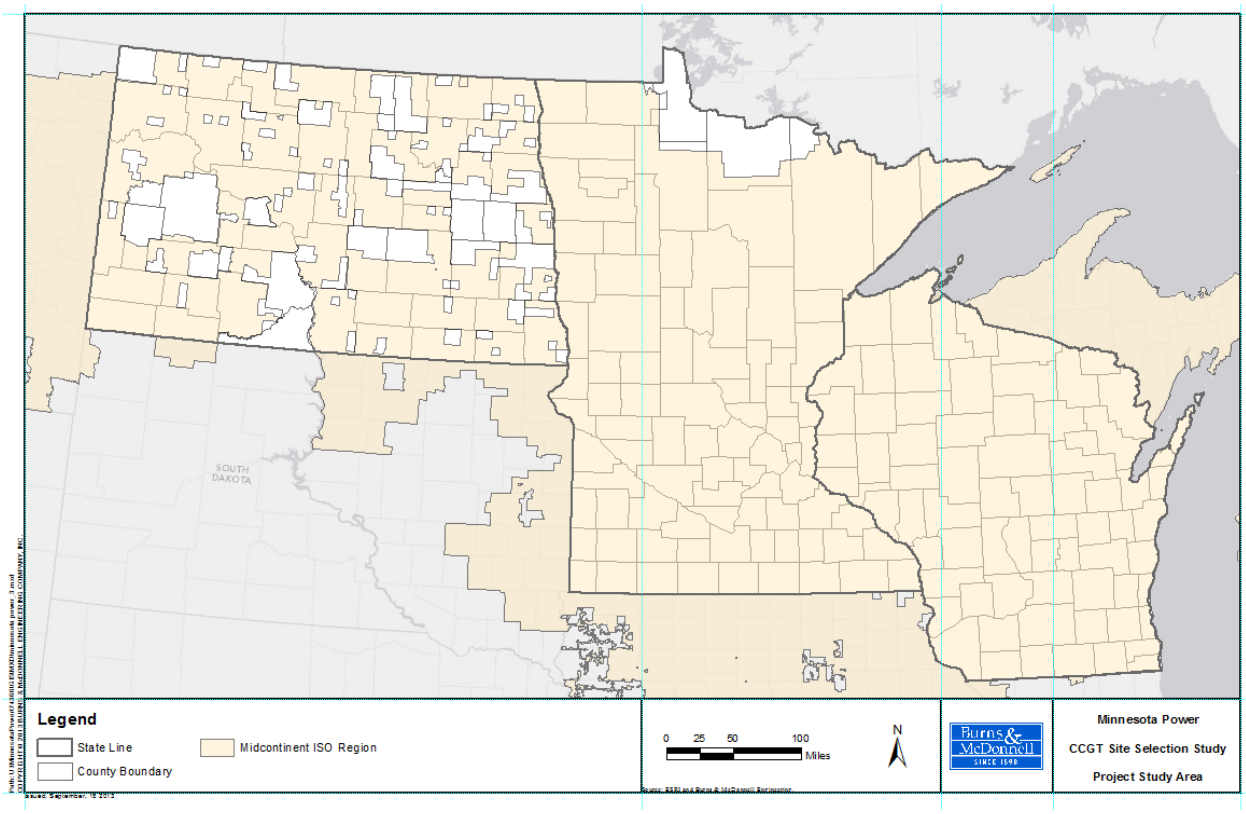
1.1 Study Objectives

Burns & McDonnell was retained by Minnesota Power to evaluate the potential development and construction of a new natural gas-fired combined cycle power generation facility (Project) and to perform a site selection study for the power plant under consideration. The proposed sites were to be capable of accommodating a natural gas-fueled combined cycle generation facility with a nominal capacity of 900 MW, with 780 MW combined cycle gas turbine (CCGT) technology considered for the base case analysis. The objective of the Study was to perform a desktop evaluation to identify a minimum of three potential plant sites and provide the information necessary for the Client to concentrate subsequent site acquisition and permitting efforts.

1.2 Site Selection Summary

The project study area was defined by the Client and included the Midwest Independent System Operator (MISO) region as it extends through the states of North Dakota, Minnesota, and Wisconsin. The project study area boundary is identified in Figure 1-1. Preliminary site areas were identified by overlaying maps of infrastructure critical to economic combined cycle generation power plant development. This infrastructure included major surface water sources, municipal waste water treatment plants, electric transmission lines and substations rated at or exceeding 230 kV, and natural gas pipelines having a diameter of 16 inches or greater. Line taps and substations were identified as potential development sites; however, existing power plants were not considered for expansion. Substations had to be within five miles of a natural gas pipeline and both substations and line taps had to be within five miles of a significant source of water. Based on these criteria, 115 sites were identified.

Figure 1-1: Project Study Area



The identified areas were then subjected to a desktop screening analysis to eliminate or consolidate sites with obvious development constraints, such as dense population or lack of room for development, or redundant characteristics, such as sites that were both electrically and geographically similar. Through this screening process, 81 of the 115 sites were eliminated or consolidated. The resulting 34 locations were designated as preliminary sites, which are shown in Figure 1-2.

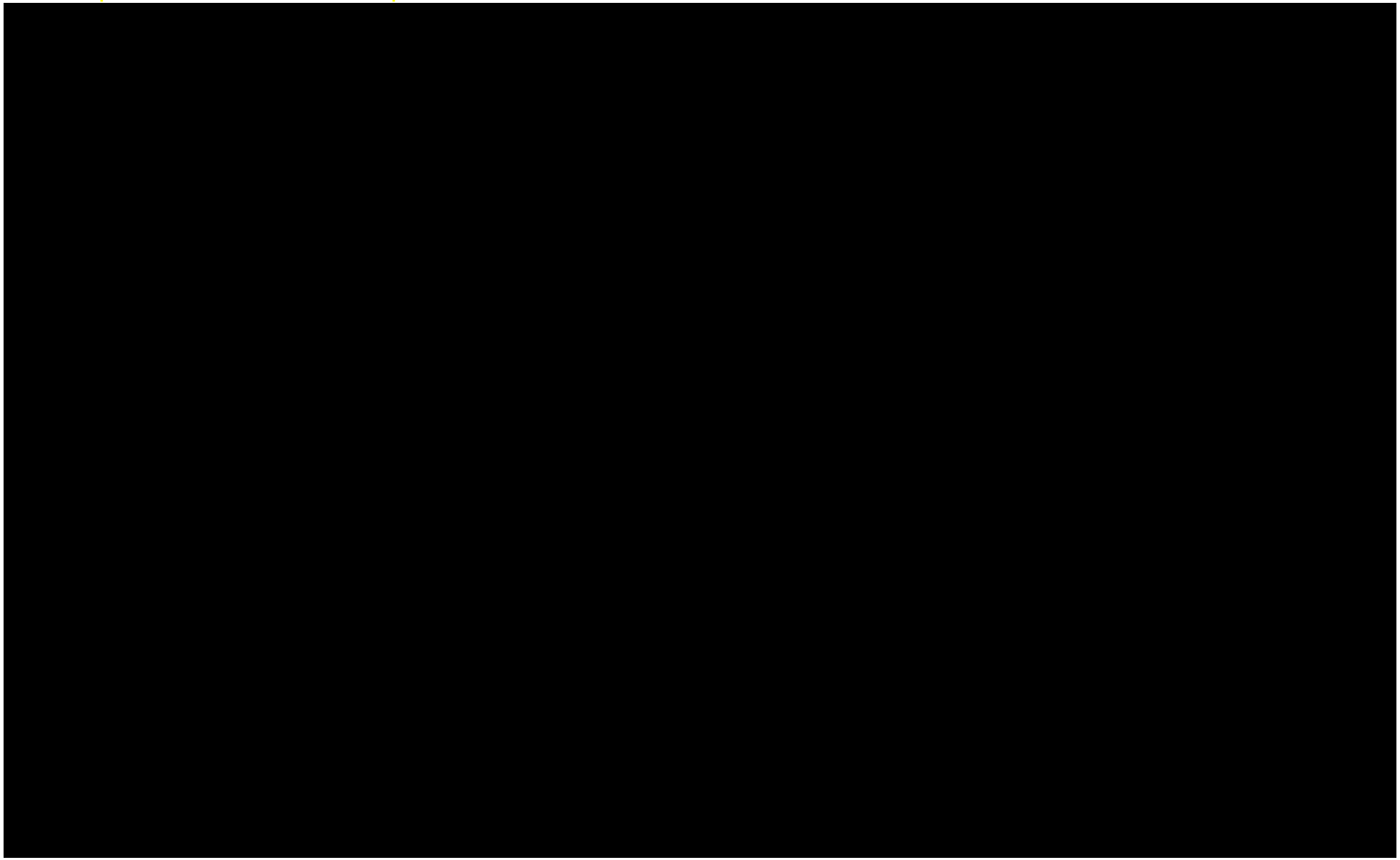
In order to achieve a reasonable number of sites for more detailed analysis, it was necessary to identify the best candidate site areas from among these preliminary site areas. To achieve this, the natural gas pipeline screening diameter was increased to 20 inches. Sites were then subjected once again to individual review and were evaluated relative to one another for strength of attributes. In addition, at the request of the Client, the preliminary site **[TRADE SECRET DATA EXCISED]** [redacted] was removed and two sites, SupGen and **[TRADE SECRET DATA EXCISED]** [redacted], were added to the candidate sites. This resulted in a total of 16 candidate sites, which can be seen in Figure 1-3.

[TRADE SECRET DATA EXCISED]

Figure 1-2: Preliminary Sites

[TRADE SECRET DATA EXCISED]

Figure 1-3: Candidate Sites



The candidate sites were then ranked based on a predefined set of scoring criteria and weightings, as agreed upon by the Client and BMcD. The selected criteria and the assigned weights and subweights are show in Table 1-1.

Table 1-1: Candidate Site Evaluation Criteria

CANDIDATE SITE AREA EVALUATION CRITERIA					
Major Category	**Category Weight**	**Criterion**	**Scoring**	**Criterion Weight**	**Equivalent Pts (100 Pt Scale)**
Electric Transmission	20%	*Transmission Ranking from Load Flow Analysis*		45%	9.0
		0% to 20% Relative Ranking	50		
		21% to 40% Relative Ranking	40		
		41% to 60t% Relative Ranking	30		
		61% to 80% Relative Ranking	20		
		81% to 100% Relative Ranking	10		
		LMP Analysis		45%	9.0
		Top 20th Percentile	50		
		21st to 40th Percentile	40		
		41st to 60th Percentile	30		
		61st to 80th Percentile	20		
		Bottom 20th Percentile	10		
		Interconnection Cost		10%	2.0
		Existing Switchyard Expansion - Bay Space Available	50		
		New Switchyard - Line Tap Location	10		
Fuel Supply & Delivery	30%	*Distance to Interconnection*		20%	6.0
		0 to 2 miles from site	50		
		2 to 4 miles form site	30		
		Greater than 4 miles	10		
		Competitive Supply		30%	9.0
		2 or more fuel suppliers within 15 miles of site	50		
		Only one fuel supplier within 15 miles of site	10		
		Pipeline Delivery Pressure		20%	6.0
		Equal to or greater than 650 PSIG	50		
		Less than 650 PSIG	10		
		System Upgrade Costs		30%	9.0
		Minimal upgrades required (< $25.0 million)	50		
		Moderate upgrades required ($25 to $50 million)	30		
		Significant upgrades required (>$50 million)	10		
Water Supply & Delivery	20%	*Surface Water Availability*		30%	6.0
		High Probability of Water Availability within 5 miles	50		
		Moderate Probability of Water Availability within 5 miles	30		
		Low Probability of Water Availability within 5 miles	10		
		Groundwater Availability		30%	6.0
		High Probability of Water Availability within 10 miles	50		
		Moderate Probability of Water Availability within 10 miles	30		
		Low Probability of Water Availability within 10 miles	10		
		Municipal Reclaim Water Availability		30%	6.0
		Sufficiently Permitted Reclaimed Water source within 5 miles	50		
		Sufficiently Permitted Reclaimed Water source within 10 miles	30		
		Sufficiently Permitted Reclaimed Water source within 15 miles	10		
		Water Discharge Location		10%	2.0
		Acceptable Water Discharge Location within 1 miles	50		
		NO Acceptable Water Discharge Location within 1 miles	10		

Site Environmental	10%	*Wetlands*		25%	2.5
		High Probability of Avoiding Wetlands	50		
		Moderate Probability of Avoiding Wetlands	30		
		Low Probability of Avoiding Wetlands	10		
		Floodplain		25%	2.5
		Site Outside of Floodplain	50		
		Part of Site within Floodplain, Potential Developable Area	30		
		Extensive Floodplain, Limited Developable Area	10		
		Cultural Resources		25%	2.5
		Limited Potential for Cultural Resources to be Present	50		
		Moderate Potential for Cultural Resources to be Present	30		
		Significant Potential for Cultural Resources to be Present	10		
		Sensitive Species		25%	2.5
		10 Sensitive Species or Less Within County	50		
		11 to 20 Sensitive Species Within County	30		
		Greater than 20 Sensitive Species Within County	10		
Air Quality Impacts	10%	*Class I Areas*		30%	3.0
		Greater than 100 Kilometers from Class I Area	50		
		50 to 100 Kilometers from Class I Area	30		
		Class I Area within 50 Kilometers	10		
		Air Permit Feasibility		35%	3.5
		Low relative probability of having NAAQS exceedances	50		
		Moderate relative probability of having NAAQS exceedances	30		
		High relative probability of having NAAQS exceedances	10		
		Nonattainment Status		35%	3.5
		Site is not in a nonattainment county	50		
		Site is in an area with high potential to go nonattainment	30		
		Site is in a nonattainment county	10		
Site Development	10%	*Existing Use*		20%	2.0
		Industrialized / Brownfield Site Area	50		
		Agricultural Site Area	30		
		Forested / Natural / Undisturbed Site Area	10		
		Site Access		10%	1.0
		Less than 0.5 Mile to Paved Road	50		
		0.5 to 1.5 Miles to Paved Road	30		
		Limited Site Access or Greater than 1.5 Miles to Paved Road	10		
		Rail Access		10%	1.0
		Class I Rail Line Within 1 Mile of Site	50		
		Class I Rail Line Within 1 to 5 Miles of Site	30		
		Class I Rail Line Greater than 5 Miles from Site	10		
		Proximity to FAA Facilities		10%	1.0
		No FAA facilities within 5 miles of site	50		
		FAA facility within 1 to 5 miles of site	30		
		FAA facility within 1 mile of site	10		
		Noise / Visual Receptors		20%	2.0
		No Receptors Within 0.5 Mile of Site	50		
		1 to 5 Receptors Within 0.5 Mile of Site	30		
		Greater than 5 Receptors Within 0.5 Mile of Site	10		
		Site Expansion		15%	1.5
		200+ Acres available w/sufficient buffer zone	50		
		100-200 Acres available	30		
		Fewer than 100 acres available	10		
		Site Ownership		15%	1.5
		Owned by Client	50		
		Partially Owned by Client	30		
		Site Owned by One or More Third Parties	10		
					100.0

Each of the 16 candidate sites was assigned a score that ranged from 10 to 50 for each of the evaluation criteria, with 10 being the lowest (poorest) score and 50 being the highest (best) score. Of the scoring criteria presented in Table 1-1, all were used in the evaluation of the candidate sites except for the Transmission Ranking from Load Flow Analysis criterion. The load flow analysis was reserved for the top six candidate sites, or "preferred sites". The scores of all except the Load Flow Analysis criterion were combined with their respective criterion weights listed in Table 1-1 to yield a weighted composite score for each candidate site. These scores are shown graphically inFigure 1-4. The highest ranked site

was the **[TRADE SECRET DATA EXCISED]** site with a composite score of 32.80, and the lowest ranked site was the **[TRADE SECRET DATA EXCISED]** site with a composite score of 20.30.

Figure 1-4: Candidate Site Rankings

[TRADE SECRET DATA EXCISED]

The top eight ranking sites were reviewed and two were eliminated based on Client input. As the Client has previous knowledge of the **[TRADE SECRET DATA EXCISED]** and did not feel it was well-suited for development, and the **[TRADE SECRET DATA EXCISED]** site is located in the operating territory of Xcel Energy Inc., it was the preference of the Client that these sites be removed from further consideration. Of the remaining candidate sites, the top six performing sites, referred to as "preferred sites", were carried on to the next stage of the site selection process. The preferred sites include:

[TRADE SECRET DATA EXCISED]

- SupGen

The transmission load flow analysis was then performed on these six sites. To evaluate each site, 780 MW of new capacity was added, incrementally, to the proposed point of interconnection. At each site, the number of overloads resulting from the new generation was tallied and weighted according to the particular assets that were overloaded. Impacts on affected systems, either transmission lines or substations, were weighted according to the expected level of upgrades required on the transmission system. The percentage rank for each site was then calculated based on the site with the highest total score. Sites scores were then determined based on percentage rank with a low score of 10 for those sites with the greatest impact and a high score of 50 for those sites having the least amount of impact. The results of the transmission load flow analysis were then incorporated into the site scoring matrix; the resulting site scores may be seen in Table 1-2.

Table 1-2: Preferred Site Scores

[TRADE SECRET DATA EXCISED]

[redacted]

As can be seen in Table 1-2 the **[TRADE SECRET DATA EXCISED]** [redacted] site received the highest overall score of 33.70 and the **[TRADE SECRET DATA EXCISED]** [redacted] site received the lowest overall score of 28.80. The relative rankings of the preferred sites are depicted graphically in Figure 1-5.

Figure 1-5: Preferred Site Rankings

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1.3 Conclusions and Recommendations

The quantitative scoring results are only intended to aid the decision-making process; the results should not be relied upon exclusively and proper consideration must be given to strategic factors that may not be captured in the scoring analysis. The objective of the Study was to identify sites suitable for future development of a CCGT plant with a nominal capacity of 900 MW and to provide the information necessary for the Client to concentrate subsequent site acquisition and permitting efforts. It is the recommendation of the project team at Burns & McDonnell that all of the preferred sites be considered as suitable alternatives for future development activities. As site visits were not included in the scope of the Study, the ability of the BMcD project team to investigate the preferred sites and rank them relative to one another was limited. The Client is encouraged to conduct site visits to confirm the findings of the desktop analysis. Confirmation of water availability is also recommended. It is also advised that the Client take measures to further investigate the transmission constraints at each of the preferred sites and evaluate transmission deliverability with respect to load and capacity zones.

* * * * *

2.0 INTRODUCTION

Burns & McDonnell Engineering Company, Inc. (BMcD) was retained by Minnesota Power Company, a subsidiary of ALLETE Inc., to perform a Gas-Fired Power Plant Site Selection Study (Study) to evaluate the potential development and construction of a new natural gas-fired power generation facility (Project).

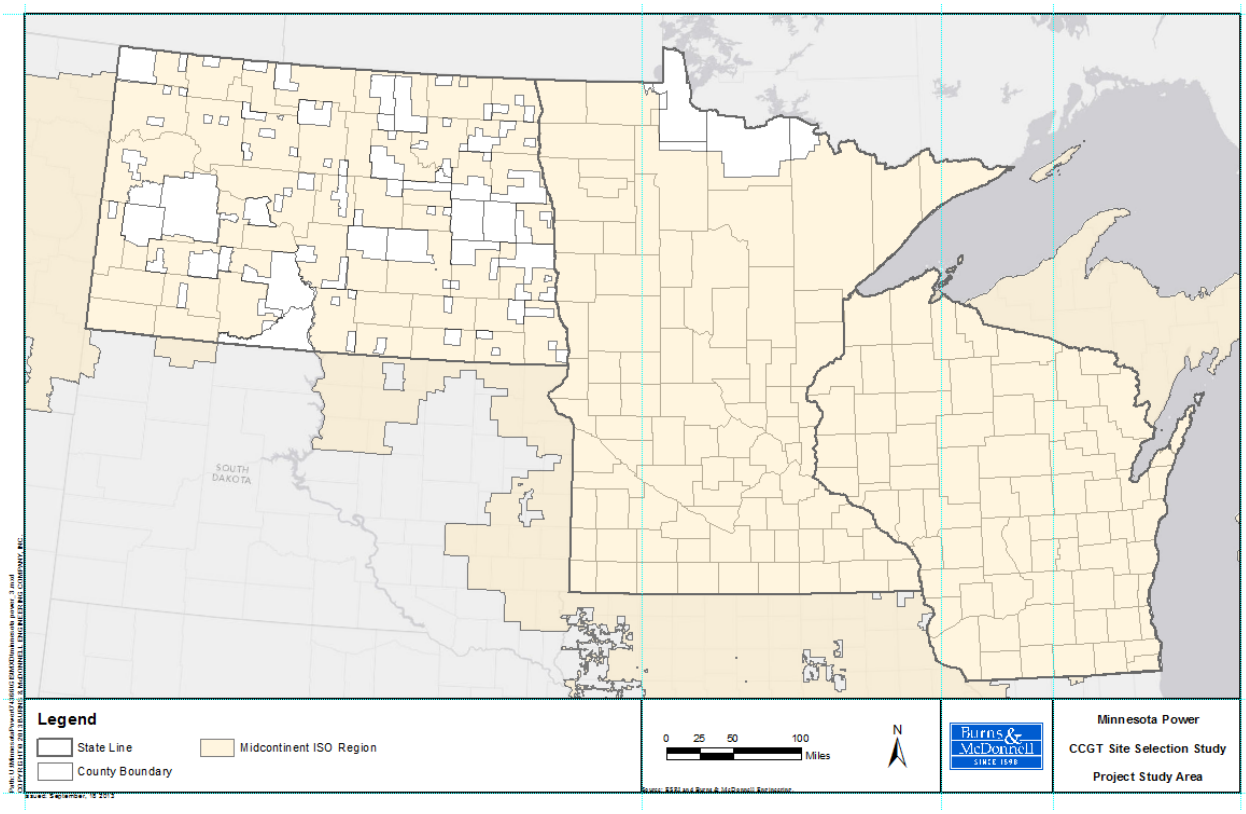
2.1 Study Objectives

Burns & McDonnell was retained by Minnesota Power to evaluate a combined cycle power plant, and perform a site selection study for the power plant under consideration. The proposed sites were to be capable of accommodating at least 900 MW of natural gas-fueled combined cycle generation, with 780 MW combined cycle gas turbine technology considered for the base case analysis. The objective of the Study was to perform a desktop screening to identify a minimum of three potential plant sites and provide the information necessary for the Client to concentrate subsequent site acquisition and permitting efforts.

2.2 Project Study Area

The project study area was defined by the Client and included the Midwest Independent System Operator (MISO) region as it extends through the states of North Dakota, Minnesota, and Wisconsin. The project study area boundary is identified in Figure 2-1.

Figure 2-1: Project Study Area



2.3 Study Methodology

The Study was completed in several phases. A brief description of each phase of the site selection process is included below.

- Phase 1 – Identify Preliminary Sites: The first phase of the site selection process was to identify preliminary site areas that were near high voltage transmission lines and major natural gas pipelines.
- Phase 2 – Identify Candidate Sites: Preliminary site areas were then screened using readily available maps and aerial photographs to eliminate sites with obvious development constraints and to consolidate sites that were geographically or electrically similar to each other. The remaining sites were designated candidate site areas.
- Phase 3 – Candidate Site Quantitative Analysis: The candidate site areas were then quantitatively evaluated against several criteria organized into six major categories: transmission access, fuel delivery, water supply, environmental, air quality impacts, and site development. The results of the quantitative analysis were used to rank the sites in order from the most preferred site to the least preferred site.

- Phase 4 – Identify Preferred Sites: The results of the quantitative analysis were reviewed by the collective project team and the six highest performing sites were selected for further consideration.
- Phase 5 – Transmission Analysis of Preferred Sites: The preferred sites were then run through a transmission load flow analysis to identify potential overloads on the transmission system caused by injecting power at each of the preferred sites. These results were incorporated in the scoring matrix and the preferred sites ranked relative to one another with scoring assessed in all categories, including transmission load flow.

2.4 Project Team

This Study was completed by a multi-disciplinary team of professionals from BMcD and the Client. The project team included individuals with experience in the planning, permitting, design and operation of electric generating facilities and individuals with experience in the planning and design of the electric transmission system.

2.5 Statement of Limitations

In the preparation of this report, the information provided to BMcD by the Client was used by BMcD to make certain assumptions with respect to conditions which may exist in the future. While BMcD believes the assumptions made are reasonable for the purposes of this report, BMcD makes no representation that the conditions assumed will, in fact, occur. In addition, while BMcD has no reason to believe that the information provided by the Client, and on which this report is based, is inaccurate in any material respect, BMcD has not independently verified such information and cannot guarantee its accuracy or completeness. To the extent that actual future conditions differ from those assumed herein or from the information provided to BMcD, the actual results will vary from those forecast.

All historical data, information, and research utilized herein are subject to change. Further, data, information, and research relied upon may be inaccurate or in conflict with other reputable or more recent sources not available or not utilized in the preparation of this report. User recognizes and acknowledges the inherent risk that data and information can change during the execution and pendency of the research, investigation, and analysis; and that such data and information cannot be constantly monitored and reflected in the report and the assumptions, conclusions, and opinions stated. User also recognizes that even as of the date of publication, some of the data and information relied upon may have changed, and/or new or more important news, factors, priorities, or information may have evolved that may not be reflected in the report. User should confirm the timeliness, accuracy and completeness of such data, information, and priorities, and any changes in information or news since the commissioning of the

services of BMcD, prior to making commitments or decisions based upon the assumptions, conclusions, and opinions contained herein.

* * * * *

3.0 CANDIDATE SITE SELECTION

The initial step in the site selection process was to identify preliminary sites within the study area, analyze each preliminary site through a high-level desktop analysis, and identify candidate site areas to carry forward for detailed analysis. Candidate site areas are general locations, which may be larger than the amount of land actually required for plant development, that possess the necessary infrastructure and other characteristics that may allow them to be suitable power plant sites. As discussed in this chapter, the investigations completed to identify candidate site areas included the following major tasks:

- Identify and map locations within the project study area for infrastructure that is critical to power plant development and where plant locations may be restricted for environmental and regulatory reasons.
- Identify preliminary site areas with consideration of the necessary infrastructure, environmental constraints and other development factors.
- Screen preliminary site areas using readily available maps and other resources.

The methodology and results of these investigations are described in the following subsections.

3.1 Preliminary Infrastructure Screening

In order to minimize the potential impacts and costs of plant development, prospective site areas should be located as near as practical to the necessary infrastructure, or physical resources, required by the Project. Preliminary site areas were identified based on the proximity of a site area to regional natural gas pipeline and transmission infrastructure. The first step in this process was to develop a composite map that overlaid natural gas pipeline infrastructure and high voltage transmission infrastructure. The basic infrastructure requirements used for this study were as follows:

- Preliminary site areas must have been located directly adjacent to a transmission line or substation operating at 230-kV or higher.
- Preliminary site areas must have been within five miles of a 16-inch diameter or larger natural gas pipeline.
- Preliminary site areas must have been greenfield in nature, no existing power generation facilities were reviewed for expansion.

- Preliminary sites must have been located within five miles of either a major river or a municipal waste water treatment facility of sufficient capacity. The details of the water selection criteria are described in section 3.2.2.

Using the criteria listed above, the locations of infrastructure critical to economic power plant development were determined and corresponding site areas were identified. This resulted in the identification of 115 site areas.

3.2 Desktop Screening for Preliminary Site Areas

The identified areas were then subjected to a desktop screening analysis to eliminate or consolidate sites with obvious development constraints or redundant characteristics. For example, a site that was clearly surrounded by a residential neighborhood would be eliminated, and two sites that were geographically and electrically similar in nature would be consolidated into one site. In addition, sites that were within a national, state, or local park were eliminated. Through this process, 81 of the 115 sites were eliminated or consolidated. The resulting 34 locations were designated as preliminary sites, which are shown below on Figure 3-1. Each infrastructure point represents a line tap (intersection of a major gas pipeline with a high voltage transmission line) or an existing substation.

Figure 3-1: Preliminary Site Areas

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3.3 Candidate Site Areas

In order to achieve a reasonable number of sites for more detailed analysis, it was necessary to identify the best candidate site areas from among these preliminary site areas. To achieve this, the first step was to further refine the infrastructure screening by increasing the requisite natural gas pipeline diameter from a minimum of 16 inches to a minimum of 20 inches. Sites were then subjected once again to individual review and were evaluated relative to one another for strength of attributes. Two site areas, SupGen and **[TRADE SECRET DATA EXCISED]** , were added at the request of the Client. The **[TRADE SECRET DATA EXCISED]** was also removed from consideration upon Client request. Following the desktop screening, and Client review, 16 candidate site areas were identified. The 16 candidate sites are listed below in Table 3-1 in alphabetical order and their locations are shown on Figure 3-2.

A narrative description of each candidate site area is provided in Section 5 of this report.

Table 3-1: Candidate Sites

Site Name **[TRADE SECRET DATA EXCISED]**	Site Type	County **[TRADE SECRET DATA EXCISED]**	State
[redacted]	Line Tap	[redacted]	North Dakota
	Line Tap		Wisconsin
	Line Tap		Minnesota
	Line Tap		North Dakota
	Substation		Minnesota
	Substation		Minnesota
	Line Tap		North Dakota
	Line Tap		Minnesota
	Line Tap		Minnesota
	Line Tap		Wisconsin
	Substation		Minnesota
	Substation		Wisconsin
	Line Tap		Wisconsin
	Line Tap		Wisconsin
	Substation		Minnesota
	Line Tap		Wisconsin

Figure 3-2: Candidate Site Locations

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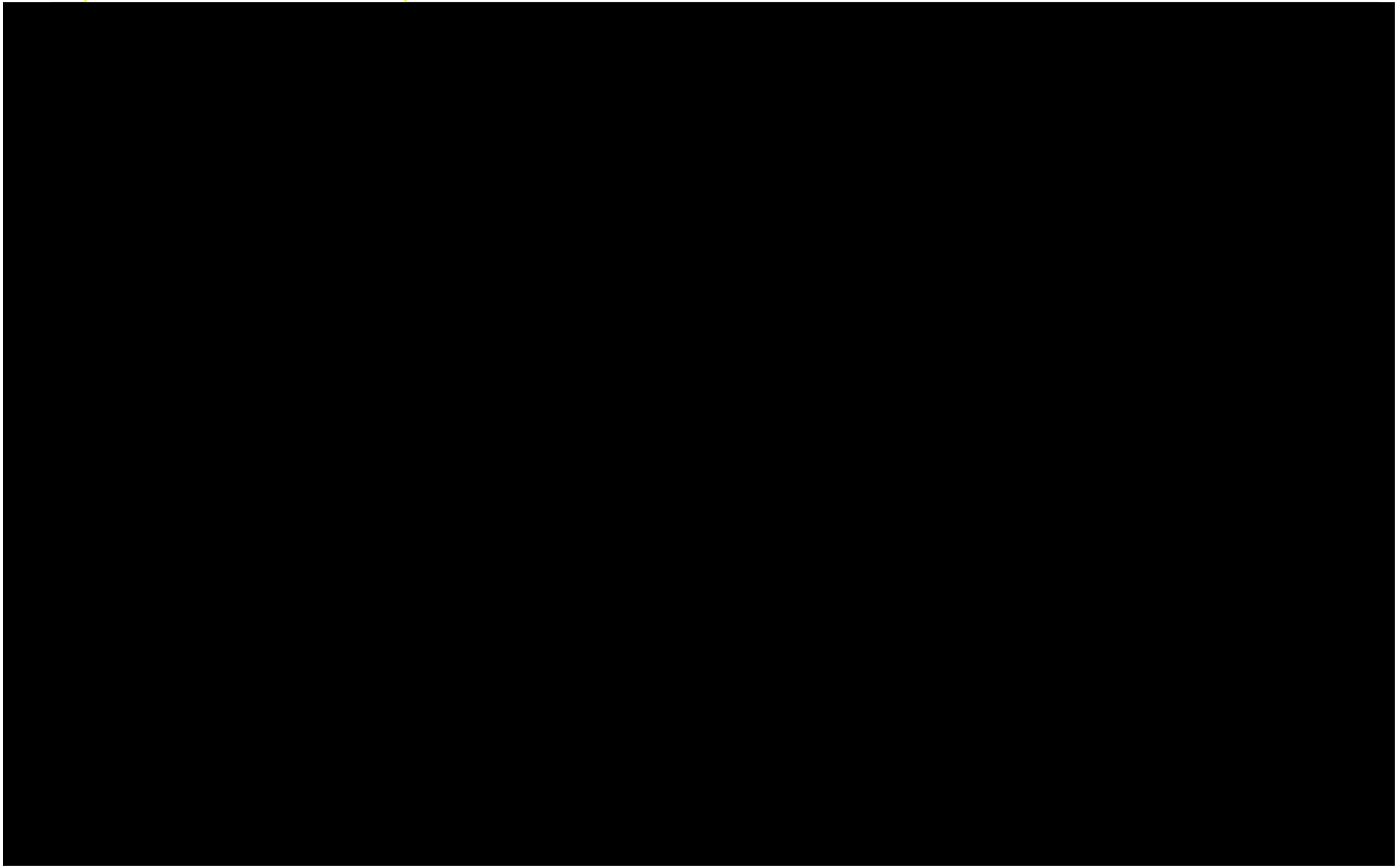

4.0 CANDIDATE SITE EVALUATION

A quantitative analysis process was used to rank the candidate site areas. The first step in using such a process is to identify the objectives or criteria to be used to evaluate the alternatives. The focus of the candidate site evaluation, and the criteria discussed in this section, was to assess the advantages and disadvantages of each candidate site on a relative basis.

4.1 Candidate Site Ranking Approach

The evaluation criteria used to judge the relative suitability of the candidate site areas to support a gas-fired combined cycle generation facility cover a number of specific attributes. Each of these attributes represents a characteristic that is important in the evaluation of prospective sites and also serves to differentiate the candidate site areas from one another. These evaluation criteria are not equivalent in their importance to the decision-making process. Therefore, each criterion was also assigned a weight indicative of its relative importance to the decision process. Criteria with the highest weights are considered the most critical for site development. The assignment of weights to the evaluation criteria was based on the collective professional judgment of the Client and the BMcD staff who participated in this Study.

In total, 25 different criteria were used to evaluate the candidate site areas. These criteria were first organized into six major categories, and these major categories were allocated weights that totaled 100 percent. For example, the Site Environmental category was assigned a weight of 10 percent. Therefore, 10 percent of an overall evaluation score was based on environmental criteria. Within each major category, the criteria were assigned subweights indicative of each criterion's relative importance. The composite weight for each individual criterion was then calculated as an aggregate of all subweighted criteria within a major category. The evaluation categories, category weights, criteria, criteria subweights, and composite weights are summarized in Table 4-1. A summary description of each candidate site follows the candidate site evaluation criteria table.

Table 4-1: Candidate Site Evaluation Criteria

CANDIDATE SITE AREA EVALUATION CRITERIA					
Major Category	Category Weight	Criterion	Scoring	Criterion Weight	Equivalent Pts (100 Pt Scale)
Electric Transmission	20%	*Transmission Ranking from Load Flow Analysis*		45%	9.0
		0% to 20% Relative Ranking	50		
		21% to 40% Relative Ranking	40		
		41% to 60% Relative Ranking	30		
		61% to 80% Relative Ranking	20		
		81% to 100% Relative Ranking	10		
		LMP Analysis		45%	9.0
		Top 20th Percentile	50		
		21st to 40th Percentile	40		
		41st to 60th Percentile	30		
		61st to 80th Percentile	20		
		Bottom 20th Percentile	10		
		Interconnection Cost		10%	2.0
		Existing Switchyard Expansion - Bay Space Available	50		
		New Switchyard - Line Tap Location	10		
Fuel Supply & Delivery	30%	*Distance to Interconnection*		20%	6.0
		0 to 2 miles from site	50		
		2 to 4 miles form site	30		
		Greater than 4 miles	10		
		Competitive Supply		30%	9.0
		2 or more fuel suppliers within 15 miles of site	50		
		Only one fuel supplier within 15 miles of site	10		
		Pipeline Delivery Pressure		20%	6.0
		Equal to or greater than 650 PSIG	50		
		Less than 650 PSIG	10		
		System Upgrade Costs		30%	9.0
		Minimal upgrades required (< $25.0 million)	50		
		Moderate upgrades required ($25 to $50 million)	30		
		Significant upgrades required (>$50 million)	10		
Water Supply & Delivery	20%	*Surface Water Availability*		30%	6.0
		High Probability of Water Availability within 5 miles	50		
		Moderate Probability of Water Availability within 5 miles	30		
		Low Probability of Water Availability within 5 miles	10		
		Groundwater Availability		30%	6.0
		High Probability of Water Availability within 10 miles	50		
		Moderate Probability of Water Availability within 10 miles	30		
		Low Probability of Water Availability within 10 miles	10		
		Municipal Reclaim Water Availability		30%	6.0
		Sufficiently Permitted Reclaimed Water source within 5 miles	50		
		Sufficiently Permitted Reclaimed Water source within 10 miles	30		
		Sufficiently Permitted Reclaimed Water source within 15 miles	10		
		Water Discharge Location		10%	2.0
		Acceptable Water Discharge Location within 1 miles	50		
		NO Acceptable Water Discharge Location within 1 miles	10		

Site Environmental	10%	*Wetlands*		25%	2.5
		High Probability of Avoiding Wetlands	50		
		Moderate Probability of Avoiding Wetlands	30		
		Low Probability of Avoiding Wetlands	10		
		Floodplain		25%	2.5
		Site Outside of Floodplain	50		
		Part of Site within Floodplain, Potential Developable Area	30		
		Extensive Floodplain, Limited Developable Area	10		
		Cultural Resources		25%	2.5
		Limited Potential for Cultural Resources to be Present	50		
		Moderate Potential for Cultural Resources to be Present	30		
		Significant Potential for Cultural Resources to be Present	10		
		Sensitive Species		25%	2.5
		10 Sensitive Species or Less Within County	50		
		11 to 20 Sensitive Species Within County	30		
		Greater than 20 Sensitive Species Within County	10		
Air Quality Impacts	10%	*Class I Areas*		30%	3.0
		Greater than 100 Kilometers from Class I Area	50		
		50 to 100 Kilometers from Class I Area	30		
		Class I Area within 50 Kilometers	10		
		Air Permit Feasibility		35%	3.5
		Low relative probability of having NAAQS exceedances	50		
		Moderate relative probability of having NAAQS exceedances	30		
		High relative probability of having NAAQS exceedances	10		
		Nonattainment Status		35%	3.5
		Site is not in a nonattainment county	50		
		Site is in an area with high potential to go nonattainment	30		
		Site is in a nonattainment county	10		
Site Development	10%	*Existing Use*		20%	2.0
		Industrialized / Brownfield Site Area	50		
		Agricultural Site Area	30		
		Forested / Natural / Undisturbed Site Area	10		
		Site Access		10%	1.0
		Less than 0.5 Mile to Paved Road	50		
		0.5 to 1.5 Miles to Paved Road	30		
		Limited Site Access or Greater than 1.5 Miles to Paved Road	10		
		Rail Access		10%	1.0
		Class I Rail Line Within 1 Mile of Site	50		
		Class I Rail Line Within 1 to 5 Miles of Site	30		
		Class I Rail Line Greater than 5 Miles from Site	10		
		Proximity to FAA Facilities		10%	1.0
		No FAA facilities within 5 miles of site	50		
		FAA facility within 1 to 5 miles of site	30		
		FAA facility within 1 mile of site	10		
		Noise / Visual Receptors		20%	2.0
		No Receptors Within 0.5 Mile of Site	50		
		1 to 5 Receptors Within 0.5 Mile of Site	30		
		Greater than 5 Receptors Within 0.5 Mile of Site	10		
		Site Expansion		15%	1.5
		200+ Acres available w/sufficient buffer zone	50		
		100-200 Acres available	30		
		Fewer than 100 acres available	10		
		Site Ownership		15%	1.5
		Owned by Client	50		
		Partially Owned by Client	30		
		Site Owned by One or More Third Parties	10		
					100.0

4.2 Overview of Scoring Criteria

Each scoring criterion is summarized in the following sections to provide information on why each criterion was included in the scoring process and how the sites were judged relative to each other with respect to each criterion. Sites were scored in the most objective manner possible; quantifiable data from publicly available and internal data sources was used when available. In some cases, when data was not readily available or was cost prohibitive to obtain at this stage of the site selection process, a more subjective scoring process was utilized. The results of the scoring process were not intended to be

comprehensive on a standalone basis. Study conclusions were based on desktop screening only, as no field reconnaissance was performed as part of this study. Additionally, other strategic factors that may not have been captured in the scoring process may need to be considered in future decisions by the Client.

4.2.1 Electric Transmission Scoring Criteria

The electric transmission category was assigned a total weight of 20 percent and was comprised of three evaluation criteria with each criterion contributing a percentage to the overall electric transmission category:

- Transmission Ranking from the Load Flow Analysis (45 percent)
- LMP Analysis (45 percent)
- Switchyard Interconnection Requirements (10 percent)

These criteria are described in the following sections:

4.2.1.1 Transmission Ranking from Load Flow Analysis

The electric transmission portion of the candidate ranking scores was based on the LMP Analysis and Switchyard Interconnection Requirements criteria alone. As the load flow analysis was performed only on the top six ranking candidate sites, the Transmission Ranking from the Load Flow Analysis criterion score was applied exclusively to the evaluation and ranking of the preferred sites. Further explanation of the load flow analysis methodology is provided in Chapter 6, Preferred Site Evaluation.

4.2.1.2 LMP Analysis

The project study area is located within the Midwest Independent System Operator (MISO) region. MISO utilizes Locational Marginal Pricing (LMPs) at various settlement locations ("nodes") across the power grid to communicate electric power prices to the market. The LMP is essentially the price that provides the least-cost incremental unit of energy at a specific location. For this Study, historical hourly LMPs were downloaded from MISO for regional nodes located in the project study area for the 12-month period from January 2012 through December 2012. On-peak LMP averages were then calculated for the nodes and each candidate site was scored based on the average market value for its corresponding node. Nodes with relatively high LMPs received higher scores than nodes with low LMPs as it often more economical to construct a generating facility in an area where the demand for power is relatively high and the electricity being generated can be sold at the highest possible price. Site areas with scores in the top 20th percentile received the highest score of 50; sites with a score in the 61st to 80th percentile received a score of 40; sites with a score in the 41st to 60th percentile received a score of 30; sites with a score in the

21st to 40th percentile received a score of 20; and sites with a score in the bottom 20th percentile received the lowest possible score of 10.

4.2.1.3 Interconnection Cost

This criterion evaluated whether or not an existing switchyard was located on the site and if sufficient space appeared to be available for switchyard expansion to support the Project. Sites that had a switchyard onsite with available space received a score of 50. Sites that did not have an existing switchyard onsite, which included all line tap sites, received a score of 10.

4.2.2 Fuel Supply Scoring Criteria

The fuel delivery category was assigned a total weight of 30 percent and was comprised of four evaluation criteria with each criterion contributing a percentage to the overall fuel delivery category:

- Distance to Interconnection (20 percent)
- Competitive Supply (30 percent)
- Pipeline Deliver Pressure (20 percent)
- System Upgrade Costs (30 percent)

These criteria are described in the following sections.

4.2.2.1 Distance to Interconnection

A gas-fired generating plant needs access to a high pressure natural gas transmission pipeline. The capital cost for the interconnection of the Project's facilities to one of these pipelines is largely driven by the distance from the pipeline to the Project site. Thus, the distance to the nearest pipeline, at least 20 inches in diameter, was used to assign scores for this criterion. Sites within two miles of a 20-inch or greater natural gas pipeline received a score of 50, sites between two and four miles received a score of 30, and sites greater than four miles from a pipeline received a score of 10.

4.2.2.2 Competitive Supply

To secure the most competitive fuel delivery rates for natural gas, it is advantageous to locate a generating facility where it can be served by at least two different natural gas suppliers or obtain fuel from differing supply basins. Sites with the potential of developing competitive natural gas supply options within 15 miles of the site area were awarded a score of 50, while sites that could only be served by a single entity were assigned the lowest score of 10. It should be noted that ancillary natural gas lines located within 15

miles of a site were not considered to offer a competitive advantage if that line rated poorly as a primary source of fuel for other sites considered in the Study.

4.2.2.3 Pipeline Delivery Pressure

To increase the overall operating efficiency of newer combined cycle power plants, manufacturers have improved the design of their combustion turbines to compress intake air to higher pressures. These higher intake air pressures require the injection pressure of the natural gas fuel supply to increase accordingly. Many larger combined cycle units now require injection pressures of 575 pounds per square inch-gauge (psig) or greater. If the normal operating pressure range of the pipeline falls below the required inlet pressure, an auxiliary natural gas compressor must be installed to ensure that the fuel inlet pressure requirements of the combustion turbines are continuously met. An auxiliary natural gas compressor increases the capital cost and ongoing maintenance costs of the facility. Pipelines operating at a pressure of 650 psig or higher received a score of 50, while pipelines operating at less than 650 psig received a score of 10.

4.2.2.4 System Upgrade Costs

In addition to the infrastructure required to interconnect the Project to the existing natural gas pipelines, costs for upgrading the existing pipelines may be incurred in order for the existing infrastructure to serve the natural gas requirements of the Project. For the purposes of this Study, BMcD contacted and evaluated the major fuel suppliers near each candidate site area to estimate the expected cost of natural gas system upgrades required at each candidate site.

4.2.3 Water Supply Scoring Criteria

The water supply category was assigned a total weight of 20 percent and was comprised of four evaluation criteria with each criterion contributing a percentage to the overall water supply category:

- Surface Water Availability (30 percent)
- Groundwater Resource Availability (30 percent)
- Municipal Reclaim Water Availability (30 percent)
- Water Discharge (10 percent)

These criteria are described in the following sections.

4.2.3.1 Surface Water Availability

Natural gas-fueled combined cycle generating facilities typically require a reliable and abundant supply of water for steam cycle makeup and for cooling. In the instance of a combined cycle plant sized up to 900 MW, a significant and reliable water source is required for operation. Although water requirements can be greatly reduced by utilizing dry cooling, the requirement for water supply is not completely eliminated. Additionally dry cooling results in significantly increased capital costs and reduced plant efficiency. For this reason, sites that would have adequate water supply to support wet cooling were favored.

The most reliable water supply for the proposed generating station will likely come from surface water resources. Thus, a candidate site area was preferred if it was located near a significant river or large body of water. The ratings for this criterion were based upon the lowest consecutive seven-day average river flow rate that occurs once every 10 years (7Q10). The water requirements for a 900-MW gas-fired generating facility were estimated at 4,500 gallons per minute (gpm) of water, or approximately 6.5 million gallons per day (MGD). Thus, a river with a 7Q10 flow rate of 65 MGD would mean that the water consumption of the Project would be less than 10% of the 7Q10 flow of the river. Sites were initially screened based on a distance of five miles or less to water and then assigned a score, based on the 7Q10 flow rate discusses above, corresponding to the probability of surface water availability. Sites within five miles of a river with a 7Q10 flow rate greater than 45 MGD received a score of 50 for high probability, those with a 7Q10 flow rate between 20 MGD and 45 MGD were considered as having a moderate probability of surface water availability and received a score of 30, and a site area with a 7Q10 flow rate of 20 MGD or below was considered as having a relatively low probability of surface water availability and received a score of 10.

4.2.3.2 Groundwater Availability

The ability to secure groundwater at a candidate site area was evaluated by examining nearby aquifers and yields from existing wells as well as the permitting potential for those sites. Based on the aquifers available near a site area and yield data available for established regional wells, each candidate site area was estimated as either having a low, moderate, or high probability of having sufficient groundwater at or near the candidate site area. Scores of 10, 30, or 50 were assigned, respectively.

4.2.3.3 Municipal Reclaim Water Availability

The ability to secure a significant amount of water through a municipal reclaim water supply was evaluated as an additional potential source of water for the Project. To obtain a significant amount of treated wastewater effluent, the site would need to be located near a large municipality with an available supply of municipal reclaim water. For purposes of this evaluation, wastewater treatment plants

permitted to discharge at least 19.5 MGD of treated effluent, which is three times the estimated daily water requirement of the proposed generating facility, were considered as a potential municipal reclaim water supply. This flow rate was selected to be conservative as wastewater treatment plants typically permit for their maximum flow, which includes storm water intrusion and other high flow events. In addition, a drought in the area could greatly reduce the water flow from a wastewater treatment plant. They are also constructed and permitted to allow for future growth in their system. Thus, on a consistent basis, a wastewater treatment plant is likely not operating at or near its permitted level. Sites within five miles of a municipal reclaim water resource that met the permitting requirements received a score of 50, sites between five and ten miles received a score of 30, and sites greater than ten miles away received a score of 10.

4.2.3.4 Water Discharge Locations

In addition to consumptive water use, the Project as conceived will generate water from the cooling system that must be routed to a suitable discharge location. Sites with a discharge location within one mile of the site received a score of 50, and sites without a potential discharge location nearby received a score of 10.

4.2.4 Site Environmental Scoring Criteria

The site environmental category was assigned a total weight of 10 percent and was comprised of the following four evaluation criteria with each criterion contributing a percentage to the overall site environmental category:

- Wetlands (25 percent)
- Floodplains (25 percent)
- Cultural Resources (25 percent)
- Sensitive Species (25 percent)

These criteria are described in the following sections.

4.2.4.1 Wetlands

Wetlands and streams can be under jurisdiction of federal and/or state regulatory agencies, thus if impacted, can require permits, mitigation, and trigger other regulatory compliance requirements. Any permanent impacts to wetlands have to be mitigated by the creation or restoration of wetlands, or the purchase of wetland mitigation credits that are equal to or greater than the quantity of the wetlands impacted. To minimize permitting requirements and reduce potential regulatory issues, wetland and

stream impacts should be avoided or minimized to the extent practicable by a project. As a result, readily available wetland and stream data (from national wetland inventory data, USGS topographic maps, and aerials) was reviewed to estimate the likelihood of avoiding wetland and/or stream resources at each of the candidate sites. The scoring for each site area was based on a scale of 10 to 50, where the highest probability for avoiding onsite wetlands received a score of 50, moderate probability received a score of 30, and the lowest probability received a score of 10.

4.2.4.2 Floodplain

A power plant is a critical infrastructure resource that must remain operational even during a significant flood event. Therefore, the major facilities at a power plant should either be located outside of the 100-year floodplain, or otherwise protected from flooding by raising the site above floodwater levels or constructing levees. Any construction within a floodplain that could have the unintended effect of increasing floodwater levels upstream should be avoided.

Available electronic FEMA maps and state GIS floodplain data were reviewed to determine floodplain locations relative to candidate site locations. Sites located outside of the 100-year floodplain were scored a 50, whereas those located within a 100-year floodplain (but appeared to potentially have adequate area within the site to avoid floodplains) were given a 30, and site areas located within a floodplain, but with limited development area were given the lowest score of 10.

4.2.4.3 Cultural Resources

A desktop review was conducted to determine the likelihood of impacting cultural resources during the development of the proposed power plant for each site area. A portion of the desktop review involved considering the proximity of registered historic sites, as listed on the National Register of Historic Places (NRHP), to the candidate site areas. In addition, site areas were assessed for their probability of having onsite cultural resources. This was based on topography, proximity to water resources, and the Project team's knowledge of the area. The scoring for each site area was based on a 50, 30, 10 scale, where site areas with a high potential for having intact cultural resources and research potential received a low score of 10 and those sites with the lowest potential received a score of 50. For sites that received the maximum score of 50, the potential still exists for existing buried cultural resources to be present. The only way to determine if cultural resources exist on a site is to perform a cultural resource survey or have knowledge that the land area had been previously disturbed by construction measures (i.e. deep soil impacts, intense grading or earth moving, mining, etc.) that would most likely have compromised the integrity of the site and any onsite cultural resources that may have previously existed.

4.2.4.4 Sensitive Species

The Endangered Species Act of 1973 and state regulations provide for the protection of federal- and state-listed threatened or endangered species of plants and animals, along with their habitats. To estimate the likelihood of having a project adversely affect a sensitive species or their habitat, this Study included a review of federal and state listed species for each county for where a site was located. It was anticipated that a higher quantity of listed species for a given county increased the likelihood of a sensitive species occurring within or near a site; and conversely, it was anticipated that a lower quantity of listed species suggested that they are less likely to occur within or near a site. Site locations that had fewer than 10 species listed received a score of 50, sites that had between 11 and 20 species listed received a score of 30, and sites that had greater than 20 species listed received a score of 10.

4.2.5 Air Quality Scoring Criteria

Gas-fired generation facilities emit various quantities of certain regulated pollutants. The emitted pollutants from gas-fired generation facilities of greatest concern are nitrogen oxides (NO_x), particulate matter with aerodynamic diameter less than or equal to 2.5 micrometers ($PM_{2.5}$), and carbon dioxide (CO_2). Natural gas-fired power plants also emit trace quantities of various other pollutants, known as hazardous air pollutants (HAP). The air quality category was assigned a total weight of 10 percent and was comprised of the following three evaluation criteria with each criterion contributing a percentage to the overall air quality category:

- Class I Areas (30 percent)
- Air Permit Feasibility (35 percent)
- Nonattainment Status (35 percent)

These criteria are described in the following sections.

4.2.5.1 Class I Areas

The Clean Air Act (CAA) Amendments of 1977 resulted in establishment of the Prevention of Significant Deterioration (PSD) regulations. Under these regulations, maximum increases (increments) were established for each criteria pollutant. These allowable increments are smallest for Class I areas. The presence of a Class I area near a proposed emission source (project site) can cause additional permitting or other issues or constraints. To reduce the possibility of adverse visibility or other impacts at a Class I area, sites that were located further away from the nearest Class I area were preferred. For this criterion, candidate sites were scored based on their distances to Class I areas. Sites greater than 100 km from a

Class I area received a score of 50, sites within 50 to 100 km received a score of 30, and sites less than 50 km from a Class I area received a score of 10.

4.2.5.2 Air Permit Feasibility

Sites were scored for proximity to large sources of NO_x and $PM_{2.5}$. NO_x and $PM_{2.5}$ are the primary pollutants associated with National Ambient Air Quality Standards (NAAQS) exceedances. The closer the sites are to existing, large sources of NO_x and $PM_{2.5}$, the more likely the potential for NAAQS exceedances. If there are NAAQS exceedances, there is an increased likelihood that the project would have operational restrictions and in some instances, it may be a fatal flaw to development of the Project.

For the air permit feasibility analysis, all the sources of NO_x and $PM_{2.5}$ located within 21 kilometers of each site were identified. The emissions for each individual source were divided by that source's distance to the candidate site and then these values were summed. If the addition of the relative emissions for all of the sources within 21 km was less than 10 tons of each pollutant (NO_x and $PM_{2.5}$), the candidate site received the top score of 50 for air permitting feasibility. If the pollutant sum was between 10 tons and 150 tons, the site received a score of 30, and sites with pollutant amounts exceeding 150 tons received a low score of 10.

4.2.5.3 Nonattainment Status

Nonattainment areas are regions where ambient ground-level concentrations of one or more criteria pollutants are higher than the National Ambient Air Quality Standards (NAAQS) as established by the Environmental Protection Agency (EPA). Thus depending upon the anticipated emissions from a fossil-fuel power generation facility, air permitting could be more challenging and offsets could be required for certain pollutants. Sites received a score of 50 if it was not located in a nonattainment county, a score of 30 if located in a county that was likely to be classified as nonattainment in the near future, and a score of 10 if located in a county that is currently designated as nonattainment for one of the criteria pollutants.

4.2.6 Site Development Scoring Criteria

Site development constraints include factors that may hinder the development of the Project due to characteristics of the specific parcel of land or the immediate area surrounding the specific parcel of land being evaluated. The following sections describe development factors that were considered during the evaluation of the candidate site areas. The site development category was assigned a total weight of 10 percent and was comprised of the following seven evaluation criteria with each criterion contributing a percentage to the overall site development category:

- Existing Use (20 percent)
- Site Access (10 percent)
- Rail Access (10 percent)
- Noise/Visual Receptors (20 percent)
- Site Ownership (15 percent)
- Proximity to FAA (10)
- Site Expansion (15)

These criteria are described in the following sections.

4.2.6.1 Existing Use

Existing land use may affect the ability to develop the Project. Generally, site in industrialized areas or brownfield sites are considered to be preferred areas for development because they are in an area that has already been disturbed and are compatible with the surrounding development. Sites in industrialized areas were given a score of 50. If an industrialized area is not available, areas of cultivated land would be the next most preferred site as they tend to allow for fewer environmental impacts relative to areas that contain more native or natural areas such as prairie or forest areas. Sites in cultivated land were assigned a score of 30. While forested areas can potentially serve as a means to screen the Project to reduce the potential for visual impacts, forested areas may need to be cleared for development which may increase the risk of potential environmental impacts. Forested sites received a score of 10.

4.2.6.2 Site Access

It is advantageous to the Project if existing paved roadways are already in place at a candidate site in order to support materials and equipment delivery and construction and operation of the Project. This helps to minimize the cost of building new roads. The sites were scored based on the distance to paved roads with sites within a half mile of paved roads receiving a score of 50, sites greater than one and a half miles from paved roads receiving a score of 10, and sites with paved roads between a half to one and a half miles to paved roads receiving a score of 30.

4.2.6.3 Rail Access

In addition to road access, sites that were located near an existing railroad were also scored more favorably. Rail access is necessary for equipment delivery and sites closer to rail will require less heavy haul distance via road, reducing the potential for heavy haul impacts and associated upgrades. Site areas within one mile of a Class I rail line received a high score of 50, those within one to five miles received a score of 30, and all site areas greater than five miles from a Class I real line received a low score of 10.

4.2.6.4 Noise / Visual Receptors

There are a number of factors that will determine whether the noise from construction or operation of the Project will significantly impact any sensitive receptors (i.e. buildings, residences, places of worship, hospitals, schools, etc.) in the vicinity. The number of such receptors close to a given site is one variable that can be measured in a desktop review. To determine potential noise and visual impacts created at each site by developing the Project, aerial photography at each candidate site area was reviewed to identify the quantity of potential receptors nearby. Sites with no receptors within a half mile of the site received a high score of 50, sites with one to five receptors within a half mile of the site received a score of 30, and sites with more than five receptors within a half mile of the site received a score of 10.

4.2.6.5 Site Ownership

Candidate sites that were already controlled or owned by the Client were given preference. Site areas wholly owned by the Client received a preferential score of 50. Partial ownership resulted in a score of 30, and candidate site areas owned in full by one or more third parties received a low score or 10.

4.2.6.6 Proximity to FAA Facilities

The Federal Aviation Administration (FAA) regulates airspace related facilities (i.e. airports, heLMPads, etc.) that could affect power plant siting beyond the boundaries of their facilities. Each potential power plant site must be evaluated on an individual basis for the potential effects upon facilities of this nature. Potential impacts to site development from FAA facilities were considered by identifying the locations of these facilities and their relative proximity to each candidate site area. Sites that had no FAA facilities within five miles of the site received a score of 50, sites with an FAA facility within one to five miles of the site received a score of 30, and sites with an FAA facility within one mile of the site received a score of 10.

4.2.6.7 Site Expansion

A gas-fired generation facility requires a relatively large contiguous area of land. Wherever possible, a standard plot of approximately 160 acres was identified at or near the infrastructure point identified for site area scoring purposes. An ideal site would have at least 200 acres of land available to support the Project and to provide an area large enough to support potential future expansion at the site. For the purposes of this study, those sites with fewer than 100 acres available received a low score of 10. Those offering between 100 and 200 acres received a score of 30. Any site offering acreage in excess of 200 received a top score of 50.

5.0 CANDIDATE SITE AREA DESCRIPTIONS

This chapter contains summary descriptions of the 16 candidate site areas. Candidate site maps are provided in Appendix A. Based on real estate considerations and further analyses, the site boundaries at any site for eventual development could be modified from the boundaries shown on the candidate site maps.

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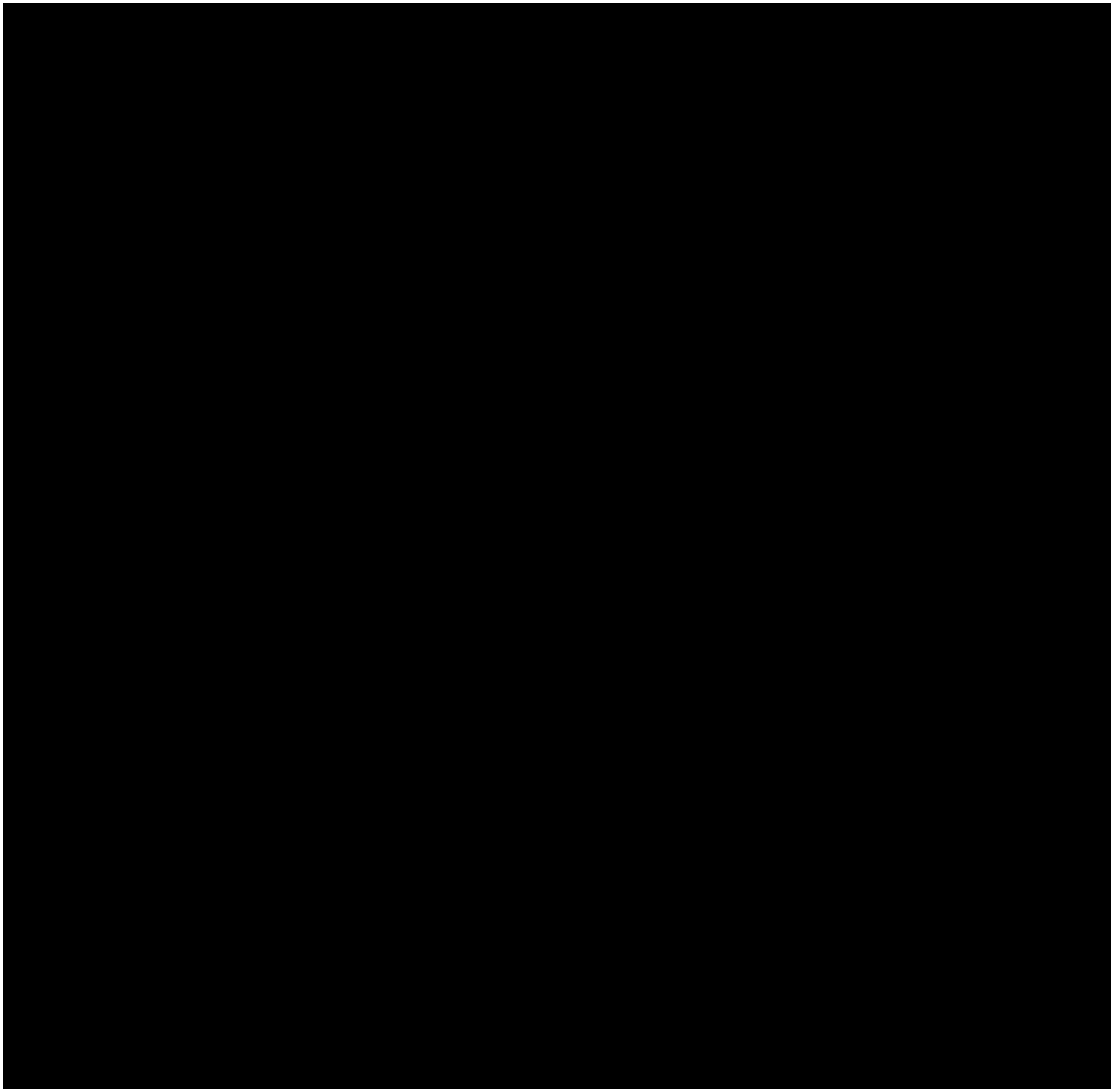
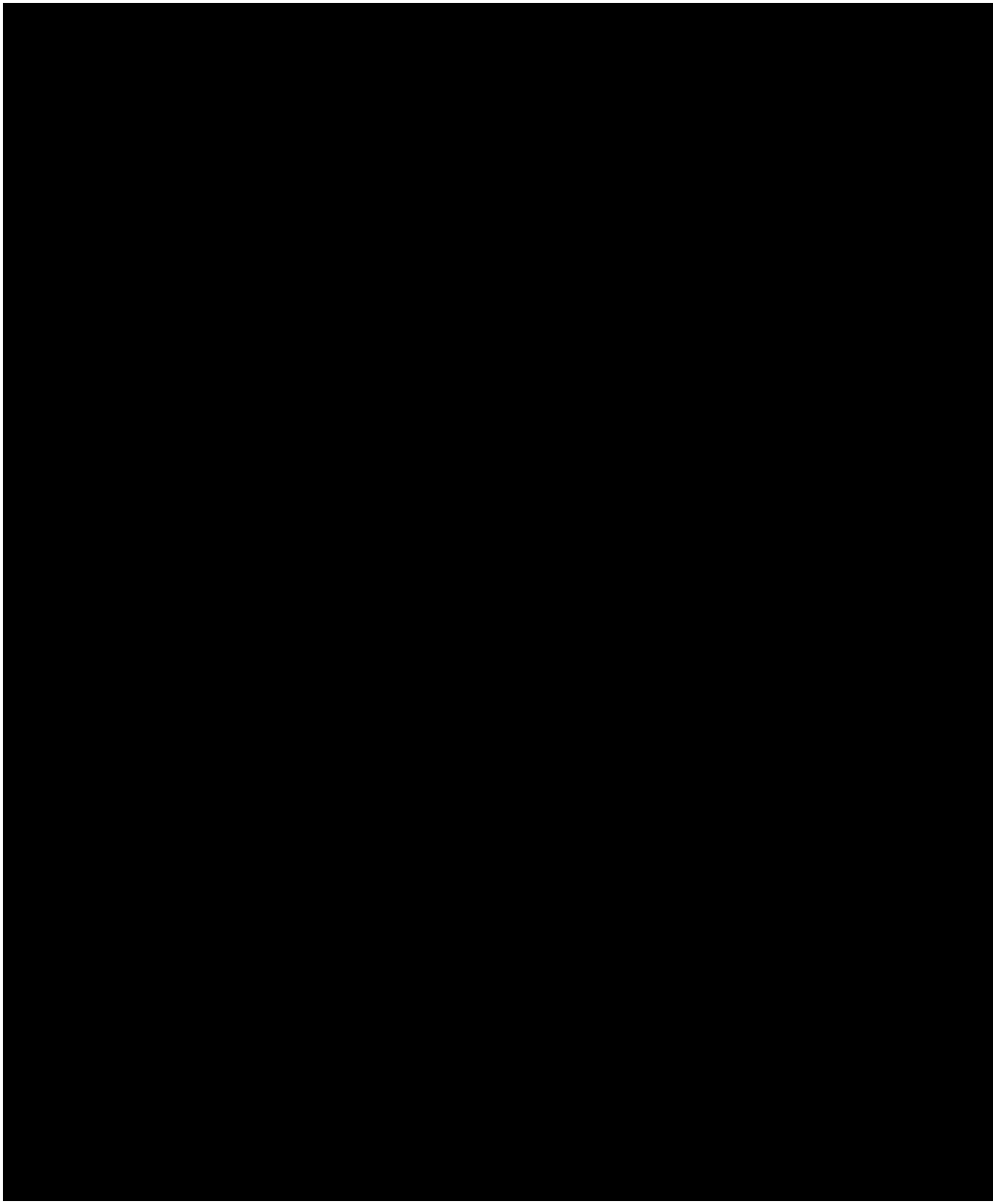
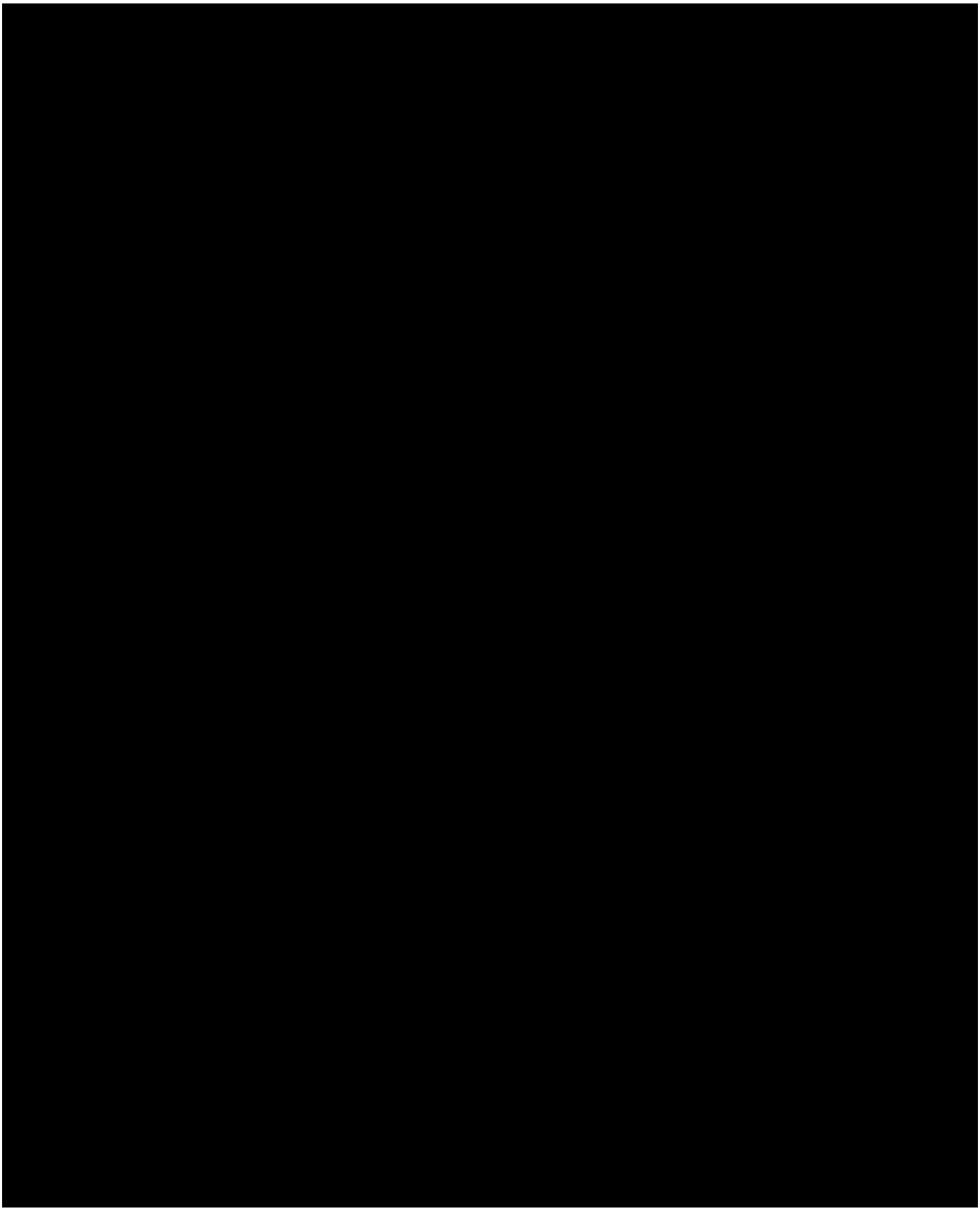
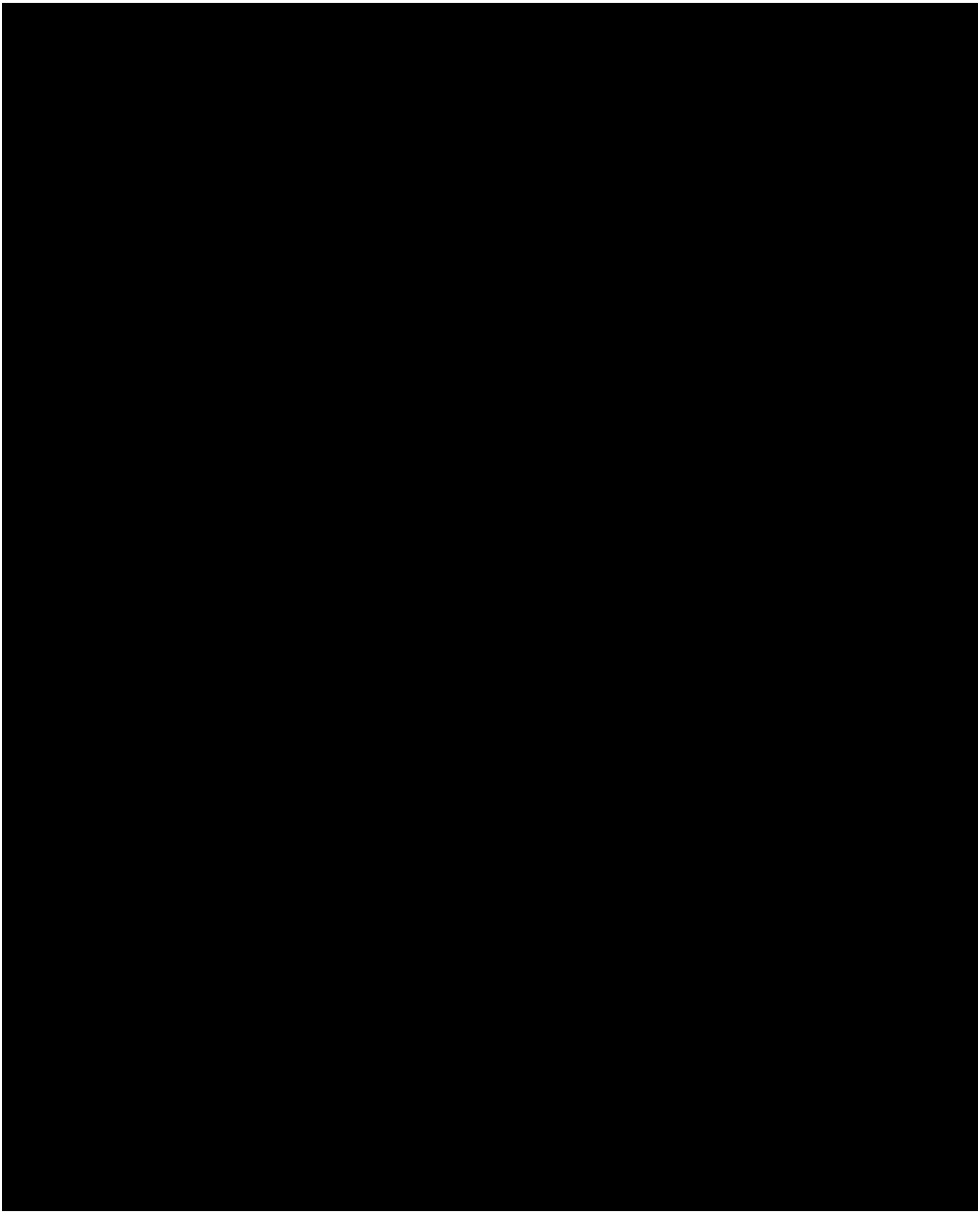
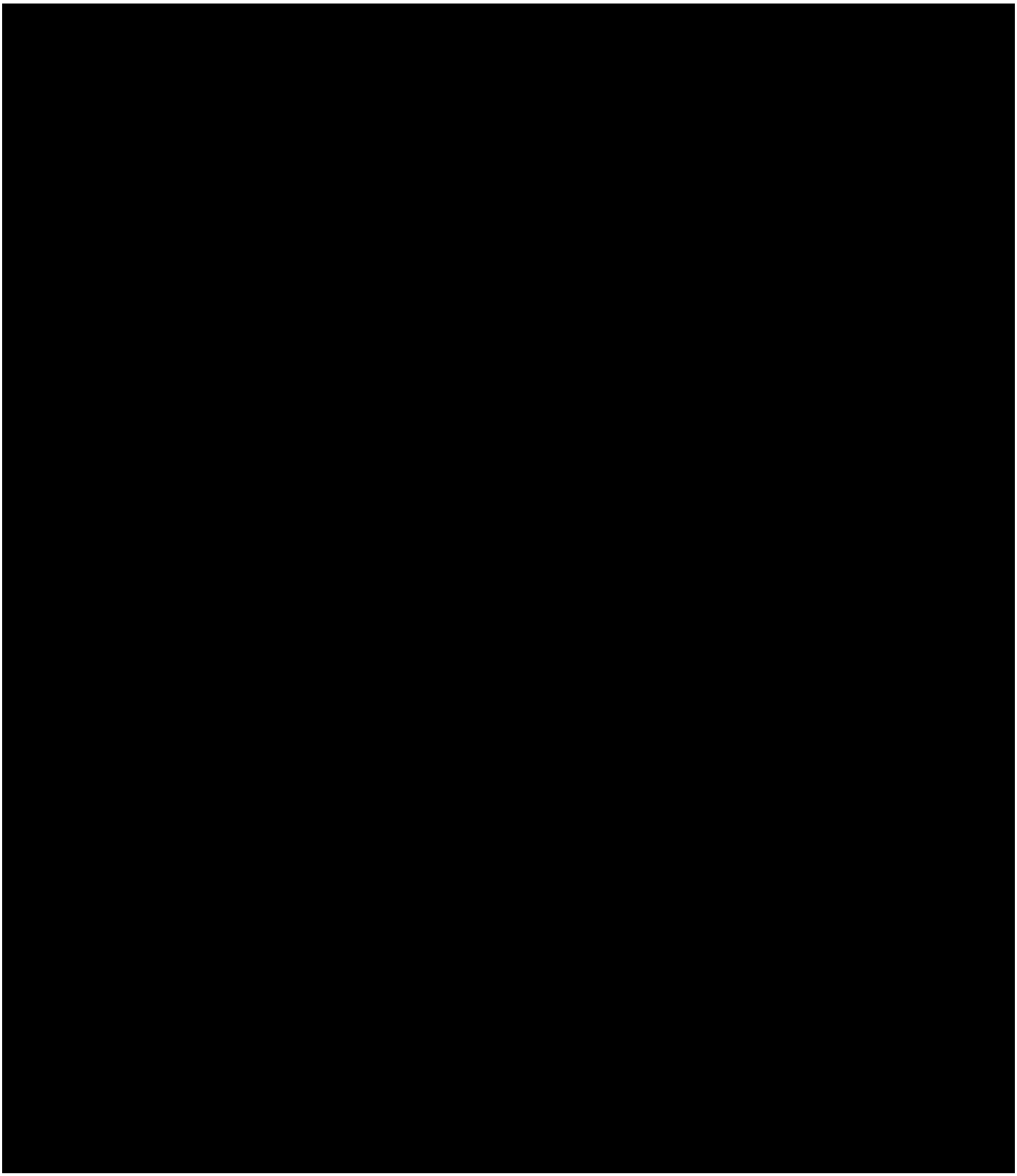
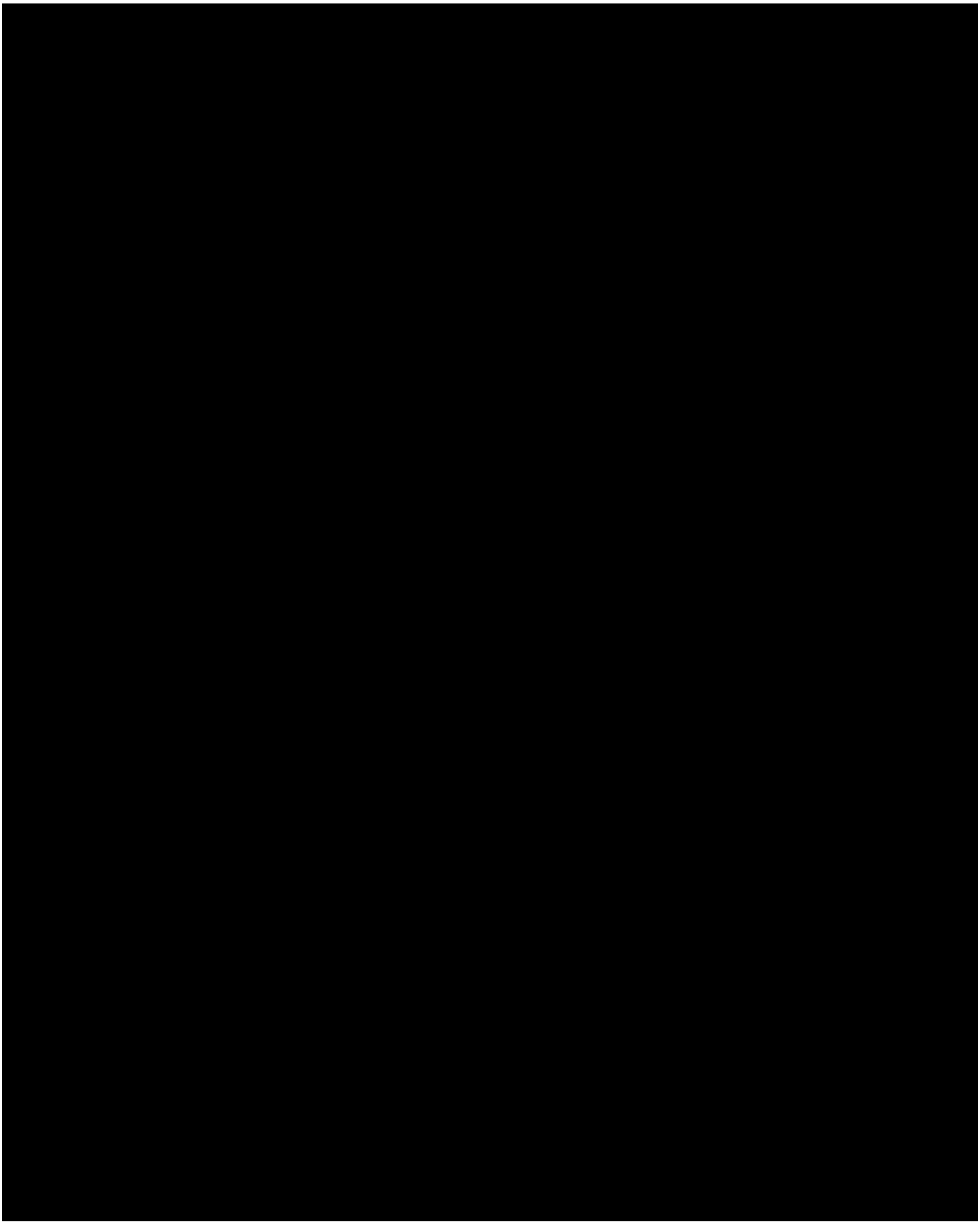


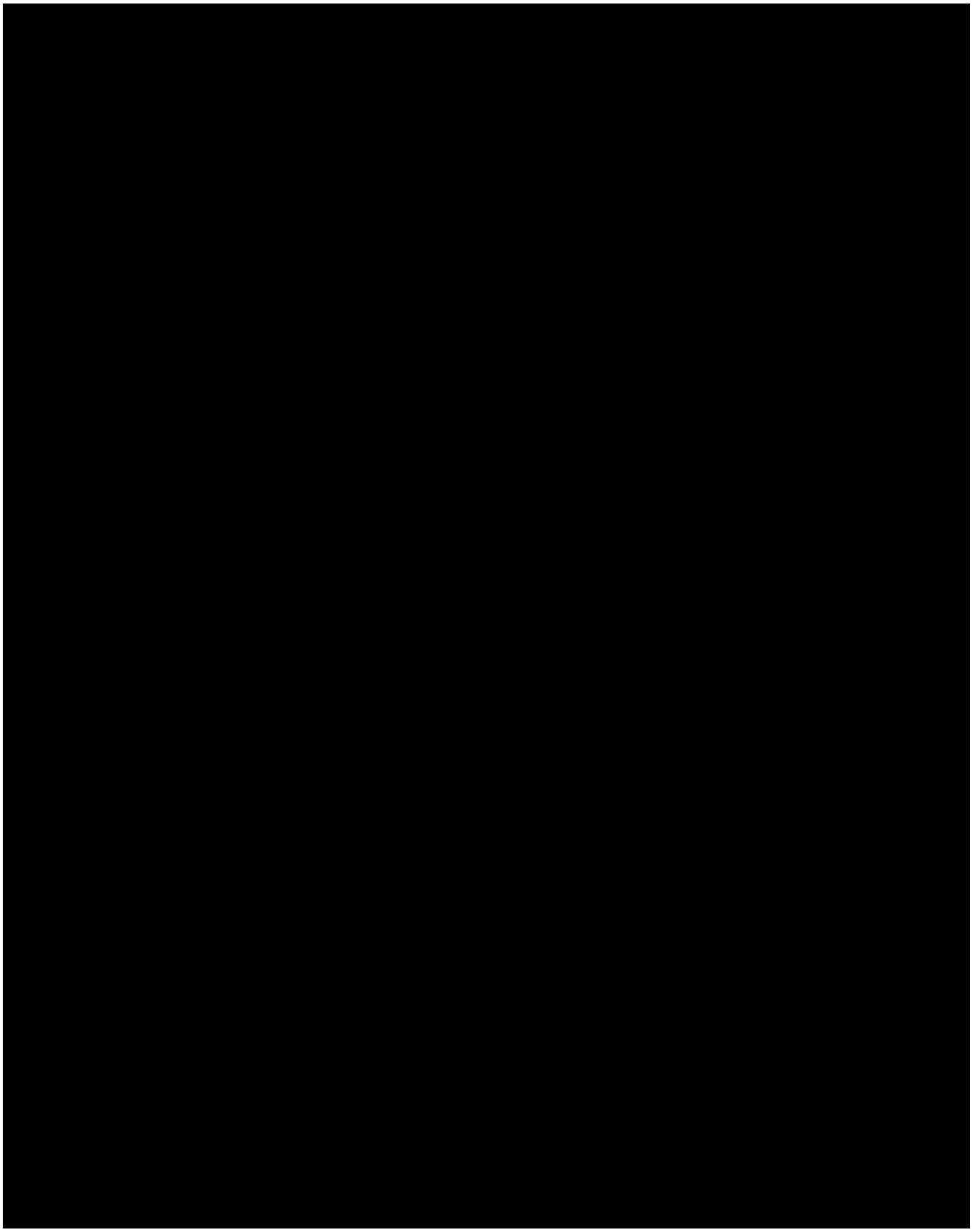


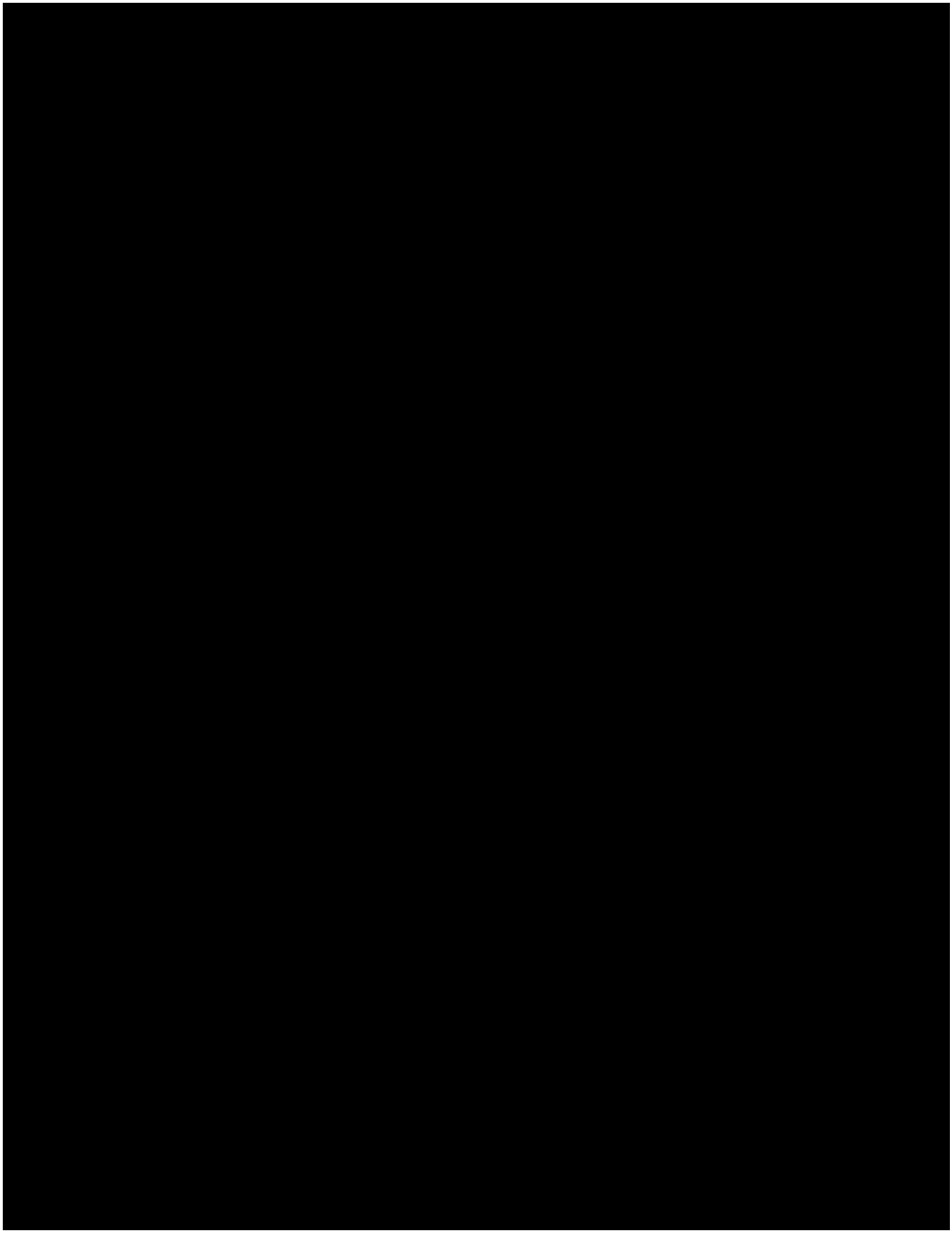












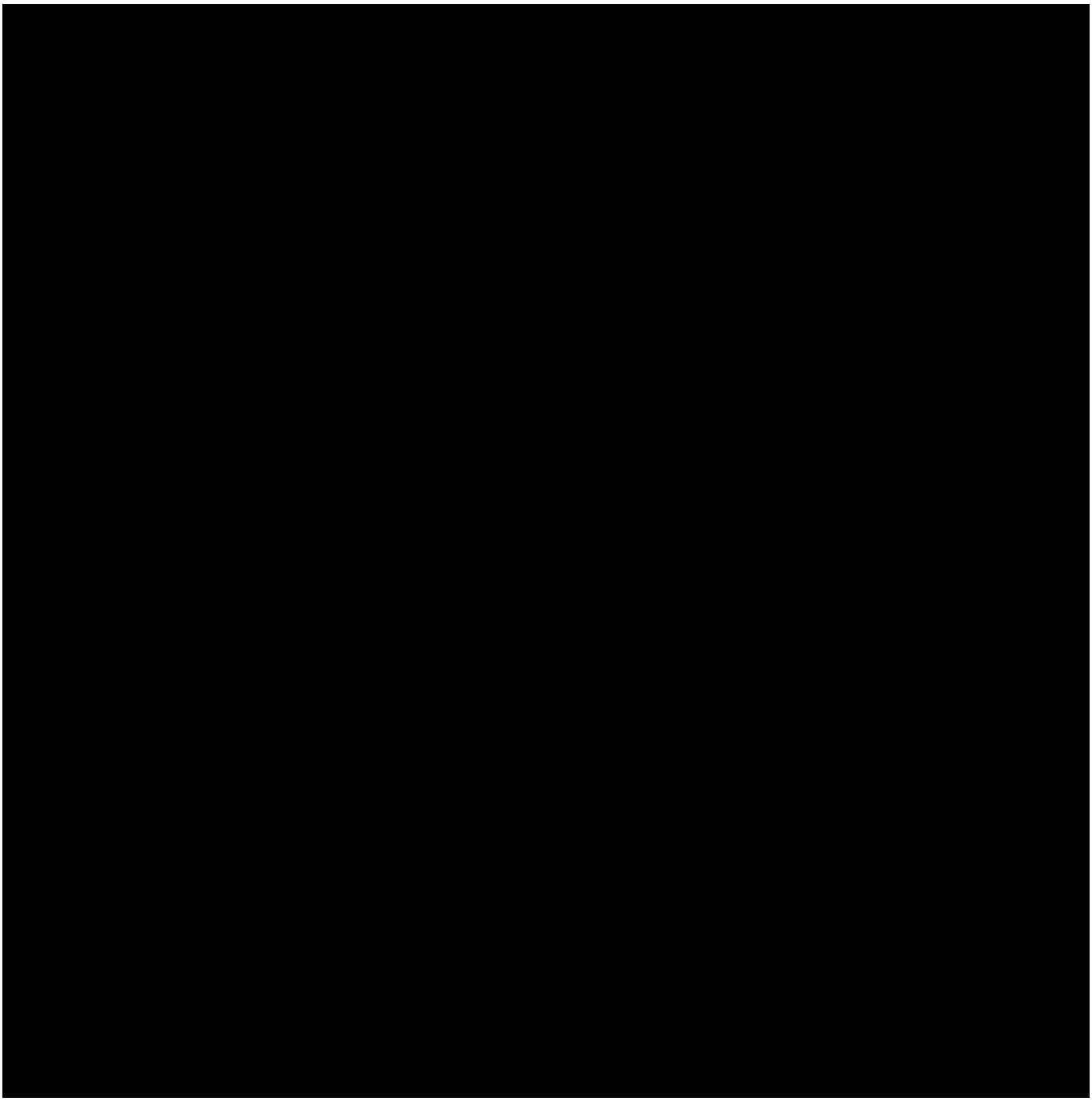
5.13 SupGen

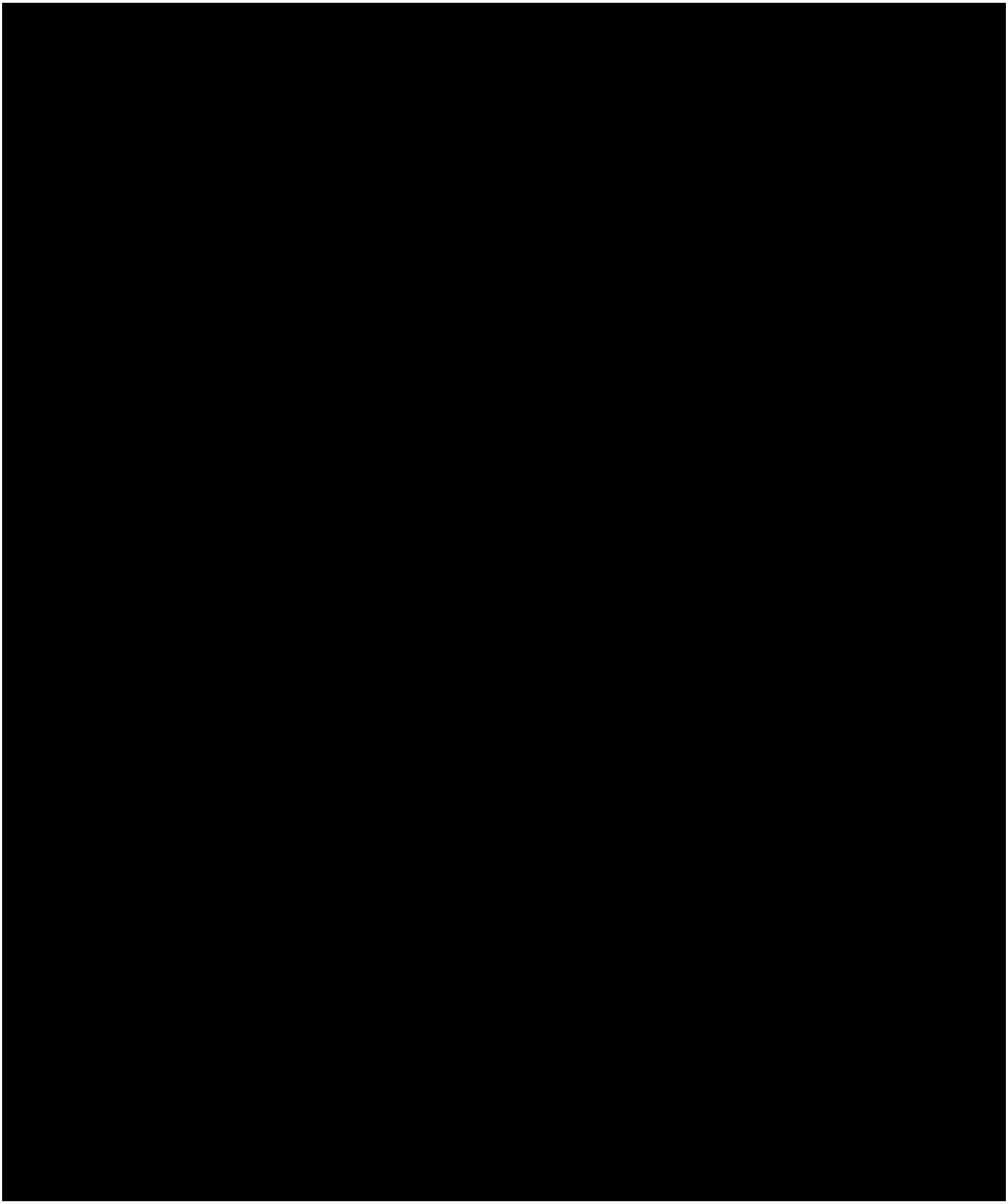
SupGen is a Client-owned site located in Douglas County, Wisconsin, on the outskirts of the city of Superior. The Stone Lake to Arrowhead 345 kV electric transmission line, owned by American Transmission Company, traverses the site area. The closest natural gas pipeline is located approximately five and a half miles south of the site area and includes two 36-inch diameter lines, owned by Great Lakes Gas Transmission Limited. The site is situated directly on the bank of the Nemadji River and less than two miles from Lake Superior. The site area itself is partially forested and relatively free of development, except for a small concrete foundation and pond in the western-most corner. Much of the surrounding area has been appropriated for industrial use. The site is accessed directly by 31st Avenue E., and there is a branch of the BNSF rail line less than half a mile to the northwest.

Following the scoring process, this site ranked 2nd out of 16 sites due to the following factors:

- Fuel Supply & Delivery: Scores in this category were strong. This site received the highest possible scores for distance to interconnection, pipeline delivery pressure, and system upgrade costs. It is located within close proximity to the Great Lakes Gas Transmission Ltd. pipeline corridor allowing it to receive one of the highest scores of any of the candidate sites in this category. This site is also located approximately 8.5 miles from a 20-inch diameter Northern Natural Gas Company pipeline. This site was not, however, awarded a high score for competitive supply as this line rated poorly as a primary source of fuel for other sites considered in the Study.

- Water Supply & Delivery: This site received one of the strongest overall scores of any candidate site in this category. It received the highest score for probability of surface water availability as it is located within two miles of Lake Michigan. It also received moderate scores for both probability for groundwater availability and proximity to a sufficiently permitted waste water treatment facility.
- This site scored competitively in all other categories and received a moderate score in the LMP analysis.





5.17 Candidate Site Scoring Summary

The following figures present the results of the quantitative scoring process for the 16 candidate sites.

Table 5-1: Candidate Site Scores

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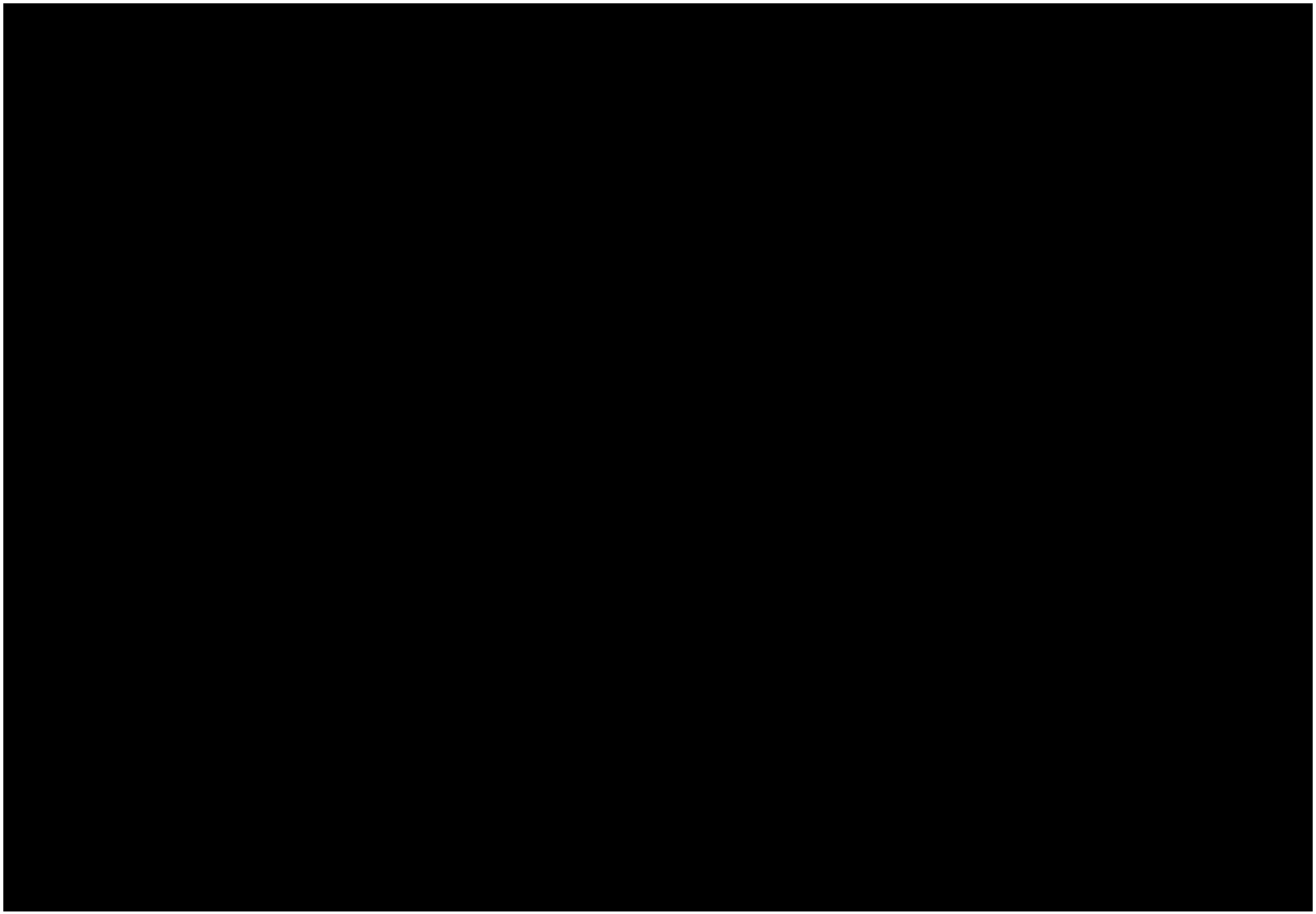

Figure 5-1: Candidate Site Rankings

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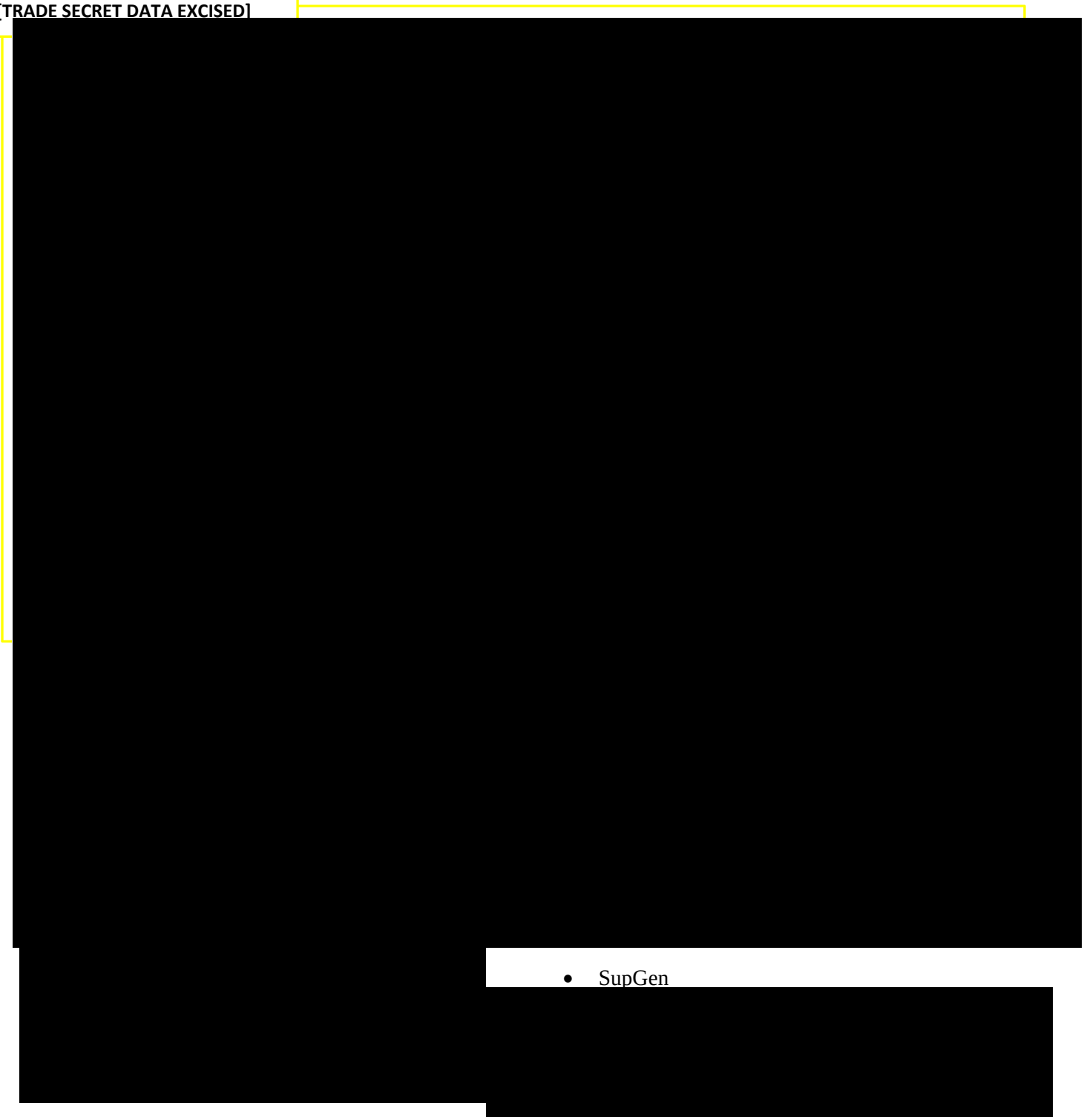

- SupGen

6.0 PREFERRED SITE EVALUATION

This chapter presents the methodology used for conducting the transmission load flow analysis and the subsequent evaluation and ranking of the preferred sites.

6.1 Transmission Load Flow Analysis

The transmission load flow analysis was performed using Power Technologies, Inc. (PTI) and Management and Utilizing System Transmission (MUST) software for each of the proposed interconnection points. The model utilized the latest MISO summer heavy flow case and a 3% distribution factor was used for the analysis. To evaluate each site, 780 MW of new capacity was added, incrementally, to the proposed interconnection. At each site, the number of overloads resulting from the new generation was tallied and weighted according to the particular assets that were overloaded. Impacts on affected systems, either transmission lines or substations, were weighted according to the relative significance of the implied infrastructure upgrades required. For instance, a 500 kV transmission line overload was weighted five times more than a 138/115-kV transmission line overload and weighted twice as much as a 500 kV transformer overload. The relative percentage for each site was then calculated based on the difference in score between the sites with the lowest total score and the highest total score. Sites scores to be incorporated into the site scoring matrix were determined based on these relative percentages with a low score of 10 for those sites with the greatest impact and a high score of 50 for those sites having the least amount of impact. The nature and number of overloads encountered for each individual site can be seen in Table 6-1.

Table 6-1: Transmission Load Flow Analysis Scores [TRADE SECRET DATA EXCISED]

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6.2 Preferred Site Ranking

Transmission Load Flow Analysis scores were incorporated into the site scoring matrix and the resulting site score totals were used to determine the rankings of the preferred sites relative to one another. The results can be seen in Table 6-2 and Figure 6-1.

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Table 6-2: Preferred Site Scores

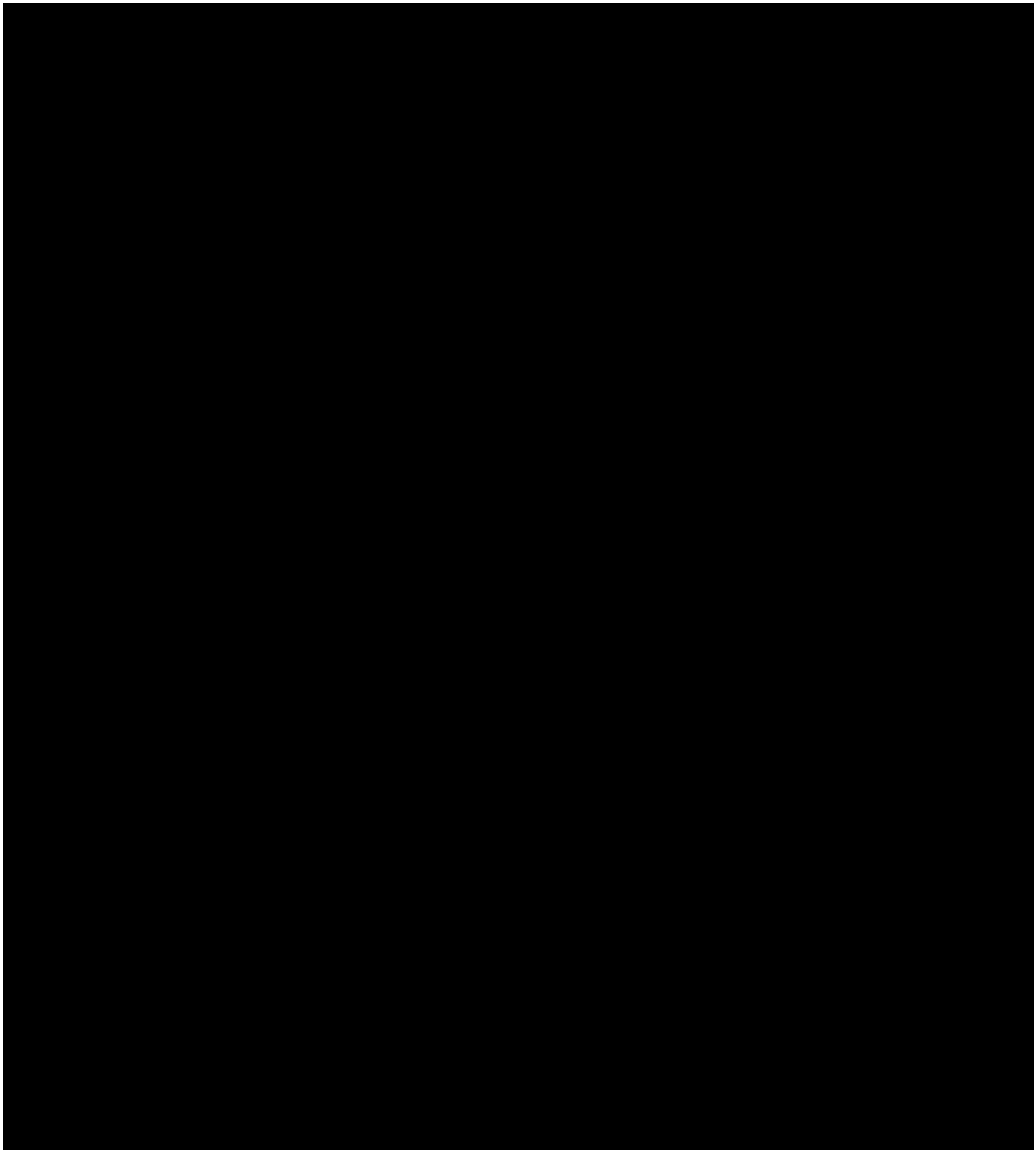

Figure 6-1: Preferred Site Rankings

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6.3 Sensitivity Analyses

Once the transmission load flow evaluation was completed, a number of sensitivity analyses were performed to test the sensitivity of the composite evaluation scores to various changes in criteria weighting. For these sensitivity analyses, only the weights assigned to the six major evaluation categories were adjusted. The sub-weights for the criteria within their respective categories and the individual scores assigned to the sites for each criterion were not changed. Six different sensitivity cases were executed: one case each for transmission, fuel, water, environmental, air quality and site development.

The weight for the category that was emphasized was increased 10 percent, and the other five categories were reduced by two percent each. The composite weights for each category and weighted composite scores for each site were then recalculated. Table 6-3 contains a schedule of the category weights used in the sensitivity analyses.

Table 6-3: Category Weights for Sensitivity Analyses

Category	Base Weighted (%)	Transmission Weighted (%)	Fuel Weighted (%)	Water Weighted (%)	Environmental Weighted (%)	Air Quality Weighted (%)	Site Dev Weighted (%)
Electric Transmission	20%	30%	18%	18%	18%	18%	18%
Fuel Supply & Delivery	30%	28%	40%	28%	28%	28%	28%
Water Supply & Delivery	20%	18%	18%	30%	18%	18%	18%
Site Environmental	10%	8%	8%	8%	20%	8%	8%
Air Quality Impacts	10%	8%	8%	8%	8%	20%	8%
Site Development	10%	8%	8%	8%	8%	8%	20%
TOTAL	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

The results of the sensitivity analyses were summarized by comparing each site's ranking under the various cases. A site's rank was determined by sorting the sites based on their composite evaluation scores and then numbering them sequentially, with a rank of one assigned to the site with the highest base score. These ranks are summarized in Table 6-4. The shaded cells in this table indicate the sensitivity cases where individual sites either increased or decreased in rank.

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Table 6-4: Preferred Site Rankings for Sensitivity Analyses

Review of Table 6-4 indicates that site base rankings remained unchanged when evaluated for sensitivity to both the Environmental and Air Quality scoring categories. In each of the remaining sensitivity analyses, however, the site rankings were affected as indicated by shaded cells. Red cells indicate sites

increasing in rank, and green cells indicate sites decreasing in rank from the base case scenario. The changes in ranking for a site under each sensitivity case provide an indication of the relative strengths and weaknesses of each site and the drivers for each site's overall ranking.

7.0 CONCLUSIONS AND RECOMMENDATIONS

This chapter presents the conclusions reached as a result of the investigations and evaluations conducted during this Study. As previously discussed, the quantitative scoring results are only intended to aid the decision-making process; the results should not be relied upon exclusively and proper consideration must be given to strategic factors that may not be captured in the scoring analysis.

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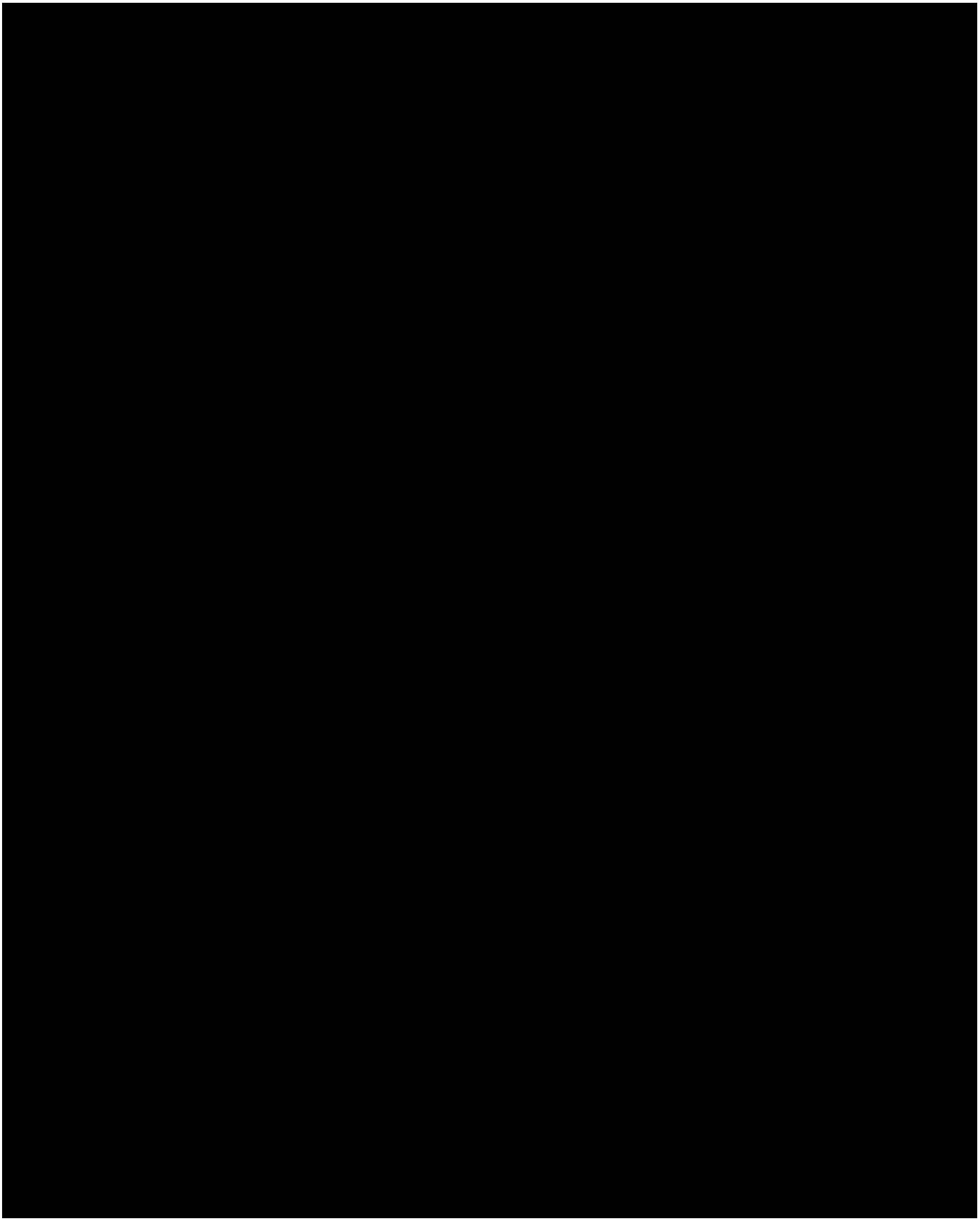

7.4 SupGen

The following is a summary of conclusions reached with regard to the potential of the SupGen site for advanced development activities:

- Electric Transmission: This site received the second highest electric transmission score of any of the preferred sites. While it did receive a low score for interconnection cost due to the need for construction of a line tap, it received the third highest score for the LMP analysis and the highest possible score for the transmission load flow analysis. With the addition of 780 MW, two individual assets would be overloaded requiring infrastructure updates for one 230-kV transmission line and one 345-kV substation.
- Fuel Supply & Delivery: Scores in this category were strong. This site received the highest possible scores for distance to interconnection, pipeline delivery pressure, and system upgrade costs. It is located within close proximity to the Great Lakes Gas Transmission Ltd. pipeline corridor allowing it to receive one of the highest scores of any of the candidate sites in this category. This site is also located approximately 8.5 miles from a 20-inch diameter Northern Natural Gas Company pipeline. This site was not, however, awarded a high score for competitive supply as this line rated poorly as a primary source of fuel for other sites considered in the Study. It should be noted, however, that although there is currently no capacity available on the Northern Natural Gas pipeline, the close proximity of the line may still be considered an advantage in the long term. While it is anticipated that interconnecting to this pipeline for the purposes of this Project would incur potentially significant upgrade costs, it is nonetheless a fuel supply alternative, the existence of which may provide negotiating leverage and the potential for tapping an alternative fuel supply basin, should the need arise.

- Water Supply & Delivery: This site received one of the strongest overall scores of any candidate site in this category. It received the highest score for probability of surface water availability as it is located within two miles of Lake Michigan. It also received moderate scores for both probability for groundwater availability and proximity to a sufficiently permitted waste water treatment facility.
- This site scored competitively in all other categories.

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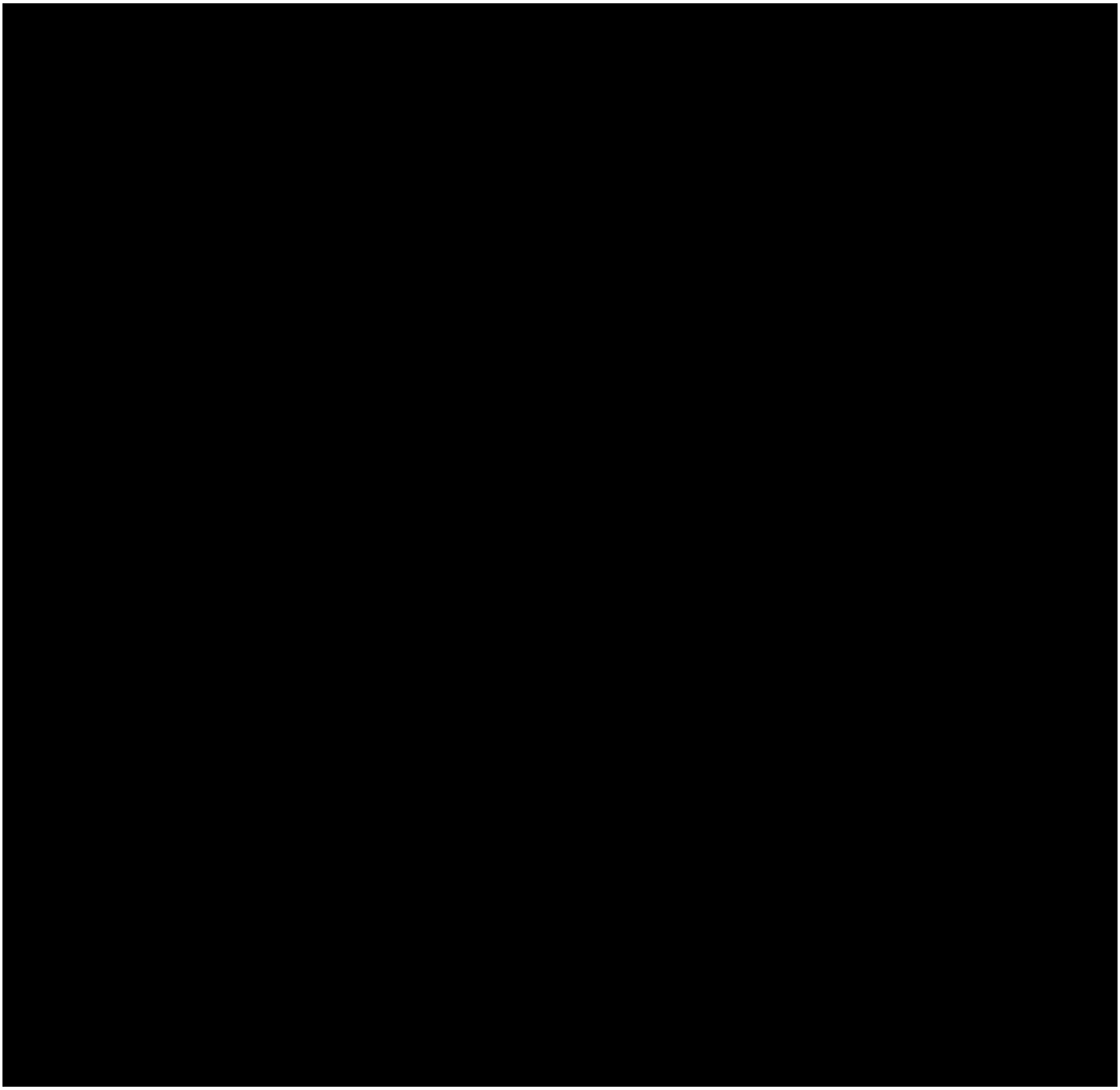

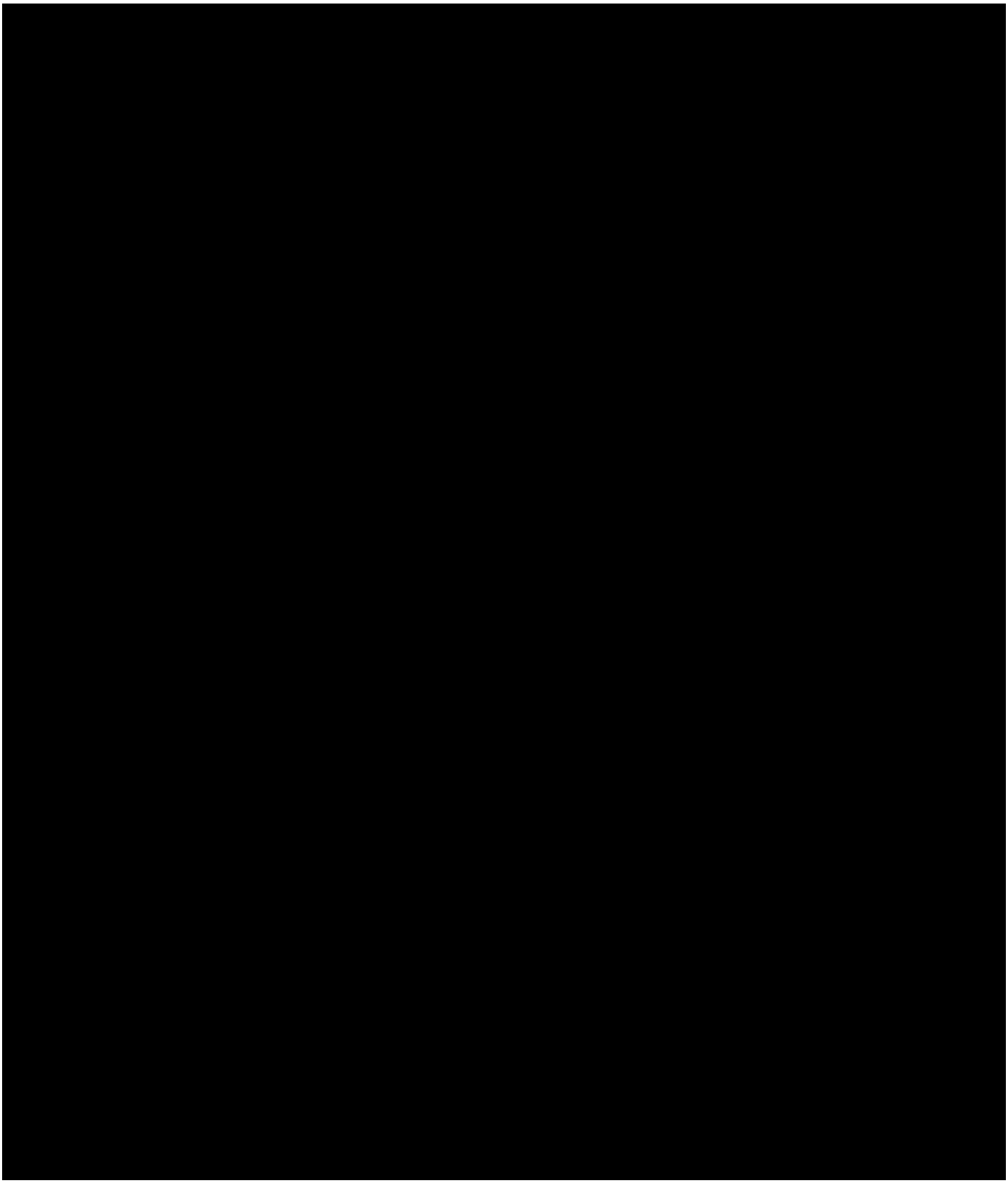

APPENDIX A - CANDIDATE SITES

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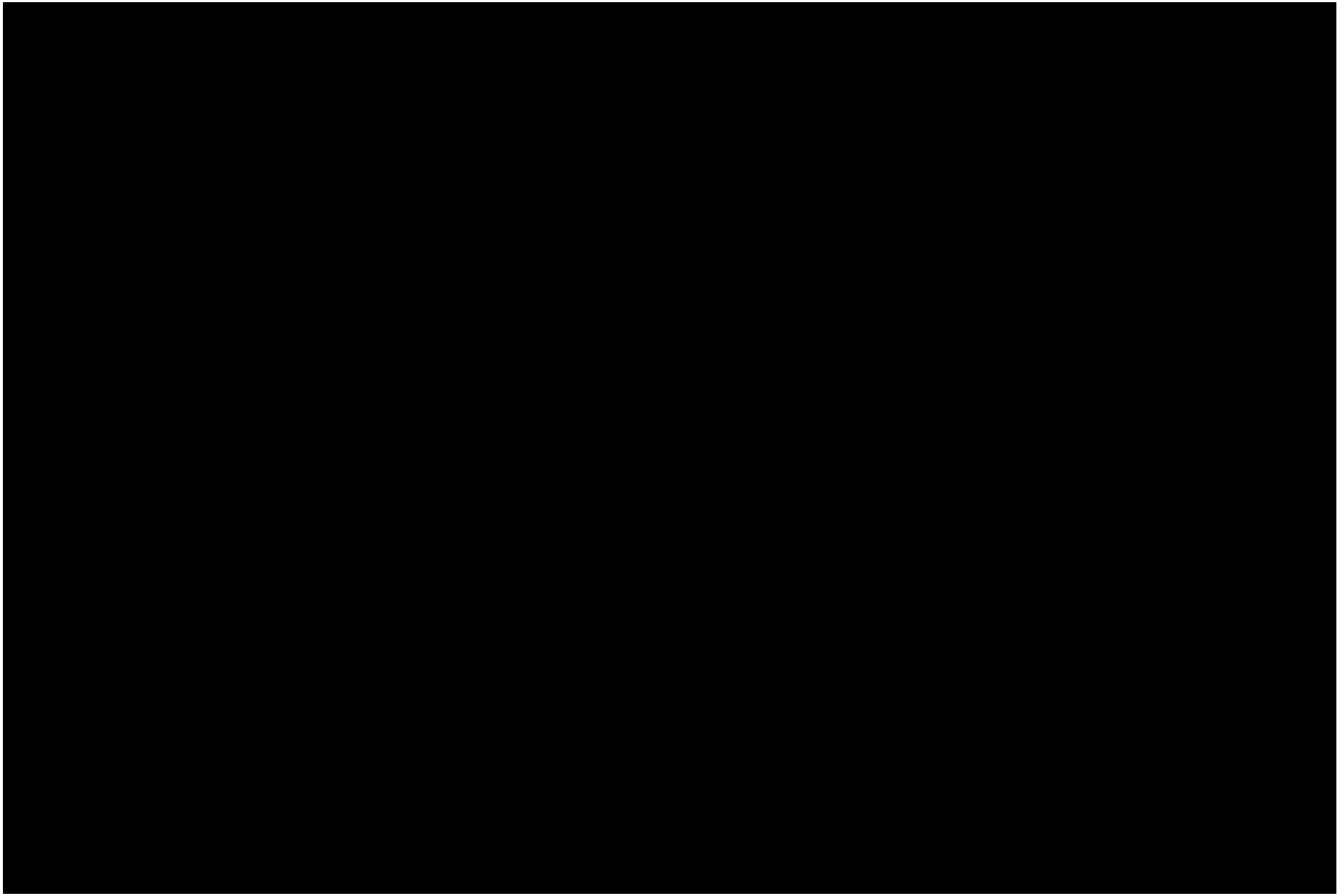

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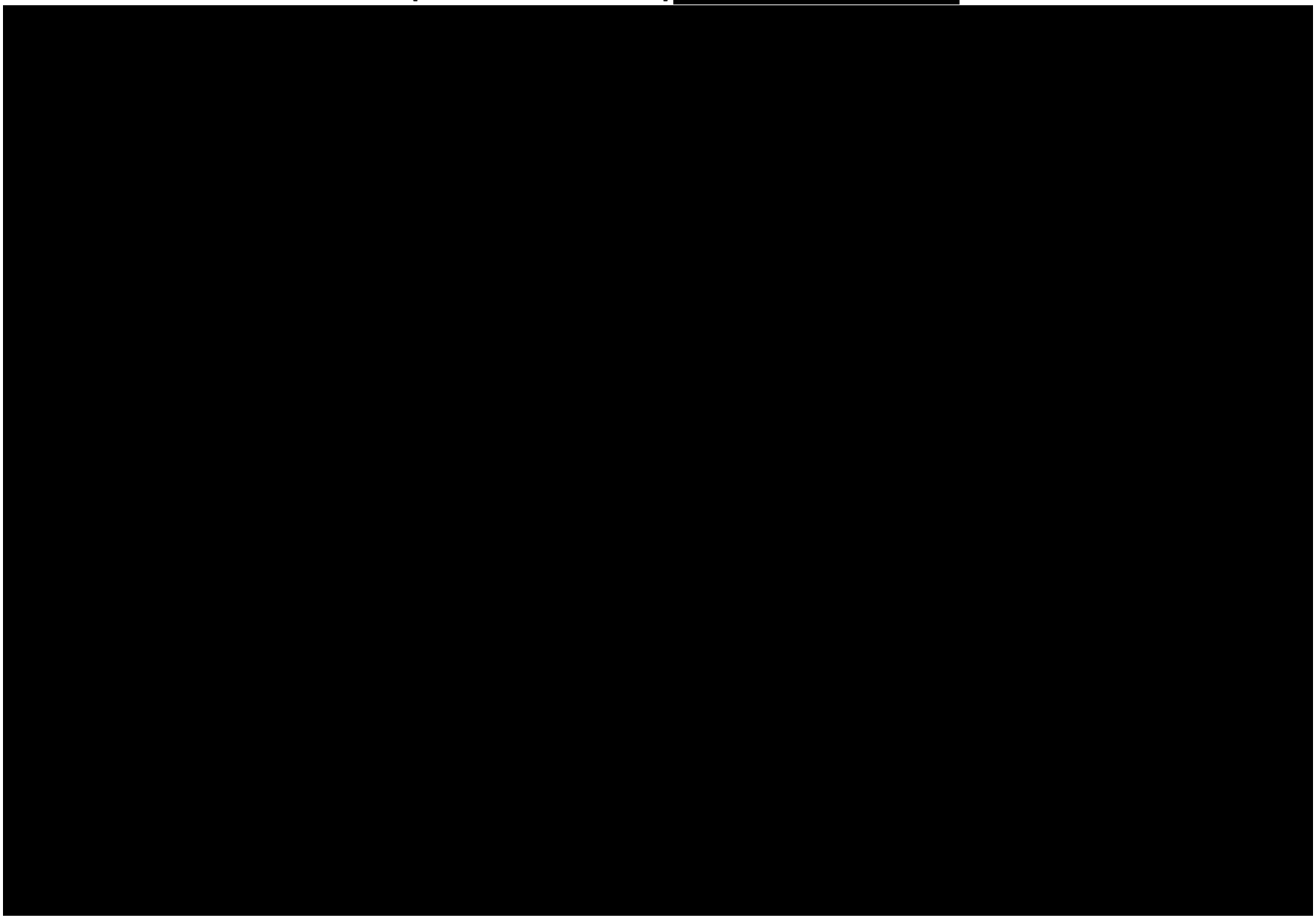

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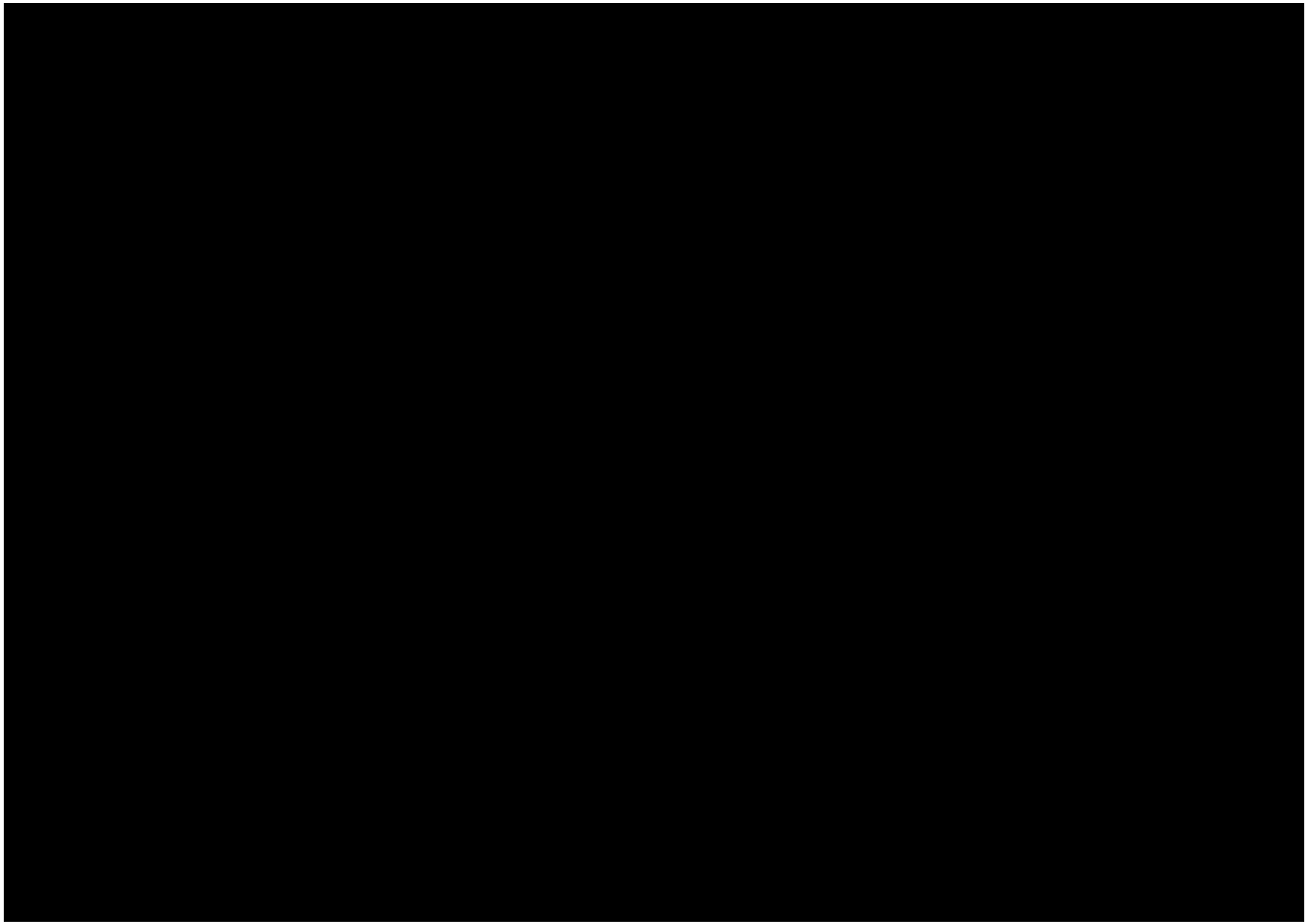
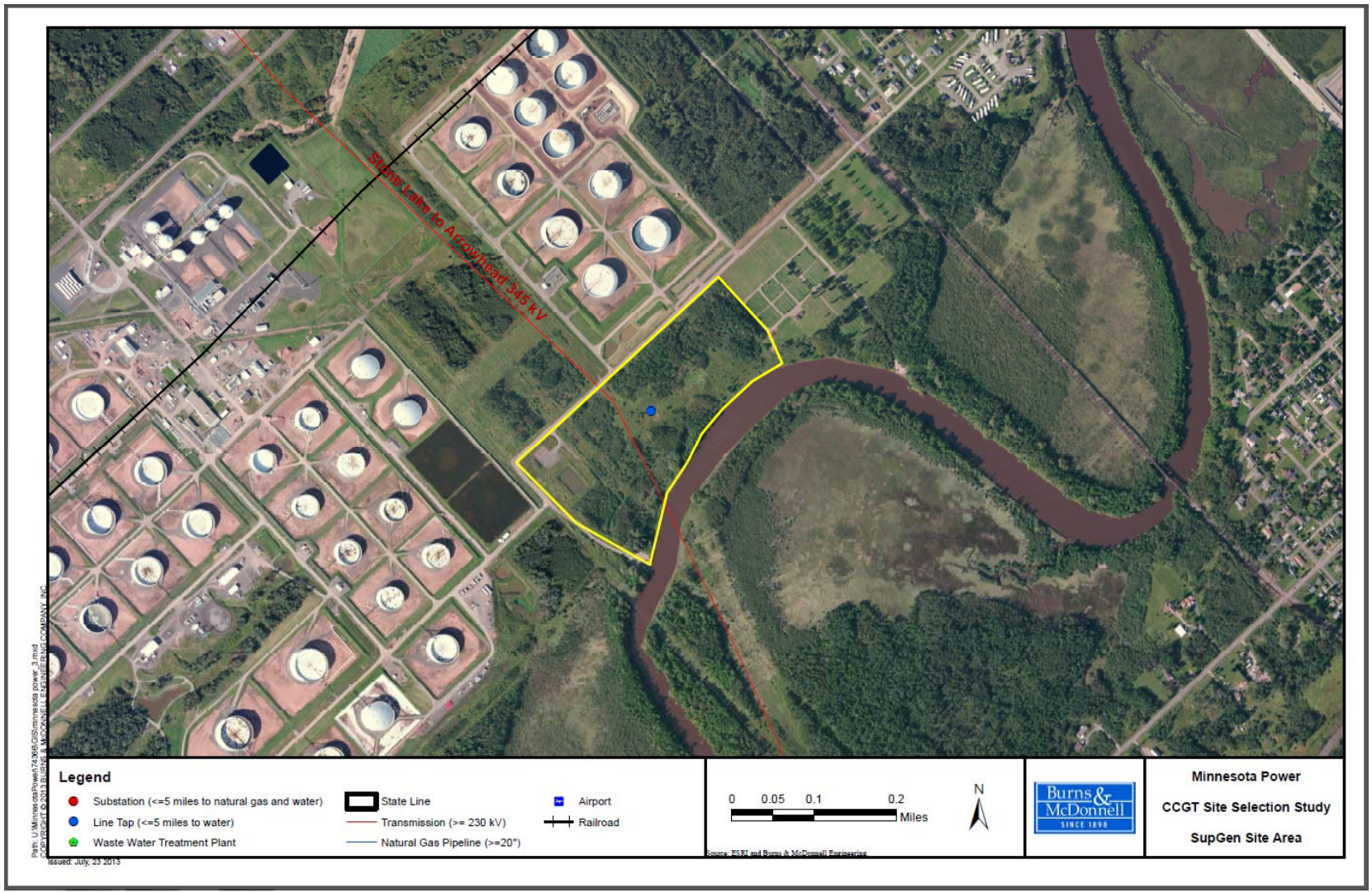


SupGen


Stone Lake to Arrowhead 345 kV
Legend
Substation (<=5 miles to natural gas and water)
Line Tap (<=5 miles to water)
Waste Water Treatment Plant
State Line
Transmission (>= 230 kV)
Natural Gas Pipeline (>=20")
Airport
Railroad
0 0.05 0.1 0.2
Miles
N
Burns & McDonnell
SINCE 1898
Minnesota Power
CCGT Site Selection Study
SupGen Site Area

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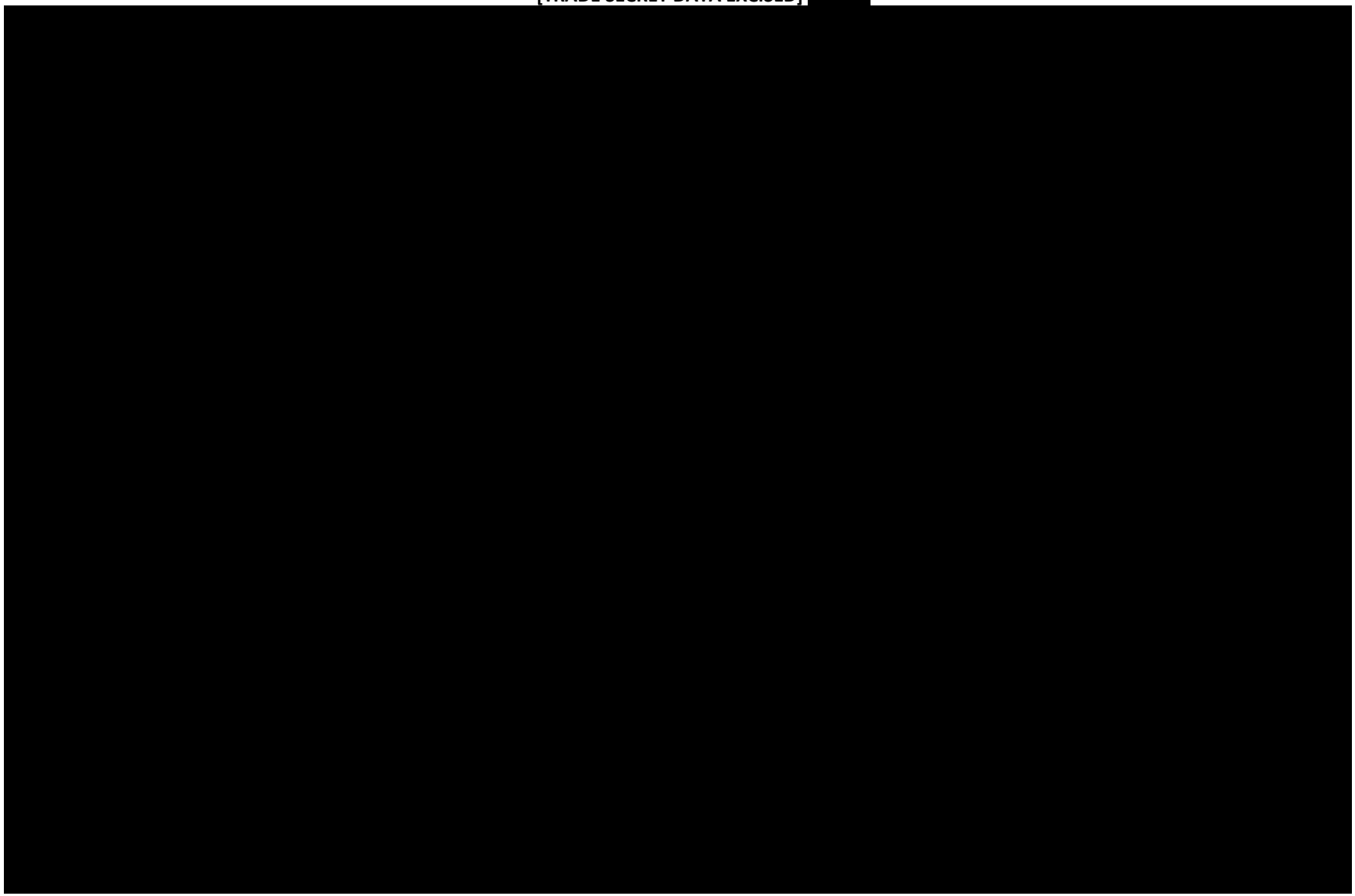

APPENDIX B - SITE SELECTION ADDENDUM

1.0 ADDITIONAL SITE CONSIDERATION

The objective of the site selection study (Study) was to identify the most appropriate potential sites for subsequent development of a CCGT facility based on the screening criteria agreed upon between BMcD and the Client. This Site Selection Addendum (Addendum) has been included with the Study in response to a Client request to provide a high-level evaluation of select additional sites. The sites discussed in the Addendum were identified in the preliminary site screening of the Study but were subsequently eliminated based on the site selection criteria. These sites have been evaluated independently of the Study sites, and of each other, and have not been scored or ranked.

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Table B- 1: Cost & Performance Impacts of Dry Cooling

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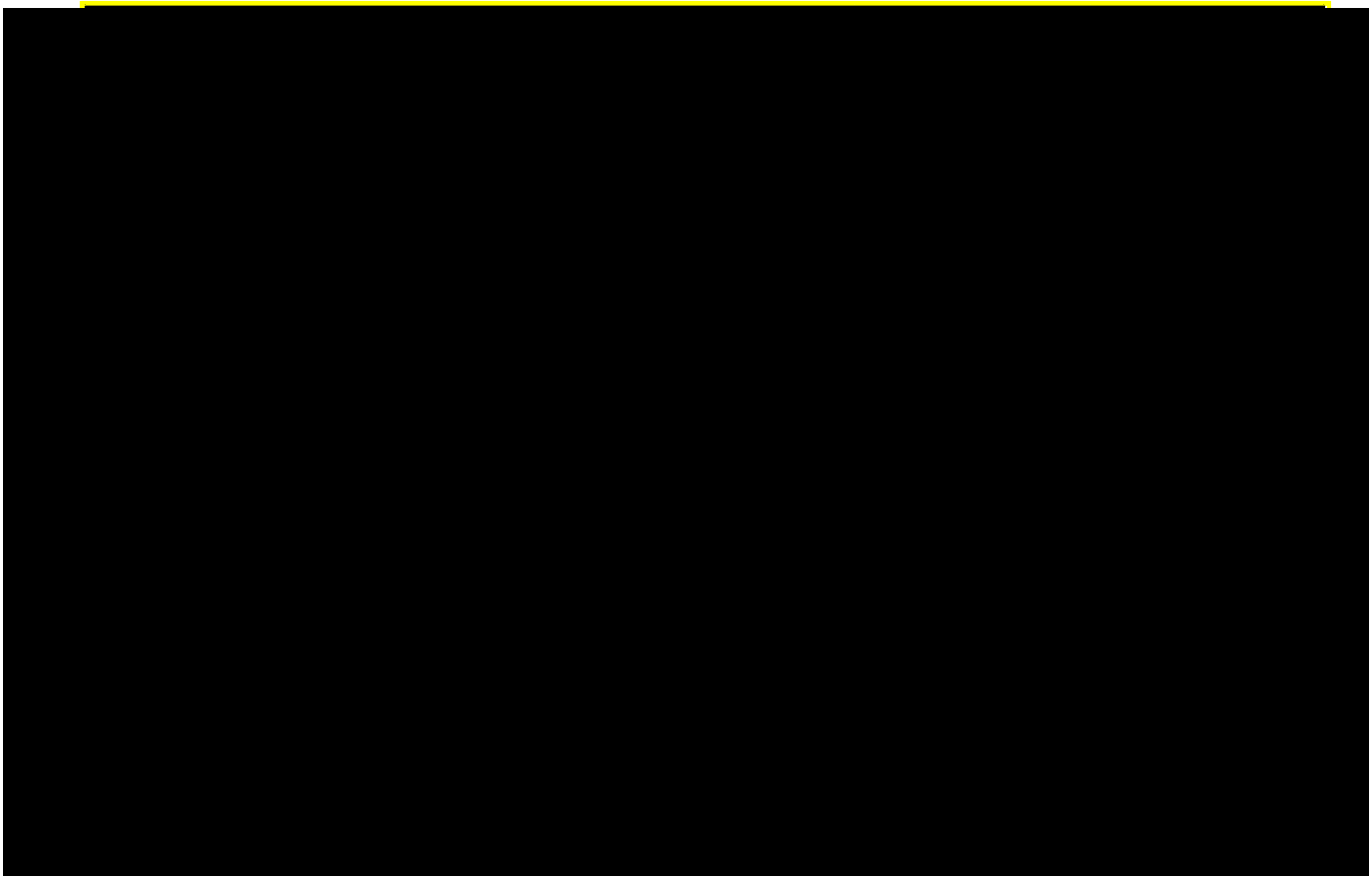

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1.0 INTRODUCTION

The objective of the site selection study (Study) was to identify the most appropriate potential sites for subsequent development of a CCGT facility based on the screening criteria agreed upon between BMcD and the Client. This **[TRADE SECRET DATA EXCISED]**

1.1 Objective

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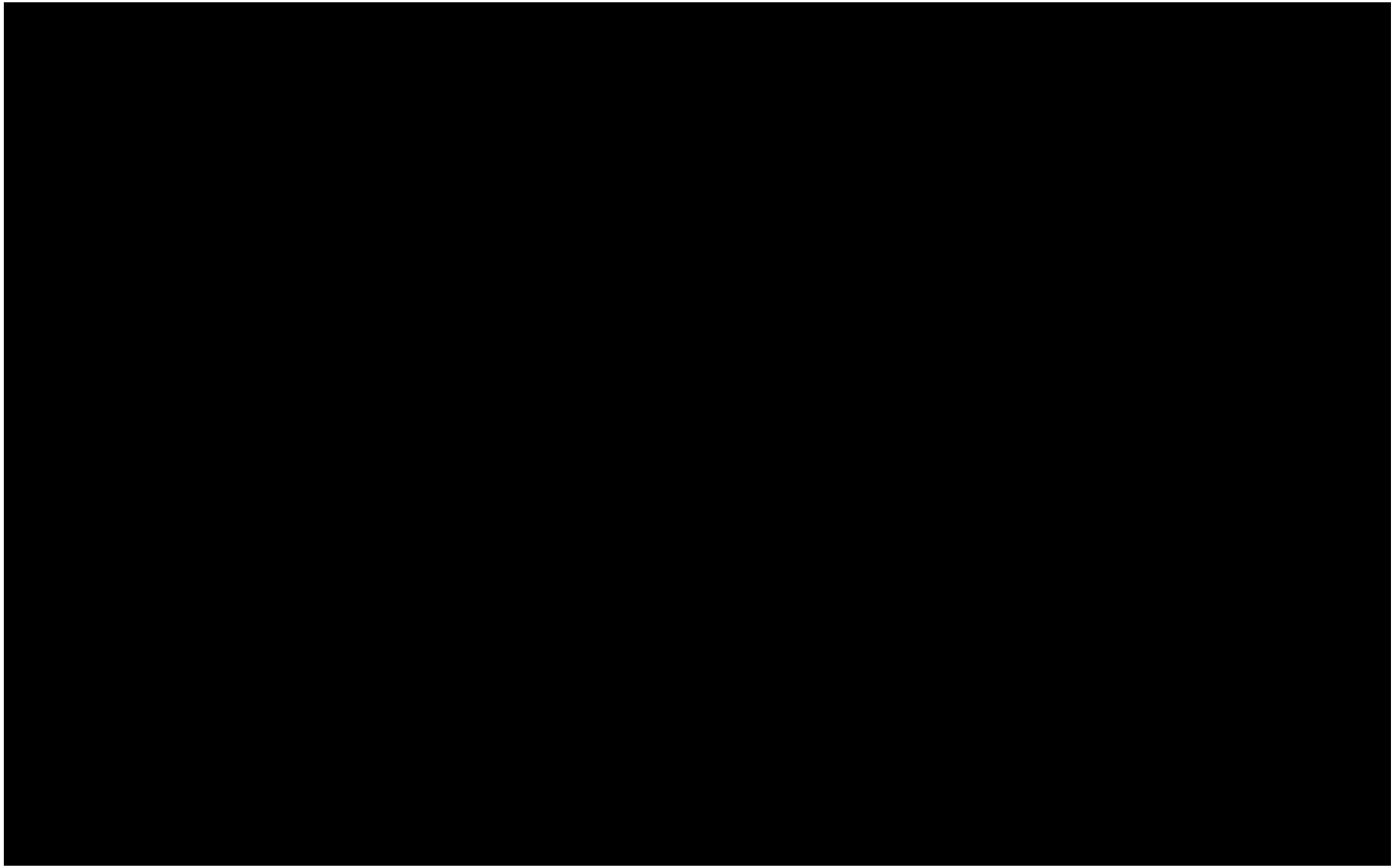

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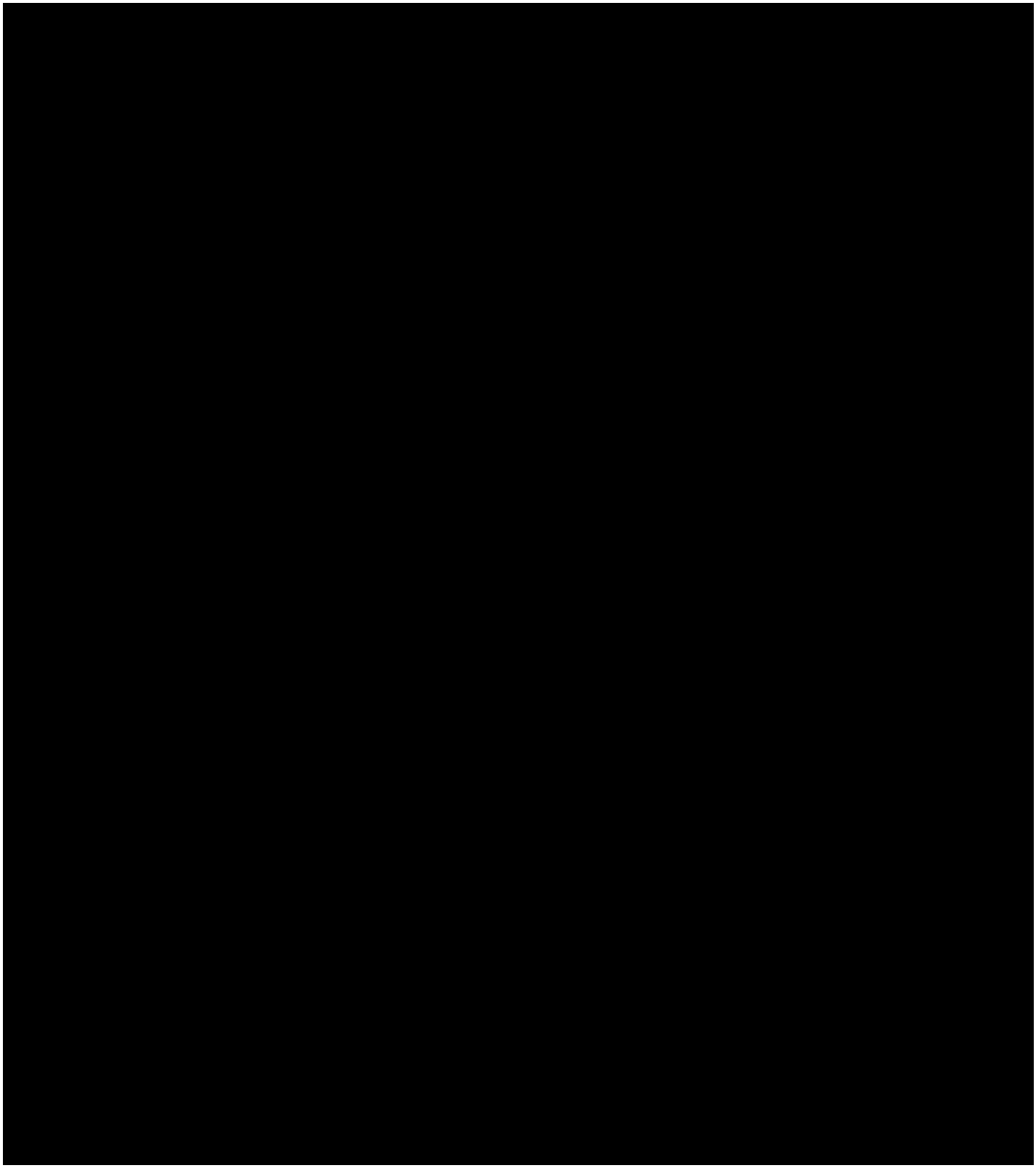

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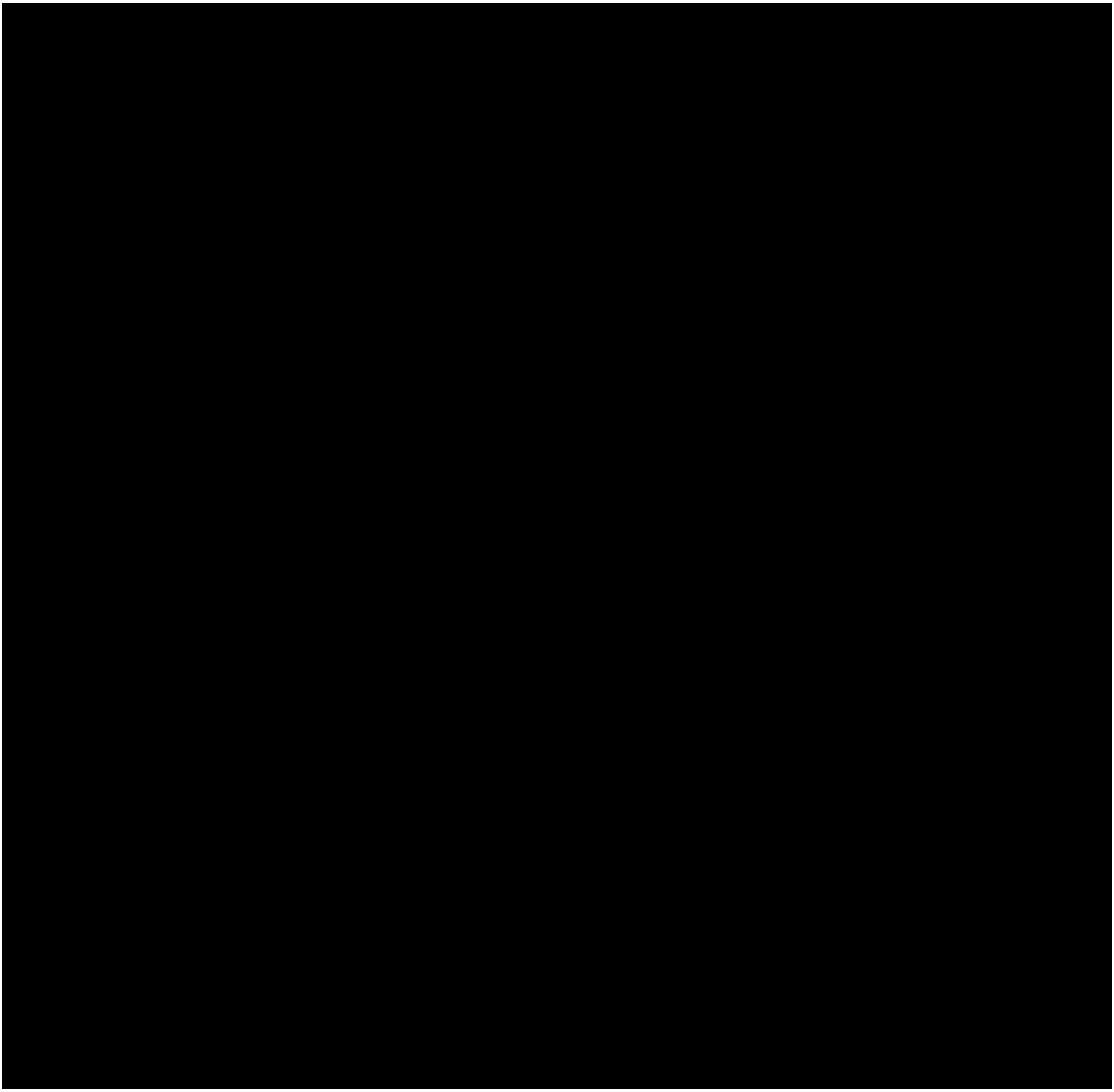

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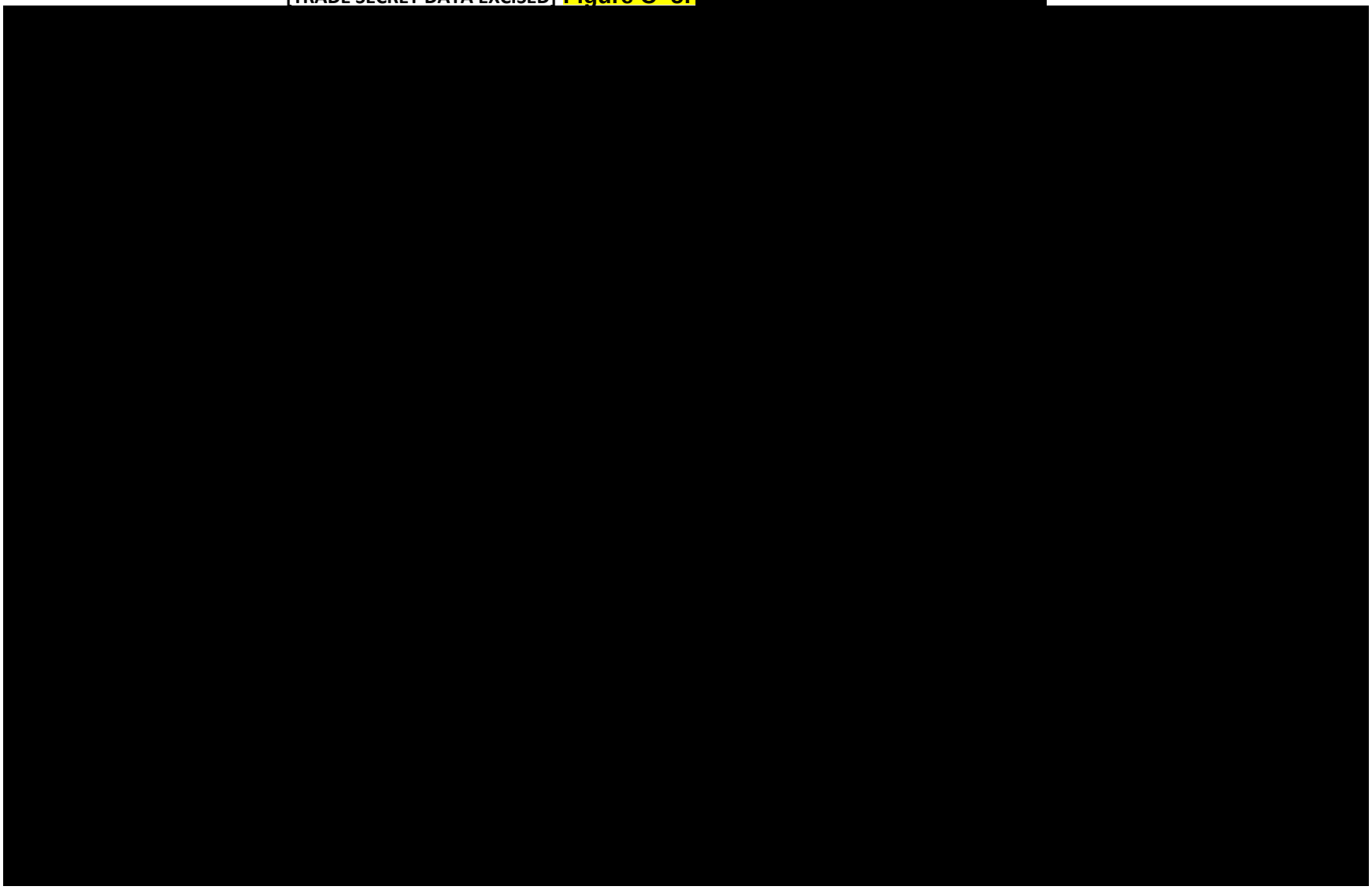

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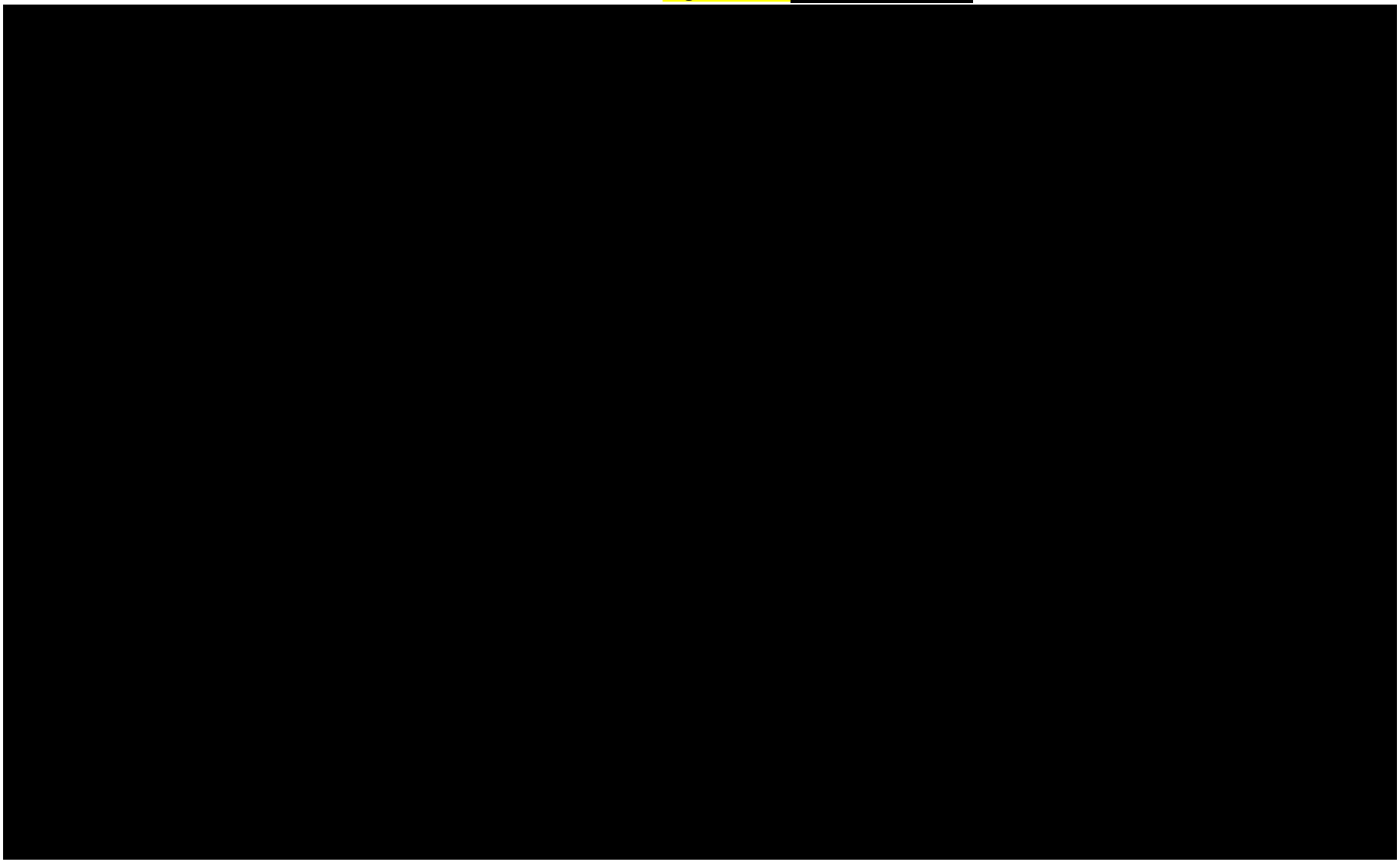

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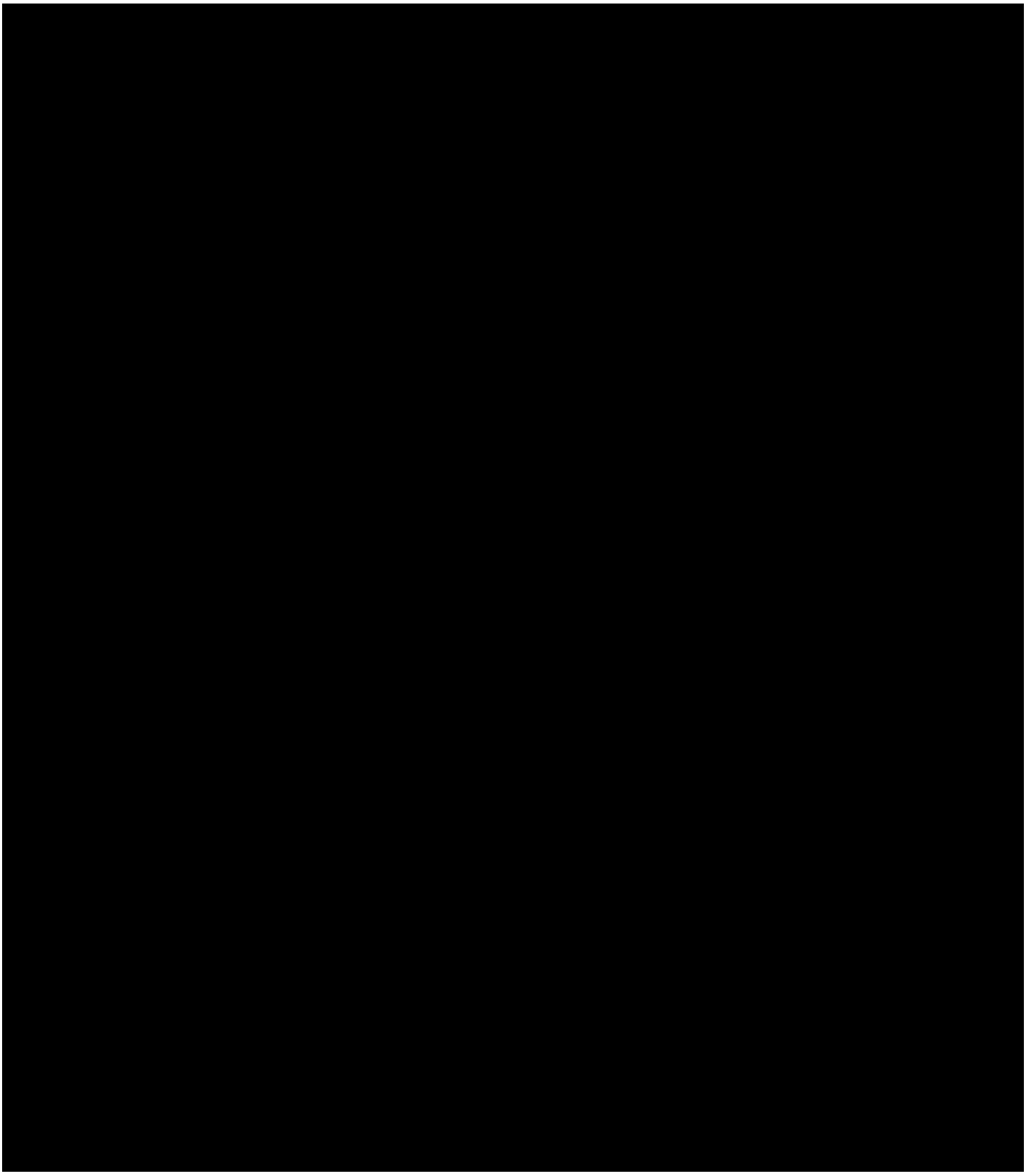

Table C- 2: Transmission Load Flow Analysis Scores [TRADE SECRET DATA EXCISED]

[TRADE SECRET DATA EXCISED] **Table C- 3:** [redacted]

[redacted]

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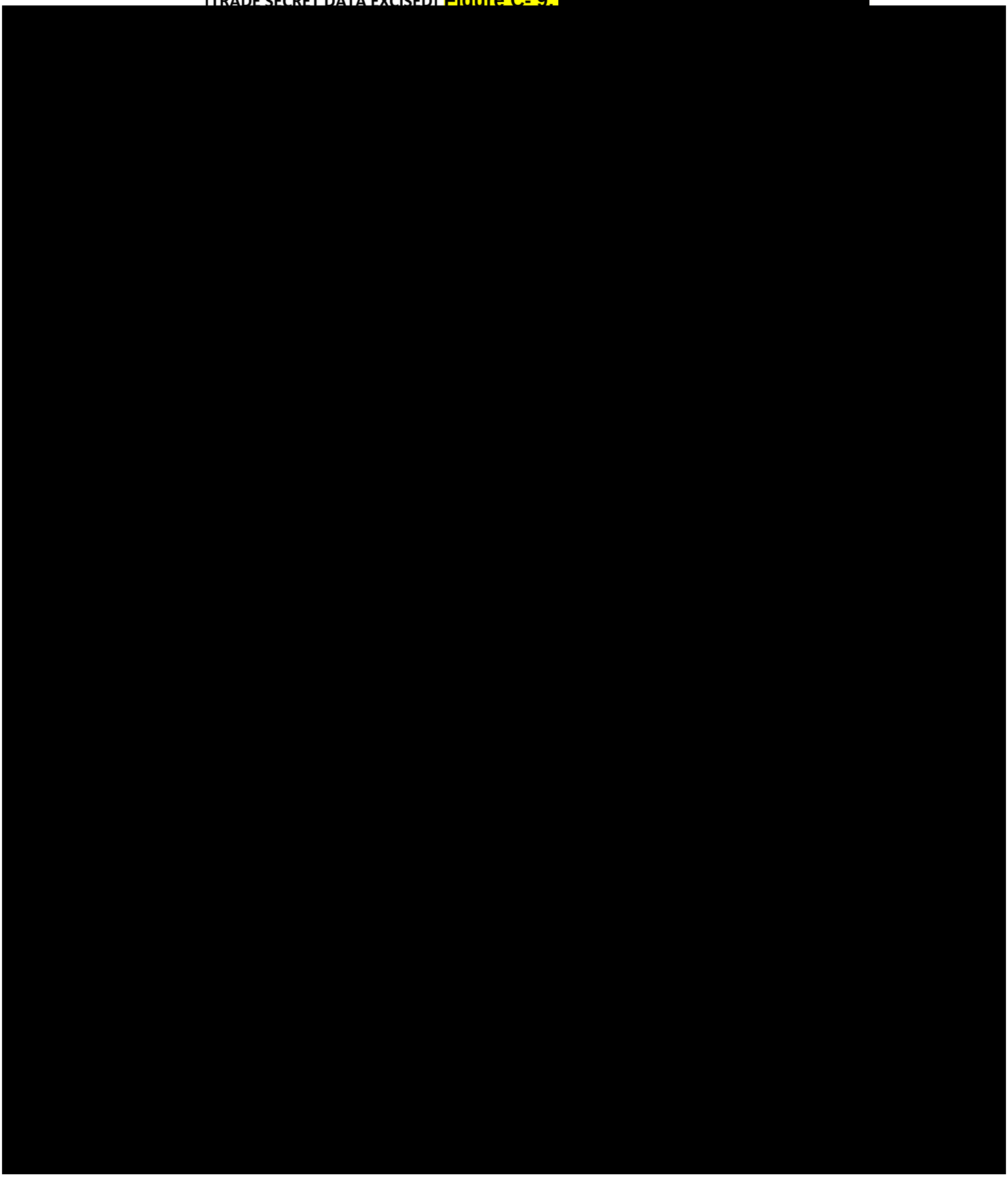

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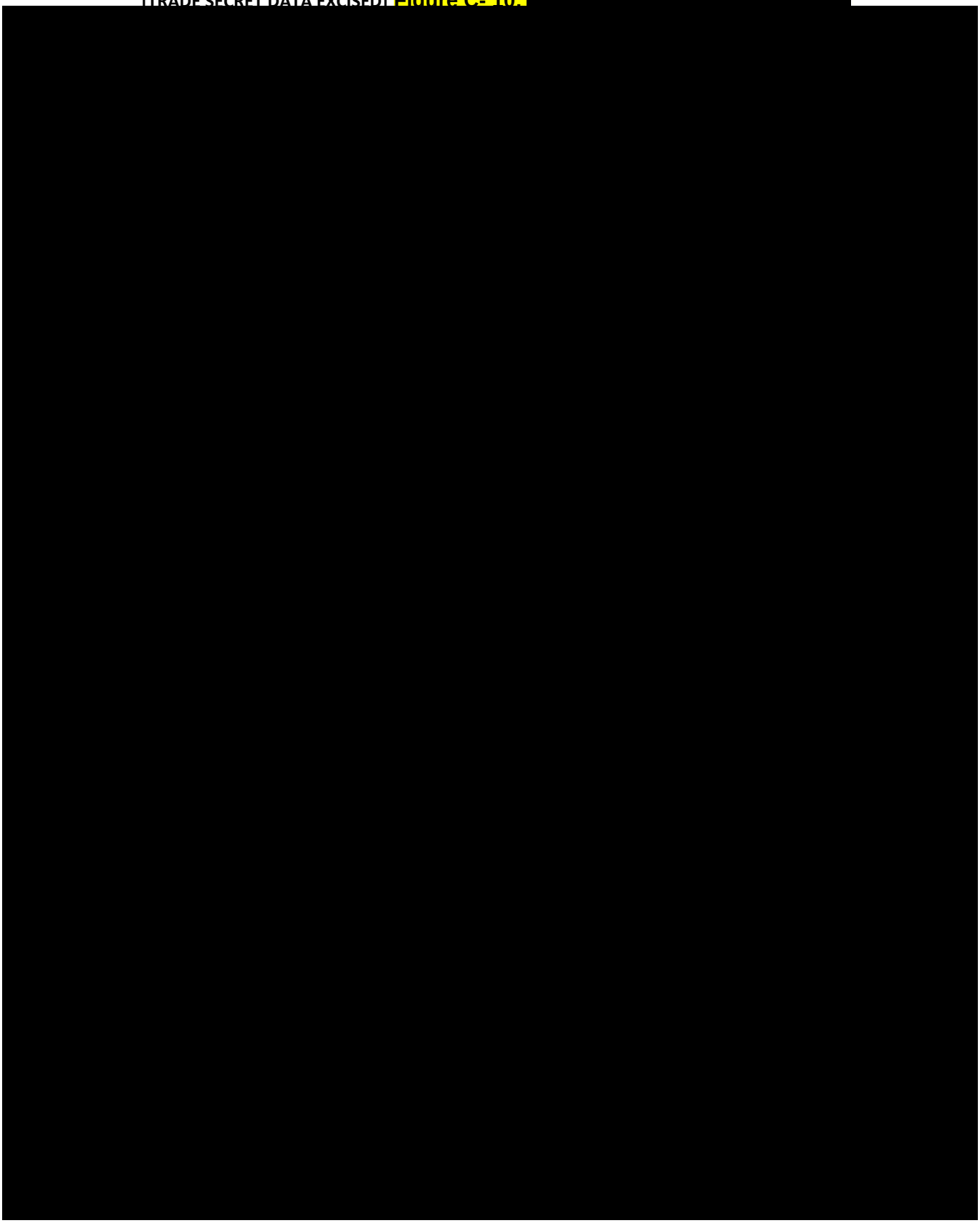

APPENDIX D - [TRADE SECRET DATA EXCISED]

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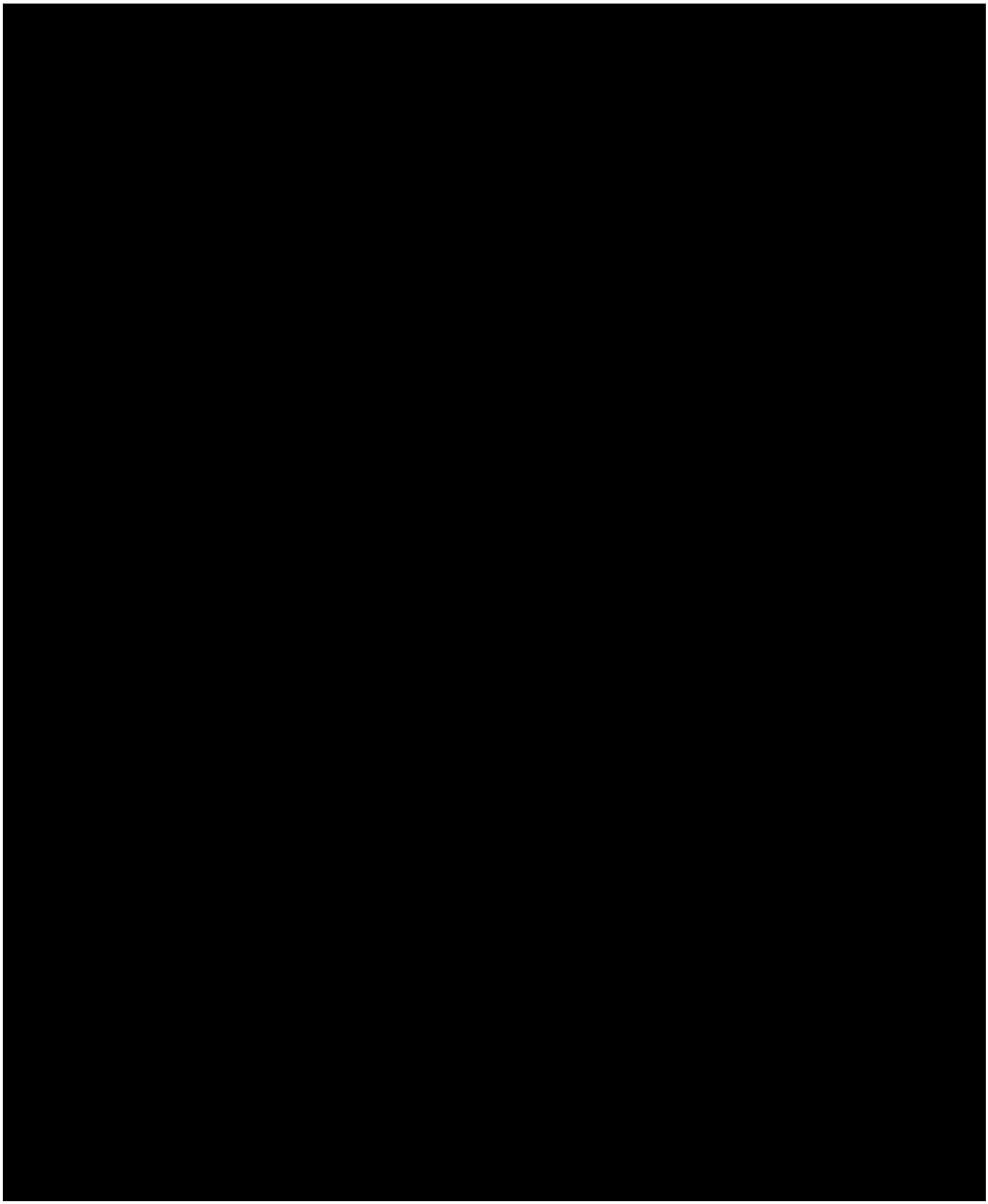

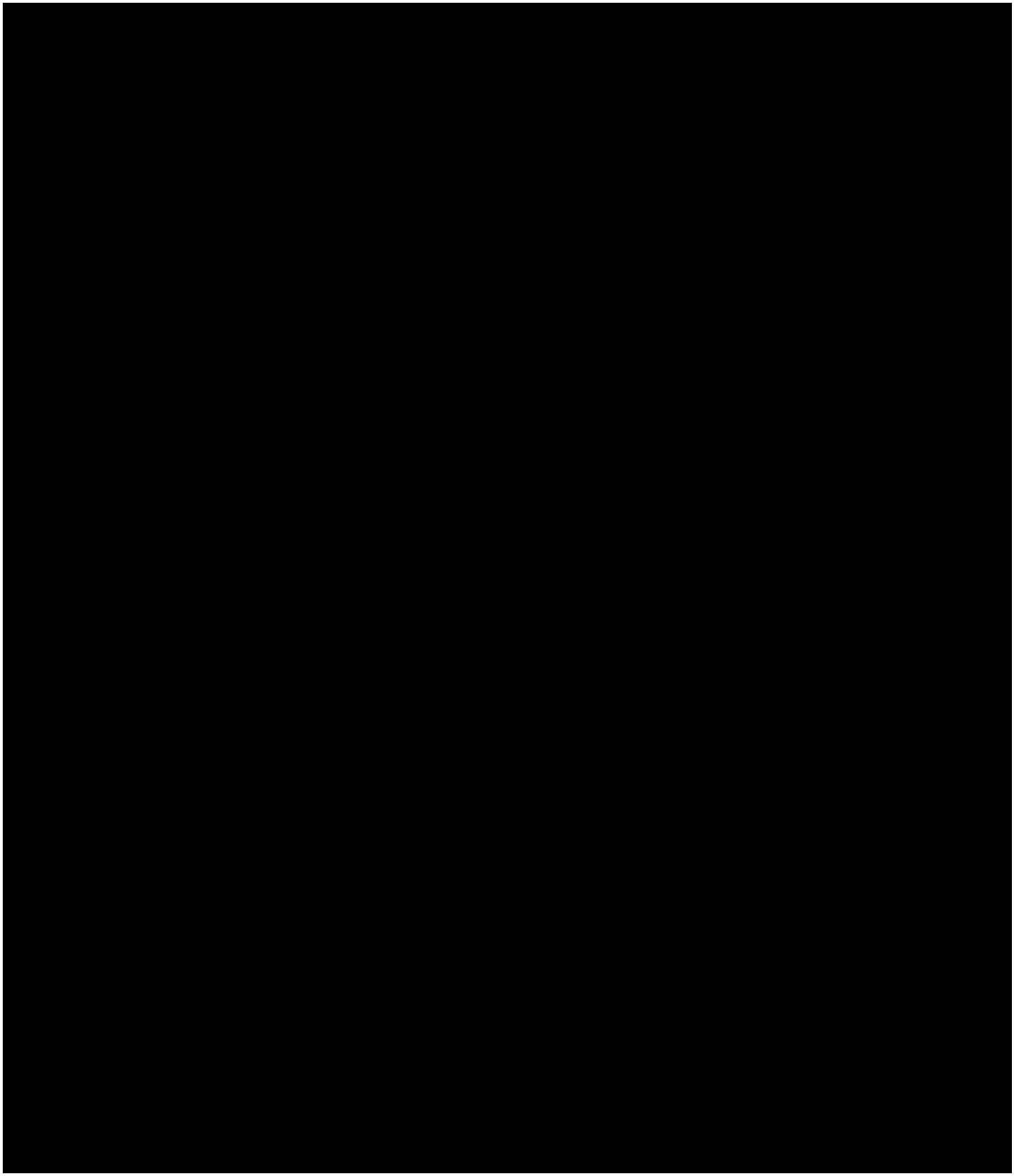

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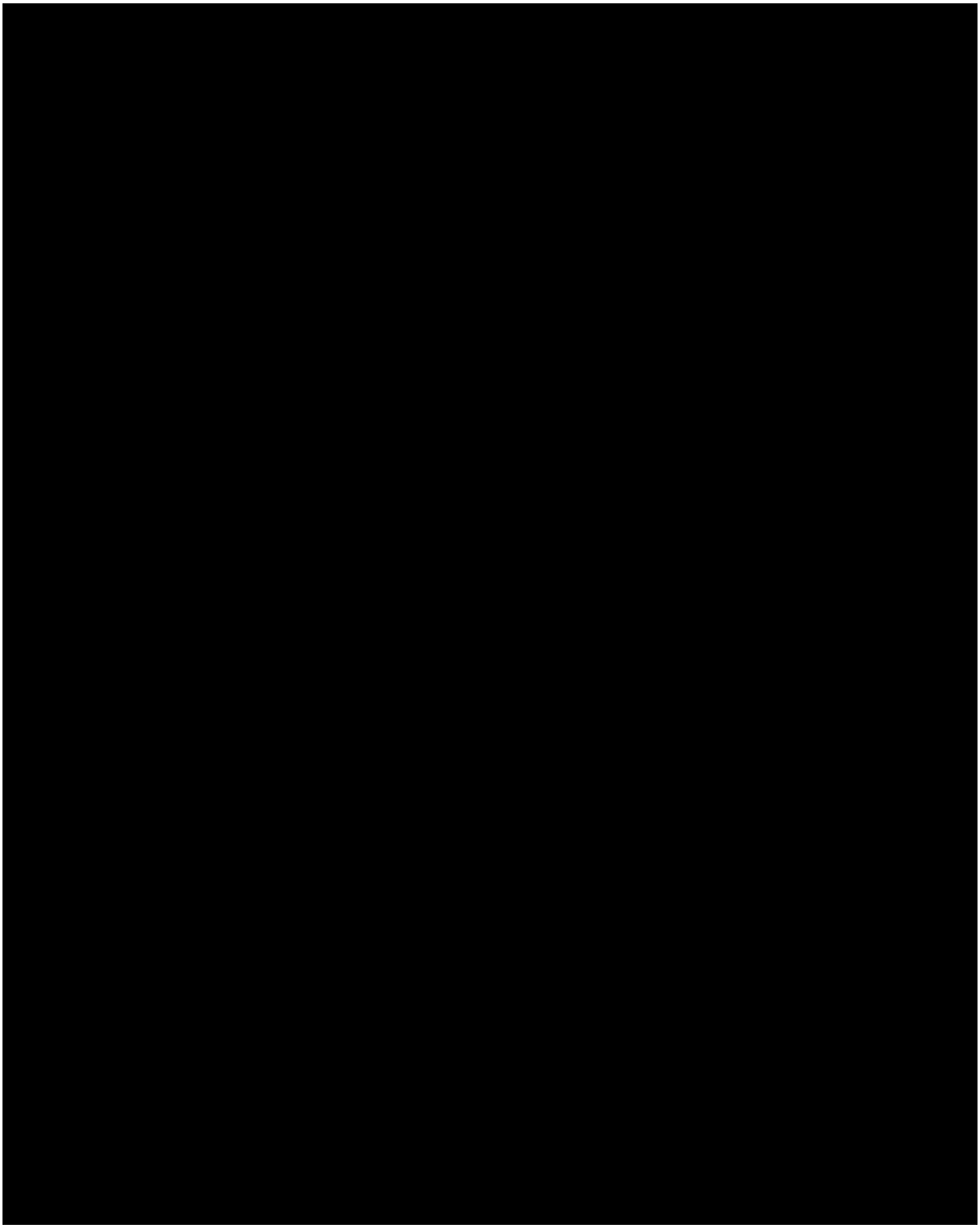

[TRADE SECRET DATA EXCISED] **Figure D- 2:** [redacted]

APPENDIX E - [TRADE SECRET DATA EXCISED]

[TRADE SECRET DATA EXCISED]

Figure E-1: Geographic Division of Northern Tier Preferred Sites

[TRADE SECRET DATA EXCISED]

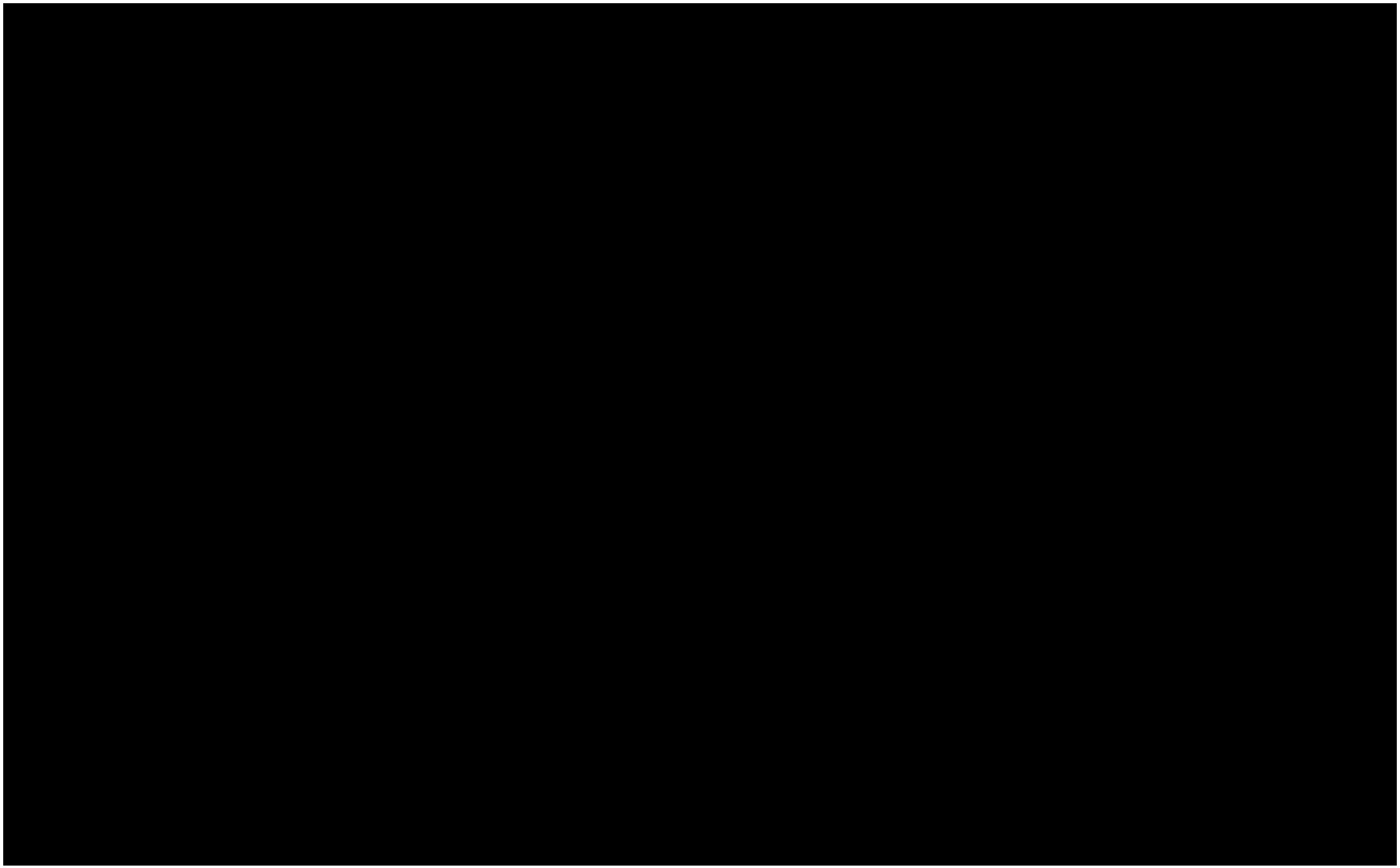

Table E-1: Western Region Site Scores

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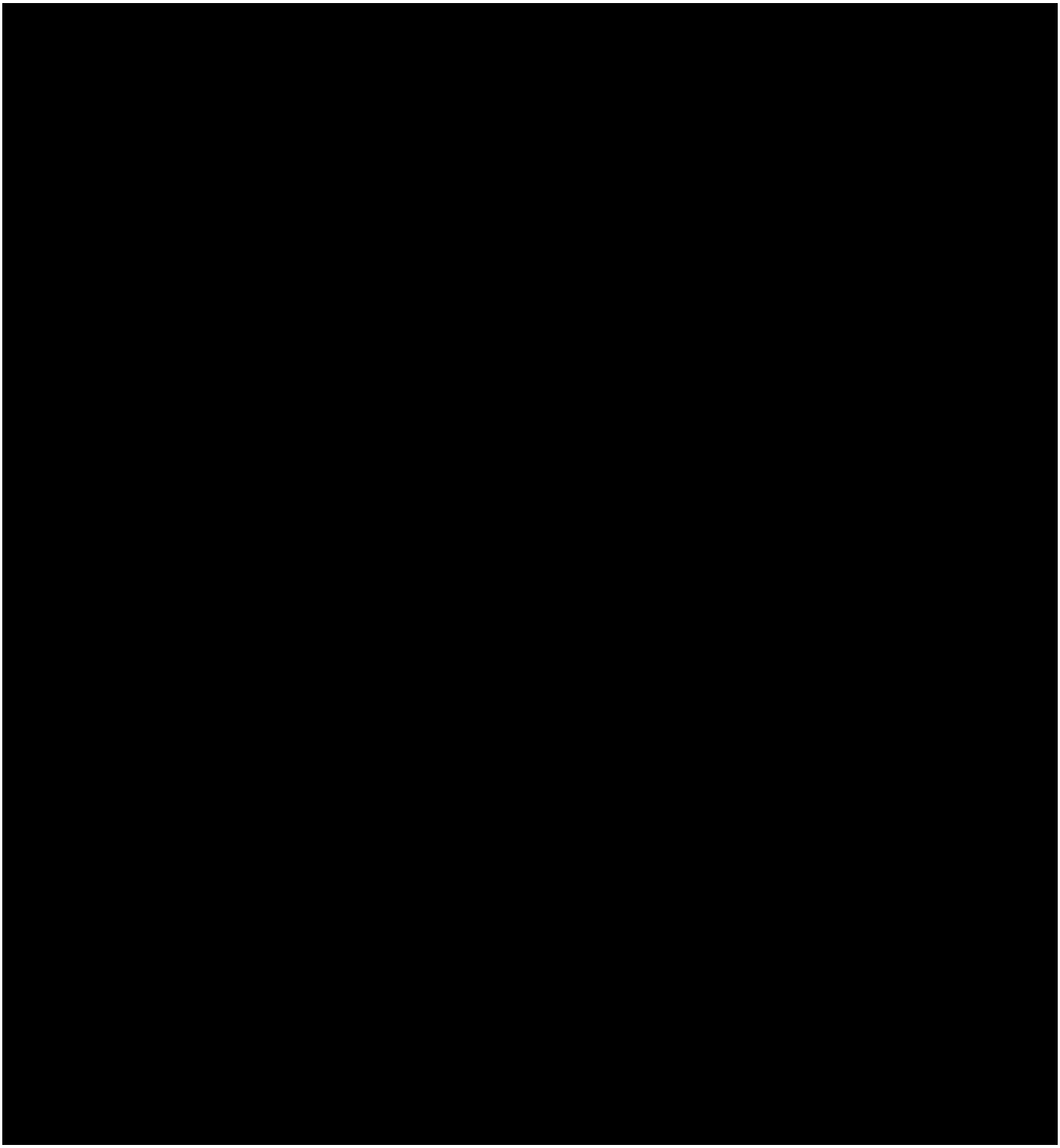


Figure E-2: Western Region Site Rankings

[TRADE SECRET DATA EXCISED]

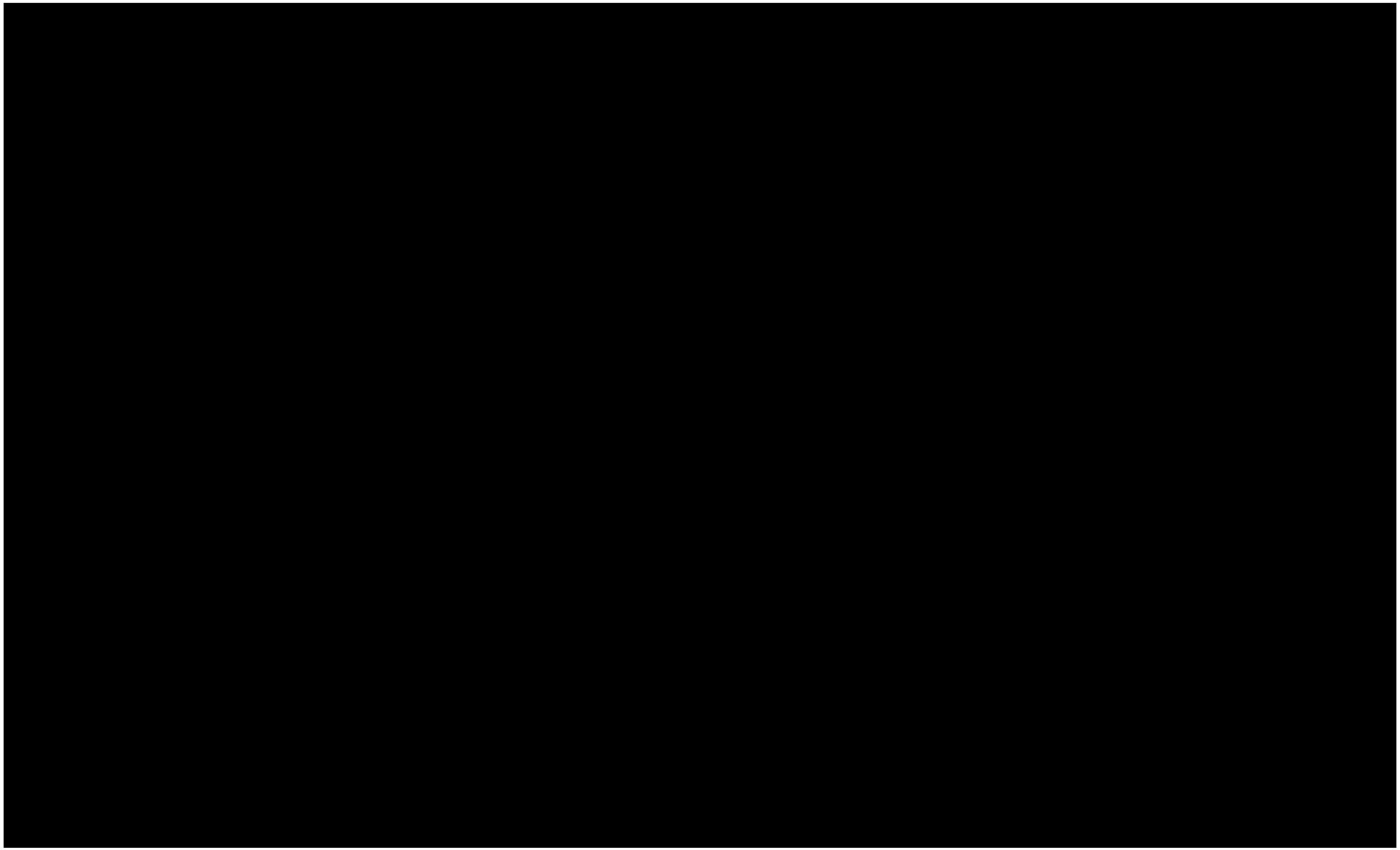
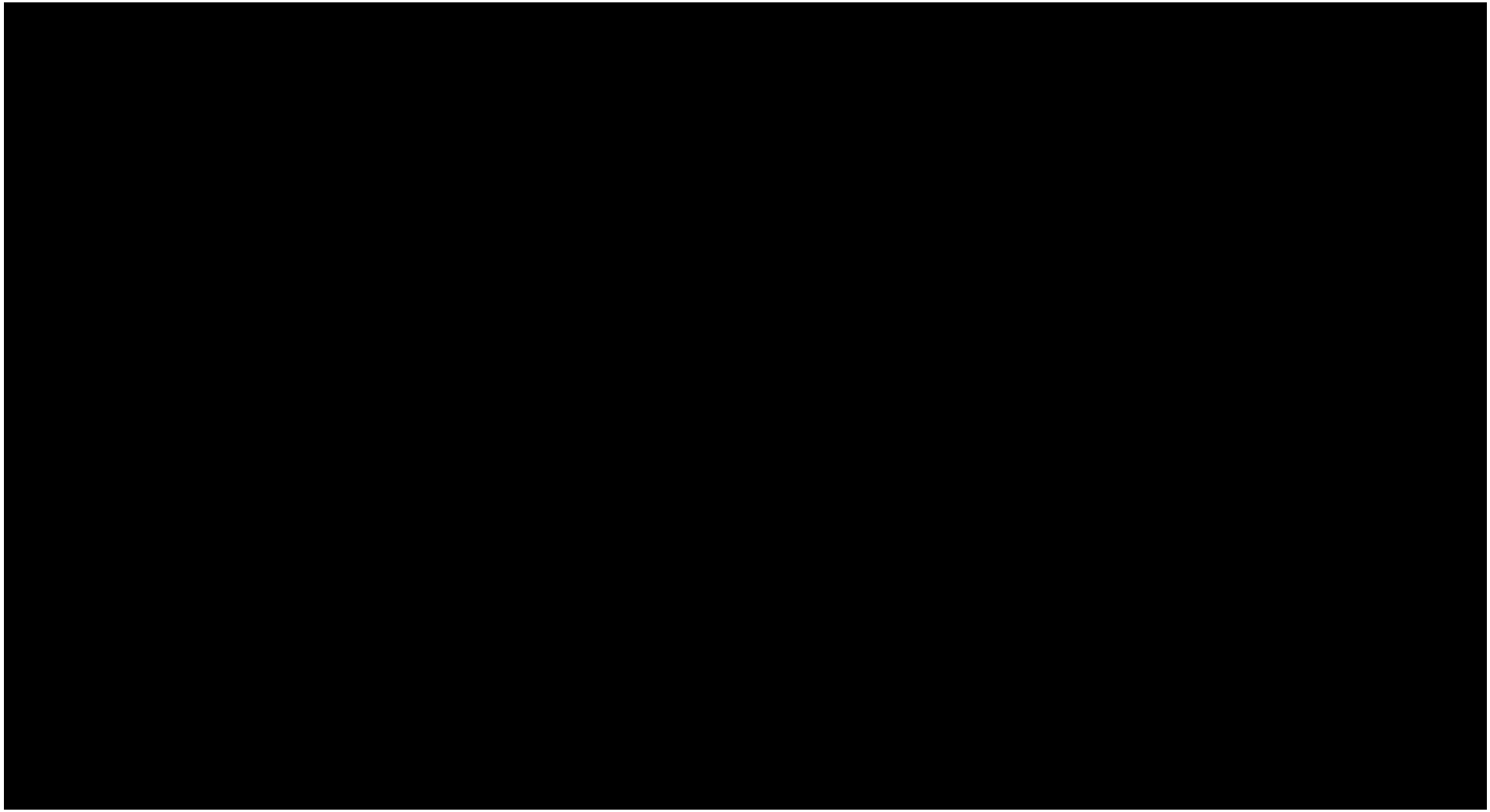


Table E-2: Eastern Region Site Scores

[TRADE SECRET DATA EXCISED]

Figure E-3: Eastern Region Sites Rankings

[TRADE SECRET DATA EXCISED]



Burns & McDonnell World Headquarters
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APPENDIX X: NTEC REQUEST FOR PROPOSALS FOR NATURAL GAS TRANSPORTATION SERVICE

NORTHERN TIER ENERGY CENTER

REQUEST FOR PROPOSALS
For
Natural Gas Transportation Service

Release Date:	April 16, 2015
Proposal Submission Date:	May 18, 2015 5:00 p.m. CDT

STATEMENT OF CONFIDENTIALITY

All information exchanged under this RFP process shall be governed by the Non-disclosure Agreement to be executed between Minnesota Power on behalf of the Northern Tier Energy Center project participants and the Respondent. A copy of the Non-disclosure Agreement is being issued as part of this RFP package (see Appendix A). Minnesota Power requires each Respondent to execute two (2) copies of the enclosed Non-disclosure Agreement. Upon receipt of the Non-disclosure Agreements from each Respondent, Minnesota Power will sign and execute them and return one (1) original to the Respondent.

Table of Contents Page

Appendices

I. INTRODUCTION

Northern Tier Energy Center ("NTEC"), a consortium of upper Midwest electric utilities, including Minnesota Power, are evaluating the development of a combined-cycle natural gas power generating facility ("Facility") at one of two (2) possible locations in the state of Wisconsin, i.e., the Superior site or the Edgerton site. NTEC is requesting proposals for natural gas transportation services to support the selection later this year of the Facility site and the Facility's natural gas transportation service providers.

NTEC's Facility will be a natural gas-fired combined cycle facility that will serve the load needs of its owners as well as serve the Midcontinent Independent System Operators ("MISO") energy, capacity, and ancillary service markets. The Facility will include two (2) "F" class combustion turbines combined with a heat recovery steam generator and a steam turbine to produce up to 856 megawatts per hour. It is expected to be an intermediate dispatch facility with annual capacity factors between 25 and 50 percent. Assuming an average hourly fuel consumption rate of 4,400 MMBtu's per hour, NTEC would expect to transport between 10 and 19 billion cubic feet of natural gas per year to the Facility.

All proposals submitted by interested pipeline companies are non-binding. Only proposals received through NTEC's assigned email address will be considered.

The schedule for the Request for Proposal ("RFP") process is included below:

Issue RFP	April 16, 2015
Notice of Intent to Submit Due	April 23, 2015
Non-disclosure Agreement Due	April 23, 2015
Proposals Due	May 18, 2015
Selection of Pipeline(s)	July 1, 2015

Potential Respondents should submit a Notice of Intent to Submit to NTEC by April 23, 2015. A Notice of Intent to Submit form is included with this RFP as Appendix B.

II. PURPOSE AND SCOPE

The purpose of this RFP is to procure information and interest needed to select the NTEC Facility site and the Facility's natural gas transportation service providers later this year. It is the intention of NTEC members to include the Facility in future integrated resource plans. The integrated resource plans will require specific details about natural gas transportation services required by NTEC. In addition, NTEC seeks to select transportation service providers prior to beginning development of the project. After NTEC selects a site and natural gas transportation service providers, it is NTEC's intention to work solely with the selected pipeline(s) through the development and construction phases of the project, negotiating agreements as needed in a timely manner, until the project is brought to commercial operation. Given this desire by NTEC, this RFP seeks valid and supportable proposals for natural gas transportation service to either Facility proposed site so that NTEC can evaluate such proposal to support the final site selection and the selection of transportation service providers to work with through the course of project development.

III. NTEC CONTACT INFORMATION

NTEC requires each Respondent to execute two (2) copies of the Non-disclosure Agreement (included as Appendix A) and send them to the attention of:

Sandy Winek
Fuels Delivery and Supply Analyst II – Strategy and Planning
ALLETE/Minnesota Power
30 West Superior Street
Duluth, MN 55802
swinek@mnpower.com
218-355-3419

All other contacts concerning this RFP, including the Notice of Intent Form (included as Appendix B), questions, and proposal submissions (including a completed Appendix C for each of the two sites under consideration), should be submitted electronically to the contact designated by NTEC as listed below:

Robert Mulholland
Vice President
L. E. Peabody & Associates, Inc.
rmulholland@lepeabody.com
(703)517-1118

IV. DESCRIPTION OF DESIRED SERVICE

NTEC will need natural gas transportation services sufficient to insure economic dispatch of the Facility into MISO's day-ahead energy markets for any given day. To accomplish this, NTEC will require deliverability of up to 4,400 MMBtu's per hour, most likely for up to 24 hours consistently, but for no less than four (4) hours consistently. Also, given that the Facility will have duct-firing capability, the Facility will require the ability to add up to an additional 1,700 MMBtu's per hour on an hourly basis. It is expected that duct firing will be utilized less than 10 percent of the time for any given year.

NTEC understands generally the risks associated with the delivery of natural gas and seeks to strike a balance between the cost to ensure natural gas deliverability and the opportunity that would be lost should the facility not dispatch do to natural gas deliverability. Given this view and the understanding that the availability of pipeline capacity varies by season, NTEC seeks to match service levels to the Facility's seasonal needs and to the seasonal availability of pipeline capacity. NTEC would also need the ability to balance supply variances to allowable daily and hourly schedules, with limitations, on a monthly basis.

A representation of NTEC's expected capacity factors is as follows:

Winter:	30% - 60%
Spring:	20% - 40%
Summer:	40% - 70%

Fall: 20% - 40%

A framework of NTEC's service needs are provided below:

Term: Ten-to-fifteen years beginning Spring 2021

Delivery Points (potential Facility sites):

Superior Generation	Hurd Site
1616 31st Avenue East	9300 U.S. 51
Superior, WI 54889	Edgerton, WI 53534

Receipt Points: Any transportation agreement would need to include receipt points that offer NTEC adequate market liquidity to meet the needs of an intermediate dispatch combined-cycle generating facility. Respondents should describe or demonstrate liquidity and operational flexibility for hubs and supply regions served.

Volume: Maximum Daily Quantity of up to 106,000 MMbtu per day, maximum hourly quantity of 4,400 MMBtu per hour, Swing volume (for duct-firing) up to 1,700 MMBtu per hour. Please note that typical runtimes will be 16 hours per day.

Capacity Ratability: Shipper desires an average of 16 hours for daily takes. NTEC will place significant value on the ability to schedule one day's worth of natural gas over less than 24 hours.

Pressure at Delivery Point: Minimum 535 psig

V. INFORMATION TO BE INCLUDED BY RESPONDENTS

A. Service Parameters

Respondents must fill out a separate Schedule of Proposal Parameters (included as Appendix C to this RFP) for each of the two sites under consideration. NTEC understands that Respondents may not be able to guarantee service parameters applicable to the 2021 time period. However, to allow NTEC to properly evaluate site and transportation options, Respondents should provide the latest forward rates, fees, and other parameters currently available. Respondents should list receipt points and describe or demonstrate liquidity and operational flexibility for hubs and supply regions served. Respondents are also encouraged to add additional pertinent parameters as well as provide qualifiers for parameters provided.

NTEC will make assumptions about inflation of rates and fees. Respondents are encouraged to provide perspective around the inflation of such rates and fees for the purpose of evaluation only. All rates and fees should be expressed on a seasonal basis.

B. Estimate of lateral costs

NTEC is evaluating multiple options for constructing a lateral pipeline to serve the facility. These include self-build and pipeline-build. In addition to the information provided in Appendix C, please include an estimate of costs to construct a lateral pipeline to the facility, along with a discussion of the process and timeline associated with that endeavor. Please also include a discussion of any requirements related to timing and/or benchmarks that must be met to move forward with the various phases of the effort.

C. Estimate of lateral FT service

Please provide a description of the service and rates associated with providing transportation service through the constructed lateral pipeline discussed in item V. B. above. Please identify the location of inter-connect and meter under each of the two lateral pipeline scenarios: (1) plant self-build, and (2) pipeline-build. Please also indicate contract term requirements under a pipeline-build scenario.

VI. OTHER TERMS AND CONDITIONS

A. Right to Select and Extend

NTEC reserves the right, without qualification, to select or reject any or all proposals or any combination of proposals and to wave any formality, technicality, requirement, or irregularity in the proposals received. NTEC also reserves the right to request further information, as necessary, to complete its evaluation of the proposals received. NTEC reserves the right to grant timeline extensions on a case by case basis.

B. Hold Harmless

Those who participate in this process shall have no recourse or claim of liability against NTEC, or any of their agents, employees or officials for the rejection or failure to execute an agreement for transportation service for any reason.

C. Cost of Proposal

The Respondent prepares and submits the proposal at Respondent's own cost.

D. Disclaimer

This RFP does not commit NTEC to any specific course of action, and NTEC may withdraw this RFP at any time, without prior notice.

VII. PROPOSAL EVALUATION

All proposals will be evaluated based on economics, levels of service and operational flexibility. Evaluations will consider delivered cost of natural gas based on forward prices for natural gas supply. Evaluations will consider the impact varying delivered prices have on the expected dispatch of the facility. Evaluations will also consider flexibility offered by multiple receipt

points, where applicable. Evaluations for each potential Facility site will be done under two (2) scenarios: assuming NTEC builds a lateral for connection to a pipeline and assuming the pipeline builds the lateral to the Facility.

Appendix A

NORTHERN TIER ENERGY CENTER
CONTRACTOR OR BIDDER
NON-DISCLOSURE AGREEMENT

This Non-Disclosure Agreement ("Agreement") is entered into as of _____, 2015, by Minnesota Power (an operating division of ALLETE, Inc., a Minnesota corporation) as agent for the participants in the Northern Tier Energy Center project, including itself, (the "Project"), and _____, a _____ (the "Respondent"). Minnesota Power and the Respondent are referred to individually as a "Party" and collectively as the "Parties."

The Parties agree as follows:

1. As used herein, the term "Confidential Information" means information which is of a non-public, proprietary or confidential nature to Minnesota Power or the other Project participants (each a "Disclosing Participant" and collectively the "Disclosing Participants"), which information includes all reports and analyses, documents, technical and economic data, studies, forecasts, trade secrets, research or business strategies, customer information, financial or contractual information or other written or oral information regarding the Disclosing Participants. Confidential Information may be in any form whatsoever, including but not limited to writings, computer programs, logic diagrams, component specifications, drawings or other media. All information disclosed by the Disclosing Participants to the Respondent, whether orally, in writing, by inspection or otherwise, shall be deemed to be Confidential Information unless otherwise expressly agreed in writing by the Disclosing Participant.

"Confidential Information" shall expressly include:

- the nature of the Project;
- the identities of the Disclosing Participants; and
- the fact that the Disclosing Participants are considering the Project.

As used in this Agreement, the term "Representative" means, as to any person, such person's Affiliates (as defined below) and its and their directors, officers, employees, agents, advisors (including, without limitation, financial advisors, legal counsel and accountants) and controlling persons, and (b) the term "Affiliates" means all entities that are controlling, controlled by or under common control with a person.

2. Notwithstanding the provisions of Section 1 above, the term "Confidential Information" shall not include, and the Respondent shall not be under any obligation to maintain in confidence or not use, any information (or any portion thereof) disclosed to it by the Disclosing Participants to the extent that the Respondent can demonstrate that such information:

(i) is in the public domain at the time of disclosure by a Disclosing Participant; or

(ii) following disclosure by a Disclosing Participant, becomes generally known or available through no breach of this Agreement by the Respondent; or

(iii) is known, or becomes known, to the Respondent from a source other than a Disclosing Participant or their Representatives (as defined herein), provided that disclosure by such source is not in breach of a confidentiality or non-disclosure agreement with a Disclosing Participant; or

(iv) is independently developed by the Respondent without violating any of its obligations under this Agreement.

Confidential Information shall not be deemed to fall within the exceptions of subparts (i) to (iv) above merely because it is included in a document which also includes information that does fall within such exceptions.

3. The Respondent shall be permitted to disclose Confidential Information required to be disclosed by it or its Affiliates pursuant to applicable law or regulation, a subpoena or order of a court, or for evidentiary purposes in any relevant action, proceeding or arbitration to which the Respondent or any of its partners, officers, directors, shareholders or Affiliates is a party. In the event that the Respondent receives a request to disclose any Confidential Information under such subpoena, order or otherwise, the Respondent shall: (a) promptly notify Minnesota Power thereof, (b) consult with Minnesota Power on the advisability of taking steps to resist or narrow such request, and (c) if disclosure is required, reasonably cooperate with the Disclosing Participant in any attempt that it may make to obtain an order or other reliable assurance that confidential treatment will be accorded to the Confidential Information; provided, however, that such reasonable cooperation does not cause the Respondent to be in violation of applicable law, regulation, subpoena or order.

Further, the Respondent shall be permitted to disclose that portion of the Confidential Information that it is advised by its outside counsel that it is legally required to disclose: (i) to be in compliance with any applicable law or regulation and/or (ii) to any regulatory, self-regulatory or legislative body of competent jurisdiction in connection with any regulatory or legislative docket, report, audit or other request for information. In the event that the Respondent receives such a request, the Respondent shall promptly notify Minnesota Power thereof, provided that such notification does not violate the terms of such request, and the Respondent shall reasonably cooperate with the Disclosing Participant to ensure that confidential treatment will be accorded to the Confidential Information.

4. The Respondent shall keep the Confidential Information confidential and shall use the Confidential Information solely in connection with the Project. The Respondent shall not disclose the Confidential Information to any person, except that the Respondent may disclose Confidential Information to any of its Representatives who require access to such information in connection with the Project, or who otherwise have reason to know (including legal, compliance, credit, accounting, and audit personnel and any other personnel who perform similar control and/or risk management functions in the normal course of performing their respective duties) the Confidential Information. Before disclosing any Confidential Information to its Representative, the Respondent shall inform such Representative of the confidential or proprietary nature thereof and of the Respondent's obligations under this Agreement. The Respondent shall be responsible

for any use or disclosure of Confidential Information by any of its Representatives, and shall indemnify the Disclosing Participants with respect to all losses, claims and damages arising out of a breach by the Respondent or any of its Representatives of the terms of this Agreement.

5. All rights to Confidential Information disclosed pursuant to this Agreement are reserved to the Disclosing Participants. No license or conveyance of any rights relating to the Confidential Information is granted or implied by the Disclosing Participants to the Respondent.

6. This Agreement shall commence as of the date first set forth above and shall continue in effect until the earlier of (i) two years from the date hereof, or (ii) written notice from either Party to the other Party stating that it is no longer interested in pursuing the Project. The obligations of confidentiality, non-disclosure and non-use contained herein shall survive and continue for a period of three years after termination or expiration of this Agreement.

7. Nothing in this Agreement shall obligate any Disclosing Participant to disclose any Confidential Information to the Respondent, and any disclosure of Confidential Information shall be at the Disclosing Participants' sole discretion. This Agreement does not grant to the Respondent any rights whatsoever with respect to the Project.

8. To the extent legally permissible, as promptly as practicable but in any event within 30 days after Minnesota Power's request, the Respondent shall return to Minnesota Power or destroy all Confidential Information in the possession of the Respondent or its Representatives, including all copies of such Confidential Information, all notes or other documents with respect to or reflecting such Confidential Information, and all materials derived from such Confidential Information. Notwithstanding the foregoing, the Respondent shall be entitled to retain one copy of such Confidential Information in its Legal Department to the extent such retention is consistent with the Respondent's policies; provided that all such retained Confidential Information shall remain subject to the terms of this Agreement. Upon completing the foregoing, an officer of the Respondent shall certify to Minnesota Power in writing the Respondent's compliance with this Section.

9. This Agreement is binding on, and inures to the benefit of, the Parties' respective successors and permitted assigns. This Agreement may not be assigned by either Party without the prior written consent of the other Party except in connection with the sale of all or substantially all of the business or assets of the assigning Party. Any purported assignment without the consent required hereunder shall be null and void.

10. The Disclosing Participants who are not Parties to this Agreement are intended third-party beneficiaries of this Agreement.

11. Without prejudice to the rights and remedies otherwise available, any Disclosing Participant shall be entitled to equitable relief by way of injunction if there is a breach or threat of a breach of any of the provisions of this Agreement by the Respondent. The Parties agree and acknowledge that damages would not be an adequate remedy in the event of a breach of this Agreement.

12. All notices and other communications hereunder shall be in writing and shall be deemed given (as of the time of delivery or, in the case of a faxed communication, of transmission confirmation) if delivered personally, or sent by nationally recognized overnight courier (with proof of delivery) to the arties at the following addresses or such other address as a party may specify by like notice:

If to Minnesota Power:

Minnesota Power
30 West Superior Street
Duluth, MN 55802
Attention: General Counsel

If to Respondent:

_____
_____
_____
Attention:_____

13. This Agreement shall be governed by the laws of the State of Minnesota, without regard to the conflicts of law principles thereof, and any litigation arising out of or in connection in any way with this Agreement shall take place in a State or Federal court of competent jurisdiction in Minnesota.

14. This Agreement may be executed in counterparts, including by facsimile, each of which shall be deemed to be an original and all of which shall constitute one and the same document.

15. This Agreement comprises the full and complete agreement of the Parties hereto with respect to the disclosure of the Confidential Information and supersedes and cancels all prior communications, understandings and agreements between the Parties hereto, whether written or oral, expressed or implied. No amendments, changes or modifications to this Agreement shall be valid except if the same are in writing and signed by a duly authorized representative of each of the Parties hereto.

16. The provisions of this Agreement are severable, and if any one or more of such provisions is determined to be judicially invalid or unenforceable, the remaining provisions shall nevertheless be binding and enforceable.

[Remainder of page intentionally blank]

IN WITNESS WHEREOF the Parties have signed this Non-disclosure Agreement as of the date first set forth above.

_____	**Minnesota Power**
By: _____	By: _____
Name:_____	Name:_____
Title:_____	Title:_____

Appendix B

Notice of Intent Form

Email to: rmulholland@lepeabody.com (Robert Mulholland)

Due: By 5:00 p.m. CDT, April 23, 2015

Note that completion of all information is required.

This response is an indication of our interest in the NTEC Request for Proposals in NTEC's April 16, 2015 RFP. This response also establishes contact information for future communications regarding this RFP.

Company: _____
(legal name of entity of intended signatory to a contract)

Contact Name: _____

Contact Title: _____

Address: _____

City: _____ State: ____ Zip: _____

Phone Number: _____

Email address: _____

Appendix C

Email to: rmulholland@lepeabody.com (Robert Mulholland)
Due: By 5:00 p.m. CDT, May 18, 2015
Note that completion of all information is required. Submit a separate form for each site.

NTEC NATURAL GAS TRANSPORTATION PROPOSAL PARAMETERS

	Item	Winter (Nov-Mar)	Summer (Apr-Oct)
1.	Pipeline and/or Natural Gas Supplier		
2.	Maximum Daily Quantity Capability (Dth/day)		
3.	Maximum Hourly Quantity Capability (Dth/hour)		
4.	Rate Schedules 1/		
5.	Term Start Date		
6.	Term End Date 2/		
7.	Receipt Point(s)		
8.	Delivery Point (Indicate Superior or Hurd)		
9.	Balancing Fees		
10.	Monthly Balancing Limitations		
11.	Storage Options and Rates		
12.	Maximum Delivery Point Pressure (psig)		
13.	Minimum Delivery Point Pressure (psig)		
14.	Pressure Guarantee (psig)		
15.	Heating value of the gas (HHV) Btu per scf		
16.	Chemical composition (C1-C8), i.e., CO2		
17.	Sulfur (total, including any odorizer)		
18.	H2O content		

1/ Please specify for different types and levels of service available to serve NTEC. Please also provide separately a description of service levels. Please indicate whether capacity expansion will be required to serve this facility.

2/ Please provide end date for which rates provided are effective. Also please indicate if evergreen clauses or rights of first refusal are available for rates and term.

APPENDIX Y: ASSIGNMENT OF RIGHTS AGREEMENT (CONSTRUCTION AGENT) BETWEEN SOUTH SHORE AND MINNESOTA POWER

FINAL 07/28/2017

ASSIGNMENT AND ASSUMPTION AGREEMENT
BY AND BETWEEN
SOUTH SHORE ENERGY, LLC, A SUBSIDIARY OF ALLETE, INC.
AND
MINNESOTA POWER, AN OPERATING PUBLIC UTILITY DIVISION OF ALLETE, INC.

(Development and Construction Agreement)

This Assignment and Assumption Agreement (hereinafter called the "**Assignment of Rights Agreement (Construction Agent**"), is made and entered into as of this 28th day of July, 2017 ("**Effective Date**"), by and between Minnesota Power, an operating division of ALLETE, Inc., a Minnesota corporation and a Minnesota rate-regulated investor-owned public utility (hereinafter "**Minnesota Power**"), and South Shore Energy, LLC a Wisconsin limited liability company, and a wholly-owned subsidiary of ALLETE, Inc. and an Affiliate of Minnesota Power (hereinafter "**South Shore**")(each of Minnesota Power and South Shore a "**Party**" and collectively the "**Parties**").

WHEREAS, South Shore is co-developing with Dairyland Power Cooperative ("**Dairyland**") a combined-cycle natural-gas power plant, known as the Nemadji Trail Energy Center ("**NTEC**"), located in Superior, Wisconsin, in which each of South Shore and Dairyland (collectively the "**NTEC Owners**") will own an undivided fifty percent (50%) interest, and

WHEREAS, the NTEC Owners are parties to the (i) *Nemadji Trail Energy Center Development and Construction Management Agreement by and Among Dairyland Power Cooperative and South Shore Energy, LLC, as Owners, and South Shore Energy, LLC as Construction Agent* dated as of June 1, 2017 (the "**D&C Agreement**"), and the (ii) *Nemadji Trail Energy Center Ownership and Operating Agreement by and Among Dairyland Power Cooperative and South Shore Energy, LLC, as Owners, and South Shore Energy, LLC as Operating Agent* dated as of June 1, 2017 (the "**O&O Agreement**"); and

WHEREAS, under the D&C Agreement, the NTEC Owners have designated South Shore as the Construction Agent on behalf of the NTEC Owners to take all actions necessary to develop and construct NTEC; and

WHEREAS, pursuant to Section pursuant to 3.7.5 of the D&C Agreement, "South Shore Energy shall assign all of its rights and obligations as Operating Agent under this Agreement and all other Project Agreements to Minnesota Power, as soon as reasonably practicable after receipt by Minnesota Power of all Governmental Approvals required for such assignment.;" and

WHEREAS, South Shore desires to assign all of its duties as Construction Agent under the D&C Agreement to Minnesota Power and, subject to receipt of all Governmental Approvals required for such assignment, Minnesota Power desires to assume all of the duties as Construction Agent under the D&C Agreement.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, Minnesota Power and South Shore hereby agree as follows:

1. Subject to the conditions set forth in this Assignment of Rights Agreement (Construction Agent), South Shore hereby assigns to Minnesota Power and Minnesota Power hereby assumes all of the rights, obligations and duties of the Construction Agent (as defined in the D&C Agreement) to the full extent set forth in the D&C Agreement. Upon satisfaction of such conditions, Minnesota Power shall henceforth perform all rights, obligations and duties of the Construction Agent under the D&C Agreement as if Minnesota Power had executed the D&C Agreement in its own name and in its own right.

2. This Assignment of Rights Agreement (Construction Agent) is expressly conditioned upon:

    a. Receipt by Minnesota Power of MPUC Approval of each of (i) this Assignment of Rights Agreement (Construction Agent), (ii) the Assignment of Rights Agreement (Operating Agent) of the O&O Agreement, between Minnesota Power and South Shore of even date herewith, and (iii) the Capacity Dedication Agreement between Minnesota Power and South Shore of even date herewith. MPUC Approval means a final, non-appealable written order of the MPUC making the affirmative determination that Minnesota Power's execution of the subject agreement is reasonable, in the public interest, and all costs incurred under such agreement are recoverable from the retail customers pursuant to Applicable Law, subject only to the requirement that the MPUC retains ongoing prudency review of Minnesota Power's performance and administration of such agreement.

    b. Receipt by South Shore of written ratification from Dairyland that Dairyland ratifies the Assignment of Rights Agreement (Construction Agent) as in conformance with South Shore's obligations under the D&C Agreement.

    c. This Assignment of Rights Agreement (Construction Agent) shall terminate automatically and without further liability to either of the Parties in the event that MPUC Approval is (i) rejected or conditionally approved with unreasonable conditions, or (ii) Minnesota Power fails to obtain MPUC Approval of any of the agreements by October 31, 2018.

3. Upon effectiveness of this Assignment of Rights Agreement (Construction Agent), all terms and conditions under the D&C Agreement applicable to the Construction Agent shall apply to Minnesota Power in its role as Construction Agent and all rights, obligations and duties arising under the D&C Agreement shall be directly enforceable against Minnesota Power.

4. Any disputes arising under this Assignment of Rights Agreement (Construction Agent) shall be resolved in accordance with the procedures set forth in the D&C Agreement.

5. This Assignment of Rights Agreement (Construction Agent) shall be governed by the laws of the State of Wisconsin without regard to its conflict of laws provisions.

IN WITNESS WHEREOF, each of the Parties has caused this Agreement to be executed and delivered by its duly authorized representative.

MINNESOTA POWER, an operating division of ALLETE, Inc.

Bradley W. Oachs

By: Bradley W. Oachs
Its: President-Regulated Operations

SOUTH SHORE ENERGY. LLC

A. Hodnik

By: Alan R. Hodnik
Its: Chief Executive Officer

APPENDIX Z: ASSIGNMENT OF RIGHTS AGREEMENT (OPERATING AGENT) BETWEEN SOUTH SHORE AND MINNESOTA POWER

FINAL 07/28/2017

ASSIGNMENT AND ASSUMPTION AGREEMENT
BY AND BETWEEN
SOUTH SHORE ENERGY, LLC, A SUBSIDIARY OF ALLETE, INC.
AND
MINNESOTA POWER, AN OPERATING PUBLIC UTILITY DIVISION OF ALLETE, INC.

(Ownership and Operations Agreement)

This Assignment and Assumption Agreement (hereinafter called the "**Assignment of Rights Agreement (Operating Agent**"), is made and entered into as of this 28th day of July, 2017 ("**Effective Date**"), by and between Minnesota Power, an operating division of ALLETE, Inc., a Minnesota corporation and a Minnesota rate-regulated investor-owned public utility (hereinafter "**Minnesota Power**"), and South Shore Energy, LLC a Wisconsin limited liability company, and a wholly-owned subsidiary of ALLETE, Inc. and an Affiliate of Minnesota Power (hereinafter "**South Shore**")(each of Minnesota Power and South Shore a "**Party**" and collectively the "**Parties**").

WHEREAS, South Shore is co-developing with Dairyland Power Cooperative ("**Dairyland**") a combined-cycle natural-gas power plant, known as the Nemadji Trail Energy Center ("**NTEC**"), located in Superior, Wisconsin, in which each of South Shore and Dairyland (collectively the "**NTEC Owners**") will own an undivided fifty percent (50%) interest, and

WHEREAS, the NTEC Owners are parties to the (i) *Nemadji Trail Energy Center Development and Construction Management Agreement by and Among Dairyland Power Cooperative and South Shore Energy, LLC, as Owners, and South Shore Energy, LLC as Construction Agent* dated as of June 1, 2017 (the "**D&C Agreement**"), and the (ii) *Nemadji Trail Energy Center Ownership and Operating Agreement by and Among Dairyland Power Cooperative and South Shore Energy, LLC, as Owners, and South Shore Energy, LLC as Operating Agent* dated as of June 1, 2017 (the "**O&O Agreement**"); and

WHEREAS, under the O&O Agreement, the NTEC Owners have designated South Shore as the Operating Agent on behalf of the NTEC Owners to take all actions necessary to operate and maintain NTEC; and

WHEREAS, pursuant to Section pursuant to 4.7.5 of the O&O Agreement, "South Shore Energy shall assign all of its rights and obligations as Operating Agent under this Agreement and all other Project Agreements to Minnesota Power, as soon as reasonably practicable after receipt by Minnesota Power of all Governmental Approvals required for such assignment;" and

WHEREAS, South Shore desires to assign all of its duties as Operating Agent under the O&O Agreement to Minnesota Power and, subject to receipt of all Governmental Approvals required for such assignment, Minnesota Power desires to assume all of the duties as Operating Agent under the O&O Agreement.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, Minnesota Power and South Shore hereby agree as follows:

1. Subject to the conditions set forth in this Assignment of Rights Agreement (Operating Agent), South Shore hereby assigns to Minnesota Power and Minnesota Power hereby assumes all of the rights, obligations and duties of the Operating Agent (as defined in the O&O Agreement) to the full extent set forth in the O&O Agreement. Upon satisfaction of such conditions, Minnesota Power shall henceforth perform all rights, obligations and duties of the Operating Agent under the O&O Agreement as if Minnesota Power had executed the O&O Agreement in its own name and in its own right.

2. This Assignment of Rights Agreement (Operating Agent) is expressly conditioned upon:

    a. Receipt by Minnesota Power of MPUC Approval of each of (i) this Assignment of Rights Agreement (Operating Agent), (ii) the Assignment of Rights Agreement (Construction Agent) of the D&C Agreement, between Minnesota Power and South Shore of even date herewith, and (iii) the Capacity Dedication Agreement between Minnesota Power and South Shore of even date herewith. MPUC Approval means a final, non-appealable written order of the MPUC making the affirmative determination that Minnesota Power's execution of the subject agreement is reasonable, in the public interest, and all costs incurred under such agreement are recoverable from the retail customers pursuant to Applicable Law, subject only to the requirement that the MPUC retains ongoing prudency review of Minnesota Power's performance and administration of such agreement.

    b. Receipt by South Shore of written ratification from Dairyland that Dairyland ratifies the Assignment of Rights Agreement (Operating Agent) as in conformance with South Shore's obligations under the O&O Agreement.

    c. This Assignment of Rights Agreement (Operating Agent) shall terminate automatically and without further liability to either of the Parties in the event that MPUC Approval is (i) rejected or conditionally approved with unreasonable conditions, or (ii) Minnesota Power fails to obtain MPUC Approval of any of the agreements by October 31, 2018.

3. Upon effectiveness of this Assignment of Rights Agreement (Operating Agent), all terms and conditions under the O&O Agreement applicable to the Operating Agent shall apply to Minnesota Power in its role as Operating Agent and all rights, obligations and duties arising under the O&O Agreement shall be directly enforceable against Minnesota Power.

4. Any disputes arising under this Assignment of Rights Agreement (Operating Agent) shall be resolved in accordance with the procedures set forth in the O&O Agreement.

5. This Assignment of Rights Agreement (Operating Agent) shall be governed by the laws of the State of Wisconsin without regard to its conflict of laws provisions.

IN WITNESS WHEREOF, each of the Parties has caused this Agreement to be executed and delivered by its duly authorized representative.

MINNESOTA POWER, an operating division of ALLETE, Inc.

Bradley W. Oachs

By: Bradley W. Oachs
Its: President-Regulated Operations

SOUTH SHORE ENERGY. LLC

Hodnik

By: Alan R. Hodnik
Its: Chief Executive Officer

APPENDIX AA: MINNESOTA POWER ELECTRIC RATE BOOK, VOL. 1, SECTION V, PAGE 50-50.1, PROPOSED CLEAN AND REDLINE TARIFF CHANGES

CLEAN TARIFF SHEETS

RIDER FOR FUEL AND PURCHASED ENERGY

FUEL AND PURCHASED ENERGY COST

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules Rate Codes 73 and 79 and Erie Mine Site Service Schedule - Rate Code 72.

There shall be added to the monthly bill a Fuel and Purchased Energy (FPE) Cost per kilowatt-hour determined as the Forecasted FPE Cost divided by the Forecasted Kilowatt-Hour Sales.

There shall also be added to or deducted from the monthly bill a True-up FPE Cost per kilowatt-hour determined as the amount by which the Forecasted FPE Cost per kWh is greater than or less than the actual calculated FPE Cost per kWh.

The Forecasted System Average FPE Cost shall be the Forecasted FPE Cost divided by the Forecasted Kilowatt-Hour Sales. The True-up FPE Cost shall be the Actual System Average FPE Cost less the Forecasted System Average FPE costs. The applicable True-up FPE Cost applied to the Forecasted Kilowatt-Hour Sales for the billing month will be included monthly on each customer's bill according to customer's rate class.

FORECASTED AVERAGE FUEL AND PURCHASED ENERGY COST

The Forecasted FPE Cost shall be the **sum** of the following forecasted amounts for the billing month:

(a) The fossil and nuclear fuel consumed in Company's generating stations,
(b) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis, this encompasses energy being purchased to substitute for Company's own higher cost energy,
(c) The identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (b) above,
(d) The cost of steam from other sources used in the generation of electricity at the Company's generating stations,
(e) The cost of the Released Energy Credit paid to Customer(s) for avoided energy purchases under the Rider for Released Energy,

RIDER FOR FUEL AND PURCHASED ENERGY

(f) The cost of the Buyback Energy Credit paid to Customer(s) for avoided energy purchases under the Rider for Voluntary Energy Buyback,
(g) Fuel and purchased energy expenses incurred by the Company over the duration of any Commission approved contract, as provided for by Minnesota Statutes, Section 216B.1645, to satisfy the renewable energy obligations set forth in Minnesota Statutes, Section 216B.1691,
(h) All RTO (Regional Transmission Organization) market costs net of revenues
(i) The cost of the purchase of SO_2 and NOx allowances,
(j) Reagents and chemicals for environmental compliance,
(k) Premiums related to business interruption insurance,
(l) Amortization of the FPE transition cost recovery amount
(m) Natural gas fuel consumed for the Company's share of the Nemadji Trail Energy Center.

and **less**

(n) Revenues from the sale of SO_2 allowances and NOx allowances,
(o) Proceeds from recoveries under business interruption insurance
(p) The cost of fossil and nuclear fuel and the cost of steam from other sources recovered through inter-system sales including the fuel and steam costs related to economy energy sales and other energy sold on an economic dispatch basis and
(q) Net revenues from the sale of environmental attributes from any Commission approved contract.
(r) Net Revenues from sales of the Company's share of energy and other attributes related to the Nemadji Trail Energy Center into the MISO market.

The Kilowatt-Hour Sales shall be Company's total kilowatt-hour Sales of Electricity, excluding inter-system sales referred to in (o) above; all for the billing month.

ACTUAL FUEL AND PURCHASED ENERGY COST

The FPE Cost shall be the **sum** of the actual costs for the following for the billing month:
(a) The fossil and nuclear fuel consumed in Company's generating stations,
(b) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis, this encompasses energy being purchased to substitute for Company's own higher cost energy,
(c) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (b) above,
(d) The cost of steam from other sources used in the generation of electricity at the Company's generating stations,
(e) The cost of the Released Energy Credit paid to Customer(s) for avoided energy purchases under the Rider for Released Energy,

RIDER FOR FUEL AND PURCHASED ENERGY

(f) The cost of the Buyback Energy Credit paid to Customer(s) for avoided energy purchases under the Rider for Voluntary Energy Buyback,

RIDER FOR FUEL AND PURCHASED ENERGY

(g) Fuel and purchased energy expenses incurred by the Company over the duration of any Commission approved contract, as provided for by Minnesota Statutes, Section 216B.1645, to satisfy the renewable energy obligations set forth in Minnesota Statutes, Section 216B.1691,
(h) All RTO market costs net of revenues
(i) The cost of the purchase of SO_2 and NOx allowances,
(j) Reagents and chemicals for environmental compliance,
(k) Premiums related to business interruption insurance
(l) Amortization of the FPE transition cost recovery amount, and
(m) Natural gas fuel consumed for the Company's share of the Nemadji Trail Energy Center

and **less**

(n) Revenues from the sale of SO_2 allowances and NOx allowances,
(o) Proceeds from recoveries under business interruption insurance
(p) The cost of fossil and nuclear fuel and the cost of steam from other sources recovered through inter-system sales including the fuel and steam costs related to economy energy sales and other energy sold on an economic dispatch basis and
(q) Net revenues from the sale of environmental attributes from any Commission approved contract, and
(r) Net Revenues from sales of the Company's share of energy and other attributes related to the Nemadji Trail Energy Center into the MISO market.

The Kilowatt-Hour Sales shall be Company's total kilowatt-hour Sales of Electricity, excluding inter-system sales referred to in (o) above; all for the billing month.

CLASS COST FACTORS

A separate Class Cost Factor shall be applied to calculate the FPE Cost for each Rate Class.

Rate Class	Class Cost Factor
Residential	1.01356
General Service	1.03467
Large Light & Power	1.00932
Large Power	0.98975
Municipal Pumping	1.01522
Lighting	0.82532

BASE COST OF ENERGY

RIDER FOR FUEL AND PURCHASED ENERGY

The System Average Base Cost of Energy is 2.103¢/kWh. The class-specific Base Cost of Energy for each rate class is obtained by multiplying 2.103¢/kWh by the applicable Class Cost Factor.

RIDER FOR FUEL AND PURCHASED ENERGY

Rate Class	Base Cost of Energy
Residential	2.132¢/kWh
General Service	2.176¢/kWh
Large Light and Power	2.123¢/kWh
Large Power	2.081¢/kWh
Municipal Pumping	2.135¢/kWh
Lighting	1.736¢/kWh

FORECASTED FUEL AND PURCHASED ENERGY COST
The Forecasted FPE Cost for each rate class shall be determined by multiplying the Forecasted System Average FPE Cost by the applicable Class Cost Factor.

TRUE-UP FUEL AND PURCHASED ENERGY COST
The True-up FPE Cost for each rate class shall be determined by multiplying the True-up System Average FPE Cost by the applicable Class Cost Factor.

REDLINE TARIFF SHEETS

RIDER FOR FUEL AND PURCHASED ENERGY ~~ADJUSTMENT~~

FUEL AND PURCHASED ENERGY COST~~ADJUSTMENT~~

Applicable to electric service under all Company's Retail Rate Schedules except Competitive Rate Schedules Rate Codes 73 and 79 and Erie Mine Site Service Schedule - Rate Code 72.

There shall be added to ~~or deducted from~~ the monthly bill ~~an amount~~a Fuel and Purchased Energy (FPE) Cost per kilowatt-hour determined as the ~~amount by which the~~ Forecasted ~~Fuel and Purchased Energy~~ FPE Cost~~s~~ divided by the ~~actual~~ Forecasted Kilowatt-Hour Sales ~~is greater than or less than the Base Cost of Energy as specified below~~.

There shall also be added to or deducted from the monthly bill a True-up FPE Cost per kilowatt-hour determined as the amount by which the Forecasted FPE Cost per kWh is greater than or less than the actual calculated FPE Cost per kWh.

The Forecasted System Average ~~Fuel and Purchased Energy~~ FPE Cost shall be the Forecasted FPE Cost divided by the Forecasted Kilowatt-Hour Sales. The True-up FPE Cost~~System Average FPE Adjustment~~ shall be the Actual System Average FPE Cost less the Forecasted System Average ~~Base Cost of Energy~~FPE costs. The applicable True-up FPE Cost ~~Adjustment~~ applied to the Forecasted Kilowatt-Hour Sales for the billing month will be included monthly on each customer's bill according to customer's rate class.

FORECASTED AVERAGE FUEL AND PURCHASED ENERGY COST

The Forecasted ~~Fuel and Purchased Energy~~FPE Cost shall be the **sum** of the following forecasted amounts~~during the first two of the preceding three~~ for the billing month~~s~~:

(a) ~~t~~The fossil and nuclear fuel consumed in Company's generating stations,
(b) ~~t~~The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis, this encompasses energy being purchased to substitute for Company's own higher cost energy,
(c) ~~t~~The ~~actual~~ identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (b) above,
(d) ~~t~~The cost of steam from other sources used in the generation of electricity at the Company's generating stations,
(e) ~~t~~The cost of the Released Energy Credit paid to Customer(s) for avoided energy purchases under the Rider for Released Energy,

RIDER FOR FUEL AND PURCHASED ENERGY ~~ADJUSTMENT~~

(f) ~~t~~The cost of the Buyback Energy Credit paid to Customer(s) for avoided energy purchases under the Rider for Voluntary Energy Buyback,

(g) ~~f~~Fuel ~~-~~and purchased energy expenses incurred by the Company over the duration of any Commission approved contract, as provided for by Minnesota Statutes, Section 216B.1645, to satisfy the renewable energy obligations set forth in Minnesota Statutes, Section 216B.1691,

(h) A~~a~~ll ~~MISO~~ RTO (Regional Transmission Organization) market costs net of revenues ~~allowed to flow through the FPE Adjustment by Commission's December 20, 2006 Order in Docket No. E-015/M-05-277, excluding the MISO Day 2 costs that are recovered under provision (b) of the FPE Rider, and~~

(i) ~~t~~The cost of the purchase of SO_2 and NOx allowances,

(j) Reagents and chemicals for environmental compliance.

(k) Premiums related to business interruption insurance.

(l) Amortization of the FPE transition cost recovery amount

(m) Natural gas fuel consumed for the Company's share of the Nemadji Trail Energy Center.

and **less**

(~~j~~nm) ~~r~~Revenues from the sale of SO_2 allowances and NOx allowances,

(~~o~~nk) Proceeds from recoveries under business interruption insurance

(~~p~~o) ~~t~~The cost of fossil and nuclear fuel and the cost of steam from other sources recovered through inter-system sales including the fuel and steam costs related to economy energy sales and other energy sold on an economic dispatch basis and

(~~l~~gp) N~~n~~et revenues from the sale of environmental attributes from any Commission approved contract.

(r) Net Revenues from sales of the Company's share of energy and other attributes related to the Nemadji Trail Energy Center into the MISO market.

The Kilowatt-Hour Sales shall be Company's total kilowatt-hour Sales of Electricity, excluding inter-system sales referred to in (o~~k~~) above; all for the billing~~first two of the preceding three~~ month~~s~~.

ACTUAL FUEL AND PURCHASED ENERGY COST

The FPE Cost shall be the **sum** of the actual costs for the following for the billing month:

(a) The fossil and nuclear fuel consumed in Company's generating stations.

(b) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. this encompasses energy being purchased to substitute for Company's own higher cost energy.

(c) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in (b) above.

RIDER FOR FUEL AND PURCHASED ENERGY ~~ADJUSTMENT~~

(d) The cost of steam from other sources used in the generation of electricity at the Company's generating stations.
(e) The cost of the Released Energy Credit paid to Customer(s) for avoided energy purchases under the Rider for Released Energy.
~~(a)~~(f) The cost of the Buyback Energy Credit paid to Customer(s) for avoided energy purchases under the Rider for Voluntary Energy Buyback.

RIDER FOR FUEL AND PURCHASED ENERGY ~~ADJUSTMENT~~

(g) Fuel and purchased energy expenses incurred by the Company over the duration of any Commission approved contract, as provided for by Minnesota Statutes, Section 216B.1645, to satisfy the renewable energy obligations set forth in Minnesota Statutes, Section 216B.1691,
(h) All RTO market costs net of revenues
(i) The cost of the purchase of SO_2 and NOx allowances,
(j) Reagents and chemicals for environmental compliance,
~~(b)~~(k) Premiums related to business interruption insurance
~~(c)~~(l) Amortization of the FPE transition cost recovery amount, and~~.~~
(m) Natural gas fuel consumed for the Company's share of the Nemadji Trail Energy Center

and **less**

(n) Revenues from the sale of SO_2 allowances and NOx allowances,
(o) Proceeds from recoveries under business interruption insurance
(p) The cost of fossil and nuclear fuel and the cost of steam from other sources recovered through inter-system sales including the fuel and steam costs related to economy energy sales and other energy sold on an economic dispatch basis and
(q) Net revenues from the sale of environmental attributes from any Commission approved contract, and
(r) Net Revenues from sales of the Company's share of energy and other attributes related to the Nemadji Trail Energy Center into the MISO market.~~.~~

The Kilowatt-Hour Sales shall be Company's total kilowatt-hour Sales of Electricity, excluding inter-system sales referred to in (o) above; all for the billing month.

CLASS COST FACTORS

A separate Class Cost Factor shall be applied to calculate the ~~Base Cost of Energy and~~ FPE Cost ~~Adjustment~~ for each Rate Class.

Rate Class	Class Cost Factor
Residential	~~1.07076~~1.01356
General Service	~~1.07093~~1.03467
Large Light & Power	~~1.00424~~1.00932
Large Power	~~0.97769~~0.98975
Municipal Pumping	~~0.98103~~1.01522
Lighting	~~0.74029~~0.82532

RIDER FOR FUEL AND PURCHASED ENERGY ~~ADJUSTMENT~~

BASE COST OF ENERGY

The System Average Base Cost of Energy is ~~1.018~~2.103¢/kWh. The class-specific Base Cost of Energy for each rate class is obtained by multiplying ~~1.018~~2.103¢/kWh by the applicable Class Cost Factor.

RIDER FOR FUEL AND PURCHASED ENERGY ~~ADJUSTMENT~~

Rate Class	Base Cost of Energy
Residential	~~1.090~~2.132¢/kWh
General Service	~~1.090~~2.176¢/kWh
Large Light and Power	~~1.022~~2.123¢/kWh
Large Power	~~0.995~~2.081¢/kWh
Municipal Pumping	~~0.999~~2.135¢/kWh
Lighting	~~0.754~~1.736¢/kWh

FORECASTED FUEL AND PURCHASED ENERGY COST ~~ADJUSTMENT~~

The Forecasted FPE Cost ~~Adjustment~~ for each rate class shall be determined by multiplying the Forecasted System Average FPE Cost ~~Adjustment~~ by the applicable Class Cost Factor.

TRUE-UP FUEL AND PURCHASED ENERGY COST

The True-up FPE Cost for each rate class shall be determined by multiplying the True-up System Average FPE Cost by the applicable Class Cost Factor.

APPENDIX BB: VERIFICATION OF FILING

STATE OF MINNESOTA)
) ss
COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA ELECTRONIC FILING

Herbert Minke III, being first duly sworn, deposes and says that he is the Vice President of Regulatory ALLETE; that he has read the foregoing Petition and knows the contents thereof; that he has read the agreements and Appendices attached hereto; and that he verifies the information contained therein is correct and true to the best of his knowledge.

Herbert Minke III
Vice President – Regulatory
ALLETE

Subscribed and sworn to before me
this 27th day of July, 2017

Notary Public, State of Minnesota

PATTI A SCHUMAN
Notary Public
Minnesota
My Commission Expires
Jan 31, 2021

APPENDIX CC: LIST OF ACRONYMS, TERMS AND DESCRIPTION

ACRONYM	DEFINITION
2010 Plan	Minnesota Power's 2010 Integrated Resource Plan
2013 Plan	Minnesota Power's 2013 Integrated Resource Plan
2014 AFR	2014 Annual Electric Utility Forecast Report
2015 Plan	Minnesota Power's 2015 Integrated Resource Plan
2016 AFR	2016 Annual Electric Utility Forecast Report
2016 Rate Case	Minnesota Power's 2016 General Rate Case
2017 AFR	2017 Annual Electric Utility Forecast Report
AFR	Annual Electric Utility Forecast Report
Assignment Agreements	Assignment of Rights Agreement (Construction Agent) and Assignment of Rights Agreement (Operating Agent)
ATC	American Transmission Company
BEC	Boswell Energy Center
BEC1&2	Boswell Energy Center Units 1 & 2
BEC3	Boswell Energy Center 3
Bison	Bison Wind Energy Center
Bison 1	Bison 1 Wind Facility
Bison 2	Bison 2 Wind Facility
Bison 3	Bison 3 Wind Facility
Bison 4	Bison 4 Wind Facility
BTU	British Thermal Units
CAC	Central Air Conditioning
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CDA	Unit Contingent Capacity Dedication Agreement
CEO	Clean Energy Organizations
CIP	Conservation Improvement Program
CO	Carbon Monoxide
CO_2	Carbon Dioxide
Commission	Minnesota Public Utilities Commission
Company	Minnesota Power
CP	Coincident Peak
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
CSAPR	State Air Pollution Rule
CT	Combustion Turbine
Dairyland	Dairyland Power Cooperative
Dairyland's O-IRP	Dairyland's 2017 Optional Resource Plan Compliance Report

ACRONYM	DEFINITION
D&C Agreement	Development and Construction Management Agreement
Department	Department of Commerce – Division of Energy Resources
DPP	Definitive Planning Phase
DSM	Demand Side Management
EFRP	Energy*Forward* Resource Package
EPA	Environmental Protection Agency
ERIS	Energy Resource Interconnection Service
FERC	Federal Energy Regulatory Commission
FPE	Fuel and Purchased Energy
Futures	Minnesota Power included the midpoint of the Commission's approved CO_2 range in one of the Base Case ("Futures") scenarios.
Gas RFP	Minnesota Power's 2015 Request for Proposals for Gas-Fired Resource
GIA	Generation Interconnection Agreement
GIP	Generator Interconnection Procedures
GTG	Gas Turbine Generator
GW	Gigawatt
GWh	Gigawatt Hour
HAC	Heteroscedasticity and Autocorrelation Consistent
HRSG	Heat Recovery Steam Generator
HW	Hot Water Heater
IC	Interconnection Customer
ITC	Investment Tax Credit
July 2016 IRP Order	2015 Plan, ORDER APPROVING RESOURCE PLAN WITH MODIFICATIONS (July 18, 2016)
Keetac	Keewatin Taconite
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
LEC	Laskin Energy Center
LEC1&2	Laskin Energy Center, Units 1 and 2
LGIA	Large Generator Interconnection Agreement
LMP	Locational Marginal Pricing
LNG	Liquefied Natural Gas
LOLE	MISO Loss of Load expectation Report
LP	Low Pressure Turbines
LPI	Large Power Intervenors
MATS	Mercury and Air Toxics Rule
MHEB	Manitoba Hydro-Electric Board
Minnesota Wind	Wind located in southwestern Minnesota
MISO	Midcontinent Independent System Operator
MISO Tariff	MISO Open Access Transmission Tariff

ACRONYM	DEFINITION
MMBtu	One million British Thermal Units
MW	Megawatt
MWh	Megawatt Hour
NAEMA	North American Energy Markets Association
NERC	North American Electric Reliability Corporation
NO_x	Oxides of Nitrogen
NRIS	Network Resource Interconnection Service
NTEC	Nemadji Trail Energy Center
NTEC Owners	Dairyland and South Shore
NTEC Project Agreements	D&C Agreement and O&O Agreement
O&M	Operating and Maintenance
O&O Agreement	Ownership and Operating Agreement
OAH	Office of Administrative Hearings
OMS	Outage Management System
Pb	Lead
Peabody	L.E. Peabody & Associates, Inc.
PM	Particulate Matter
PPA	Power Purchase Agreement
PRM	Planning Reserve Margin
PSCW	Public Service Commission of Wisconsin
PTC	Production Tax Credit
PV	Photovoltaics
RECs	Renewable Energy Credits
RES	Renewable Energy Standard
RFP	Request for Proposals
RICE	Simple Cycle Reciprocating Internal Combustion Engine
ROW	Right of Way
SC Aero	Simple Cycle Aero Derivative
SC GT	Simple Cycle Gas Turbine – Combustion Turbine
Sedway Consulting	Sedway Consulting, Inc.
SES	Solar Energy Standard
SIS	System Impact Study
SO_2	Sulfur Dioxides
Solar RFP	Minnesota Power's 2016 Request for Proposals for Solar Resource
Solar Thin Film	Thin Film Photovoltaic Solar
South Shore	South Shore Energy, LLC
Square Butte	Square Butte Cooperative
S-RECs or SREC	Solar Renewable Energy Credits
STG	Steam Turbine Generator
Strategist	Strategist Proview modeling

ACRONYM	DEFINITION
SWL&P	Superior Water Light & Power
THEC	Taconite Harbor Energy Center
THEC1&2	Taconite Harbor Energy Center Units 1 and 2
THEC3	Taconite Harbor Energy Center Unit 3
TOs	Transmission Owners
Transport RFP	Minnesota Power's 2015 Request for Proposals for Natural Gas Transportation Service
UCAP	Unforced Generating Capacity
WACC	Weighted Average Cost of Capital
WDNR	Wisconsin Department of Natural Resources
Wind RFP	Minnesota Power's 2016 Request for Proposals for Wind Resource
XEFORd	Equivalent Forced Outage Rate Demand
Young 2	Square Butte's Milton R. Young 2 lignite coal generating station