BEFORE THE MINNESOTA OFFICE OF ADMINISTRATIVE HEARINGS
600 North Robert Street
St. Paul, MN 55101

FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION
121 7th Place East, Suite 350
St Paul MN 55101-2147

IN THE MATTER OF THE APPLICATION OF XCEL ENERGY AND ITC MIDWEST LLC, FOR A CERTIFICATE OF NEED FOR THE HUNTLEY-WILMARTH 345-KV TRANSMISSION LINE PROJECT	MPUC Docket No. E6675,E002/CN-17-184 OAH Docket No. 82-2500-35157

DIRECT TESTIMONY AND ATTACHMENTS OF MATTHEW LANDI

ON BEHALF OF

OF
THE MINNESOTA DEPARTMENT OF COMMERCE
DIVISION OF ENERGY RESOURCES

NOVEMBER 7, 2018

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TABLE OF CONTENTS

Section **Page**

I. INTRODUCTION

Q. Would you state your name, occupation and business address?

A. My name is Matthew Landi. I am employed as a Public Utilities Rates Analyst by the Minnesota Department of Commerce, Division of Energy Resources (DOC-DER). My business address is 85 7th Place East, Suite 280, St. Paul, Minnesota 55101-2198.

Q. What is your educational and professional background?

A. A summary of these items is included as DER Ex. __ at ML-1 (Landi Direct).

II. PURPOSE AND SCOPE

Q. What are your responsibilities in this proceeding?

A. I am submitting testimony on behalf of DOC-DER that provides analysis of alternatives to the proposed Huntley-Wilmarth 345 kV Transmission Line (Project).

Q. Which of the Certificate of Need decision criteria are you addressing?

A. Minnesota Statutes and Rules require that the Minnesota Public Utilities Commission (Commission) consider a number of criteria in evaluating certificate of need applications, including consideration of alternatives to the proposal contained in a certificate of need application. Specifically, my testimony addresses the following Minnesota Statutes and Rules:

- Minnesota Statutes § 216B.2422, subd. 3(a). Environmental Costs;

- Minnesota Statutes § 216B.2422, subd. 4. Preference for renewable energy facility;
- Minnesota Statutes § 216B.2426. Opportunities for distributed generation;
- Minnesota Statutes § 216B.243, subd. 3(9). Showing required for construction; and
- Minnesota Rules 7849.0120 B(1)–(3).

Below, I evaluate potential alternatives discussed by the Applicants in their Petition.

III. ANALYSIS

A. ANALYSIS OF ALTERNATIVES TO THE PROJECT

1. Overview

Q. Are there notable aspects to the proposed Project?

A. Yes. The Project was developed and analyzed through the Midcontinent Independent System Operator (MISO) Transmission Expansion Plan (MTEP) process. This process is detailed in the Direct Testimony of MISO witness Zheng Zhou on pages 4 through 8. Ultimately, as noted in the *Application to the Minnesota Public Utilities Commission for the Huntley–Wilmarth 345 kV Transmission Line Project* (Application), through MTEP's process, the Project was recommended as part of the 2016 MTEP report based on its large net economic benefits and was subsequently approved by MISO's Board of Directors.[1] Additionally, MISO's Board of Directors approved the Project as a Market

[1] Application at 1.

Efficiency Project (MEP), which is a project that is "needed to reduce transmission system congestion which will improve the efficiency of MISO's energy market resulting in lower wholesale energy costs."[2]

Q. Please provide an overview of the analyses performed by MISO that led to the Project and consideration of alternatives.

A. On page 69 of the Application, Xcel Energy and ITC Midwest LLC (Applicants) explained that the proposed Project is a culmination of MISO studies and analyses that have identified, since 2009, the Blue Earth County area (Blue Earth area) near Mankato, MN as a top congested flowgate in the MISO system. Chapter 4 of the Application describes the MISO process that identified the need for the Project and the screening analysis performed by MISO that resulted in the identification of the Project as the best solution of those studied to the transmission constraints and congestion issues along the Minnesota-Iowa border. As a part of this analysis, MISO considered several alternatives to the Project.

Q. You mentioned that the proposed Project was a culmination of MISO studies and analyses since 2009. Can you provide more detail on those studies and analyses?

A. Yes. According to the Application on pages 69-72, the proposed Project is a culmination of numerous studies and analyses completed by MISO over the past 10 years:

[2] *Id.*

- In the MTEP08 Regional Generation Outlet Study MISO first identified the congestion issues along the Minnesota-Iowa border.
- The 2011 Market Efficiency Analysis report identified the Huntley-Blue Earth-South Bend-Wilmarth transmission line as the ninth most severely congested flowgate in the MISO system.
- The MTEP12 analysis concluded that this flowgate was congested 10 to 20 percent of the year, resulting in the inability to deliver lower cost electricity to load centers during that time.
- The MTEP13 and MTEP14 again confirmed the existence of congestion issues in the Blue Earth area and anticipated a worsening problem due to forecasted additions of wind generation projects.
- The MTEP15 was the first such analysis to study a new 345 kV transmission line in the Blue Earth area as a potential solution to the congestion issue.
- The MTEP16 study was the first to analyze in detail the Project as a potential solution to the congestion issue.

Q. Did the MTEP16 study evaluate any other solutions to attempt to relieve congestion in the Blue Earth area?

A. Yes. As a part of the MTEP16 study, MISO identified 23 possible transmission solutions that were designed to relieve congestion in the Blue Earth area. Of these 23 solutions, 16 were shown to have a one-year benefit-to-cost ratio (BC ratio) equal to or greater than 0.9.[3] MISO grouped these 16 alternatives into four groups of solutions based on voltage level and design approach and ranked them on their BC ratio. The best performer in each group underwent a full 20-year Net Present Value (NPV) calculation to determine its BC ratio.[4]

One solution had a BC ratio of less than one and was eliminated from consideration. The remaining three solutions were subjected to engineering analyses of their ability to mitigate the identified congestion through 2031.[5] Of these three solutions, only one relieved 100% of the identified congestion through 2031. This solution, referred to as solution I-02, is the proposed Project.[6]

2. Alternatives

Q. Please list the criteria you used in the screening analysis to assess alternatives to the proposed Project.

A. First, Minnesota Rules 7849.0120 B (1) requires consideration of "the appropriateness of the size, the type, and the timing of the proposed facility compared to those of reasonable alternatives." Second, Minnesota Statutes § 216B.2426 requires consideration of distributed generation:

> The Commission shall ensure that opportunities for the installation of distributed generation, as that term is defined in section 216B.169, subdivision 1, paragraph (c), are considered in any proceeding under section 216B.2422, 216B.2425, or 216B.243.

[3] *Id.* at 79.
[4] *Id.* at 81.
[5] *Id.* at 82-83.
[6] *Id.*

Third, Minnesota Statutes §216B.2422, subd. 4 requires consideration of renewable energy generating facilities:

> The Commission shall not approve a new or refurbished nonrenewable energy facility in an integrated resource plan or a certificate of need, pursuant to section 216B.243, nor shall the Commission allow rate recovery pursuant to section 216B.16 for such a nonrenewable energy facility, unless that utility has demonstrated that a renewable energy facility is not in the public interest.

Q. What alternatives to the proposed Project were considered by the Applicants?

A. In addition to MISO's screening analysis described above to determine the appropriate solution(s) to the identified congestion problem, the Applicants analyzed the proposed Project with MTEP17 assumptions and data. Further, in line with Minn. Rules 7849.0120 B(1), the Applicants considered the appropriateness of the size, type, and timing of the proposed Project relative to alternatives. The alternatives considered by the Applicants include:[7]

- Size alternatives: different voltages or conductor arrays and AC/DC;
- Type alternatives: alternative terminals/substations, double circuiting with existing transmission lines, generation alternatives, and underground transmission lines;

[7] *Id.* at 98.

- No build alternative: using energy conservation and demand side management (DSM) programs as potential options to alleviate congestion;[8] and
- Generation alternatives: renewable energy resources and distributed generation resources.

3. Size

Q. You mentioned that Minnesota Rules 7949.0120 B(1) requires the Commission to consider, in part, the "size" of the proposed facility compared to reasonable alternatives. How has DOC-DER interpreted "size" in the context of Minnesota Rules 7849.0120 B(1)?

A. DOC-DER discussed the definition of size (as well as type and timing) in the context of transmission lines in DOC-DER comments in Docket No. ET6675/CN-11-826, dated January 28, 2013. In that proceeding, DOC-DER interpreted "size" as referring to the quantity of power transfers that the transmission line enables. DOC-DER maintains this interpretation.

Q. Please describe how the Applicants' interpreted "size" in the context of Minnesota Rules 7849.0120 B(1) given DOC-DER's interpretation.

[8] I note that Department Witness Dr. Rakow discussed alternatives under Minnesota Rules 7849.0120 A(4); the analysis in my testimony considers alternatives under Minnesota Rules 7849.0120 B(1) as noted above.

A. In response to Department Information Request (DOC-DER IR) No. 3, the Applicants provided their understanding of the "size" of the proposed Project and its alternatives:[9]

> The Applicants view the Department's interpretation of "size" to be best represented by the capacity of the proposed transmission line and each of the alternatives, as measured in mega volt amps [(MVA)]. This is because the capacity of a transmission line dictates the maximum amount of power that can be transferred by the line. The capacity of a transmission line is a function of its voltage as, generally speaking, higher voltage lines have higher capacity than lower voltage lines.

Q. Does the Applicants' response comport with DOC-DER's interpretation of "size" in the context of Minnesota Rules 7849.0120 B (1)?

A. Yes.

Q. Please describe the Applicants' analysis of "size" alternatives.

A. The Applicants considered transmission line voltages that are both higher and lower than the proposed Project's 345 kV voltage.

Higher-voltage transmission-line alternatives considered included 765 kV and 500 kV lines. The Applicants concluded at page 99 of the Application that the higher costs of higher voltage lines were not justified because the proposed 345 kV

[9] Ex. DER-__, ML-2 (Landi Direct) (Applicants' Response to DOC-DER IR No. 3 (May 11, 2018)).

transmission line sufficiently alleviated the identified congestion along the Minnesota-Iowa border.

Lower voltage transmission line alternatives considered by the Applicants included 69 kV, 115 kV, and 161 kV. The Applicants explained on page 99 of the Application that 230 kV and 138 kV voltage transmission lines were excluded from consideration as substations in the area would require upgrades to accommodate them.

For example, in response to DOC-DER IR No. 4, the Applicants estimated that the costs of accommodating a 138 kV transmission line at the Huntley and Wilmarth substations would total $28.9 million.[10] Similarly, the Applicants' estimate for accommodating a 230 kV transmission line at the Huntley and Wilmarth substations would total $31.2 million.[11]

Q. Did the Applicants eliminate any other size alternatives from consideration?

A. Yes. On page 101 of the Application, the Applicants explained that the 69 kV and 115 kV transmission line alternatives were also eliminated from consideration for technical reasons: in order to achieve the same capacity as a 345 kV transmission line—and thus alleviate the identified congestion issue—the 69 kV transmission line would require a current rating of approximately 15,000 amperes (amps), while the 115 kV transmission line would require a current rating of 9,000 amps.[12] The Applicants further explained that substation equipment used to protect and control transmission lines are typically

[10] Ex. DER-__, ML-3 at 3 (Landi Direct) (Applicants' Response to DOC-DER IR No. 4 (May 23, 2018)).
[11] *Id.* at 5.
[12] The Applicants define ampere on page 97 of the Application as "the unit used for measuring electric current, which is the measure of the number of electrons flowing through a conductor at a fixed rate."

limited to 3,000 amps for 345 kV transmission lines and 1,200 to 3,000 amps for lower voltages. In response to DOC-DER IR No. 6, the Applicants further explained that the lower capacity of 69 kV and 115 kV transmission lines would provide even less of a power transfer path than a 161 kV alternative, which itself is insufficient to relieve the identified congestion issue.[13]

Q. Did the Applicants consider a double-circuit option?

A. Yes, the Applicants considered whether a double-circuit 345 kV/345 kV line alternative would be appropriate. On page 113 of the Application, however, the Applicants concluded that, given that a single circuit 345 kV line relieved 100% of the identified congestion through 2031, additional transmission capacity would only increase the cost of the proposed Project without any identifiable additional benefits.

Q. What do you conclude regarding the appropriateness of the Applicants' consideration of reasonable alternatives to the proposed facility in terms of "size" in the context of Minnesota Rules 7849.0120 B(1) and as interpreted by DOC-DER?

A. I conclude that the Applicants' analysis of alternatives to the proposed Project in terms of their "size" comports with DOC-DER's interpretation of "size" in the context of Minnesota Rules 7849.0120 B(1) and was appropriate and reasonable.

[13] Ex. DER-__, ML-4 (Landi Direct) (Applicants' Response to DOC-DER IR No. 6 (May 11, 2018)).

4. Type

Q. You mentioned that Minnesota Rules 7949.0120 B (1) also requires the Commission to consider the "type" of the proposed facility compared to reasonable alternatives. How has DOC-DER interpreted "type" in the context of Minnesota Rules 7849.0120 B(1)?

A. As previously stated, DOC-DER discussed the definition of "type" in the context of transmission lines in Docket No. ET6675/CN-11-826. In that proceeding, DOC-DER interpreted "type" as referring to the following characteristics: the transmission line's nominal voltage,[14] rated capacity,[15] surge impedance loading (SIL),[16] and the nature of power transported (AC[17]or DC[18]). The Department maintains this interpretation.

Q. Please describe how the Applicants interpreted "type" in the context of Minnesota Rules 7849.0120 B(1) given DOC-DER's interpretation.

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[14] The Applicants define "voltage" as "a type of "pressure" that drives electrical charges through a circuit. Higher voltage lines generally carry power longer distances." Application at 64.

[15] The Applicants refer to this term as the "capacity of transmission facility" and define this term as "the load-carrying capacity, expressed in terms of Mega-Volt-Amperes or MVA, of a transmission line or other electrical equipment." *Id.* at 62.

[16] The Applicants defined this term in their response to DOC-DER IR No. 14 (as "the point at which the inductive and capacitive requirements of the line negate each other, or where real power and apparent power are equal." Ex. DER-__, ML-5. (Landi Direct) (Applicants' Response to DOC-DER IR No. 14 (May 11, 2018)).

[17] The Applicants define "alternating current (AC)" as "an electric current that reverses its direction many times at regular intervals. AC is the typical form in which electric power is delivered to homes and businesses." Application at 97.

[18] The Applicants define "Direct current (DC)" as "the unidirectional flow or movement of electrons. For movement of electricity over long distances, DC transmission lines can have certain advantages as compared to the more common AC transmission lines including lower electrical losses." *Id.* at 98.

A. In response to DOC-DER IR No. 14, the Applicants provided information related to the "type" characteristics of the transmission lines considered in their analysis of the proposed Project and the 161 kV transmission line alternative.[19]

Q. Did the Applicants' response comport with DOC-DER's interpretation of "type" in the context of Minnesota Rules 7849.0120 B(1)?

A. Yes.

Q. Please describe the Applicants' analysis of "type" alternatives.

A. The Applicants also considered the following alternatives to the proposed Project: (1) a transmission project with different end points; (2) reconductoring or rebuilding the existing transmission facilities that currently connect the Huntley and Wilmarth substations; (3) double-circuiting of existing transmission lines; (4) the use of high voltage direct current (HVDC) transmission lines; (5) the use of alternative conductor arrays for the Project, which affects the capacity of the transmission line; and (6) the construction of underground transmission lines.[20]

Q. Did the Applicants' analysis indicate that any of these alternatives were viable options to address the need for the proposed Project?

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[19] Ex. DER-__, ML-5.

[20] Application at 113-121.

A. No. Both the Applicants' screening analysis in Chapter 4 of the Application and alternatives analysis in Chapter 5 indicated a number of reasons why these alternatives were not viable, ranging from concerns over reliability of the alternative to the cost-effectiveness of the alternative considered.

Q. Do you agree with the Applicants' conclusions regarding each of the alternatives considered?

A. Yes. Each of the Applicants' explanations regarding the viability of the above-referenced alternatives appear to lead to the reasonable conclusion that none of these alternatives would be viable.

5. Timing

Q. Please describe DOC-DER's interpretation of "timing" within Minnesota Rules 7849.0120 B(1).

A. In Docket No. ET6675/CN-11-826, DOC-DER interpreted the "timing" of a project to refer to the proposed on-line date for the project. DOC-DER maintains this interpretation.

Q. Please describe the Applicants' interpretation of "timing" as used in Minnesota Rules 7849.0120 B(1).

A. According to the Applicants, the extensive record of the congestion issues identified in the Blue Earth area suggest that the proposed on-line date for the proposed Project by the end of 2021 is reasonable. Additionally, the Applicants expect that the identified congestion issue is likely to become more severe over time:

> As of September 2017, the MISO interconnection queue had approximately 23,100 MW of active wind projects that were expected to be placed in service in Minnesota or Iowa prior to 2021. In 2016 and 2017 alone, more than 6,600 MW of new wind generation to be located in Minnesota or Iowa entered the MISO queue. As of November 2017, the MISO interconnection queue had approximately 19,400 MW of wind that is expected to be placed in service prior to 2021.[21]

Q. Does the Applicants' response comport with DOC-DER's interpretation of "timing" in the context of Minnesota Rules 7849.0120 B(1)?

A. Yes.

Q. Do you agree with the Applicants' conclusions regarding the "timing" of the proposed Project?

A. Yes. As a result of the existing congestion issue and the likelihood that it will become more severe between now and the proposed on-line date of the end of 2021, the proposed on-line date appears reasonable.

6. No Build Alternative

Q. Did the Applicants consider any other alternatives to the proposed Project?

[21] Application at 58.

A. Yes. On pages 121 and 122 of the Application, the Applicants explained that they considered two different “no build” alternatives in which they analyzed whether the need for the proposed Project could be alleviated through (1) reducing congestion through load growth in the area and (2) reducing congestion through conservation or demand-side management programs. Additionally, the Applicants considered whether new sources of generation could address the identified congestion issue.

Q. What did the Applicants conclude regarding the “no build” alternatives?

A. The Applicants concluded that neither “no build” alternative would alleviate the identified congestion issue.

Q. What did the Applicants state regarding the load growth alternative?

A. The Applicants stated that transmission congestion “is in part the result of the fact that generation levels in the area exceed the amount of load in the area.”[22] Thus, if load grew sufficiently in the area, there would not be a need to export the excess generation away from the area. The Applicants determined that load would need to increase between 120 MW and 370 MW in order to reduce the current identified congestion issue, while it is only projected to grow by 58 MW over the next ten years. Further, this insufficiency problem is exacerbated by the known additions of wind development along the Minnesota/Iowa border.

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[22] *Id.* at 122.

Q. What did the Applicants state regarding DSM alternatives to the proposed Project?

A. The Applicants examined the effects of load reductions in the area that is congested on the need for the proposed Project. The Applicants concluded that conservation and demand-side management programs would be insufficient to alleviate the identified congestion issue. The Applicants' technical analysis suggests that, in order to alleviate the current congestion, load reduction through conservation and demand-side management would need to occur in and near Mankato and reach between 240 MW and 600 MW, and between 700 MW and 1,800 MW if no new facilities were constructed.[23]

Q. Do you agree with the Applicants' conclusions regarding the viability of the "no build" alternatives to the proposed Project?

A. Yes. I agree that neither "no build" alternative would be sufficient to alleviate the identified congestion issue.

7. Statutory Alternatives

Q. Are you aware of any other requirements in Minnesota law that the Commission must consider regarding potential alternatives to the proposed Project?

A. Yes. I am aware that Minn. Stat. §216B.2422, subd. 4 and Minn. Stat. § 216B.2426 require consideration of renewable energy facilities and distributed generation alternatives before a certificate of need is approved, respectively.

[23] *Id.* at 123-124.

Q. Please describe the Applicants' consideration of renewable energy generation and distributed generation alternatives.

A. The Applicants generally concluded that adding new generation resources to resolve the identified congestion issue would not be a reasonable alternative given that existing generation and the planned addition of new wind energy generation sources are inducing the need for the proposed Project.[24] In general, the Applicants stated the following regarding the interplay between transmission and generation:[25]

> Transmission congestion occurs when there is not enough transmission capacity to support all generation requests for transmission services at a particular time. Thus, regardless of the type of the generation facility evaluated, fossil-fueled or renewable, the construction of additional generation facilities is not a feasible and prudent alternative to the Project because such generation would: (1) further exacerbate the congestion already present on the system unless this generation is sited north of the existing congestion; (2) result in underutilization of existing generation resources; and (3) likely be more costly than the proposed Project.

Q. Setting these concerns aside, what do the Applicants believe would be necessary for a generation alternative to be feasible in this circumstance?

A. The Applicants stated the following:[26]

> A generation alternative to reduce this congestion would need to be of equal or lower cost to the wind generation that is currently being constrained and would need to be built on the north side of the identified point of congestion (i.e., the Huntley – Blue Earth – South Bend – Wilmarth 161

[24] *Id.* at 118-121.
[25] *Id.* (footnotes omitted).
[26] *Id.* at 119.

> kV line). Generation sited to the south of the congestion point would only exacerbate the existing congestion. Further, this new generation would also need to be able to generate at minimum between approximately 120 MW and 370 MW (depending on the Future scenario) during times when congestion is present to achieve the necessary congestion reduction.

Q. Did the Applicants consider any generation alternative?

A. Yes, at least on a preliminary basis. The Applicants provided the following analysis of a generation alternative:[27]

> Given these existing conditions on the transmission system, Applicants examined construction of new wind generation facilities on the north side of the identified congestion (i.e., north of the Wilmarth Substation). Siting new large-scale wind generation north of the area of congestion would be difficult given the existing development and other considerations in the urban areas near the City of Mankato. In addition, there is a decrease in the average annual wind speed in areas farther north from the Iowa border.
>
> . . . .
>
> As a result, a larger quantity of wind turbines would need to be constructed north of the area of congestion to achieve the same output as similar generation sited in areas to the south. Specifically, because of the difference in wind speeds, 15 to 30 percent more nameplate capacity would be needed as compared to wind generation installed further south or approximately 340 MW to 1,800 MW of nameplate wind generation capacity.
>
> Applicants also note that siting additional generation near the Mankato area has not been studied using a power flow model and such additional generation may have other system consequences such as reliability violations or result in new congested elements. Moreover, adding more wind generation to the north of congestion, while it may relieve certain system constraints, will also result in

[27] *Id.* at 119-121.

underutilization of existing and more efficient wind generation sited in southern Minnesota and northern Iowa.

Q. In addition to the Applicants' consideration of renewable energy, did the Applicants consider distributed generation?

A. The Applicants did not do so in their Application, but provided an analysis in response to DOC-DER IR No. 15, in which DOC-DER requested demonstration of the Applicants' consideration of distributed generation resources in compliance with Minn. Stat. § 216B.2426. Specifically, the Applicants provided their analysis of the ability of distributed rooftop solar and community solar gardens, distributed thermal resources, and distributed wind resources in the congested area to alleviate the identified congestion issue.[28] The Applicants concluded that the available distributed generation resources would be highly unlikely to resolve the identified congestion issue, and that even if such resources could do so, each of these distributed energy resource options would be either insufficient or not cost-effective alternatives to the proposed Project.

Q. Do you conclude that the Applicants appropriately considered distributed generation alternatives in their consideration of alternatives to the proposed Project?

A. Yes. The Applicants' screening analysis was performed at a sufficient level of detail to conclude that the Applicants reasonably considered these alternatives.

[28] Ex. DER-__, ML-6 (Landi Direct) (Applicants' Response to DOC-DER IR No. 15 (May 11, 2018)).

Q. Do you agree with the conclusions that the Applicants reached regarding the viability of the generation alternatives to the proposed Project considered by the Applicants?

A. Yes. The Applicants reasonably demonstrated that additional generation resources would either be insufficient or not cost-effective alternatives to the proposed Project.

8. Summary

Q. What is your conclusion regarding the Applicants' analysis of alternatives to the proposed Project?

A. I conclude that the Applicants' analysis of alternatives to the proposed Project demonstrated sufficient consideration of reasonable alternatives to the proposed Project. The Applicants also demonstrated that the proposed Project is the best choice available to the Applicants to address the congestion issue identified by MISO.

B. ECONOMIC ANALYSIS OF THE PROPOSED PROJECT AND ALTERNATIVES

1. Overview of Analysis

Q. Can you provide an overview of the economic analysis performed by the Applicants as described in the Application to determine the proposed Project's costs and benefits compared to the 161 kV transmission line alternative?

A. The Applicants provided their internal cost analysis of the proposed Project and the 161 kV alternative in Chapter 4 of the Application. After MISO approved the proposed Project for MEP status in December 2016, the Applicants analyzed the proposed transmission project under the three MTEP17 Futures: Existing Fleet (EF), Policy

Regulations (PR), and Accelerated Alternative Technologies (AAT). MISO assigned each of these Futures a different weight, or likelihood of each Future occurring relative to one another: 31% for EF, 43% for PR, and 26% for AAT.

The Applicants then estimated project benefits under each Future by calculating the Adjusted Production Cost (APC) savings over a 20-year period. The Applicants defined APC and APC savings on page 62 of the Application. The APC is "the total production costs of a generation fleet including fuel, variable operations and maintenance, startup cost, and emissions, adjusted for import costs and export revenue," whereas APC savings "are calculated as the difference in total production costs of a generation fleet adjusted for import costs and export revenues with and without the [Project]." Given an estimated range of project costs and the expected APC savings under each Future, the Applicants determined a weighted APC savings amount of $273.11 million (in 2016 dollars) over the 20-year period analyzed.[29] Applicants subsequently calculated BC ratios, estimating that the proposed Project has BC ratios between 1.64 and 2.14.[30]

Q. Did DOC-DER request that the Applicants provide additional information or analysis regarding the proposed Project's costs and benefits compared to the 161 kV transmission line alternative?

[29] Application at 92.
[30] *Id.*

A. Yes. In DOC-DER IR No. 17, DOC-DER asked the Applicants to provide "a narrative explanation of the economic analysis performed that evaluated the costs and benefits of the proposed Project (including the costs and benefits of the various routing options considered and the 161 kV alternative)." The Applicants' stated that they conducted three different types of economic analyses of the proposed Project and the 161 kV alternative, summarized as:

(1) Present Value (PV) benefit-to-cost analysis using APC savings;

(2) Curtailment analysis; and

(3) Externalities analysis.

The Applicants detailed each of the economic analyses performed and provided updated economic analysis of the proposed Project and the 161 kV alternative in the Petition's Attachments A through G.

Q. Did the Applicants provide further information about the 161 kV alternative?

A. Yes. On August 31, 2018, the Applicants provided a supplemental response to DOC-DER IR No. 17, explaining that there was a calculation error in the original response that incorrectly excluded the final year's present value of costs for the proposed Project and the 161 kV alternative, resulting in 20 years of present value benefits being compared to 19 years of present value costs.[31]

[31] Ex. DER- __, ML-7, Attach. A, at 2 (Landi Direct) (Applicants' Supplemental Response to DER IR No. 17 (Aug. 31, 2018)).

Further, on August 13, 2018, DOC-DER requested that the Applicants explain whether the Department's Environmental Impact Statement (EIS) Scoping Decision,[32] issued July 17, 2018,[33] changed the high or low end of the cost estimate for the project. If the high or low end of the cost estimate changed, DOC-DER requested that the Applicants provide the same level of benefit-cost analysis as was done for the Project and the alternatives in the Petition. In response the Applicants provided further benefit-cost analysis of the Project.[34]

Q. What did you observe in your investigation of the Applicants' economic analyses of the 161 kV alternative?

A. The Applicants at times referenced several different ranges in estimating project costs and benefits on a 20-year PV basis and the resulting BC ratios. The Applicants summarized the economic analyses performed to compare the internal costs of the Project and the 161 kV alternative in Table 21-Second Revised in their supplemental response to DOC-DER IR No. 17.[35] In Table 17-Second Revised, also in the supplement response to DOC-DER IR No. 17, the Applicants detailed the PV benefits of the Project calculated depending on the MTEP17 Future scenario analyzed, the resulting weighted PV benefit of the Project, and the corresponding BC ratios of each scenario and the

[32] The EIS Scoping Decision is the final determination of the exact routes that will be considered by the Department's environmental review of the proposed Project and its routing alternatives, and thus represent the only routes that are subject to the Commission's decision.

[33] Ex. DER-__ ML-8 (Landi Direct) (Department of Commerce Environmental Impact Statement Scoping Decision (July 17, 2018)).

[34] Ex. DER-__ at ML-9 (Landi Direct) (Applicants' Response to DOC-DER IR No. 23 (Aug. 13, 2018)).

[35] Ex. DER-__, ML-7 at 7.

weighted BC ratio.[36] However, in response to an informal request from DOC-DER, the Applicants clarified that their response to DOC-DER IR No. 23 provided only the Projects' costs, benefits, and resulting BC ratios.[37] The Applicants did not analyze the 161 kV alternative in response to the Department's EIS Scoping Decision.

Q. Do you have an opinion regarding whether the Applicants should have analyzed the 161 kV alternative after the Department released the EIS Scoping Decision?

A. Yes. I conclude that it was reasonable for the Applicants to forgo further analysis of the 161 kV alternative for two primary reasons: (1) the screening analysis of alternatives, and the more thorough analysis of the 161 kV alternative, in the Application reasonably concluded that the 161 kV alternative would not sufficiently address the congestion issue; and (2) the 161 kV alternative would not qualify as an MEP in MISO, which means that Minnesota ratepayers would be required to pay a higher proportion of the project costs for the 161 kV alternative compared to the Project. For these two reasons, DOC-DER concludes that the Applicants reasonably determined that further analysis of the 161 kV alternative was unnecessary.

Q. What are your observations regarding the Applicants' approach to the economic analysis they performed of the Project and the 161 kV alternative?

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[36] *Id.* at 6.

[37] Ex. DER-__, ML-10 (Landi Direct) (Applicants' Response to DOC-DER Email dated September 20, 2018).

A. The Applicants' analysis appears to be a standard economic analysis of a project that accrues benefits and costs for many years in the future. The Applicants' explanation of their methodology is in their supplemental response to DOC-DER IR No. 17. As a result, I conclude that the Applicants' response is reasonable.

Q. What analysis did DOC-DER focus on in its investigation to determine the Projects' estimated costs, benefits, and BC ratios?

A. DOC-DER's investigation is based on the Applicants' internal cost analysis as provided in Attachment A to DOC-DER IR No. 23 and the additional explanation provided by the Applicants in their response to DOC-DER's informal request. In addition, I considered external costs of the proposed Project compared to alternatives.

2. Internal Costs

Q. Are you aware of any criteria used to analyze alternatives that considers internal costs?

A. Yes, Minnesota Rules 7849.0120 B(2) states that the Commission must consider "the cost of the proposed facility and the cost of energy to be supplied by the proposed facility compared to the costs of reasonable alternatives and the cost of energy that would be supplied by reasonable alternatives." This cost comparison involves direct, internal costs.

Q. What is the range of estimated PV costs, benefits and corresponding BC ratios of the Project?

A. In the Application, the Applicants' analysis of the Project concluded that the project had a weighted 20-year PV benefit of approximately $273.11 million.[38] This figure was updated in the Supplemental Response to DOC-DER IR No. 17, and was reported to be slightly higher, at $275.83 million.[39] Project costs, as described in Attachment A to DOC-DER IR No. 23, were estimated to range from a low of $104.8 million to a high of $160.7 million.[40] The resulting BC ratios range from a low of 1.42 to a high of 2.18.[41]

However, as mentioned above, the project costs represented by the Applicants in Attachment A of DOC-DER IR No. 23 are not the same as the value of the annual costs of the project. The Applicants explained in response to DOC-DER's informal information request that, for each of the 20 years analyzed, the annual costs include a 20.76% "adder" to the construction cost estimate for each route/design that accounts for the annual revenue requirements, the discount rate, and the inflation rate. Further, in response to DOC-DER IR No. 17, the Applicants explained that the annual revenue requirements were found in Attachment GG of the MISO Tariff, explaining that these rates are posted for each Transmission Owner for a 20-year period.[42] Last, the PV of project costs is determined by summing the PV of the annual project costs each year over the 20-year period.

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[38] Application at 92.
[39] Ex. DER-__, ML-7, Attach. A, at 1.
[40] Ex. DER-__ at ML-9.
[41] *Id.*
[42] Ex. DER-__, ML-11 (Landi Direct) (Applicants' Response to DOC-DER IR No. 27 (Oct. 5, 2018)).

Q. Please summarize the information about BC analyses.

A. Table 2 below summarizes the estimates of project costs, benefits, and BC ratios provided by the Applicants. Additionally, Table 2 includes my analysis of the PV costs of the project, which includes the 20.76% adder in the calculation of the 20-year PV of costs.

Table 2. Applicants' Estimates of Project Costs, Benefits, and BC Ratios

Route	Cost Estimate	Project Cost (millions, 2016$) *(Applicant Calc.)*	20-Year Present Value of Costs (millions, 2016$) *(DOC-DER Calc.)*	Benefit-Cost Ratio (millions, 2016$) *(Applicant Calc.)*	20-Year Present Value of Benefits (millions, 2016$) *(DOC-DER Calc.)*
Purple	Low	$ 104.8	$ 126.6	2.18	$ 275.89
	High	$ 147.3	$ 177.9	1.55	$ 275.71
Green	Low	$ 108.2	$ 130.7	2.11	$ 275.70
	High	$ 124.8	$ 150.7	1.83	$ 275.80
Red	Low	$ 134.4	$ 162.3	1.70	$ 275.91
	High	$ 143.8	$ 173.7	1.59	$ 276.11
Blue	Low	$ 123.7	$ 149.4	1.85	$ 276.35
	High	$ 142.5	$ 172.1	1.60	$ 275.33
Purple-E-Red	Low	$ 157.0	$ 189.6	1.46	$ 276.81
	High	$ 160.7	$ 194.1	1.42	$ 275.57

Once this adder is factored into the analysis of the 20-year PV of costs, the weighted PV benefits correspond approximately to the weighted PV benefits found in Table 17-Second Revised of Attachment A to the Applicants' Supplemental Response to DOC-DER IR No. 17, which reports a weighted 20-year PV benefit of $275.83 million (in 2016 dollars). As a result, I was able to confirm the Applicants' updated figures.

Q. Please describe your analysis of the 161 kV alternative.

A. The Applicants did not provide an estimated range of project costs for the 161 kV alternative. Rather, they provided a project cost estimate for the shortest route proposed in the Application (the Green Route), which Applicants estimated to cost $80.9 million (in 2016 dollars). The Applicants did not provide estimates of the 20-year PV benefit for each MTEP17 Future scenario in the Application. The Applicants, however, provided a weighted 20-year PV benefit of $200.7 million (in 2016 dollars) in Table 21-Second Revised found in Attachment A of the Supplemental Response to DOC-DER IR No. 17.

DOC-DER's analysis confirmed this weighted 20-year PV benefit, as shown in Table 3 below. Additionally, the Applicants provided the estimates for the 20-year PV costs, benefits, and BC ratios for the 161 kV alternative under each MTEP17 Future in the Excel spreadsheets referred to as Revised Attachments E, F, and G of the Supplemental Response to DOC-DER IR No. 17. DOC-DER's analysis below summarizes the Applicants' analysis of the 161 kV alternative under each MTEP17 Future for the cost estimate of the Green Route option of the 161 kV alternative.

Table 3. MTEP17 Analysis of 161 kV Alternative

Alternative	Project Cost Estimate (2016$)	Present Value of Benefits (2016$)		Present Value of Costs (2016$)	Benefit-Cost Ratios (DOC-DER Calc.)
161 kV Huntley-Wilmarth Tranmission Line	$ 80,900,000	AAT	$ 557,465,361.19	$ 97,697,020.4	5.71
		EF	$ 8,561,537.02		0.09
		PR	$ 123,544,753.43		1.26
		Weighted (DOC-DER Calc.)	*$ 200,719,314.36*		*2.05*

Q. Please describe your analysis comparing the proposed Project and the 161 kV alternative.

A. The Applicants provided DOC-DER with the Excel spreadsheets used to calculate the PV costs, benefits, and BC ratios of the least-cost options for the proposed Project and the 161 kV alternative. DOC-DER adapted these spreadsheets using the cost estimates provided by the Applicants in DOC-DER IR No. 23 for the proposed Project and the cost estimates provided by the Applicants in the Application for the 161 kV alternative. DOC-DER provides in Table 4 an analysis of the low- and high-cost estimates for the proposed Project using the MTEP17 Future—weighted PV of benefits and BC ratios, compared to the least cost option of the 161 kV alternative.

Table 4. Department Analysis of Project and 161 kV Alternative

Project	Applicants' Project Cost Estimate (2016$)	PV Benefits (2016$, Millions)				PV Costs (2016$, Millions)				BC Ratios (2016$, Millions)			
		AAT	*EF*	*PR*	*Weighted*	*AAT*	*EF*	*PR*	*Weighted*	*AAT*	*EF*	*PR*	*Weighted*
161 kV Huntley-Wilmarth Transmission Line Alternative	$80.9 Million	$557,465,361.19	$ 8,561,537.02	$123,544,753.43	$200,719,314.36	$97,697,020.39				5.71	0.09	1.26	2.05
345 kV Huntley-Wilmarth Transmission Line *Purple Low Route*	$104.8 Million	$816,043,675.29	$ 13,917,740.86	$138,009,303.50	$275,829,855.75	$126,559,304.54				6.45	0.11	1.09	2.18
345 kV Huntley-Wilmarth Transmission Line *Purple-E-Red High Route*	$160.7 Million	$816,043,675.29	$ 13,917,740.86	$138,009,303.50	$275,829,855.75	$194,065,651.14				4.20	0.07	0.71	1.42

Q. What do you conclude about the internal cost analysis of the proposed Project and the 161 kV alternative?

A. DOC-DER's analysis of the internal costs of both the Project and the 161 kV alternative indicates that the proposed Project appears to be a more reasonable investment, depending on the final route chosen. Even if the highest cost route is chosen, however, the overall net PV benefit of the proposed Project would be higher than the net PV benefit of the 161 kV alternative. This analysis, along with consideration of the other factors described in my testimony such as the fact that the 161 kV alternative is not able to fully address the congestion problem, leads me to conclude that the Applicants reasonably determined that the 161 kV alternative is not more economical than the proposed Project.

Q. What do you conclude about the Applicants' analysis of internal costs of the project compared to the 161 kV alternative?

A. I conclude that the Applicants' internal cost analysis indicates that the 161 kV alternative is not a more reasonable and prudent alternative to the proposed Project.

3. External Costs

Q. Has the Commission ordered either ITCM or Xcel to account for CO_2 emissions in past transmission line proceedings?

A. Yes. In the Commission's November 25, 2014 order in Docket No. ET6675/CN-12-1053 the Commission required ITCM to:

> …work with the Department to develop a spreadsheet and make a compliance filing containing a spreadsheet ITC can use to calculate the cost of alternatives, including the Commission's CO_2 internal cost and externality values, in future certificate of need filings in a consistent manner.

Q. Have the Applicants provided the information required by the Commission in this proceeding?

A. Yes. This information is included in Appendix I to the Application.

Q. What other items were included in the Applicants' analysis of socioeconomic costs and benefits of the proposed Project and the 161 kV alternative?

A. The Applicants' analysis of socioeconomic costs and benefits (externalities analysis) included the environmental impact of changes to electricity generation resulting from the proposed Project and the 161 kV alternative. This environmental impact is a comparison of the changes in the emissions of CO_2, sulfur dioxide (SO_2), and nitrogen oxides (NO_x) that result from changes in electricity generation from electrical generating units (EGUs) in MISO Load Resource Zones (LRZ) 1, 2, and 3 that are induced by the proposed Project and the 161 kV alternative.

Q. How did the Applicants assess the environmental impacts of these types of emissions in comparing the proposed Project and the 161 kV alternative?

A. The Applicants quantified the environmental impacts in monetary terms by using the range of externality cost estimates for emissions of CO_2, SO_2, and NO_x that were approved by the Commission in Docket No. E-999/CI-14-642, *Order Updating Environmental Cost Values* dated January 3, 2018 (Externalities Order). The Applicants refer to these quantified values as the "public policy benefits" of the proposed Project and the 161 kV alternative.[43] Further, the Applicants used a low and high value for a range of CO_2 externality costs to provide a range of public policy benefits.

The Applicants noted that there was a significant difference in CO_2 emission changes as a result of the proposed Project and the 161 kV alternative relative to one

[43] Application at 105.

another. The Applicants declined to use a low and high value range of externality costs for SO_2 and NO_x in quantifying public policy benefits, though they do provide a low, median, and high value for externality costs of these pollutants. Instead the Applicants used the median value of the rural location as approved in the Externalities Order, due to the relatively small change in SO_2 and NO_x emission changes as a result of the proposed Project or the 161 kV alternative relative to one another.

Q. What do you conclude about the Applicants' decision to use the median value of SO_2 and NO_x externality costs?

A. I conclude that the Applicants' approach is reasonable, given my review of the changes in emissions of CO_2, SO_2, and NO_x resulting from the proposed Project and the 161 kV alternative relative to one another. Specifically, the difference in SO_2 and NO_x emissions between the proposed Project and 161 kV alternative is much smaller than the difference between CO_2 emissions, indicating that using high and low values for SO_2 and NO_x emissions would have no meaningful effect on the results.

Q. Please summarize the differences in emission reductions of CO_2, SO_2 and NO_X under the proposed Project and the 161 kV alternative.

A. Table 5 below summarizes the emission reductions for CO_2, SO_2, and NO_x for the proposed Project and the 161 kV alternative for years 2021, 2026, and 2031 as modeled by the Applicants. The three columns to the right of Table 5 provide the estimated differences in emission reductions, for each emission type, between the proposed

Project and the 161 kV alternative. Positive figures indicate that the proposed Project would reduce emissions more than the 161 kV alternative. Since all figures are positive, it is appears that the proposed Project would result in greater emissions reductions of CO_2, SO_2, and NO_x for years 2021, 2026, and 2031 relative to the 161 kV alternative.

Table 5. Annual Emission Reductions of the Proposed Project and the 161 kV Alternative

Annual Emissions Reductions (short tons)											
Huntley-Wilmarth 345 kV				Huntley-Wilmarth 161 kV				Difference Between 345 kV and 161 kV			
PROMOD Year	SO2	NOx	CO2	PROMOD Year	SO2	NOx	CO2	PROMOD Year	SO2	NOx	CO2
2021	105.36	84.66	159,048.38	*2021*	59.60	54.02	76,280.43	*2021*	45.76	30.64	82,767.94
2026	57.17	131.27	339,622.20	*2026*	51.64	89.89	210,511.42	*2026*	5.53	41.38	129,110.79
2031	21.60	33.39	442,764.48	*2031*	19.76	32.69	316,322.91	*2031*	1.84	0.70	126,441.57

The table also illustrates the magnitude of the difference in emissions reductions: reductions of SO_2 (8.5 percent to 43 percent) and NO_x (2.1 percent to 36.2 percent) resulting from the proposed Project relative to the 161 kV alternative are expected to be much smaller than reductions of CO_2 (29 percent to 52 percent) resulting from the proposed Project relative to the 161 kV alternative.

Q. What do you conclude regarding the differences in emission reductions of CO_2, SO_2 and NO_X under the proposed Project and the 161 kV alternative?

A. Given the smaller magnitude in the difference between SO_2 and NO_x emissions than CO_2 emissions, I conclude that applying a low and high value for SO_2 and NO_x externality costs wouldn't have a material difference in the comparison of the public policy benefits of the proposed Project and the 161 kV alternative. I therefore conclude that the Applicants' decision to use the median values for SO_2 and NO_x externality costs, instead of a range of costs as they did for CO_2 externality costs, was reasonable.

Q. Please describe the Applicants' externalities analysis of the proposed Project and the 161 kV alternative.

A. The Applicants described their externalities analysis in response to DOC-DER IR No. 20.[44] The Applicants assumed high, medium, and low cost route options for the proposed Project and assumed a medium cost route option for the 161 kV alternative. The Applicants quantified the costs and benefits of the three route options of the proposed Project and the single route option of the 161 kV alternative.

Q. What approach did the Applicants use for this externality analysis?

A. Over an assumed 63-year evaluation period to match the assumed life of the transmission assets, and relying on MISO assumptions for a few financial variables,[45] the Applicants quantified the total benefits by summing the economic benefits (the APC savings) and the public policy benefits (reduced emissions) of the three route options for the proposed Project and the 161 kV alternative for each year beginning in 2022 and ending in 2084. As noted above, the Applicants used low and high values for CO_2 externality costs to calculate a range of public policy benefits.

The Applicants then calculated the present value of the annual revenue requirements of the three route options and the 161 kV alternative. Next, the Applicants subtracted the present value of the annual revenue requirements from the present value of the annual total benefits to determine the present value of the annual

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[44] Ex. DER-_, ML-12 (Landi Direct) (Applicants' Response to DOC-DER IR No. 20 (June 8, 2018)).

[45] These assumptions include: a Levelized Fixed Charge Rate that is an average of ITC Midwest and Xcel Energy levelized fixed charge rates derived analogous to MISO's Schedule 26-Indicative Annual Charge Rates, an inflation rate of 2.50%, and a discount rate of 7.10%.

net benefit of the three route options of the proposed Project and the 161 kV alternative. Last, the Applicants summed the annual net benefits and determined the cumulative net benefit of the three route options of the proposed Project and the single route option of 161 kV alternative. The Applicants represented the net benefits for each as a range of net benefits given their use of low and high values for CO_2 externality costs.

Figure 1 below provides a simplified formula to help illustrate the Applicants' calculation of net benefits.

Figure 1. Applicants' Net Benefit Calculation in Externalities Analysis

$$\sum_{t=2022}^{63} Economic\ Benefits_t + Public\ Policy\ Benefits_t - Revenue\ Requirements_t$$

Q. What did you observe about the APC "Benefits" found in the Applicants' externalities analysis?

A. The APC "Benefits" used in the Applicants' externalities analysis were different than the APC "Savings" used in the Applicants' economic analysis for both the proposed Project and the 161 kV alternative. The Applicants explained in their response to IR No. 20 that they adjusted the APC Benefits used in the externalities analysis to avoid double counting emissions reductions by removing the change in emission costs from the APC benefit for all MISO North/Central resources.

Table 6 below summarizes the difference between the APC Benefits used in the Applicants' economic analysis and the Modified APC Benefits used in the Applicants' externalities analysis.

Table 6. APC Benefits vs. Modified APC Benefits

Alternative	Modeled Years	APC Benefits	Modified APC Benefits	Difference
Huntley-Wilmarth 345 kV	*2021*	$ 2,530,635	$ 2,542,357	$ (11,722)
	2026	$ 19,316,251	$ 18,109,417	$ 1,206,834
	2031	$ 44,233,463	$ 34,146,457	$ 10,087,006
Huntley-Wilmarth 161 kV	*2021*	$ 1,980,774	$ 1,979,035	$ 1,739
	2026	$ 15,445,589	$ 14,419,053	$ 1,026,536
	2031	$ 32,073,406	$ 24,231,427	$ 7,841,979

Q. What did you observe about the Applicants' reported range of net benefits for the proposed Project and the 161 kV alternative?

A. At the time of the Applicants' response to DOC-DER IR No. 20, in which they provided a range of net benefits for the proposed Project and the 161 kV alternative, the Department had not issued the EIS Scoping Decision. Thus, the Applicants relied on the original project cost estimates in the Application in their calculation of the annual revenue requirements, and not the updated project cost estimates provided in response to DOC-DER IR No. 23, which incorporated the route alternative as detailed in the EIS Scoping Decision. As a result, the reported net benefits of the Applicants' externalities analysis is out of date.

Q. Please explain how the Applicants' externalities analysis is out of date.

A. The Applicants relied on the Blue, Green, and Purple routes in their cost estimates for high, medium, and low cost route options in their externalities analysis. The Department's EIS Scoping Decision considered an additional route: the Purple-E-Red

Route.[46] The Purple-E-Red Route has estimated costs that exceed the bounds considered in the Applicants' externalities analysis. Specifically, the Blue route in the Applicants' externalities analysis has an estimated cost of $138.02 million, whereas the Purple-E-Red Route has cost estimates ranging from $157.0 million to $160.7 million. The costs of the various routing options, as provided by the Applicants in their response to DOC-DER IR No. 23, were provided in Table 2 above.

Q. How did you reconcile the updated economic analysis provided in response to DOC-DER IR No. 23 with the out-of-date externalities analysis provided in response to DOC-DER IR No. 20?

A. I adjusted the underlying project cost assumptions in the spreadsheet provided by the Applicants in response to DOC-DER IR No. 19, used to perform the Applicants' externalities analysis, to match the project cost assumptions provided in response to DOC-DER IR No. 23. I used the following routes and their respective costs to update the Applicants' externalities analysis: (1) High Cost: high-end cost estimate of the Purple-E-Red Route ($160.7 million); (2) Medium Cost: low-end cost estimate of the Red Route ($134.4 million); and (3) Low Cost: low-end cost estimate of the Purple Route ($104.8 million).

Q. What effect did use of the updated information from the EIS Scoping Decision have on the Applicants' externalities analysis?

[46] Ex. DER-__, ML-8.

A. Updating the project cost assumptions in the externalities analysis to reflect the cost estimates of the routing options presented in the EIS Scoping Decision and the Applicants' Response to DOC-DER IR No. 23 changed the overall net benefits of the proposed Project. However, updating the project cost assumptions did not have an appreciable effect on the economic benefits or the public policy benefits of the project, even though the net benefits changed somewhat.

Table 7 below summarizes my updated analysis of the proposed Project's net benefits using updated project cost estimates for the routing options presented in the EIS Scoping Decision and the Applicants' Response to DOC-DER IR No. 23. The Applicants' externalities analysis of the 161 kV alternative did not need to be updated but is provided in Table 7 for reference.

Table 7. The Department's Updated Externalities Analysis

Alternative	Route	Project Cost (2016$)	Present Value (2016$)			
			Economic Benefit	Public Policy Benefit	Revenue Requirement	Net Benefits
Huntley-Wilmarth 345 kV	Low Cost: Purple Route (Low)	$ 104,800,000	$ 470,716,689	$ 100,677,763 to $ 455,788,000	$ 154,625,649	$ 416,768,803 to $ 771,879,040
	Medium Cost: Red Route (Low)	$ 134,400,000			$ 198,298,542	$ 373,095,910 to $ 728,206,147
	High Cost: Purple-E-Red Route (High)	$ 160,700,000			$ 237,102,498	$ 334,291,954 to $ 689,402,191
Huntley-Wilmarth 161 kV	Medium Cost: Green Route	$ 80,900,000	$ 339,693,909	$ 75,134,571 to $ 331,485,787	$ 119,362,738	$ 295,465,743 to $ 551,816,959

Q. Please summarize the key information from Table 7.

A. Table 7 summarizes my analysis of the Applicants' Externalities Analysis, which uses more accurate cost estimates for the proposed Project using route options that are presented in the EIS Scoping Decision. Taking into account these more accurate cost estimates for the proposed Project, my analysis results in different results for the proposed Projects' net benefits. Table 7 also demonstrates that net benefits of the proposed Project are higher than the net benefits of the 161 kV alternative regardless of which route option of the proposed Project is selected.[47]

Q. How does this updated information affect the net benefits of the proposed Project compared to a 161 kV alternative?

A. Since my updated analysis changed the Applicants' reported net benefits of the proposed Project, I provide Table 8 below to illustrate the difference between DOC-DER's updated externalities analysis and the Applicants' original externalities analysis for the proposed Project. Positive figures indicate that the Applicants' estimate of net benefits of the proposed Project are lower than DOC-DER's updated analysis incorporating the EIS Scoping Decision, whereas negative figures indicate that the Applicants' estimated net benefits are higher.

[47] This can be determined by determining the difference between the net benefits of each of the routing options for the proposed Project and the 161 kV alternative. In each case, the proposed Project has a higher net benefit than the 161 kV alternative.

Table 8. Comparison of the Externalities Analysis of the Proposed Project

	Route	Project Cost (2016$)	Revenue Requirement (Present Value, 2016$)	Net Benefits (Present Value, 2016$)			
Department	*Low Cost*	$ 104,800,000	$ 154,625,649	$ 416,768,803	to	$ 771,879,040
	Medium Cost	$ 134,400,000	$ 198,298,542	$ 373,095,910	to	$ 728,206,147
	High Cost	$ 160,700,000	$ 237,102,498	$ 334,291,954	to	$ 689,402,191
Applicants	*Low Cost*	$ 105,800,000	$ 156,130,593	$ 415,263,859	to	$ 770,374,759
	Medium Cost	$ 121,320,000	$ 178,999,845	$ 392,394,608	to	$ 747,505,509
	High Cost	$ 138,020,000	$ 203,639,619	$ 367,754,834	to	$ 722,865,735
Difference	*Low Cost*	*$ (1,000,000)*	*$ (1,504,944)*	*$ 1,504,944*	to	*$ 1,504,281*
	Medium Cost	*$ 13,080,000*	*$ 19,298,697*	*$ (19,298,698)*	to	*$ (19,299,362)*
	High Cost	*$ 22,680,000*	*$ 33,462,879*	*$ (33,462,880)*	to	*$ (33,463,544)*

Q. Overall, what does Table 8 indicate?

A. Table 8 indicates that the use of updated project cost estimates in my analysis results in a higher net benefit for the low-cost route option for the proposed Project relative to the Applicants' low cost route option for the proposed Project, and a lower net benefit for both the medium and high cost route options relative to the Applicants' medium and high cost route options. These results are due to the lower revenue requirement for the low cost route option and the higher revenue requirements for the medium and high cost route options.

Q. What do you conclude about the Applicants' externalities analysis?

A. I conclude that the Applicants' externality analysis appropriately used the Commission's externality values and cost of future CO_2 regulation values. I also conclude that the methodology employed by the Applicants to conduct the externality analysis is reasonable.

Further, my investigation of the Applicants' externality analysis confirms that the proposed Project is superior to the 161 kV alternative due to the higher net benefits associated with the proposed Project. As indicated by Table 7 above, and assuming that the highest cost route is selected for the proposed Project, its net benefits range from approximately $38.8 million ($334,291,954 minus $295,465,743) to $137.6 million ($689,402,191 minus $551,816,959) higher than the 161 kV alternative. Also as indicated by Table 7 above, if the lowest cost route is selected for the proposed Project, its net benefits range from approximately $121.3 million ($416,768,803 minus $295,465,743) to $220 million higher ($771,879,040 minus $551,816,959) than the 161 kV alternative.

4. Other Considerations

Q. Are you aware of any other factors the Commission is required to evaluate?

A. Minnesota Statutes § 216B.243, subd. 3(9) states that the Commission must evaluate "with respect to a high-voltage transmission line, the benefits of enhanced regional reliability, access, or deliverability to the extent these factors improve the robustness of the transmission system or lower costs for electric consumers in Minnesota."

Q. Did the Applicants perform any analysis of the 161 kV alternative in the context of the considerations stated in Minnesota Statutes § 216B.243, subd. 3(9)?

A. Yes. The Applicants considered three additional metrics in developing alternatives to the proposed Project: (1) the effect of the proposed Project and the 161 kV alternative on the deliverability of wind generation by reducing wind resource curtailments; (2) the effect of the proposed Project and the 161 kV alternative on transmission system efficiency by reducing system losses during off-peak, high-wind conditions and summer peak conditions; and (3) providing congestion relief to the identified congestion issue.

The Applicants concluded that the proposed Project was generally better than the 161 kV alternative for all three metrics, with the exception of the magnitude in the reduction of system losses during summer peak conditions: the 161 kV alternative had a slightly larger reduction in system losses than the proposed Project during these conditions.

Q. What did you conclude regarding the Applicants' analysis of reductions in wind curtailments?

A. I reviewed the Applicants' analysis of the expected wind resource curtailments resulting from the proposed Project and the 161 kV alternative under the three MTEP17 Futures. Table 9 below summarizes my analysis of the expected wind resource curtailments resulting from the proposed Project and the 161 kV alternative.

Table 9. Weighted Impact of the Proposed Project and the 161 kV Alternative On Wind Resource Curtailments

Alternative	Modeled Years	Base Curtailments (MWh)	Curtailments with Project Added (MWh)	Reduction in Curtailments (MWh)	Percent Reduction
Huntley-Wilmarth 345 kV	*2026*	2,222,478	1,896,455	326,047	18.7%
	2031	5,333,712	4,805,331	528,380	15.8%
Huntley-Wilmarth 161 kV	*2026*	2,222,478	1,984,634	239,158	9.9%
	2031	5,333,712	4,957,460	376,252	11.5%

Q. What does Table 9 indicate?

A. Table 9 shows that the proposed Project is projected to have a larger impact on the reduction in wind resource curtailments than the 161 kV alternative. In other words, more electricity generation from wind resources would likely be delivered as a result of the proposed Project than the 161 kV alternative. Reducing wind resource curtailments would likely put a downward pressure on electricity prices in MISO due to the generally lower variable costs of wind resources.

Q. What did you conclude regarding the Applicants' analysis of reductions in system losses?

A. I investigated the Applicants' analysis of the expected reduction in system losses resulting from the proposed Project and the 161 kV alternative. Table 10 below is a re-creation of Table 25 in the Application and details the expected system losses during summer peak conditions and during off-peak, high wind conditions.

Table 10. Impact of the Proposed Project and the 161 kV Alternative On the Reduction of System Losses

Alternative	Summer Peak (Reduction in System Losses)	Off-Peak, High Wind (Reduction in System Losses)
Huntley-Wilmarth 345 kV	2.3 MVA	75.89 MVA
Huntley-Wilmarth 161 kV	3.4 MVA	12.6 MVA

Q. What does Table 10 indicate?

A. Table 10 indicates that the proposed Project would be much more effective at reducing system losses during off-peak, high wind conditions than the 161 kV alternative. However, as noted above, the 161 kV alternative performs slightly better than the proposed Project at reducing system losses during summer peak conditions. DOC-DER asked the Applicants to explain this result.

In response to DOC-DER IR No. 12, the Applicants explained that the 161 kV alternative performs slightly better than the proposed Project due to the assumption of low levels of wind generation during summer peak conditions resulting in potentially lower power flows over a transmission line connecting the Huntley and Wilmarth substations.[48] Due to the physical characteristics of the voltage levels of the lines and the different requirements of each line when operating in low load conditions, the proposed Project is expected to be slightly less effective than the 161 kV alternative at reducing system losses during summer peak conditions. Reducing system losses in either scenario puts a downward pressure on electricity prices and improves the "robustness" of the system by improving system reliability.

[48] Ex. DER-__, ML-13 (Landi Direct) (Applicants' Response to DOC-DER IR No. 12 (May 11, 2018)).

Q. What did you determine regarding the Applicants' analysis of congestion relief between the proposed Project and 161 kV alternative?

A. I reviewed the Applicants' analysis of the proposed Project and the 161 kV alternative's ability to relieve the congestion issue that MISO identified in the Blue Earth area. In response to DOC-DER IR Nos. 10 and 11, the Applicants provided further details of their analysis that led them to conclude that the proposed Project is better able to provide congestion relief. In the supplemental response to DOC-DER IR No. 10, the Applicants explained that the 161 kV alternative provides 100% of congestion relief in 2021, but is only able to provide 75% and 80% of congestion relief in 2026 and 2031, respectively, on a weighted basis.[49]

In response to DOC-DER IR No. 11, the Applicants explained that the proposed Project is expected to be able to provide 100% of congestion relief under any MTEP17 Future scenario, including the Advanced Alternative Technology scenario, which is the scenario where approximately 93,800 MW of capacity was added by 2031.[50]

Q. What do you conclude regarding which transmission line is more likely to result in enhanced regional reliability, access, or deliverability, improve the robustness of the system, and lower electricity prices in Minnesota?

A. Based on my investigation of the Applicants' analysis of wind resource curtailment reductions, transmission system loss reductions, and the ability of each transmission line

[49] Ex. DER-__, ML-14 (Landi Direct) (Applicants' Supplemental Response to DOC-DER IR No. 10 (Aug. 31, 2018)).
[50] Ex. DER-__, ML-15 (Landi Direct) (Applicants' Response to DOC-DER IR No. 11 (May 11, 2018)).

to provide congestion relief in the Blue Earth area, I conclude that the proposed Project would be better positioned to deliver system benefits and relieve the identified congestion issue.

For example, the magnitude of wind resource curtailment reductions of the proposed Project relative to the 161 kV alternative would better enhance regional reliability, access, and deliverability of generally lower cost wind resources, putting downward pressure on electricity prices for Minnesota ratepayers. Further, the reduction of system losses resulting from the proposed Project relative to the 161 kV alternative during off-peak, high-wind conditions would allow for greater deliverability of wind resources. While the 161 kV alternative is slightly better at reducing system losses during summer peak conditions, the magnitude of difference between the reduction in system losses projected to result from the proposed Project and the 161 kV alternative is not significant.

Moreover, the proposed Project is the only alternative examined by MISO and the Applicants that demonstrated an ability to relieve 100% of the identified congestion issue in the Blue Earth area.

Q. What do you conclude about the proposed Project compared to the 161 kV alternative?

A. Looking at a broader view of metrics in comparing the proposed Project and the 161 kV alternative, the Applicants determined that the proposed Project outperformed the 161 kV alternative with respect to:

(1) 20-Year NPV Benefit: The proposed Project has a higher 20-year NPV benefit than the 161 kV alternative (approximately $276 million vs. $200.7 million);

(2) Curtailment Reductions: The proposed Project is expected to provide 86,000 MWh more wind resource curtailment reductions in 2026 and 150,000 MWh more wind resource curtailment reductions in 2031 than the 161 kV alternative.

(4) Reduced System Losses: The proposed Project was more effective at reducing system losses in off-peak, high wind conditions than the 161 kV alternative. While the 161 kV alternative was slightly better than the proposed Project at reducing system losses during summer peak conditions, the difference doesn't appear to be significant.

(4) Congestion Relief: In the supplemental response to DOC-DER IR No. 10, the Applicants updated their analysis of the impact that the 161 kV alternative had on congestion relief and concluded that, by 2031, the alternative is expected to alleviate only 80% of the identified congestion, while the proposed Project is expected to relieve 100% of the identified congestion over the ten-year study period.

(5) Externalities Benefits: The proposed Project is expected to have higher reductions in externalities than the 161 kV alternative and a higher overall amount of net benefits than the 161 kV alternative. Even assuming the highest cost route for the proposed Project (Purple-E-Red Route, $160.7 million), net benefits for the proposed Project are expected to range from $334,291,954 to $689,402,191, while the net benefits of the 161 kV alternative are expected to

range from $295,465,743 to $551,816,959. As a result, the proposed Project is expected to provide net benefits that are $38,826,211 to $137,585,232 greater than the 161 kV alternative.

(6) <u>Cost allocation</u>: The proposed Project qualifies as an MEP, which allows for cost sharing across the MISO region, whereas all of the costs of a 161 kV alternative would be assigned locally. As an MEP, Minnesota ratepayers would pay a lower share of the costs of the proposed Project than the 161 kV alternative, whose costs would instead be assigned to the local resource zone in MISO. This aspect of the proposed Project is addressed further in Department Witness Mark Johnson's testimony.

Q. Based on the analysis you conducted above, do you have an opinion on the Applicants' analysis and their conclusion that the proposed Project is a superior option to address the identified congestion issue compared to the 161 kV transmission line alternative?

A. Yes. In consideration of the analysis above comparing the 161 kV alternative to the proposed Project, I conclude that the Applicants reasonably concluded that the proposed Project is the best choice analyzed by MISO and the Applicants to address the identified congestion issue.

By contrast, the 161 kV alternative has a lower 20-year NPV, would not fully address the identified congestion issue over the study period analyzed by MISO and the Applicants, would not reduce wind resource curtailments to the degree that the proposed Project does, would have lower reduced system losses in off-peak, high-wind conditions, would have a lower externalities benefit, and would not qualify as an MEP, which would result in higher costs to Minnesota ratepayers.

IV. SUMMARY AND RECOMMENDATIONS

Q. Overall, what do you conclude, based on your analysis above?

A. I conclude that the Applicants' analysis provides significant information regarding alternatives for the Commission to consider in making determinations under Minnesota Statutes and Rules. I also conclude that the Applicants' analysis reasonably concluded that none of the alternatives considered were better than the proposed Project.

Q. Does this complete your Direct Testimony?

A. Yes.

Education

2013 PhD Student	University of Wisconsin – Madison Environment and Resources; Energy Analysis and Policy PhD Minor
2012 MELP (H)	Vermont Law School Master of Environmental Law and Policy; Energy Law Certificate
2011 BSc (H)	University of Wisconsin – La Crosse Political Science, Public Administration, and Philosophy; Environmental Studies Minor

Professional Experience

Public Utility Rate Analyst III, Minnesota Department of Commerce ***10/17 – Present***
- Conduct analyses and provide technical support on rate design, rate of return, cost recovery methods/policies, energy conservation, resource planning, service policies, forecasting, renewable energy, regional/federal activities, and other issues in gas and electric utility matters.
- Testify before the Minnesota Public Utilities Commission in various regulatory proceedings.

Program Assistant, County of Dane, Office of Energy and Climate Change ***07/17 – 10/17***
- Support and research analyst for recently established Office of Energy and Climate Change, primarily responsible for facilitating meetings of the Dane County Council on Climate Change and meetings of various subcommittees and technical working groups.
- Responsible for researching de-carbonization, sustainability, energy efficiency, and renewable energy projects proposed by the Council on Climate Change and making technical policy recommendations.

Research Assistant, UW-Madison Department of Forest and Wildlife Ecology ***06/17 – 10/17***
- Assisted Professor Craig Johnston in the development of an academic article intended for publication
- Assessed the economic impact of incomplete exchange rate pass-through on the emergent wood pellet industry relied upon by EU countries for meeting renewable energy targets.
- Responsible for collecting and analyzing data, conducting literature reviews, and drafting article.

Program Assistant - Academic Lead, PEOPLE Program ***08/16 – 09/17***
- Co-supervisor of twelve (12) tutors for an academic enrichment program that seeks to enhance student academic achievement and professional development, and prepare students for success in college.
- Developed and/or implemented weekly academic enrichment lessons in Social Studies and English courses.
- Mentor high school students for success in the classroom and the community, provide direct academic tutoring, and assist students with ACT and AP examination preparation.

Teaching Assistant, Wisconsin School of Business ***06/16 – 09/17***
- MHR 300 – Managing Organizations. Instructor: Dr. James Sesil.
- Teaching Assistant and grader for an upper level Management and Human Resources course.
- Responsible for developing test questions for weekly tests, midterm, and final examinations, grading papers, special projects, monitoring discussion in online forum, and responding to student inquiries.

Teaching Assistant, University of Wisconsin – Madison ***01/16 - 05/16***
- GEOG/ENVIR ST 139 – Living in the Global Environment. Professor William Gartner.
- Responsible for teaching four discussion sections consisting of approximately 80 students, grading weekly assignments, and proctoring McBurney student exams.
- Created lesson plans to enhance student understanding of course material.

- Facilitated student learning through the creation of interactive and engaging discussion activities.

Science and Policy Associate, Clean Wisconsin ***05/14 – 07/17***

- Expert Witness in Wisconsin Public Service Commission Docket #5-CE-145.
- Lead or contributing author of white papers on EPA's *Clean Power Plan* (79 FR 34829) analyzing the technical, legal, and policy implications for Wisconsin's electric power sector. (Report 1, Report 2)
- Led technical analysis of Madison Gas and Electric's (MGE) 2014 Rate Case (Docket #3270-UR-120) and drafted a public comment analyzing the impacts of MGE's proposal on air quality.
- Assisted a stakeholder outreach project called the 'Wisconsin Power Sector Dialogue' that brought together utilities, regulators, academia, and public interest stakeholders to discuss the future of Wisconsin's power sector given emergent economic, technical, and legal developments.
- Oversaw development of volunteer program, including management and human resources functions.
- Extensive grant experience, including proposal development, reports, and monitoring.

Sustainable Energy Associate, University of Wisconsin - Extension ***09/13 - 05/14***

- Maintained Energy on Wisconsin and Zero Net Energy websites. Researched and drafted summaries of technical information of renewable energy, energy efficiency, and zero net energy projects.
- Utilized MailChimp for monthly newsletters targeting elected and public officials, businesses, community organizations, and individuals.

Leadership and Service

University of Wisconsin – Madison

2015 – 2017	Nelson Institute Graduate Student Mentor
2014 – 2016	Madison Civics Club, Board of Directors, Reservations Chair, Publicity Co-Chair
2014 – 2016	Wisconsin Film Festival Volunteer
2014, 2015	Nelson Institute Earth Day Conference Volunteer Earth Day

Vermont Law School

2011 – 2012	VLS Club Soccer, President
Earth Week 2012	Earth Week Committee, Public Relations Director

University of Wisconsin – La Crosse

2010 – 2011	Election Commissioner, UW-La Crosse Student Association
2009 – 2011	Member, Joint Committee on Environmental Sustainability
2008 – 2009	Vice Chair, Legislative Affairs Committee
2008 – 2010	Judicial Board, Sigma Tau Gamma Fraternity
2009 – 2010	Executive Board, Sigma Tau Gamma Fraternity

Awards and Honors

2016	Honorary Fellow, Global Legal Studies Center, University of Wisconsin Law School
2015	Spark Clean Energy Fellow Finalist
2013	Presidential Management Fellows (PMF) Program Finalist
2010	College of Liberal Studies *Excellence Award* in Political Science/Public Administration
2010 – 2011	Order of Omega Honors Society (Greek Life)
2010 – 2011	Eta Phi Alpha Honors Society (College of Liberal Studies)
2009 – 2011	Pi Sigma Alpha Honors Society (Political Science and Public Administration)
2009 – 2011	Roscoe Jenkins Scholar, Sigma Tau Gamma Fraternity
2008	Emerging Leader Award, UW-La Crosse Student Association
Fall 2008	Delta-Zeta-Iota "DZI" Award, Sigma Tau Gamma Fraternity
Fall '08/Spring '10	Highest GPA Award, Sigma Tau Gamma Fraternity
Spring 2008	Outstanding New Member Award, Sigma Tau Gamma Fraternity
2006 – 2011	Dean's List, 7 Semesters at UW-La Crosse

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Xcel Energy

Docket No.:	E002,ET6675/CN-17-184		
Response To:	MN Department of Commerce	Information Request No.	3
Requestor:	Matthew Landi / Steve Rakow		
Date Received:	May 1, 2018		

Question:

Topic: "Size" of the Proposed Transmission Line and Alternatives
Reference(s): Minnesota Rules 7849.0120 B (1); Application, Sec. 5.1, pp. 98 - 113

"Size" has been interpreted by the Department to refer to the quantity of the power transfers that the transmission line enables. Please characterize the proposed transmission line and each of the alternatives considered in the Applicants' screening analysis in terms of the Department's interpretation of "size."

Response:

The Applicants view the Department's interpretation of "size" to be best represented by the capacity of the proposed transmission line and each of the alternatives, as measured in mega volt amps. This is because the capacity of a transmission line dictates the maximum amount of power that can be transferred by the line. The capacity of a transmission line is a function of its voltage as, generally speaking, higher voltage lines have higher capacity than lower voltage lines.

Below is the voltage level and current limitations for each of the alternatives used to calculate the "size" of each[1].

Higher Voltages

Applicants did not perform a detailed analysis of either a 765 kV or a 500 kV line for the reasons stated on page 99 of the Certificate of Need Application. The typical capacities of these voltages of line are provided below:

[1] Amperage Limit: MISO Business Practice Manual -029 r2, page 59

Typical 765 kV transmission line:

- (765,000 Volts)*(4,000 Amps)*(√3) = 5,300.08 MVA (Mega volt-amps)

Typical 500 kV transmission line:

- (500,000 Volts)*(3,000 Amps)*(√3) = 2,598.08 MVA (Mega volt-amps)

Proposed Voltage

Both the Applicants and MISO studied several 345 kV alternatives to the proposed Project. The capacity of the proposed Huntley – Wilmarth 345 kV transmission line and all other 345 kV alternatives is:

- (345,000 Volts)*(3,000 Amps)*(√3) = 1,792.67 MVA (Mega volt-amps)

Lower Voltages

Applicants did not perform a detailed analysis of 230 kV, 138 kV, 115 kV, or 69 kV transmission line alternatives for the reasons discussed on pages 99-102 of the Application. The typical capacities of these voltages of line are provided below. Both MISO and the Applicants analyzed several 161 kV alternatives. The different capacities of the 161 kV alternatives that were analyzed are provided below.

Typical 230 kV transmission line:

- (230,000 Volts)*(1,200 Amps)*(√3) = 478.05 MVA (Mega volt-amps)

Typical 138 kV transmission line:

- (138,000 Volts)*(1,200 Amps)*(√3) = 286.83 MVA (Mega volt-amps)

161 kV Alternatives:

- 1,200 Amp Alternatives
  - (161,000 Volts)*(1,200 Amps)*(√3) = 334.63 MVA
- 1,600 Amp Alternatives
  - (161,000 Volts)*(3,000 Amps)*(√3) = 446.18 MVA

Typical 115 kV transmission line:

- (115,000 Volts)*(1,200 Amps)*(√3) = 239.02 MVA (Mega volt-amps)

Typical 69 kV transmission line:

- (69,000 Volts)*(1,200 Amps)*(√3) = 143.41 MVA (Mega volt-amps)

Preparer:	Drew Siebenaler
Title:	Sr. Engineer
Department:	Regional Transmission Planning
Telephone:	(612)321-3195
Date:	May 11, 2018

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Xcel Energy

Docket No.:	E002,ET6675/CN-17-184		
Response To:	MN Department of Commerce	Information Request No.	4
Requestor:	Matthew Landi / Steve Rakow		
Date Received:	May 1, 2018		

Question:

Topic: Substation Upgrades
Reference(s): Application, Sec. 5.1.1.2, p. 99

What upgrades to the Huntley and Wilmarth substations are necessary to accommodate 230 kV and 138 kV transmission lines and how much would that cost?

Response:

138 kV Substation Alternative

138 kV is not a standard voltage for ITC Midwest or Xcel Energy and is not present in Minnesota. This voltage is more predominant in southeast Wisconsin and Northern Illinois.

To accommodate a new 138 kV connection at these two substations, both utilities would build the transmission lines, breakers, and switches to 161 kV standards, but operate them at 138 kV. This will allow the use of existing stock components for these items and reduce the cost of new material additions at our warehouses. The differential in cost for these items from 138 kV to 161 kV is not material due to the fact that the basic insulation levels requirements for each voltage are relatively close.

We assumed two 138 kV line exits out of each substation and a single 345/138 kV transformer at each substation, additional exits would require more infrastructure and additional cost.

Huntley Substation:
To accommodate the transformation of the 345 kV line to 138 kV, ITC Midwest would need to build a new 138 kV fenced area adjacent to the existing Huntley Substation. This new 138 kV fenced area would be built to the east of the existing Huntley Substation. A new fenced area is required because the current fenced area is only able to accommodate additional line connections for the voltages that are currently present at this substation (i.e., 161 kV and 345 kV). The new fenced area would fit within land that is currently owned by ITC Midwest. The new fenced area would be roughly 320' x 200' with the graded area being roughly 400' x 230' for drainage control and contour matching to existing grade.

ITC Midwest estimated price for this installation adjacent to Huntley is $10.5 million (2016$).

<u>Required equipment</u>
Existing Huntley Substation:
1-345 kV Breaker
2-345 kV Switches
2-345 kV Dead end Assemblies
3-Relay Control Panels in existing control enclosure
1-345/138 kV transformer with oil containment and security walls

New Graded site adjacent to Huntley:
3-161 kV Breakers
8-161 kV Switches
4-161 kV dead ends
1-Control Enclosure
3-Relay Control Panels
1-Remote Terminal Unit for control and monitoring
1040' of fence
Bus work to complete electric connections
Total grading: approximately 2.1 acres

Wilmarth Substation:
To accommodate a 138 kV yard at Wilmarth, Xcel Energy would expand the substation by approximately 5.3 acres on property owned by Xcel Energy. This expansion area would be used to expand the existing 345 kV yard and add a new 138 kV yard. The cost at Wilmarth is estimated at $18.4 million (2016$).

<u>Required equipment</u>
2-345 kV Breakers
6-345 kV Switches

1-345/138 kV transformer with oil containment and security walls
3-161 kV Breakers
8-161 kV Switches
2-161 kV dead ends
1-Control Enclosure
13-Relay Control Panels
2,000' of fence
Bus work to complete electric connections
Additional graded area of 5.3 acres

The estimate at Wilmarth Substation is significantly higher than the Huntley Substation due to additional scope required at the Wilmarth Substation to provide an equivalent solution. The additional scope includes:

- More 345 kV scope (additional breaker and bus);
- Significant additional dollars for grading and filling a low-lying area adjacent to the existing Wilmarth yard;
- Purchase of wetland mitigation credits as part of the filled area is a wetland; and
- Significant additional dollars for foundation cost because of the known poor soils at the Wilmarth Substation site. The pier foundations at the Wilmarth Substation are approximately 70 feet deep and even breaker slabs and transformer slabs are built on piers.

Xcel Energy and ITC Midwest compared our estimates and determined our costs are very similar if the scope of work at each substation is the same.

A summary of the costs to accommodate a new 138 kV transmission line connection at the Huntley and Wilmarth substations is provided in Table 1 below:

Table 1

	Cost (2016$)
Huntley Substation modifications	$ 10.5 million
Wilmarth Substation modifications	$ 18.4 million
Total Cost	**$28.9 million**

230 kV Substation Alternative

230 kV is not common in voltage in southern Minnesota. The closest 230 kV is Xcel Energy's Blue Lake Substation in Shakopee and Xcel Energy's Red Rock Substation in Newport.

Further, 230 kV is not a standard voltage for the ITC Midwest footprint. To utilize a 230 kV voltage, ITC Midwest would need to develop new standards or construct the substation at 345 kV standards.

We assumed two 230 kV line exits (i.e., one out of each substation) were required, additional exits would require more infrastructure and additional cost.

Huntley Substation:
ITC Midwest's rough estimate to meet the timing requirements of the Information Request response is 80% of 345 kV pricing.

To accommodate the transformation of the 345 kV line to 230 kV, ITC Midwest would build the new 230 kV substation adjacent to the east of the existing Huntley Substation on property owned by ITC Midwest. A new fenced area is required due to several site features of the existing Huntley Substation. The new fenced area would fit within land currently owned by ITC Midwest. The new fenced area would be roughly 360' x 240' with the graded area being roughly 420' x 270' for drainage control and contour matching to existing grade.

<u>Required equipment</u>
Existing Huntley Substation:
1-345 kV Breaker
2-345 kV Switches
2-345 kV Dead end Assemblies
3-Relay Control Panels in existing control enclosure
1-345/230 kV transformer with oil containment and security walls

New Graded site adjacent to Huntley:
3-230 kV Breakers
8-230 kV Switches
4-230 kV dead ends
1-Control Enclosure
3-Relay Control Panels
1-Remote Terminal Unit for control and monitoring
1200' of fence
Bus work to complete electric connections
Additional graded area of 2.6 acres

ITC Midwest estimated price for this installation adjacent to the Huntley Substation is $12.1 million (2016$).

Wilmarth Substation:
To accommodate a 138 kV yard at Wilmarth, Xcel Energy would expand the substation by approximately 5.3 acres on property owned by Xcel Energy to expand the 345 kV yard and add a 138 kV yard. The cost at Wilmarth is estimated at $19.1 million (2016$).

Required equipment
2-345 kV Breakers
6-345 kV Switches
1-345/138 kV transformer with oil containment and security walls
3-230 kV Breakers
8-230 kV Switches
2-230 kV dead ends
1-Control Enclosure
13-Relay Control Panels
2,000' of fence
Bus work to complete electric connections
Additional graded area of 5.3 acres

The estimate at Wilmarth is significantly higher than Huntley due to additional scope required to provide an equivalent solution. The additional scope includes:

- More 345 kV scope (additional breaker and bus);
- Significant additional dollars for grading and filling a low-lying area adjacent to the existing Wilmarth yard;
- Purchase of wetland mitigation credits as part of the filled area is a wetland; and
- Significant additional dollars for foundation cost because of the known poor soils at the site. The pier foundations at Wilmarth are approximately 70 feet deep and even breaker slabs and transformer slabs are built on piers.

Xcel Energy and ITC Midwest compared our estimates and determined our costs are very similar if the scope of work at each substation is the same.

A summary of the costs to accommodate a new 230 kV transmission line connection at the Huntley and Wilmarth substations is provided in Table 2 below:

Table 2

	Cost (2016$)
Huntley Substation modifications	$ 12.1 million
Wilmarth Substation modifications	$ 19.1 million
Total Cost	**$ 31.2 million**

Preparer:	Corey Proctor, ITC Midwest / Grant Stevenson, Xcel Energy
Title:	Manager Design Engineering / Senior Project Manager
Department:	Design / Transmission Project Management
Telephone:	319-297-6755 / 612-330-6330
Date:	May 23, 2018

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Xcel Energy

Docket No.:	E002,ET6675/CN-17-184		
Response To:	MN Department of Commerce	Information Request No.	6
Requestor:	Matthew Landi / Steve Rakow		
Date Received:	May 1, 2018		

Question:

Topic: Transmission Line Capacity and Congestion Relief
Reference(s): Application, Sec. 5.1.1.2, pp. 100-101

Please explain why the transmission capacity ratings of the 69 kV and 115 kV alternatives considered in the Applicants' screening analysis are insufficient to relieve congestion.

Response:

The proposed Huntley – Wilmarth 345 kV transmission line is needed to fully relieve congestion along the Huntley – Blue Earth – South Bend – Wilmarth line. As described in Applicant's response to Information Request No. 5, a higher capacity line in the correct configuration and location will generally increase the amount of congestion relieved. The analysis performed during the MISO MTEP16 planning cycle, as described in Appendix G and F of the Certificate of Need Application, demonstrated that lower voltage alternatives (primarily 161 kV alternatives) do not provide a sufficient increase in capacity along the congested power transfer path to fully relieve the identified congestion in all three modeled years (5, 10 and 15 year models). For the reasons described in Applicants' response to Information Request No. 5, 69 kV and 115 kV lines have an even lower capacity as compared to the 161 kV line and, as a result, would provide even less of a power transfer path than the 161 kV alternative. As a result, a 69 kV line or 115 kV line will relieve even less of the identified congestion than the 161 kV alternatives that were analyzed. In contrast, the proposed Huntley – Wilmarth 345 kV line was shown to fully relieve the identified congestion for the entire planning horizon in all Future scenarios, utilizing both the MTEP16 and MTEP17 Futures.

Preparer: Drew Siebenaler
Title: Sr. Engineer
Department: Regional Transmission Planning and Analytics
Telephone: (612)321-3195
Date: May 11, 2018

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Xcel Energy			
Docket No.:	E002,ET6675/CN-17-184		
Response To:	MN Department of Commerce	Information Request No.	14
Requestor:	Matthew Landi / Steve Rakow		
Date Received:	May 1, 2018		

Question:

Topic: "Type" of the Proposed Transmission Line and Alternatives
Reference(s): Minnesota Rules 7849.0120 B (1); Application, Sec. 5.2, p. 113-121

"Type" has been interpreted by the Department to refer to the following characteristics: the transformer nominal voltage, rated capacity, surge impedance loading, and nature of power transported (AC or DC). In order to ensure compliance with Minnesota Rule 7849.0120 B (1), please provide information related to the rated capacity, surge impedance, and nature of power transported for the proposed transmission line and each of the alternatives considered in the Applicants' screening analysis in terms of the Department's interpretation of "type."

Response:

A general point of reference, the nominal Surge Impedance Loading (SIL) on a 345 kV transmission line is 425 MW[1]. For a short line (below 50 miles), a general rule states the SIL should be three time the nominal SIL value, or 1,275 MW. Similarly, the nominal SIL for a 161 kV transmission line is 52 MW, or 156 MW for short lines. This value represents the point at which the inductive and capacitive requirements of the line negate each other, or where real power and apparent power are equal. Since this number can be altered by a number of factors, this is not a true representation of the capabilities of the transmission line. These factors range from the characteristics of the system load to amount of reactive support on the line and from the spacing when using bundled conductors to the arrangement of the three phases on the towers.

[1] "Estimating Line Flow Limits" May 1, 2013, University of Wisconsin Madison

For example, if sufficient reactive compensation is applied to a transmission line, the point at which the inductive and capacitive requirements of the line negate each other could be well beyond the current carrying capabilities of that line

Below are the remaining characteristics of the proposed and alternate transmission lines to determine the project type as interpreted by the Department.

765 kV Transmission Line:
- 765,000 Volts (V), or 765 kV
- Rated Capacity: 5,300 MVA
- Nature of Power: Alternating Current (AC)

500 kV Transmission Line:
- 500,000 Volts (V), or 500 kV
- Rated Capacity: 2,598 MVA
- Nature of Power: Alternating Current (AC)

Proposed 345 kV Transmission Line:
- 345,000 Volts (V), or 345 kV
- Rated Capacity: 1,792 MVA
- Nature of Power: Alternating Current (AC)

230 kV Transmission Line:
- 230,000 Volts (V), or 230 kV
- Rated Capacity: 478 MVA
- Nature of Power: Alternating Current (AC)

161 kV Alternative at 1,200 amps:
- 161,000 Volts (V), or 161 kV
- Rated Capacity: 334 MVA
- Nature of Power: Alternating Current (AC)

161 kV Alternative at 1,600 amps:
- 161,000 Volts (V), or 161 kV
- Rated Capacity: 446 MVA
- Nature of Power: Alternating Current (AC)

138 kV Transmission Line:
- 138,000 Volts (V), or 138 kV

- Rated Capacity: 286 MVA
- Nature of Power: Alternating Current (AC)

115 kV Transmission Line:

- 115,000 Volts (V), or 115 kV
- Rated Capacity: 239 MVA
- Nature of Power: Alternating Current (AC)

69 kV Transmission Line:

- 69,000 Volts (V), or 69 kV
- Rated Capacity: 143 MVA
- Nature of Power: Alternating Current (AC)

Preparer: Drew Siebenaler
Title: Sr. Engineer
Department: Regional Transmission Planning and Analytics
Telephone: (612)321-3195
Date: May 11, 2018

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Xcel Energy

Docket No.:	E002,ET6675/CN-17-184		
Response To:	MN Department of Commerce	Information Request No.	15
Requestor:	Matthew Landi / Steve Rakow		
Date Received:	May 1, 2018		

Question:

Topic: Opportunities for Distributed Generation
Reference(s): Minnesota Stat. §216B.2426; Application, Sec. 5.2.6, p. 118-119

Please demonstrate that distributed generation resources were considered in the applicants' analysis of alternatives to the proposed projects as required by Minn. Stat. §216B.2426. If no such analysis exists, please perform such analysis as required by Minn. Stat. §216B.2426.

Response:

In Section 5.2.6 of the Certificate of Need (CON) Application, the Applicants analyzed relieving the identified congestion through the implementation of generation alternatives. In this section, the Applicants state that any new generation resource (including distributed generation) would need to be operating at sufficient levels and at a low enough cost to replace the low-cost generation resources being limited by the identified congestion. This distributed generation would also need to be located in such a manner as to not required additional power flows in the direction of the identified congestion (i.e., located north of the existing congestion). To illustrate this point, and help identify the weaknesses in a generation alternative, please see the examples below that outline three primary distributed generation resources.

Rooftop Solar and Community Solar Gardens:

- Solar generation, while flexible in location, is limited to production during daylight hours. Wind generation, in general, produces at the highest levels in the late evening and overnight hours. Because of this difference in generation profiles, congestion relief through greater utilization of distributed solar generation would be ineffective in relieving the most congested periods of time in the Project area. In addition, installation of new solar generation would also need to address the issue with the wholesale market dispatch balancing customer demand and generation levels on the entire MISO footprint simultaneously. To fully relieve the congestion, enough distributed solar generation would have to be installed to serve the entire demand in the MISO footprint. This is because the wind resources currently being limited are among the lowest cost generation in the MISO footprint such that all other more costly generation sources would need to be offset before the wind generation was displaced. While solar generation resources can be sited in the proper location to mitigate the identified congestion, the generation profile and size requirements necessary to relieve the identified congestion make this generation resource an unreasonable alternative.

Distributed Thermal Resources:

- Similar to the issue noted above for addressing the identified congestion with distributed solar resources, distributed thermal resources would also be an unreasonable alternative. While these resources have the ability to produce when needed and can be installed in the best possible location, these thermal resources are also generally more costly than wind resources. As a result, adding new thermal resources would have little impact on the identified congestion and could possibly make the congestion costs even higher.

Distributed Wind Resources:

- As stated in Section 5.2.6 of the CON Application, the Applicants discuss the limitations of locating new wind generation facilities in the ideal place to relieve the identified congestion. As these resources would have the same production characteristics, and would likely have similar (maybe slightly higher) costs than the generation resources being limited by the identified congestion, the cost and generation profile of distributed wind resources would align with the requirements to mitigate the congestion. However, the new wind resources would need to be located north of the congestion and be able to generate between approximately 120 and 370 MW (depending on the Future scenario) to relieve the congestion. The difficulties associated with siting a new large scale wind generation north of the area of congestion is discussed on pages 119-121 of the Application and by Figure 28 in the CON Application. Applicants also note that adding new wind generation north of the point of congestion will result in underutilization of existing and more efficient wind generation in southern Minnesota and northern Iowa.

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Xcel Energy

Docket No.:	E002,ET6675/CN-17-184		
Response To:	MN Department of Commerce	Information Request No.	17
Requestor:	Matthew Landi / Steve Rakow		
Date Received:	May 29, 2018	**SUPPLEMENT**	

Question:

Topic: Economic Analysis of the Project and Alternatives
Reference(s): Chapters 4 & 5; Appendixes G, I, & K

Please provide a narrative explanation of the economic analysis performed that evaluated the costs and benefits of the proposed 345 kV Huntley-Wilmarth transmission line (including the costs and benefits of the various routing options considered) ("Project") and the alternative 161 kV Huntley-Wilmarth transmission line ("alternative"). This explanation should include the methodology, data, and formulae used to evaluate the cost and benefits of each transmission line.

Response:

Note: In preparing the response to this IR, Applicants discovered that the benefit-to-cost ratios reported in Table 17, Table 21, and Appendix K of the Certificate of Need Application were based on MISO's December 2016 MTEP17 models rather than the June 2017 MTEP17 models that were used for the Market Congestion Study for MTEP17. Attached as **Attachment A** are a revised Table 17, Table 21, and Appendix K that utilize the June 2017 MTEP17 models and assumptions.

The Applicants conducted three different types of economic analyses of the Project and the 161 kV alternatives. These analyses can be summarized as: (1) a Present Value (PV) benefit-to-cost analysis using Adjusted Production Cost (APC) savings; (2) a curtailment analysis; and (3) an externalities analysis. For each analysis, the same PROMOD IV runs were evaluated. For each future and year, a PROMOD IV run without the Huntley – Wilmarth 345 kV Project or the 161 kV alternative called Base Case and a PROMOD IV run with the Huntley – Wilmarth Project or the 161 kV alternative called Change Case was performed.

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Present Value APC Benefit-to-Cost Analysis

MISO utilized APC savings to measure the economic benefits of the proposed Huntley –Wilmarth 345 kV Project in MTEP16. Applicants utilized this same metric to calculate the economic benefits of the Huntley – Wilmarth 345 kV Project and the 161 kV alternative under the MTEP17 Futures and assumptions. APC savings are calculated as the difference in total production costs of a generation fleet adjusted for import costs and export revenues with and without the proposed transmission project included in the transmission system. PROMOD IV, an hourly chronological security constrained unit commitment and dispatch model, is utilized as the primary tool to determine these economic benefits.

The PV benefit-to-cost analysis starts with calculating the APC of each run. In the case of MTEP17 runs, this APC calculation was conducted on PROMOD IV runs which include a Base and Change Case for the three MTEP17 Futures (Existing Fleet, Policy Regulations, and Accelerated Alternative Technologies) and three years (2021,[1] 2026, 2031). The formula to calculate the MISO North/Central APC from PROMOD IV results is as follows:

Hourly Company Adjusted Production Cost = Hourly Production Cost + Hourly Fixed Transaction Cost (renewable generation is considered a fixed transaction in PROMOD IV) + Hourly Emergency Energy Cost + Hourly Interpool Transaction Cost (transactions between MISO companies and non-MISO companies) + Hourly Within Pool Transaction Cost (transactions between MISO companies).

These hourly APC values are summed for the entire 8,760 hours in a year to produce a year APC for each Base and Change case per Future and year. Projected savings are then determined by subtracting the Change Case APC from the Base Case APC for each Future and year to produce a "Delta." A positive Delta indicates an APC savings and therefore positive benefits from a proposed project for that year and Future. Likewise, a negative Delta is indicative of a negative benefit and an increase in APC due to a proposed project.

These values are single year APC savings. To determine a benefit-to-cost ratio for a project, a 20-year PV analysis of the benefits and costs must be conducted for each Future. To determine the benefits for the 17 years that are not studied, the years between three years of modeled values are interpolated and the out years are extrapolated from the input data.

[1] For purposes of the present value calculations, Applicants assumed an in-service year of 2022. However, the Base Case PROMOD 2021 model year assumes the Project is in-service for purposes of calculating the APC savings.

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These yearly benefit values are then converted to present value along with the estimated cost of the project using a PV calculation tool. Attached as excel spreadsheets are **Attachment B, C, and D** which are the PV calculation tool used for the Huntley-Wilmarth 345 kV Project for each of the three MTEP17 Futures. These attachments have been filled in with the estimated APC savings for the Huntley-Wilmarth 345 kV Project under the MTEP17 model runs and the lowest cost design/route proposed in the Application ($105.8 million for the Purple Route, Single-Circuit, Parallel H-frame design). Attached as excel spreadsheets are **Attachments E, F, and G** which are the PV calculation tool used for the Huntley-Wilmarth 161 kV alternative. These attachments have been filled in with the estimated APC savings for the 161 kV alternative under the MTEP17 model runs and the estimated cost for this 161 kV alternative ($80.9 million for the Green Route, Monopole design). The cells highlighted in yellow on these excel spreadsheets are variable inputs that can be modified: Present Year, Discount Rate, Annual Revenue Requirements, In-service Year, Estimated Cost, and Inflation Rate. The assumptions used by the Applicants in the PV calculations for the MTEP17 analysis are: 7.1% Discount Rate, 2.5% Inflation Rate, and 2016 Present Year. Annual Revenue Requirements used are found in the "ARRs Used" tab of **Attachment A**.

After each Future's benefits and the estimated cost are translated into a PV amount, the PV benefit-to-cost ratios are calculated for each Future by dividing the PV costs from the PV benefits.

These PV benefit-to-cost values are then weighted based on the weightings agreed to by the MISO stakeholders as part of the MTEP process. This produces a weighted PV benefit-to-cost ratio that is used to evaluate a proposed project's economic impact to the MISO North/Central region. For MTEP17, the following weightings were used: 31% for Existing Fleet, 43% for Policy Regulations, and 25% for Accelerated Alternative Technologies.

Curtailment Analysis

For the curtailment analysis, the same PROMOD IV runs were studied as the runs studied in the PV benefit-to-cost analysis. However, unlike the PV benefit-to-cost analysis, the curtailment analysis does not require any formula for calculation. Annual curtailment on a wind resource is an output from PROMOD IV. For this analysis, "Report Agent" a reporting tool provided with PROMOD IV was used to filter to wind resources located in Zones 1 and 3 due to wind resources in these two zones being in closest proximity to the proposed Huntley-Wilmarth 345 kV Project. A total curtailment level, in megawatt hours (MWh), for these wind resources was summed up for the Base Case and Change Case for each year and future. The MWh of curtailments for the Change Case was subtracted from the MWh of curtailments for the Base Case to find the reduction in curtailments.

Externalities Analysis

The externalities analysis performed by ITC Midwest LLC in Appendix I follows the same general process outlined above to identify APC savings. To replicate the externalities template developed in 2015, a few changes to the input assumptions for the present value were necessary. The present value period was updated to 63 years to match the life of the transmission assets. The revenue requirement was updated to a levelized fixed charge rate. The economic benefits from PROMOD IV APC savings values were modified to "back out" the impact of emissions cost changes to incorporating incremental public policy benefits from externality evaluation. Justification for these assumptions and additional methodology details are described in Applicants' response to DOC-DER IR No. 20.

System Losses

In addition to these economic analyses, Applicants also calculated system losses for the Huntley – Wilmarth 345 kV transmission line and the 161 kV alternative. The results of this analysis are summarized in Table 25 on page 111 of the Application. These system losses were calculated using the MTEP17 reliability models for a summer peak scenario and an off-peak/high wind scenario for the in-service year. The losses (in Megawatt (MW) and mega volt amps (reactive) (MVAR) separately) for the entire eastern interconnection modeled in those scenarios were found with the proposed transmission line in-service, then with the line disconnected. The loss savings is the difference between the losses with and without the line in-service. After this difference was calculated, the Applicants converted these results from MWs and MVARs to mega volt amp (MVA).

The live versions of the spreadsheets in Attachments B through G contain Trade Secret information pursuant to Minn. Stat. 13.37, subd. 1(b), and they are marked as "Non-Public" in their entirety. The formulas contained in these live spreadsheet attachments derive independent economic value, actual or potential, from not being generally known to, or readily ascertainable through proper means by, other persons who can obtain economic value from its disclosure or use. Thus, the Applicants maintain this information as Trade Secret information.

Supplement:

Upon further inspection of Attachments A, B, C, D, E, F, and G it was found that the present value calculator used by the Applicants to calculate the benefit-to-cost ratio

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under MTEP17 for the Project and the 161 kV alternative did not include costs for the final year of the calculation. Therefore, 20 years of present value benefit was incorrectly compared to 19 years of present value cost. Applicants have since revised the present value calculators to correct this error. **Revised Attachments A-G** contain corrected present value calculators as well as corrected MTEP17 benefit-to-cost ratios for Huntley - Wilmarth 345 kV and 161 kV Projects.

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Date:	June 8, 2018 **Supplemented:** August 31, 2018

Table 17-Revised
MTEP17 Analysis with Current Project Cost Estimates (2016$)

Project	Applicants' Project Cost Estimates (2016$ Millions)	Expected In-Service	PV Benefit (Million 2016$)				Benefit-to-Cost Ratios (Millions, 2016$)			
			AAT	EF	PR	Weighted	AAT	EF	PR	Weighted
Huntley – Wilmarth 345 kV	$105.8-$138.0	2022	816.04	13.92	138.01	275.83	4.99-6.51	0.09-0.11	0.84-1.10	1.69-2.20

Table 17-Second Revised
MTEP17 Analysis with Current Project Cost Estimates (2016$)

Project	Applicants' Project Cost Estimates (2016$ Millions)	Expected In-Service	PV Benefit (Million 2016$)				Benefit-to-Cost Ratios (Millions, 2016$)			
			AAT	EF	PR	Weighted	AAT	EF	PR	Weighted
Huntley – Wilmarth 345 kV	$105.8-$138.0	2022	816.04	13.92	138.01	275.83	4.90-6.39	0.08-0.11	0.83-1.08	1.66-2.16

Table 21-Second Revised
MTEP17 PROMOD Comparison[76]

Transmission Alternative*	Cost Estimate (2016$)	Weighted Benefit-to-Cost Ratio	20-year Present Value Benefit ($millions)
Huntley – Wilmarth new 345 kV transmission line (Green Route, monopole design)	$121.3	1.88	$275.83
Huntley – Wilmarth new 161 kV transmission line (Green Route, monopole design)	$80.9	2.05	$200.7

[76] The cost estimates developed for purposes of this comparison assumed the least cost capital investment necessary to achieve the explained alternative. Therefore, any changes to route or structure type used for purposes of the estimates would impact the overall cost analysis and comparisons. This approach was undertaken to ensure consistency when comparing multiple alternatives of different size or type.

Appendix K-Revised

Benefit-to-Cost Ratios for Applicants' Proposed Routes/Designs

Assumptions:
Present Value Benfit (MTEP17): $273.11 Million
In-Service Date: 2022
Discount Rate: 7.10%
Inflation Rate: 2.50%
ARR: ITC and NSP Average

Benefit to Cost Ratios under MTEP17 for Applicants' Proposed Route/Designs

	Purple Route (West Route)			Green Route (Middle Route)		Red Route (Middle Route)		Blue Route (East Route)	
	Single-Circuit Parallel H-Frame	Single-Circuit Parallel Monopole	Double-Circuit Monopole and Single-Circuit Monopole	Single-Circuit H-Frame	Single-Circuit Monopole	Double-Circuit Monopole and Single-Circuit H-Frame	Double-Circuit Monopole and Single-Circuit Monopole	Double-Circuit Monopole and Single-Circuit H-Frame	Double-Circuit Monopole and Single-Circuit Monopole
Total Line, ROW, AFUDC ($2016)	$ 100,600,000	$ 116,500,000	$ 132,700,000	$ 103,800,000	$ 116,100,000	$ 130,000,000	$ 132,800,000	$ 118,500,000	$ 130,600,000
Wilmarth Substation ($2016)	$ 2,750,000	$ 2,750,000	$ 2,750,000	$ 2,750,000	$ 2,750,000	$ 2,750,000	$ 2,750,000	$ 2,750,000	$ 2,750,000
Huntley Substation ($2016)	$ 2,470,000	$ 2,470,000	$ 2,470,000	$ 2,470,000	$ 2,470,000	$ 2,470,000	$ 2,470,000	$ 2,470,000	$ 2,470,000
Total Project Costs including AFUDC ($2016)	**$ 105,800,000**	**$ 121,700,000**	**$ 137,900,000**	**$ 109,000,000**	**$ 121,300,000**	**$ 135,200,000**	**$ 138,000,000**	**$ 123,700,000**	**$ 135,800,000**
Benefit-to-Cost Ratio MTEP17	**2.16**	**1.88**	**1.66**	**2.10**	**1.88**	**1.69**	**1.66**	**1.85**	**1.68**

Year	MISO Gross-Plant Weighted Average - OLD*	MISO Gross-Plant Weighted Average - MTEP17**	ITCM	NSP	ITC NSP AVG***
1	16.44%	15.93%	17.42%	14.40%	15.91%
2	16.18%	15.68%	17.12%	14.17%	15.64%
3	15.93%	15.43%	16.82%	13.94%	15.38%
4	15.67%	15.18%	16.51%	13.70%	15.11%
5	15.42%	14.94%	16.21%	13.47%	14.84%
6	15.16%	14.69%	15.91%	13.24%	14.58%
7	14.91%	14.44%	15.61%	13.01%	14.31%
8	14.65%	14.19%	15.31%	12.77%	14.04%
9	14.40%	13.94%	15.01%	12.54%	13.77%
10	14.14%	13.69%	14.71%	12.31%	13.51%
11	13.89%	13.44%	14.40%	12.08%	13.24%
12	13.63%	13.20%	14.10%	11.85%	12.97%
13	13.38%	12.95%	13.80%	11.61%	12.71%
14	13.12%	12.70%	13.50%	11.38%	12.44%
15	12.87%	12.45%	13.20%	11.15%	12.17%
16	12.62%	12.20%	12.90%	10.92%	11.91%
17	12.36%	11.95%	12.60%	10.68%	11.64%
18	12.11%	11.71%	12.29%	10.45%	11.37%
19	11.85%	11.46%	11.99%	10.22%	11.11%
20	11.60%	11.21%	11.69%	9.99%	10.84%

* Used in initial PV calcs

** Provided by MISO engineers on 12-11-2017 (not used in any PV calcs)

*** Used in updated ARR calcs

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Existing Fleet Present Value Calculator

PROMOD Run Year 1	PROMOD Run Year 2	PROMOD Run Year 3			
2021	2026	2031	Present Cost	In-Service Date	B/C Ratio ([5] / [8])
1,563,618	949,460	1,937,587	$105,800,000.00	2022	**0.11**

Example Calculation of Proposed Market Efficiency Project Benefit/Cost Ratio

[a]	Discount Rate	7.1%
[b]	Inflation Rate	2.50%
	Present Year	2016

Note: Annual Charge Rate assumes straight-line depreciation and a 40-year book life

Calculation of Adjusted Production Cost Savings	Year	Present Value Period	Adjusted Production Cost Savings (Nominal$)	2016 Present Value APC Savings	Annual Revenue Requirements	Annual Costs (Project Costs * Transmission Owner Annual Charge Rate) (Nominal$)	2016 Present Value Annual Costs
[PROTECTED DATA BEGINS:							
							PROTECTED DATA ENDS]
Interpolation	2022	6	$ 1,440,787	$ 954,691	15.9%	$ 19,508,595	$ 12,926,744
Interpolation	2023	7	$ 1,317,955	$ 815,407	15.7%	$ 19,201,856	$ 11,880,013
Interpolation	2024	8	$ 1,195,123	$ 690,394	15.4%	$ 18,833,769	$ 10,879,814
Interpolation	2025	9	$ 1,072,292	$ 578,373	15.1%	$ 18,527,030	$ 9,993,108
PROMOD Model Year	2026	10	$ 949,460	$ 478,170	14.9%	$ 18,220,291	$ 9,176,152
Interpolation	2027	11	$ 1,147,085	$ 539,401	14.6%	$ 17,852,205	$ 8,394,748
Interpolation	2028	12	$ 1,344,711	$ 590,412	14.3%	$ 17,545,466	$ 7,703,556
Interpolation	2029	13	$ 1,542,336	$ 632,289	14.1%	$ 17,238,727	$ 7,067,113
Interpolation	2030	14	$ 1,739,961	$ 666,020	13.8%	$ 16,870,640	$ 6,457,716
PROMOD Model Year	2031	15	$ 1,937,587	$ 692,499	13.5%	$ 16,563,901	$ 5,919,984
Exrapolation	2032	16	$ 2,135,212	$ 712,540	13.3%	$ 16,257,162	$ 5,425,168
Exrapolation	2033	17	$ 2,332,837	$ 726,881	13.0%	$ 15,889,075	$ 4,950,826
Exrapolation	2034	18	$ 2,530,462	$ 736,189	12.7%	$ 15,582,337	$ 4,533,380
Exrapolation	2035	19	$ 2,728,088	$ 741,069	12.5%	$ 15,275,598	$ 4,149,524
Exrapolation	2036	20	$ 2,925,713	$ 742,066	12.2%	$ 14,907,511	$ 3,781,079
Exrapolation	2037	21	$ 3,123,338	$ 739,674	11.9%	$ 14,600,772	$ 3,457,777
Exrapolation	2038	22	$ 3,320,963	$ 734,338	11.7%	$ 14,294,033	$ 3,160,723
Exrapolation	2039	23	$ 3,518,589	$ 726,458	11.4%	$ 13,987,294	$ 2,887,858
Exrapolation	2040	24	$ 3,716,214	$ 716,396	11.1%	$ 13,619,208	$ 2,625,455
Exrapolation	2041	25	$ 3,913,839	$ 704,476	10.9%	$ 13,312,469	$ 2,396,193
20-Year NPV				$ 13,917,741			$ 127,766,931

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Existing Fleet Present Value Calculator

PROMOD Run Year 1	PROMOD Run Year 2	PROMOD Run Year 3			
2021	2026	2031	Present Cost	In-Service Date	B/C Ratio ([5] / [8])
3,017,371	9,157,261	21,736,351	$105,800,000.00	2022	**1.08**

Example Calculation of Proposed Market Efficiency Project Benefit/Cost Ratio

[a]	Discount Rate	7.1%
[b]	Inflation Rate	2.50%
	Present Year	2016

Note: Annual Charge Rate assumes straight-line depreciation and a 40-year book life

Calculation of Adjusted Production Cost Savings	Year	Present Value Period	Adjusted Production Cost Savings (Nominal$)	2016 Present Value APC Savings	Annual Revenue Requirements	Annual Costs (Project Costs * Transmission Owner Annual Charge Rate) (Nominal$)	2016 Present Value Annual Costs
[PROTECTED DATA BEGINS:							
							PROTECTED DATA ENDS]
Interpolation	2022	6	$ 4,245,349	$ 2,813,044	15.9%	$ 19,508,595	$ 12,926,744
Interpolation	2023	7	$ 5,473,327	$ 3,386,297	15.7%	$ 19,201,856	$ 11,880,013
Interpolation	2024	8	$ 6,701,305	$ 3,871,182	15.4%	$ 18,833,769	$ 10,879,814
Interpolation	2025	9	$ 7,929,283	$ 4,276,896	15.1%	$ 18,527,030	$ 9,993,108
PROMOD Model Year	2026	10	$ 9,157,261	$ 4,611,804	14.9%	$ 18,220,291	$ 9,176,152
Interpolation	2027	11	$ 11,673,079	$ 5,489,101	14.6%	$ 17,852,205	$ 8,394,748
Interpolation	2028	12	$ 14,188,897	$ 6,229,813	14.3%	$ 17,545,466	$ 7,703,556
Interpolation	2029	13	$ 16,704,715	$ 6,848,192	14.1%	$ 17,238,727	$ 7,067,113
Interpolation	2030	14	$ 19,220,533	$ 7,357,205	13.8%	$ 16,870,640	$ 6,457,716
PROMOD Model Year	2031	15	$ 21,736,351	$ 7,768,632	13.5%	$ 16,563,901	$ 5,919,984
Exrapolation	2032	16	$ 24,252,169	$ 8,093,177	13.3%	$ 16,257,162	$ 5,425,168
Exrapolation	2033	17	$ 26,767,987	$ 8,340,550	13.0%	$ 15,889,075	$ 4,950,826
Exrapolation	2034	18	$ 29,283,805	$ 8,519,557	12.7%	$ 15,582,337	$ 4,533,380
Exrapolation	2035	19	$ 31,799,623	$ 8,638,176	12.5%	$ 15,275,598	$ 4,149,524
Exrapolation	2036	20	$ 34,315,441	$ 8,703,625	12.2%	$ 14,907,511	$ 3,781,079
Exrapolation	2037	21	$ 36,831,259	$ 8,722,434	11.9%	$ 14,600,772	$ 3,457,777
Exrapolation	2038	22	$ 39,347,077	$ 8,700,498	11.7%	$ 14,294,033	$ 3,160,723
Exrapolation	2039	23	$ 41,862,895	$ 8,643,138	11.4%	$ 13,987,294	$ 2,887,858
Exrapolation	2040	24	$ 44,378,713	$ 8,555,146	11.1%	$ 13,619,208	$ 2,625,455
Exrapolation	2041	25	$ 46,894,531	$ 8,440,835	10.9%	$ 13,312,469	$ 2,396,193
20-Year NPV				$ 138,009,304			$ 127,766,931

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Accelerated Alternative Technologies Present Value Calculator

PROMOD Run Year 1	PROMOD Run Year 2	PROMOD Run Year 3			
2021	2026	2031	Present Cost	In-Service Date	B/C Ratio ([5] / [8])
2,909,938	57,967,125	131,493,474	$105,800,000.00	2022	**6.39**

Example Calculation of Proposed Market Efficiency Project Benefit/Cost Ratio

[a]	Discount Rate	7.1%
[b]	Inflation Rate	2.50%
	Present Year	2016

Note: Annual Charge Rate assumes straight-line depreciation and a 40-year book life

Calculation of Adjusted Production Cost Savings	Year	Present Value Period	Adjusted Production Cost Savings (Nominal$)	2016 Present Value APC Savings	Annual Revenue Requirements	Annual Costs (Project Costs * Transmission Owner Annual Charge Rate) (Nominal$)	2016 Present Value Annual Costs
[PROTECTED DATA BEGINS:							
							PROTECTED DATA ENDS]
Interpolation	2022	6	$ 13,921,375	$ 9,224,553	15.9%	$ 19,508,595	$ 12,926,744
Interpolation	2023	7	$ 24,932,813	$ 15,425,704	15.7%	$ 19,201,856	$ 11,880,013
Interpolation	2024	8	$ 35,944,250	$ 20,764,126	15.4%	$ 18,833,769	$ 10,879,814
Interpolation	2025	9	$ 46,955,688	$ 25,326,954	15.1%	$ 18,527,030	$ 9,993,108
PROMOD Model Year	2026	10	$ 57,967,125	$ 29,193,560	14.9%	$ 18,220,291	$ 9,176,152
Interpolation	2027	11	$ 72,672,395	$ 34,173,172	14.6%	$ 17,852,205	$ 8,394,748
Interpolation	2028	12	$ 87,377,665	$ 38,364,256	14.3%	$ 17,545,466	$ 7,703,556
Interpolation	2029	13	$ 102,082,934	$ 41,849,476	14.1%	$ 17,238,727	$ 7,067,113
Interpolation	2030	14	$ 116,788,204	$ 44,704,000	13.8%	$ 16,870,640	$ 6,457,716
PROMOD Model Year	2031	15	$ 131,493,474	$ 46,996,134	13.5%	$ 16,563,901	$ 5,919,984
Exrapolation	2032	16	$ 146,198,744	$ 48,787,898	13.3%	$ 16,257,162	$ 5,425,168
Exrapolation	2033	17	$ 160,904,014	$ 50,135,560	13.0%	$ 15,889,075	$ 4,950,826
Exrapolation	2034	18	$ 175,609,283	$ 51,090,129	12.7%	$ 15,582,337	$ 4,533,380
Exrapolation	2035	19	$ 190,314,553	$ 51,697,799	12.5%	$ 15,275,598	$ 4,149,524
Exrapolation	2036	20	$ 205,019,823	$ 52,000,370	12.2%	$ 14,907,511	$ 3,781,079
Exrapolation	2037	21	$ 219,725,093	$ 52,035,624	11.9%	$ 14,600,772	$ 3,457,777
Exrapolation	2038	22	$ 234,430,363	$ 51,837,673	11.7%	$ 14,294,033	$ 3,160,723
Exrapolation	2039	23	$ 249,135,632	$ 51,437,283	11.4%	$ 13,987,294	$ 2,887,858
Exrapolation	2040	24	$ 263,840,902	$ 50,862,163	11.1%	$ 13,619,208	$ 2,625,455
Exrapolation	2041	25	$ 278,546,172	$ 50,137,240	10.9%	$ 13,312,469	$ 2,396,193
20-Year NPV				$ 816,043,675			$ 127,766,931

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Existing Fleet Present Value Calculator

PROMOD Run Year 1	PROMOD Run Year 2	PROMOD Run Year 3			
2021	2026	2031	Present Cost	In-Service Date	B/C Ratio ([5] / [8])
678,634	1,236,437	1,241,221	$80,900,000.00	2022	**0.09**

Example Calculation of Proposed Market Efficiency Project Benefit/Cost Ratio

[a]	Discount Rate	7.1%
[b]	Inflation Rate	2.50%
	Present Year	2016

Note: Annual Charge Rate assumes straight-line depreciation and a 40-year book life

Calculation of Adjusted Production Cost Savings	Year	Present Value Period	Adjusted Production Cost Savings (Nominal$)	2016 Present Value APC Savings	Annual Revenue Requirements	Annual Costs (Project Costs * Transmission Owner Annual Charge Rate) (Nominal$)	2016 Present Value Annual Costs
[PROTECTED DATA BEGINS:							
							PROTECTED DATA ENDS]
Interpolation	2022	6	$ 790,195	$ 523,597	15.9%	$ 14,917,252	$ 9,884,439
Interpolation	2023	7	$ 901,755	$ 557,908	15.7%	$ 14,682,704	$ 9,084,055
Interpolation	2024	8	$ 1,013,316	$ 585,368	15.4%	$ 14,401,247	$ 8,319,253
Interpolation	2025	9	$ 1,124,876	$ 606,736	15.1%	$ 14,166,699	$ 7,641,233
PROMOD Model Year	2026	10	$ 1,236,437	$ 622,698	14.9%	$ 13,932,151	$ 7,016,547
Interpolation	2027	11	$ 1,237,394	$ 581,867	14.6%	$ 13,650,693	$ 6,419,047
Interpolation	2028	12	$ 1,238,351	$ 543,713	14.3%	$ 13,416,145	$ 5,890,526
Interpolation	2029	13	$ 1,239,307	$ 508,061	14.1%	$ 13,181,597	$ 5,403,870
Interpolation	2030	14	$ 1,240,264	$ 474,746	13.8%	$ 12,900,140	$ 4,937,895
PROMOD Model Year	2031	15	$ 1,241,221	$ 443,616	13.5%	$ 12,665,592	$ 4,526,718
Exrapolation	2032	16	$ 1,242,178	$ 414,526	13.3%	$ 12,431,044	$ 4,148,356
Exrapolation	2033	17	$ 1,243,135	$ 387,344	13.0%	$ 12,149,586	$ 3,785,650
Exrapolation	2034	18	$ 1,244,091	$ 361,944	12.7%	$ 11,915,038	$ 3,466,450
Exrapolation	2035	19	$ 1,245,048	$ 338,210	12.5%	$ 11,680,490	$ 3,172,935
Exrapolation	2036	20	$ 1,246,005	$ 316,031	12.2%	$ 11,399,033	$ 2,891,203
Exrapolation	2037	21	$ 1,246,962	$ 295,307	11.9%	$ 11,164,485	$ 2,643,990
Exrapolation	2038	22	$ 1,247,919	$ 275,942	11.7%	$ 10,929,937	$ 2,416,848
Exrapolation	2039	23	$ 1,248,875	$ 257,847	11.4%	$ 10,695,389	$ 2,208,202
Exrapolation	2040	24	$ 1,249,832	$ 240,938	11.1%	$ 10,413,931	$ 2,007,555
Exrapolation	2041	25	$ 1,250,789	$ 225,137	10.9%	$ 10,179,383	$ 1,832,250
20-Year NPV				$ 8,561,537			$ 97,697,020

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Policy Regulations Present Value Calculator

PROMOD Run Year 1	PROMOD Run Year 2	PROMOD Run Year 3			
2021	2026	2031	Present Cost	In-Service Date	B/C Ratio ([5] / [8])
2,766,678	7,133,553	19,457,765	$80,900,000.00	2022	**1.26**

Example Calculation of Proposed Market Efficiency Project Benefit/Cost Ratio

[a]	Discount Rate	7.1%
[b]	Inflation Rate	2.50%
	Present Year	2016

Note: Annual Charge Rate assumes straight-line depreciation and a 40-year book life

Calculation of Adjusted Production Cost Savings	Year	Present Value Period	Adjusted Production Cost Savings (Nominal$)	2016 Present Value APC Savings	Annual Revenue Requirements	Annual Costs (Project Costs * Transmission Owner Annual Charge Rate) (Nominal$)	2016 Present Value Annual Costs
[PROTECTED DATA BEGINS:							
							PROTECTED DATA ENDS]
Interpolation	2022	6	$ 3,640,053	$ 2,411,964	15.9%	$ 14,917,252	$ 9,884,439
Interpolation	2023	7	$ 4,513,428	$ 2,792,417	15.7%	$ 14,682,704	$ 9,084,055
Interpolation	2024	8	$ 5,386,803	$ 3,111,826	15.4%	$ 14,401,247	$ 8,319,253
Interpolation	2025	9	$ 6,260,178	$ 3,376,614	15.1%	$ 14,166,699	$ 7,641,233
PROMOD Model Year	2026	10	$ 7,133,553	$ 3,592,619	14.9%	$ 13,932,151	$ 7,016,547
Interpolation	2027	11	$ 9,598,395	$ 4,513,511	14.6%	$ 13,650,693	$ 6,419,047
Interpolation	2028	12	$ 12,063,238	$ 5,296,515	14.3%	$ 13,416,145	$ 5,890,526
Interpolation	2029	13	$ 14,528,080	$ 5,955,869	14.1%	$ 13,181,597	$ 5,403,870
Interpolation	2030	14	$ 16,992,923	$ 6,504,524	13.8%	$ 12,900,140	$ 4,937,895
PROMOD Model Year	2031	15	$ 19,457,765	$ 6,954,259	13.5%	$ 12,665,592	$ 4,526,718
Exrapolation	2032	16	$ 21,922,607	$ 7,315,781	13.3%	$ 12,431,044	$ 4,148,356
Exrapolation	2033	17	$ 24,387,450	$ 7,598,806	13.0%	$ 12,149,586	$ 3,785,650
Exrapolation	2034	18	$ 26,852,292	$ 7,812,156	12.7%	$ 11,915,038	$ 3,466,450
Exrapolation	2035	19	$ 29,317,135	$ 7,963,823	12.5%	$ 11,680,490	$ 3,172,935
Exrapolation	2036	20	$ 31,781,977	$ 8,061,048	12.2%	$ 11,399,033	$ 2,891,203
Exrapolation	2037	21	$ 34,246,819	$ 8,110,383	11.9%	$ 11,164,485	$ 2,643,990
Exrapolation	2038	22	$ 36,711,662	$ 8,117,750	11.7%	$ 10,929,937	$ 2,416,848
Exrapolation	2039	23	$ 39,176,504	$ 8,088,497	11.4%	$ 10,695,389	$ 2,208,202
Exrapolation	2040	24	$ 41,641,347	$ 8,027,447	11.1%	$ 10,413,931	$ 2,007,555
Exrapolation	2041	25	$ 44,106,189	$ 7,938,944	10.9%	$ 10,179,383	$ 1,832,250
20-Year NPV				$ 123,544,753			$ 97,697,020

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Docket No. E002,E6675/CN-17-184
Information Request DOC-17 Supplement
Attachment G, Page 1 of 1

Accelerated Alternative Technologies Present Value Calculator

PROMOD Run Year 1	PROMOD Run Year 2	PROMOD Run Year 3			
2021	2026	2031	Present Cost	In-Service Date	B/C Ratio ([5] / [8])
2,233,562	46,134,101	89,699,186	$80,900,000.00	2022	**5.71**

Example Calculation of Proposed Market Efficiency Project Benefit/Cost Ratio

[a]	Discount Rate	7.1%
[b]	Inflation Rate	2.50%
	Present Year	2016

Note: Annual Charge Rate assumes straight-line depreciation and a 40-year book life

Calculation of Adjusted Production Cost Savings	Year	Present Value Period	Adjusted Production Cost Savings (Nominal$)	2016 Present Value APC Savings	Annual Revenue Requirements	Annual Costs (Project Costs * Transmission Owner Annual Charge Rate) (Nominal$)	2016 Present Value Annual Costs
[PROTECTED DATA BEGINS:							
							PROTECTED DATA ENDS]
Interpolation	2022	6	$ 11,013,670	$ 7,297,855	15.9%	$ 14,917,252	$ 9,884,439
Interpolation	2023	7	$ 19,793,778	$ 12,246,229	15.7%	$ 14,682,704	$ 9,084,055
Interpolation	2024	8	$ 28,573,885	$ 16,506,444	15.4%	$ 14,401,247	$ 8,319,253
Interpolation	2025	9	$ 37,353,993	$ 20,147,993	15.1%	$ 14,166,699	$ 7,641,233
PROMOD Model Year	2026	10	$ 46,134,101	$ 23,234,180	14.9%	$ 13,932,151	$ 7,016,547
Interpolation	2027	11	$ 54,847,118	$ 25,791,086	14.6%	$ 13,650,693	$ 6,419,047
Interpolation	2028	12	$ 63,560,135	$ 27,906,872	14.3%	$ 13,416,145	$ 5,890,526
Interpolation	2029	13	$ 72,273,152	$ 29,628,787	14.1%	$ 13,181,597	$ 5,403,870
Interpolation	2030	14	$ 80,986,169	$ 30,999,755	13.8%	$ 12,900,140	$ 4,937,895
PROMOD Model Year	2031	15	$ 89,699,186	$ 32,058,739	13.5%	$ 12,665,592	$ 4,526,718
Exrapolation	2032	16	$ 98,412,203	$ 32,841,079	13.3%	$ 12,431,044	$ 4,148,356
Exrapolation	2033	17	$ 107,125,220	$ 33,378,800	13.0%	$ 12,149,586	$ 3,785,650
Exrapolation	2034	18	$ 115,838,237	$ 33,700,897	12.7%	$ 11,915,038	$ 3,466,450
Exrapolation	2035	19	$ 124,551,254	$ 33,833,596	12.5%	$ 11,680,490	$ 3,172,935
Exrapolation	2036	20	$ 133,264,271	$ 33,800,592	12.2%	$ 11,399,033	$ 2,891,203
Exrapolation	2037	21	$ 141,977,288	$ 33,623,273	11.9%	$ 11,164,485	$ 2,643,990
Exrapolation	2038	22	$ 150,690,305	$ 33,320,918	11.7%	$ 10,929,937	$ 2,416,848
Exrapolation	2039	23	$ 159,403,322	$ 32,910,883	11.4%	$ 10,695,389	$ 2,208,202
Exrapolation	2040	24	$ 168,116,339	$ 32,408,776	11.1%	$ 10,413,931	$ 2,007,555
Exrapolation	2041	25	$ 176,829,356	$ 31,828,604	10.9%	$ 10,179,383	$ 1,832,250
20-Year NPV				$ 557,465,361			$ 97,697,020

In the Matter of the Certificate of Need and Route Permit Applications of Xcel Energy and ITC Midwest LLC for the Huntley to Wilmarth 345 kV Transmission Line Project in South Central Minnesota

ENVIRONMENTAL IMPACT STATEMENT SCOPING DECISION

DOCKET NO. E002, ET6675/CN-17-184
DOCKET NO. E002, ET6675/TL-17-185

The above matter has come before the deputy commissioner of the Department of Commerce (Department) for a decision on the scope of the environmental impact statement (EIS) to be prepared for the Huntley to Wilmarth 345 kV transmission line project proposed by Xcel Energy and ITC Midwest LLC (applicants) in south central Minnesota.

Project Description

The applicants propose to construct approximately 50 miles of new 345 kV transmission line from the Wilmarth substation in Mankato, Minnesota to the Huntley substation near Winnebago, Minnesota. The project includes equipment additions and reconfigurations within the Wilmarth and Huntley substations to connect the new 345 kV line. Transmission line structures will range from 75 to 170 feet in height, with a span between structures of approximately 1,000 feet.

The applicants are requesting a 1,000 foot route width for project; they indicate that the new 345 kV line will require a right-of-way (easement) of 150 feet. The applicants have proposed four possible routes for the project and six route segment alternatives. The routes are designated by color – purple, green, red, and blue; the route segment alternatives are designated by letters – segments A through F. The applicants anticipate that project construction will begin in 2020 and that the new line will be in service by the end of 2021.

Project Purpose

The applicants indicate that the proposed project is needed to relieve transmission congestion in southern Minnesota and northern Iowa. Applicants suggest that relieving this congestion will increase market access to lower cost energy generation, provide economic benefits, strengthen the regional grid, and reduce curtailments of wind generators. The project was studied by the Midcontinent Independent Transmission System Operator (MISO) and approved by MISO as a market efficiency project in December 2016.

Regulatory Background

The applicants' proposed project requires two separate approvals from the Minnesota Public Utilities Commission (Commission) – a certificate of need (CN) and route permit. A certificate of need application for the project was submitted to the Commission on January 17, 2018, and accepted as complete by the Commission on March 28, 2018. A route permit application was submitted to the Commission on January 22, 2018. The applicants subsequently revised the alignment and route width for a section of a route in their application, the blue route.[1] The route permit application was accepted as complete on March 28, 2018.

Department of Commerce, Energy Environmental Review and Analysis (EERA) staff is responsible for conducting environmental review for CN and route permit applications submitted to the Commission.[2] As two concurrent environmental reviews are required – one for the CN application and one for the route permit application – the Commission has authorized EERA staff to combine the environmental review for the two applications.[3] An environmental impact statement (EIS) will be prepared to meet the requirements of both review processes.

Scoping Process

Scoping is the first step in the development of the EIS for the project. The scoping process has two primary purposes: (1) to gather public input as to the impacts, mitigation measures, and alternatives to study in the EIS, and (2) to focus the EIS on those impacts, mitigation measures, and alternatives that will aid in the Commission's decisions on the CN and route permit applications.

EERA staff gathered input on the scope of the EIS through four public meetings and an associated comment period. EERA staff also facilitated input on the scope of the EIS through an advisory task force. This scoping decision identifies the impacts and mitigation measures that will be analyzed in the EIS, including routing alternatives for the project. Additionally, this scoping decision identifies alternatives to the project itself that will be analyzed in the EIS.

Public Scoping Meetings

Commission and EERA staff held joint public information and environmental impact statement scoping meetings on April 17, 2018, in the city of Mankato and on May 9, 2018, in the cities of Winnebago and Mapleton. Total attendance at these meetings was approximately 440 persons. Comments were received from 85 persons at these meetings.[4] Commenters expressed concern about a variety of potential impacts associated with the project, including impacts to agriculture, property values, and communities.

Public Comments

A comment period, ending on May 18, 2018, provided the public an opportunity to submit comments to EERA staff on potential impacts and mitigation measures for consideration in the scope of the EIS. Comments were received from two agencies,[5] four local units of government,[6] the

[1] Applicants' Letter to the Commission Regarding Alignment of the Blue Route, March 16, 2018, eDockets Number 20183-141145-01.
[2] Minnesota Rule 7849.1200; Minnesota Rule 7850.2500.
[3] Commission Order Finding Applications Complete and Notice of and Order for Hearing, March 28, 2018, eDockets Number 20183-141450-01.
[4] Oral Comments from Public Information and EIS Scoping Meetings, eDockets Number 20185-143325-07 [hereinafter Oral Comments].
[5] Written Agency Comments on Scope of EIS, eDockets Number 20185-143325-01 [hereinafter Agency Comments].
[6] Written Local Government Comments on Scope of EIS, eDockets Number 20185-143325-05 [hereinafter LGU Comments].

applicants,[7] and from 80 citizens.[8] Several of these comments included specific route or alignment alternatives for consideration in the EIS. Approximately one-half of citizen commenters expressed a preference for, or displeasure with, a routing option proposed in the route permit application.

Agency Comments

The Minnesota Department of Transportation (MnDOT) noted its accommodation policy for the placement of utilities along highway rights-of-way.[9] MnDOT also indicated that the EIS for the project should consider future improvements to the highway system in the project area.

The MnDOT Division of Aeronautics noted that the applicants' proposed blue route for the project is within an airport safety zone – zone C – for the Mankato Regional airport.[10] Within this safety zone there are certain land use restrictions. The MnDOT Division of Aeronautics indicated the types of approval that would be needed in order for the blue route to be constructed within zone C.

The Minnesota Department of Natural Resources (DNR) noted a number of potential natural resource impacts that should be analyzed in the EIS.[11] The DNR provided comments on specific routes and route segments proposed in the applicants' route permit application. They indicated that route segment C was inconsistent with Minnesota Rule 7850.4300 and should not be carried forward for study in the EIS.[12] The DNR also proposed two route segments near the Watonwan River for consideration in the EIS (route segments J and K).[13]

Comments from Local Units of Government

The city of Mankato noted a number of potential human and environmental impacts associated with the proposed blue route.[14] The city described potential impacts to infrastructure investments and planned community development that should be analyzed in the EIS.[15] The city also noted potential impacts to the Mankato Regional airport.

The city of North Mankato noted potential impacts to the city's comprehensive plan and future growth – particularly with respect to the proposed red and green routes and route segments A, B, and C.[16] The city also noted potential impacts to residences, property values, and the city's tax base.[17]

[7] Applicants' Comments on Scope of EIS, eDockets Number 20185-143325-03 [hereinafter Applicants' Comments].
[8] Written Public Comments on Scope of EIS, eDockets Numbers 20185-143325-09, 20185-143325-11 [hereinafter Written Public Comments].
[9] Comment Letter of Minnesota Department of Transportation, Agency Comments.
[10] Comment Letter of Minnesota Department of Transportation, Division of Aeronautics, Agency Comments.
[11] Comment Letter of Minnesota Department of Natural Resources, Agency Comments.
[12] Id.
[13] Id.
[14] Comment Letter of the City of Mankato, LGU Comments.
[15] Id.
[16] Comment Letter of the City of North Mankato, LGU Comments.
[17] Id.

Nicollet County indicated potential impacts associated with the proposed red and green routes and route segments A, B, and C – including impacts to the city of North Mankato, impacts to scenic resources such as Minnemishinona Falls Park, and impacts to farmland.[18]

Blue Earth County noted that proposed route segment C has the potential to impact the Williams Nature Center Park.[19]

Applicants' Comments

The applicants proposed four route segments for study in the EIS.[20] The applicants proposed a route segment, along the purple route, to avoid a land parcel (Pheasants Forever parcel) that is in the process of being transferred to federal ownership as a waterfowl production area (route segment L).[21] The applicants proposed two route segments along existing transmission lines that facilitate reaching the Huntley substation from the green, red, and blue routes (route segments Q and R).[22] The applicants also proposed a variation on route segment E that could minimize impacts to residences (route segment E2).[23]

Advisory Task Force

The Commission authorized an advisory task force to aid development of the scope of the EIS.[24] The task force identified several potential impacts and mitigation measures for consideration in the EIS.[25] The task force proposed one route segment (route segment G) and one combination of existing routing options (purple-E-red route) for study in the EIS.[26]

Alternatives to the Project

Two citizens suggested that the applicants' proposed project is undersized and that the EIS should consider the possibility of using a 500 kV line instead of a 345 kV line.[27] One citizen suggested the existing 161 kV line in the area be updated to meet the need for the project.[28] One citizen suggested that the need for the project could be met by reconductoring and double-circuiting the existing Lakefield to Wilmarth 345 kV line.[29] This citizen also suggested that the need for the project could be met by closing existing coal-fired power plants in neighboring states.[30]

[18] Comment Letter of Nicollet County, LGU Comments.
[19] Comment Letter of Blue Earth County, Public Works Department, LGU Comments.
[20] Applicants' Comments.
[21] Id.
[22] Id.
[23] Id.
[24] Commission Order Finding Applications Complete and Notice of and Order for Hearing, March 28, 2018, eDockets Number 20183-141450-01.
[25] Huntley to Wilmarth 345 kilovolt (kV) Transmission Line Advisory Task Force Report, May 2018, eDockets Number 20186-143530-01.
[26] Id.
[27] Comment Letter of Mr. Jason McMonagle, Written Public Comments; Oral Comments of Mr. Dennis Mikkelson, Mankato Public Meeting 6 p.m., Oral Comments.
[28] Comment Letter of Ms. Sharon Schaller, Written Public Comments.
[29] Comment Letter of Ms. Carol Overland, Written Public Comments.
[30] Id.

Commission Review
After close of the public comment period, EERA staff conferred with DNR staff and the applicants on the alternatives proposed for study in the EIS. On June 19, 2018, EERA staff provided the Commission with a summary of the EIS scoping process.[31] The summary discussed the routing alternatives that were proposed during the scoping process and those alternatives that the Department intended to recommend for inclusion in the scope of the EIS. On July 12, 2018, the Commission considered what action it should take with respect to the routing alternatives to be considered in the EIS. The Commission adopted EERA staff's recommendations and proposed an additional route segment for study in the EIS (route segment Y).[32]

HAVING REVIEWED THE MATTER, consulted with Department staff, and in accordance with Minnesota Rule 7850.2500, I hereby make the following scoping decision:

MATTERS TO BE ADDRESSED

The issues outlined below will be analyzed in the EIS for the proposed Huntley to Wilmarth 345 kV transmission line project. The EIS will describe the project and the human and environmental resources of the project area. It will provide information on the potential impacts of the project as they relate to the topics outlined in this scoping decision and possible mitigation measures. It will identify impacts that cannot be avoided and irretrievable commitments of resources, as well as permits from other government entities that may be required for the project. The EIS will discuss the relative merits of the route alternatives studied in the EIS using the routing factors found in Minnesota Rule 7850.4100.

The EIS will include a description and analysis of the human and environmental impacts of the proposed project and alternatives to the project that would have otherwise been required by Minnesota Rule 7849.1500 in an environmental report.

I. GENERAL DESCRIPTION OF THE PROJECT

A. Project Description
B. Project Purpose
C. Route Description
   1. Route Width
   2. Right-of-Way
D. Project Costs

[31] Department of Commerce, Comments and Recommendations on Scoping Process and Routing Alternatives, July 19, 2018, eDockets Number 20186-143985-01 [hereinafter Department Comments and Recommendations].
[32] Commission Order, July 17, 2018, eDockets Numbers 20187-144956-01 and 20187-144956-02.

II. REGULATORY FRAMEWORK

A. Certificate of Need
B. High Voltage Transmission Line Route Permit
C. Environmental Review Process
D. Other Permits and Approvals

III. ENGINEERING AND DESIGN

A. Transmission Line Structures
   1. Paralleling and Double-Circuiting
B. Transmission Line Conductors

IV. CONSTRUCTION

A. Right-of-Way Acquisition
B. Construction
C. Restoration
D. Damage Compensation
E. Operation and Maintenance

V. AFFECTED ENVIRONMENT, POTENTIAL IMPACTS, AND MITIGATIVE MEASURES

The EIS will include a discussion of the human and environmental resources potentially impacted by the proposed project and the routing alternatives described herein (Section VI). Potential impacts, both positive and negative, of the project and each alternative will be described. Based on the impacts identified, the EIS will describe mitigation measures that could reasonably be implemented to reduce or eliminate the identified impacts. The EIS will describe any unavoidable impacts resulting from implementation of the proposed project.

Data and analyses in the EIS will be commensurate with the importance of potential impacts and the relevance of the information to consideration of the need for mitigation measures.[33] EERA staff will consider the relationship between the cost of data and analyses and the relevance and importance of the information in determining the level of detail of information to be prepared for the EIS. Less important material may be summarized, consolidated, or simply referenced.

If relevant information cannot be obtained within timelines prescribed by statute and rule, or if the costs of obtaining such information is excessive, or the means to obtain it is not known, EERA staff will include in the EIS a statement that such information is incomplete or unavailable and the relevance of the information in evaluating potential impacts.[34]

A. Environmental Setting
B. Socioeconomics
C. Human Settlements
   1. Noise
   2. Aesthetics

[33] Minnesota Rule 4410.2300.
[34] Minnesota Rule 4410.2500.

3. Displacement
4. Property Values
5. Zoning and Land Use Compatibility
6. Public Services
   a) Roads and Highways
   b) Utilities
   c) Emergency Services
7. Electronic Interference
   a) Radio
   b) Television
   c) Wireless Phone / Internet Services

D. Public Health and Safety
   1. Electric and Magnetic Fields
   2. Implantable Medical Devices
   3. Stray Voltage
   4. Induced Voltage
   5. Air Quality

E. Land Based Economies
   1. Agriculture
      a) Compaction
      b) Tile Damage
      c) Aerial Spraying
      d) GPS Systems
   2. Forestry
   3. Mining
   4. Recreation and Tourism

F. Archaeological and Historic Resources

G. Natural Environment
   1. Water Resources
      a) Surface Waters
      b) Groundwater
      c) Wetlands
   2. Soils
   3. Flora
   4. Fauna

H. Threatened / Endangered / Rare and Unique Natural Resources

I. Electric System Reliability

J. Operation and Maintenance Costs that are Design Dependent

K. Adverse Impacts that Cannot be Avoided

L. Irreversible and Irretrievable Commitments of Resources

VI. ROUTES AND ROUTE ALTERNATIVES TO BE EVALUATED IN THE ENVIRONMENTAL IMPACT STATEMENT

The EIS will evaluate the routes and route segments proposed in the applicants' route permit application except for route segment C (see attached maps, Map 1). The DNR has indicated that route segment C is inconsistent with Minnesota Rule 7850.4300 and is not permittable. Accordingly, the EIS will evaluate the purple, green, red, and blue routes, and the route segments A, B, D, E, and F.

In addition, the following routes, route segments, and alignment alternatives will be evaluated in the EIS:

<u>Purple-E-Red Route</u>
The purple-E-red route is a combination of the applicants' purple and red routes, as connected by the applicants' route segment E (Map 2). The purple-E-red route utilizes those portions of the purple and red routes that follow existing transmission lines, and minimizes the extent of the route that does not (route segment E).

<u>Route Segment E2</u>
This route segment is an alternative version of route segment E that connects with the red and green routes at a more northern location, relative to route segment E (Map 3).

<u>Route Segment G</u>
Route segment G proceeds along County Road 86 on the eastern edge of the city of Mankato (Map 4). The segment provides an alternative to the blue route near the Eastwood solar farm.

<u>Route Segment H</u>
Route segment H proceeds around the western edge of the Pheasants Forever parcel, following an existing 345 kV line, and then proceeds east and south, crossing the Watonwan River along County Road 32, and then rejoins the purple route (Map 5). This segment provides an alternative to the purple route near the Watonwan River.

<u>Route Segment I</u>
Route segment I is a short corner segment that avoids a diagonal crossing of the Pheasants Forever parcel by the purple route (Map 5).

<u>Route Segment J</u>
Route segment J proceeds south from the purple route, parallels and then crosses the Watonwan River, and then rejoins the purple route. This segment provides an alternative to the purple route near the Watonwan River (Map 5).

<u>Route Segment K</u>
Route segment K proceeds south from the purple route, crosses the Watonwan River along County Road 32, and then rejoins the purple route (Map 5). This segment provides an alternative to the purple route near the Watonwan River.

Route Segment L
Route segment L proceeds eastward from the purple route, around existing waterfowl production areas, and then southward across the Watonwan River to rejoin the purple route (Map 5). This segment provides an alternative to the purple route near the Watonwan River.

Route Segment M
This route segment is similar to route segment L; however, it proceeds further eastward before turning south across the Watonwan River (Map 5).

Route Segment N
Route segment N provides an alternative to a southern section of the purple route by following existing roads and a drainage ditch and buffer strip (Map 6).

Route Segment O
Route segment O provides an alternative to a section of the green route by following Faribault County Road 107 (Map 7).

Route Segment P
Route segment P provides an alternative to a southern section of the blue route (Map 8). Route segment P turns west from the blue route and then south along field lines before rejoining the blue route.

Route Segment Q
Route segment Q follows an existing 161 kV transmission line and provides an alternative to the red and blue routes east of the Huntley substation (Map 9).

Route Segment R
Route segment R follows an existing 161 kV transmission line and provides an alternative to the red route east of the Huntley substation (Map 9).

Route Segment Y
Route segment Y provides an alternative to a section of the red route by following an existing 161 kV transmission line (Map 10).

Alignment Alternative 1 (AA-1)
This alignment alternative proceeds along the south side of U.S. Highway 169, rather than the north side, for a portion of route segment E (Map 11).

Alignment Alternative 2 (AA-2)
This alignment proceeds along a property boundary, rather than through a property, for a portion of the blue route (Map 12).

Alignment Alternative 3 (AA-3)
This alignment consists of two options: (1) triple-circuiting a portion of the purple route west of the Huntley substation, and (2) proceeding along the south side of 160th St., rather than the north, for a portion of purple route west of the Huntley substation (Map 13).

VII. ALTERNATIVES TO THE PROPOSED TRANSMISSION LINE PROJECT

The EIS, in accordance with Minnesota Rule 7849.1500, will describe and analyze the feasibility of the following system alternatives, and the human and environmental impacts and potential mitigation measures associated with each:

A. No-build Alternative
B. Demand Side Management
C. Purchased Power
D. Transmission Line of a Different Size
   1. Higher and Lower Voltage Lines
E. Upgrading of Existing Facilities
   1. Reconductoring of Existing Lines
   2. Double-Circuiting of Existing Lines
F. Generation Rather Than Transmission
G. Use of Renewable Energy Sources

VIII. IDENTIFICATION OF PERMITS

The EIS will include a list and description of permits from other government entities that may be required for the proposed project.

ISSUES OUTSIDE THE SCOPE OF THE ENVIRONMENTAL IMPACT STATEMENT

The EIS will not consider the following:

A. Any route, route segment, or alignment alternative not specifically identified for study in this scoping decision.
B. Any system alternative (an alternative to the proposed transmission line project) not specifically identified for study in this scoping decision.
C. Policy issues concerning whether utilities or local governments should be liable for the cost to relocate utility poles when roadways are widened.
D. The manner in which land owners are paid for transmission line right-of-way easements.
E. Of the alternatives proposed during the scoping process to mitigate potential impacts of the project, the following will not be included for further study in the EIS:

System Alternative – Closing of Existing Coal-Fired Power Plants
The closing of existing coal-fired power plants in neighboring states was proposed as an alternative to the project. This alternative is beyond the authority of the State of Minnesota. Further, implementation of the proposed project will, over time, accomplish the result sought by the proposer – i.e., greater access to relatively low-cost wind energy

will curtail the use of relatively higher cost coal generation in the Upper Midwest generally. This alternative would not aid in the Commission's decision on the CN application.

<u>Brown Route</u>
The brown route was proposed to follow U.S. Highway 169 and existing 69 and 115 kV transmission lines that parallel the highway.[35] This route has relatively more impacts to residences and communities than other routes proposed for the project.[36] Accordingly, the brown route would not aid in the Commission's decision on the route permit application.

<u>Route Segment S</u>
Route segment S was proposed to minimize impacts to the city of North Mankato.[37] This segment crosses Minneopa State Park and is not permittable.[38] Accordingly, route segment S would not aid in the Commission's decision on the route permit application.

<u>Route Segments T through X</u>
Route segments T through X were proposed by citizens along the purple route near the Watonwan River.[39] These segments have relatively greater impacts than other routing alternatives that mitigate impacts at the Watonwan River (segments H through M, discussed above).[40] Accordingly, route segments T through X would not aid in the Commission's decision on the route permit application.

SCHEDULE

The draft EIS is anticipated to be completed and available in December 2018. Public meetings and a comment period on the draft EIS will follow. Timely and substantive comments on the draft EIS will be responded to in a final EIS. Public hearings will be held in the project area after issuance of the draft EIS and are anticipated to occur in early 2019.

Signed this 17th day of July, 2018

STATE OF MINNESOTA
DEPARTMENT OF COMMERCE

William Grant, Deputy Commissioner

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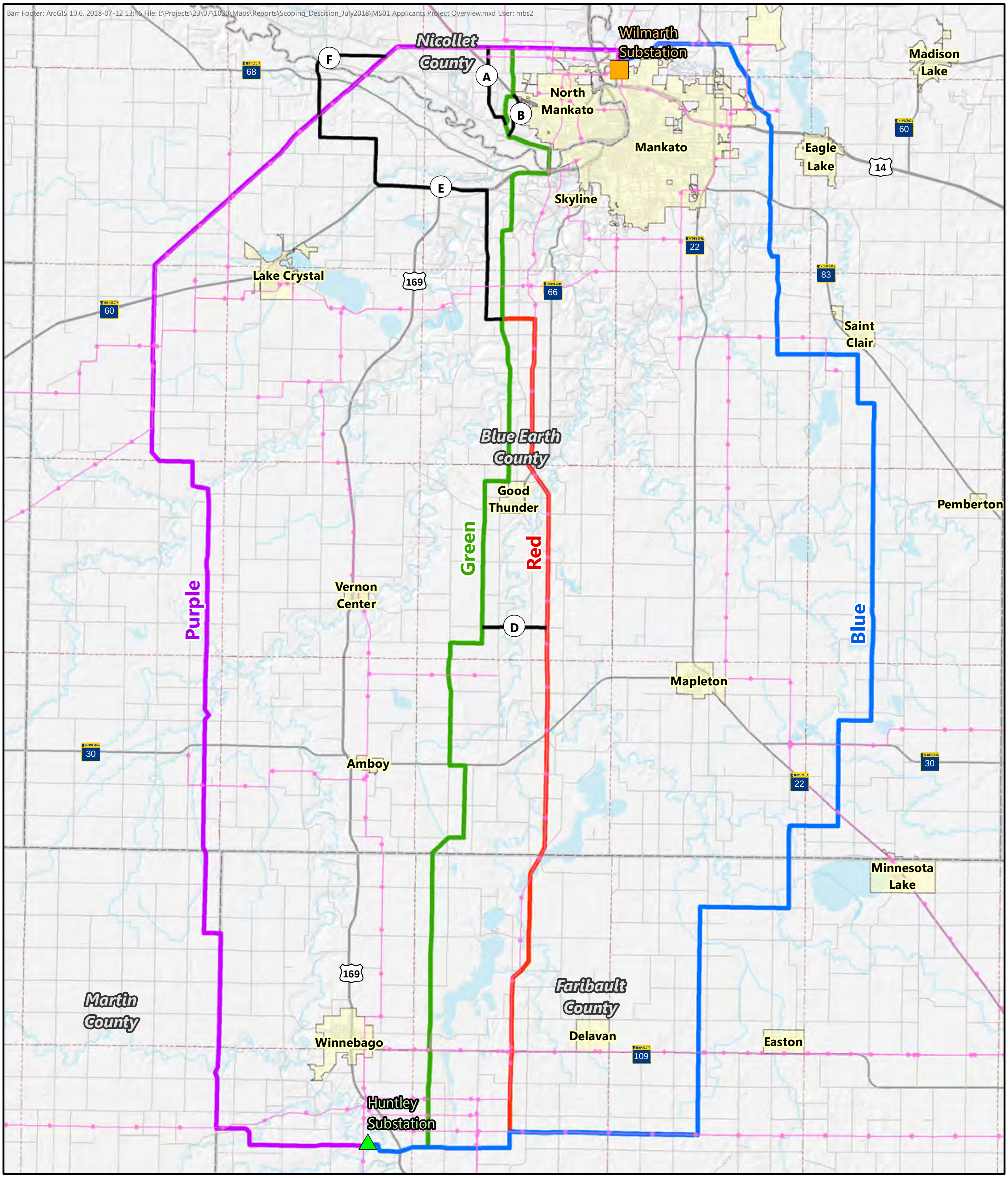
[35] Department Comments and Recommendations.
[36] Id.
[37] Id.
[38] Id.
[39] Id.
[40] Id.



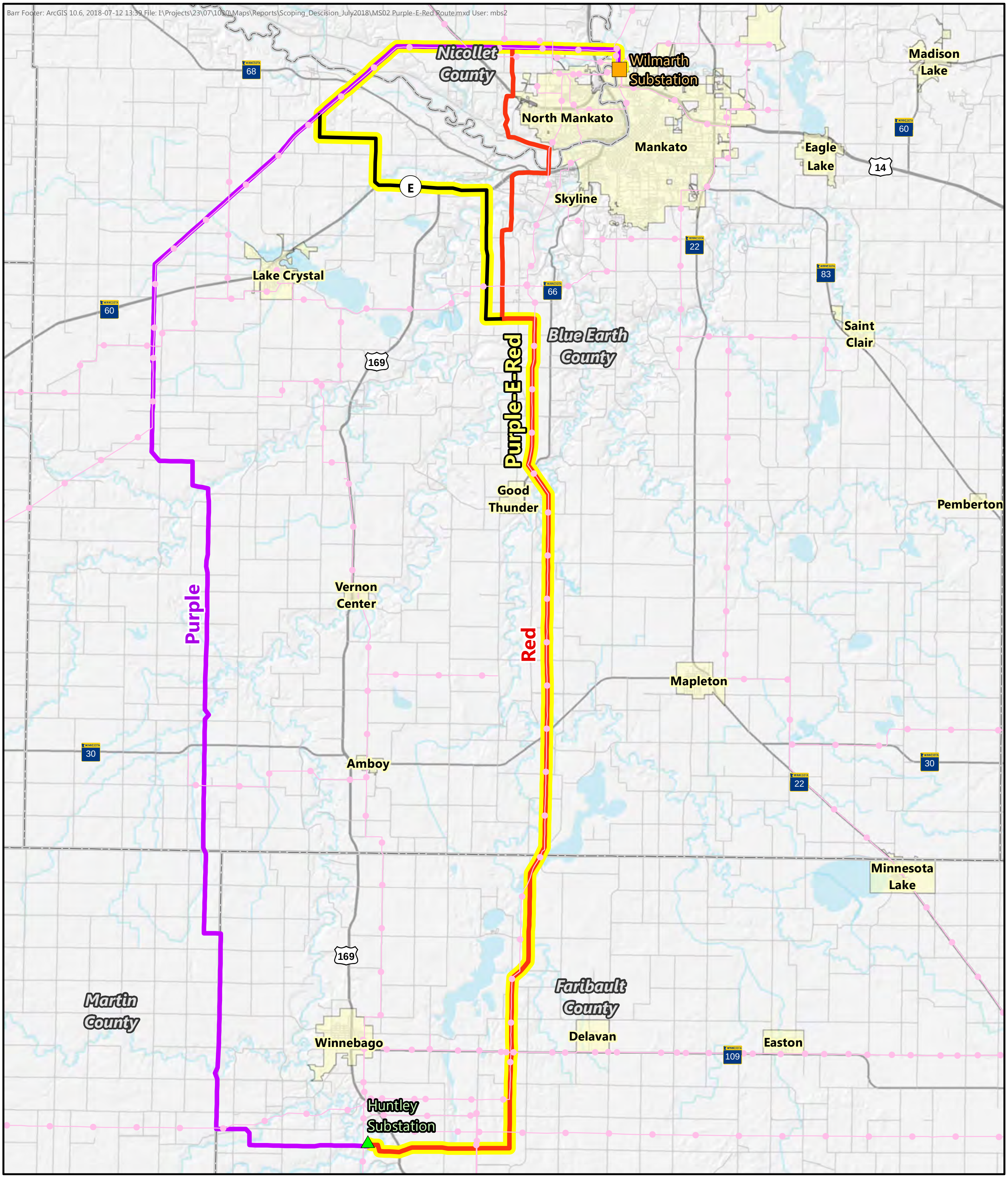
Blue Route
Green Route
Purple Route
Red Route
Route Segment
Existing Transmission Line
Huntley Substation
Wilmarth Substation
Municipal Boundary
Civil Township
County Boundary

Miles
0 2 4

Map 1 of 13

APPLICANTS' PROPOSED ROUTES AND ROUTE SEGMENTS A, B, D, E, AND F

Scoping Decision
Huntley-Wilmarth 345kV Project

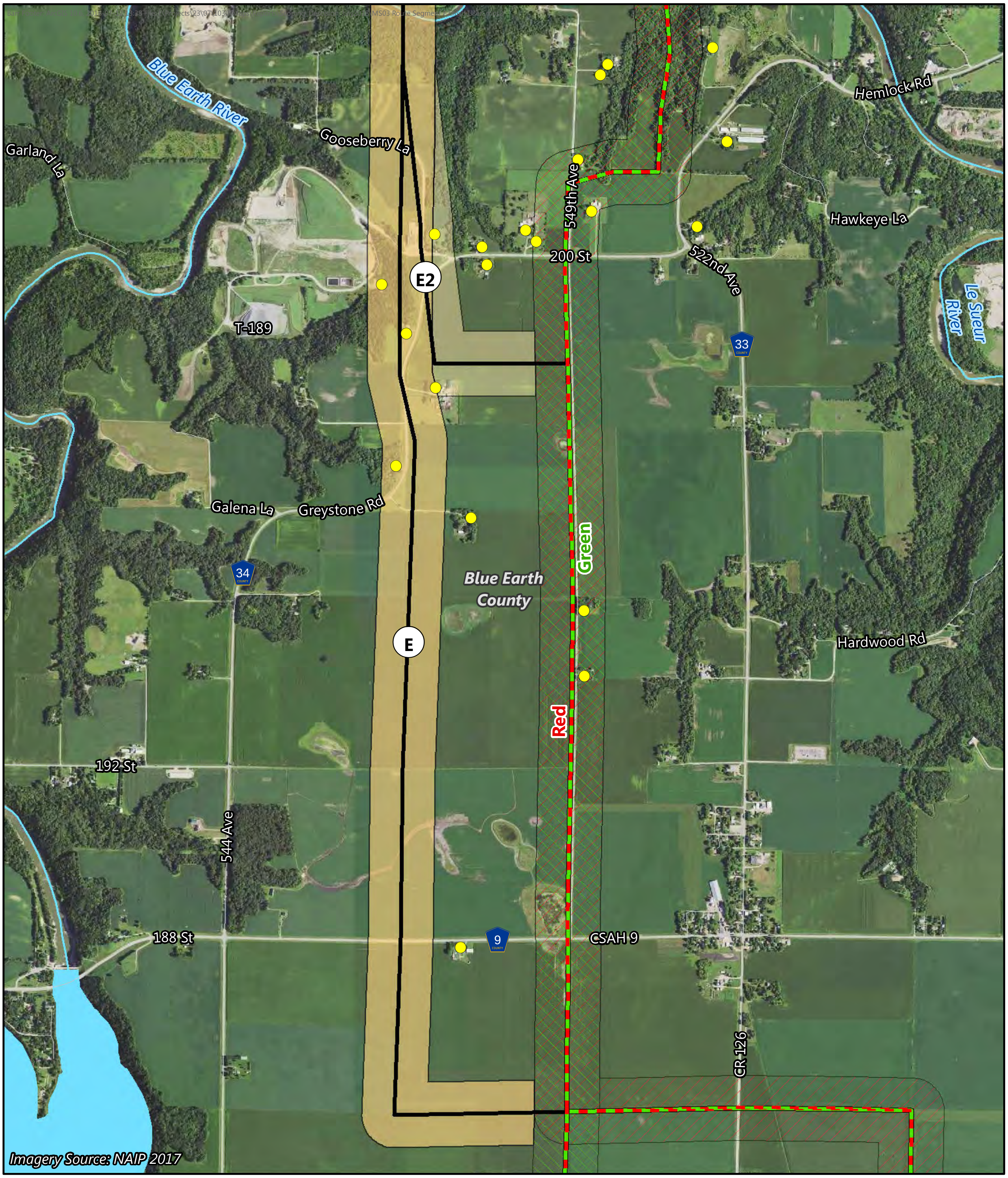


Purple-E-Red Route
Purple Route
Red Route
Route Segment
Existing Transmission Line
Huntley Substation
Wilmarth Substation

Miles
0 4

Map 2 of 13

PURPLE-E-RED ROUTE
Scoping Decision
Huntley-Wilmarth 345kV Project

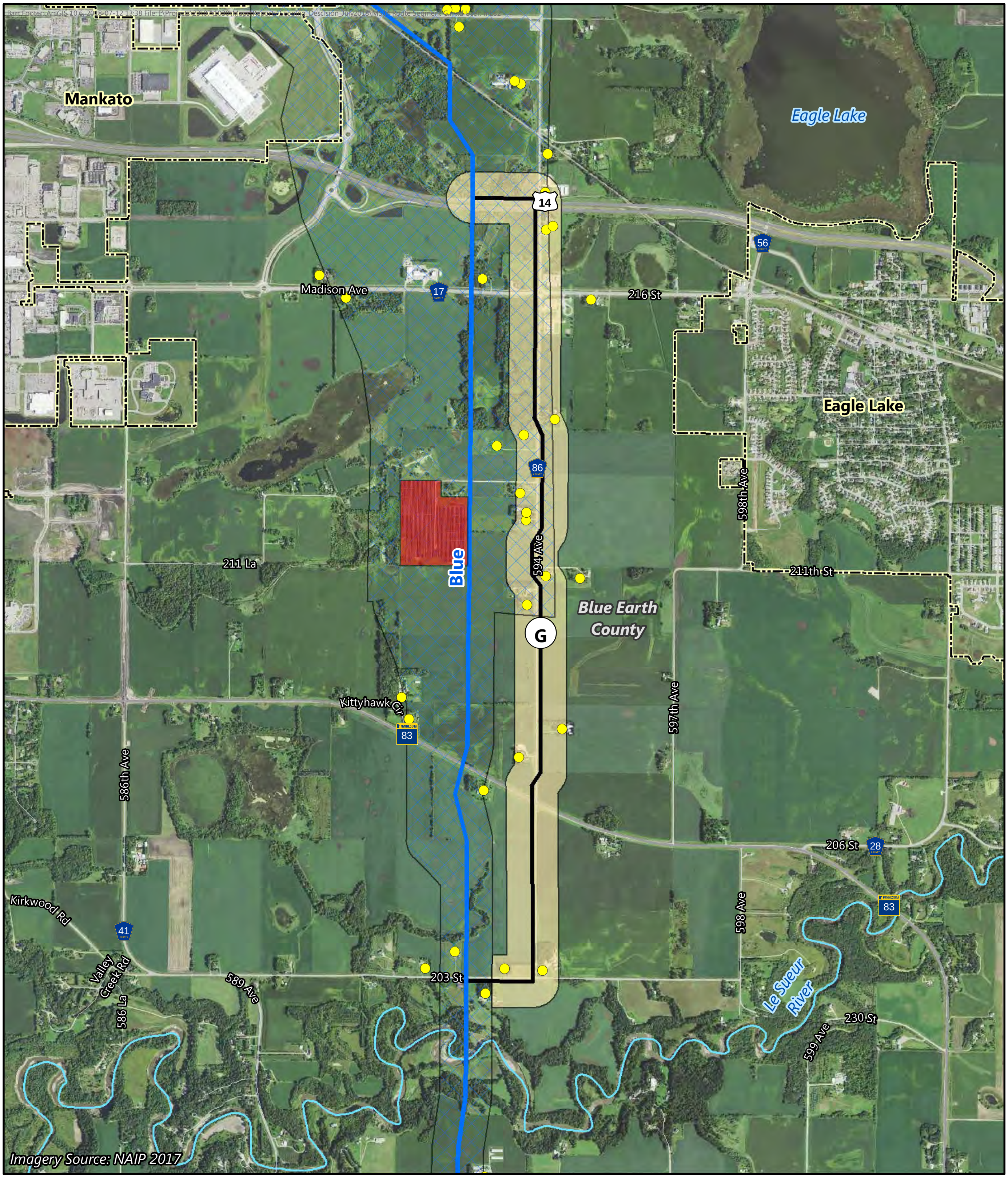


Red Route
Red Route Width
Green Route
Green Route Width
Route Segment
Route Segment Width
Residence

Feet
0 2,000

Map 3 of 13

ROUTE SEGMENT E2
Scoping Decision
Huntley-Wilmarth 345kV Project

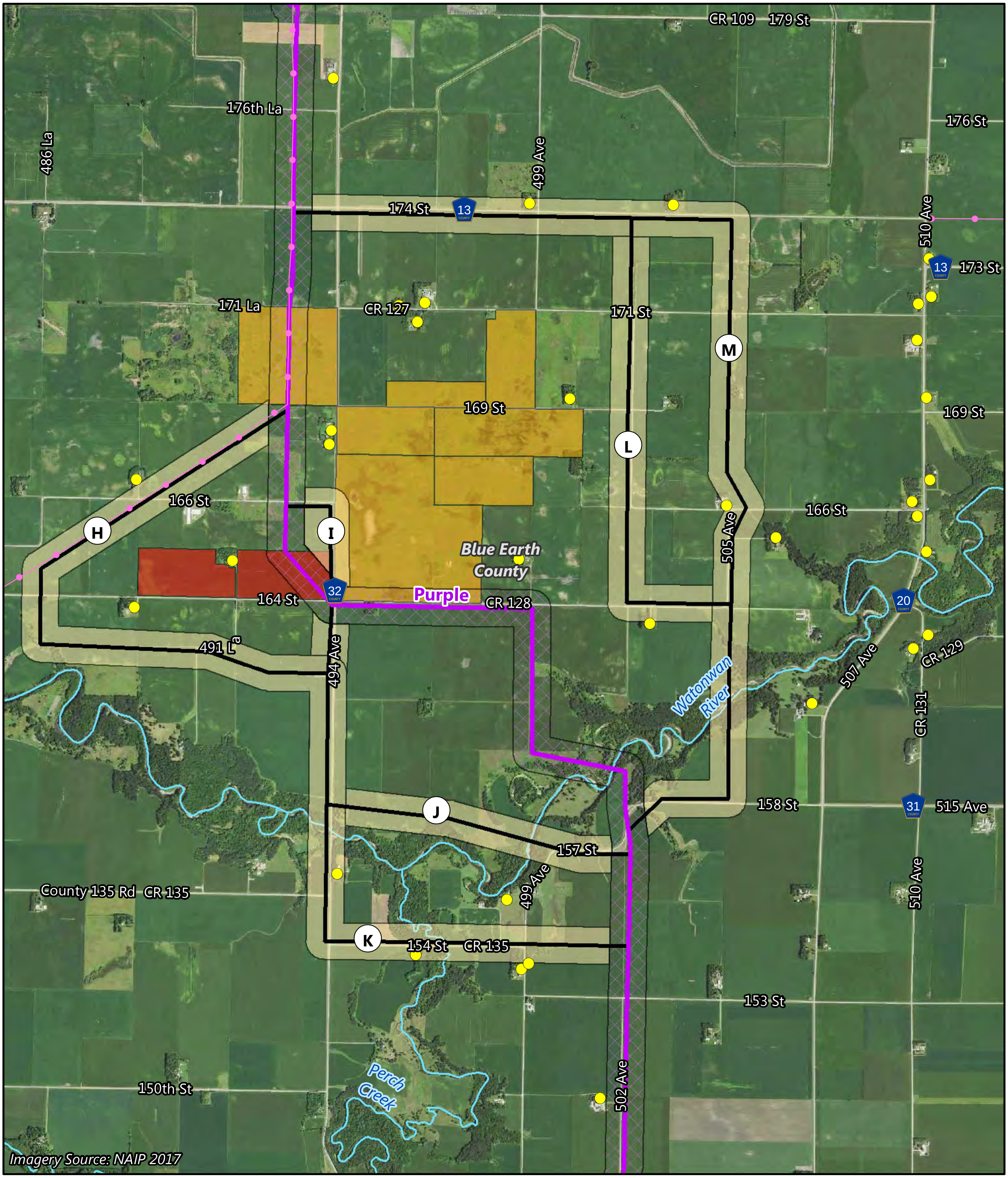


- Blue Route
- Blue Route Width
- Route Segment
- Route Segment Width
- Eastwood Solar Farm
- Residence

Feet
0 2,500

Map 4 of 13

ROUTE SEGMENT G
Scoping Decision
Huntley-Wilmarth 345kV Project

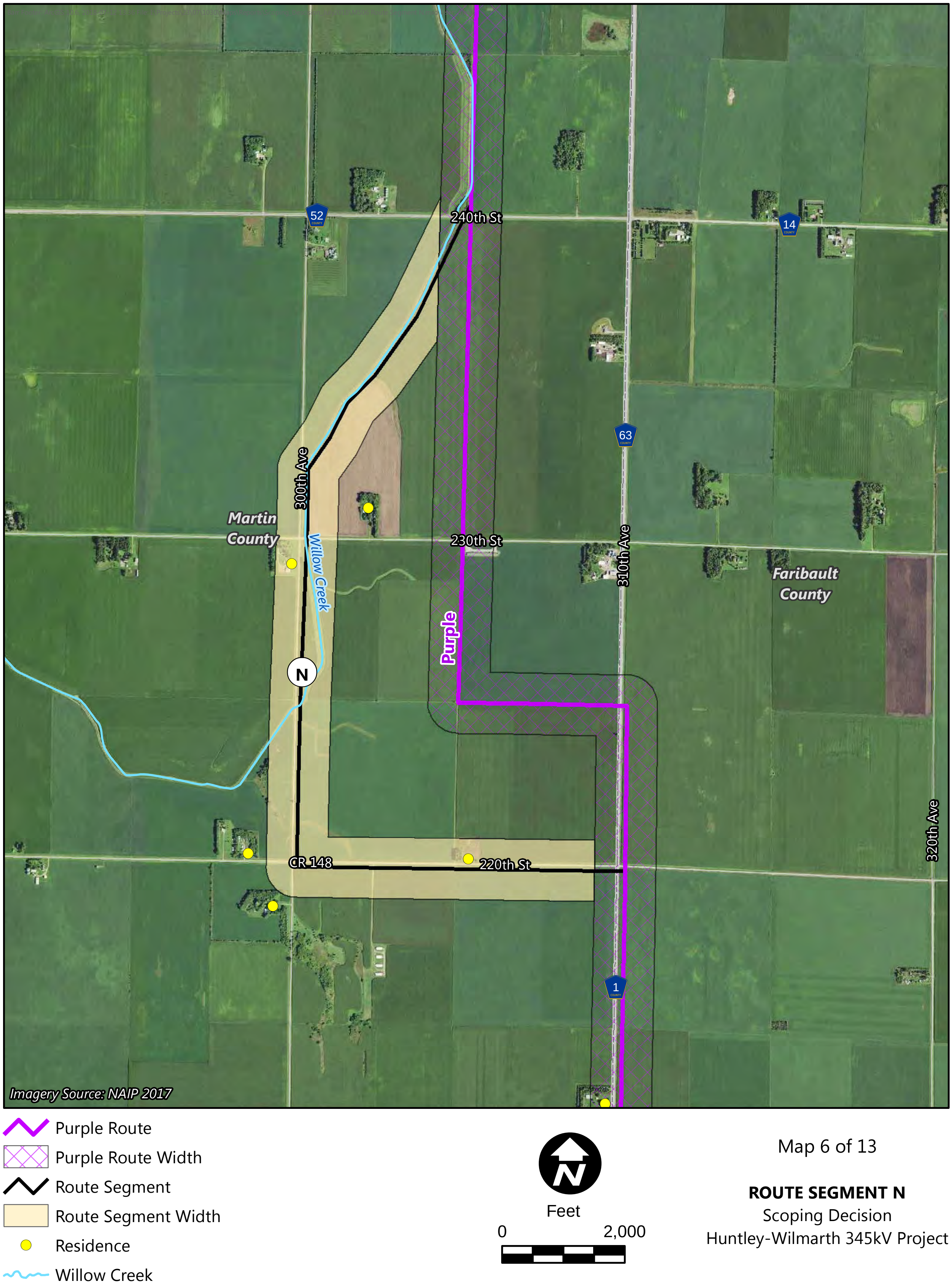


Purple Route
Purple Route Width
Route Segment
Route Segment Width
Existing Transmission Line
Residence
Pheasants Forever Parcel
Waterfowl Production Area

Feet
0 3,500

Map 5 of 13

ROUTE SEGMENTS H THROUGH M
Scoping Decision
Huntley-Wilmarth 345kV Project

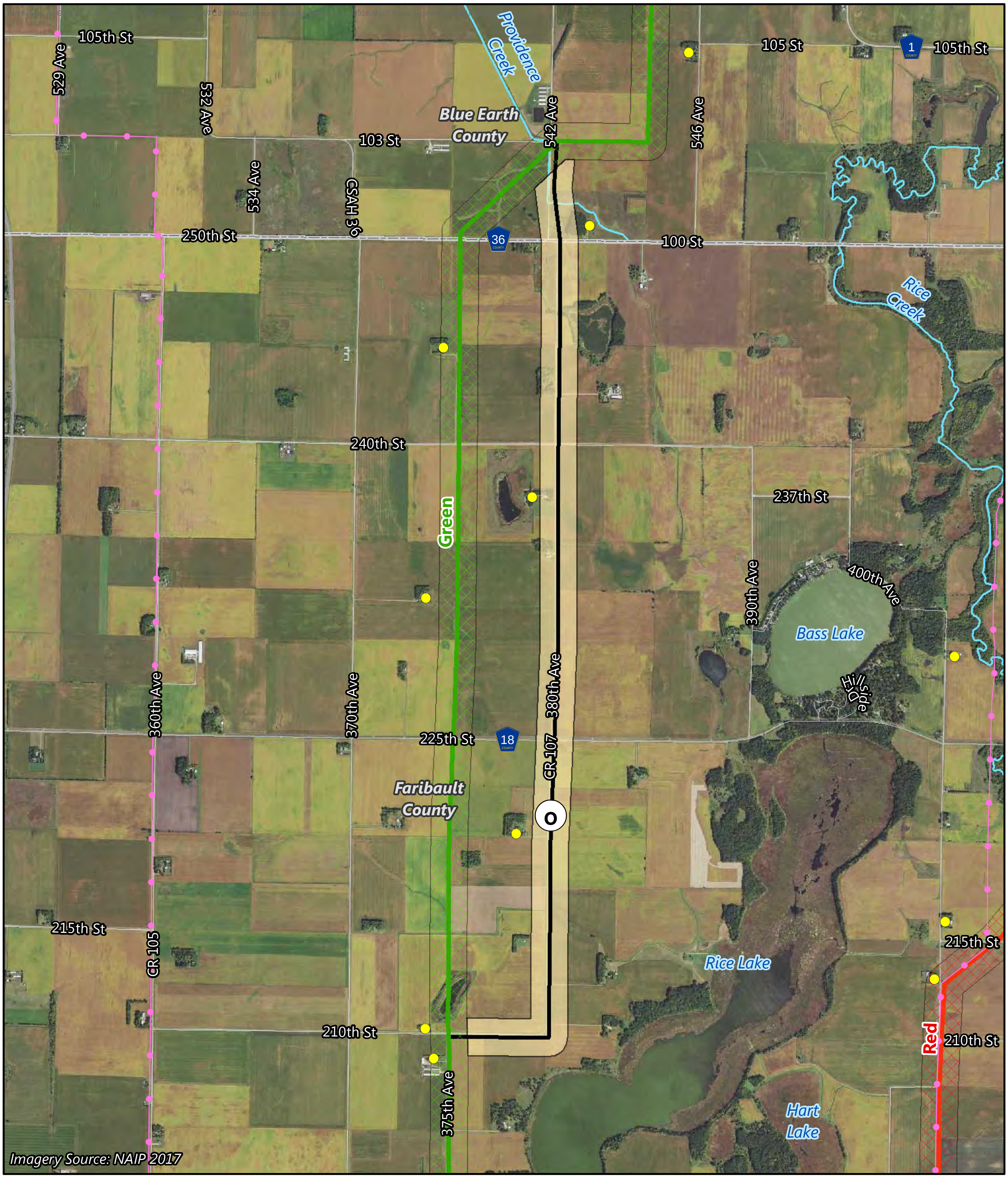


Map 6 of 13

ROUTE SEGMENT N

Scoping Decision

Huntley-Wilmarth 345kV Project



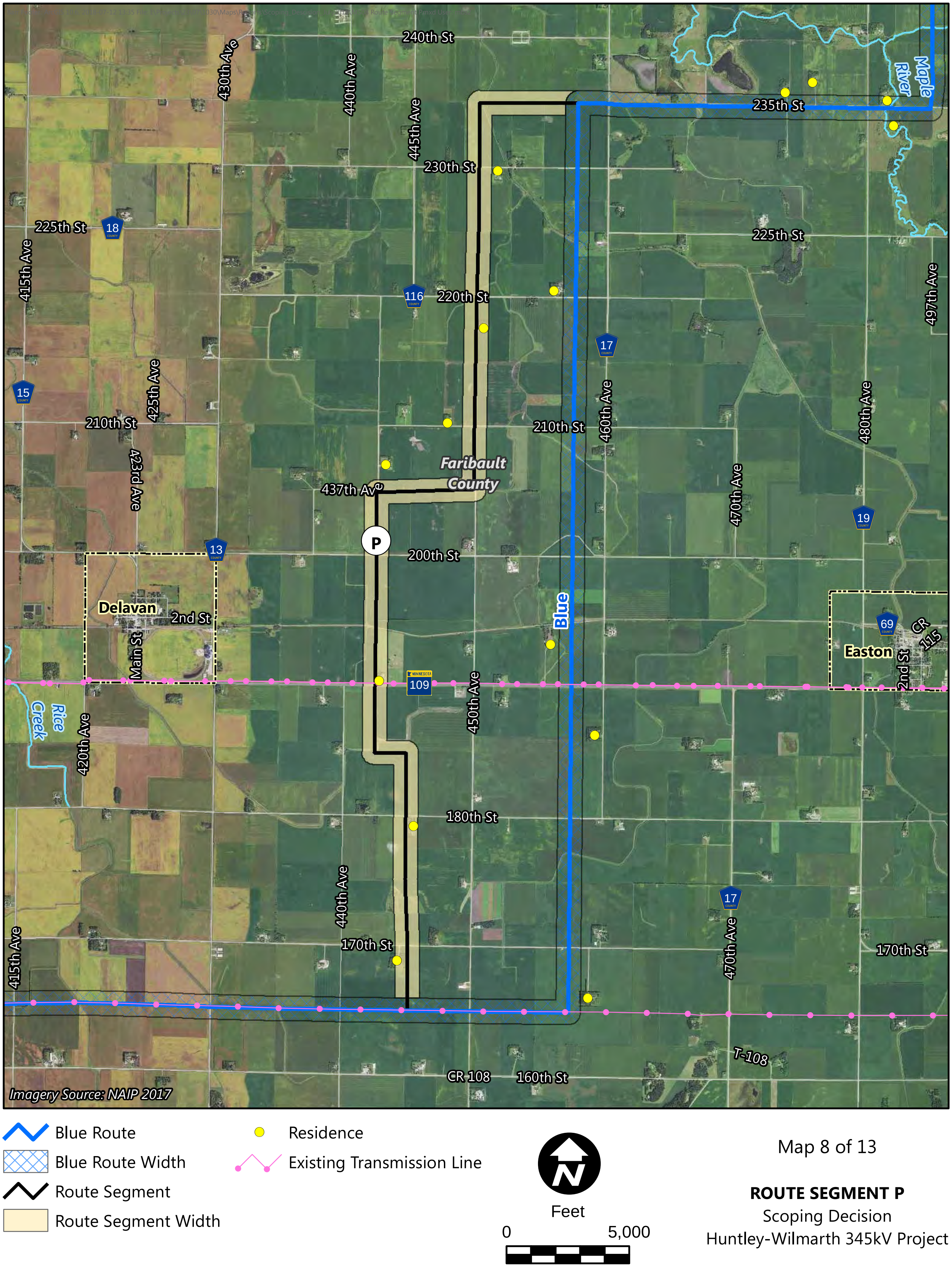
Green Route
Green Route Width
Red Route
Red Route Width
Route Segment
Route Segment Width
Residence
Existing Transmission Line

N

Feet
0 3,500

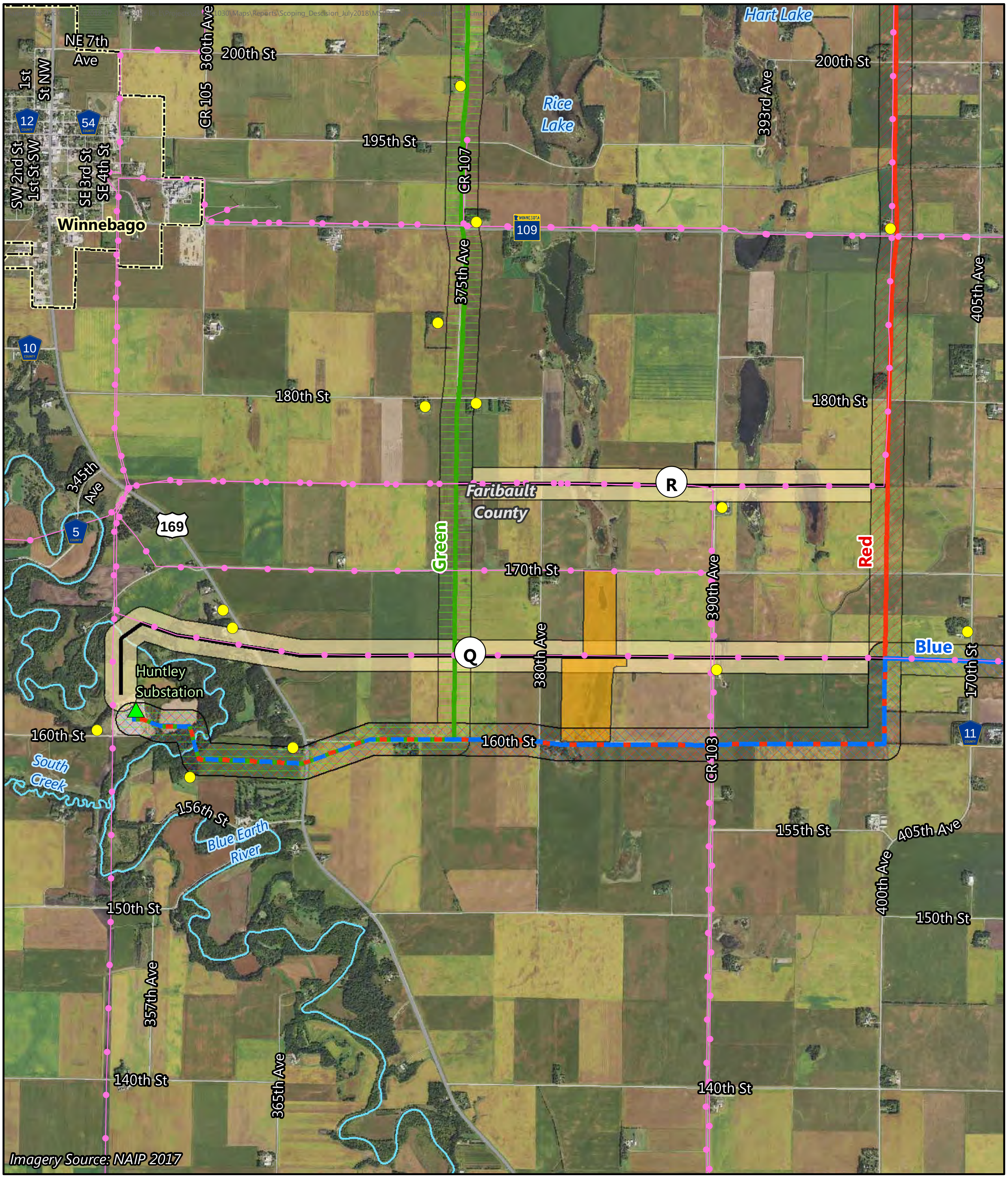
Map 7 of 13

ROUTE SEGMENT O
Scoping Decision
Huntley-Wilmarth 345kV Project



Map 8 of 13

ROUTE SEGMENT P
Scoping Decision
Huntley-Wilmarth 345kV Project



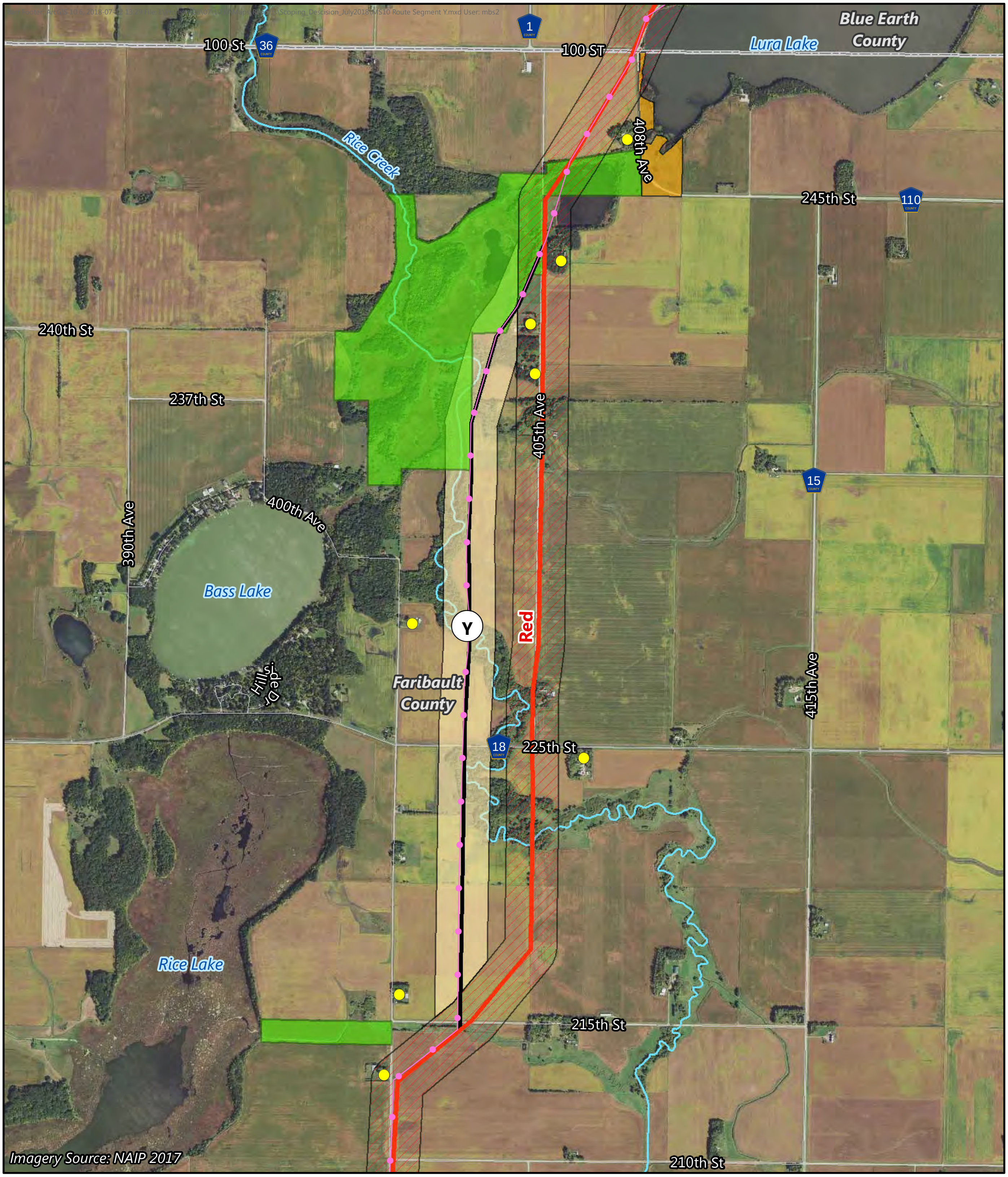
- Blue Route
- Blue Route Width
- Green Route
- Green Route Width
- Red Route
- Red Route Width
- Route Segment
- Route Segment Width
- Residence
- Existing Transmission Line
- Waterfowl Production Area

Feet
0 4,000

Map 9 of 13

ROUTE SEGMENTS Q AND R

Scoping Decision
Huntley-Wilmarth 345kV Project



Red Route
Red Route Width
Route Segment
Route Segment Width
Residence
Existing Transmission Line
Wildlife Management Area
Waterfowl Production Area

Feet
0 2,500

Map 10 of 13

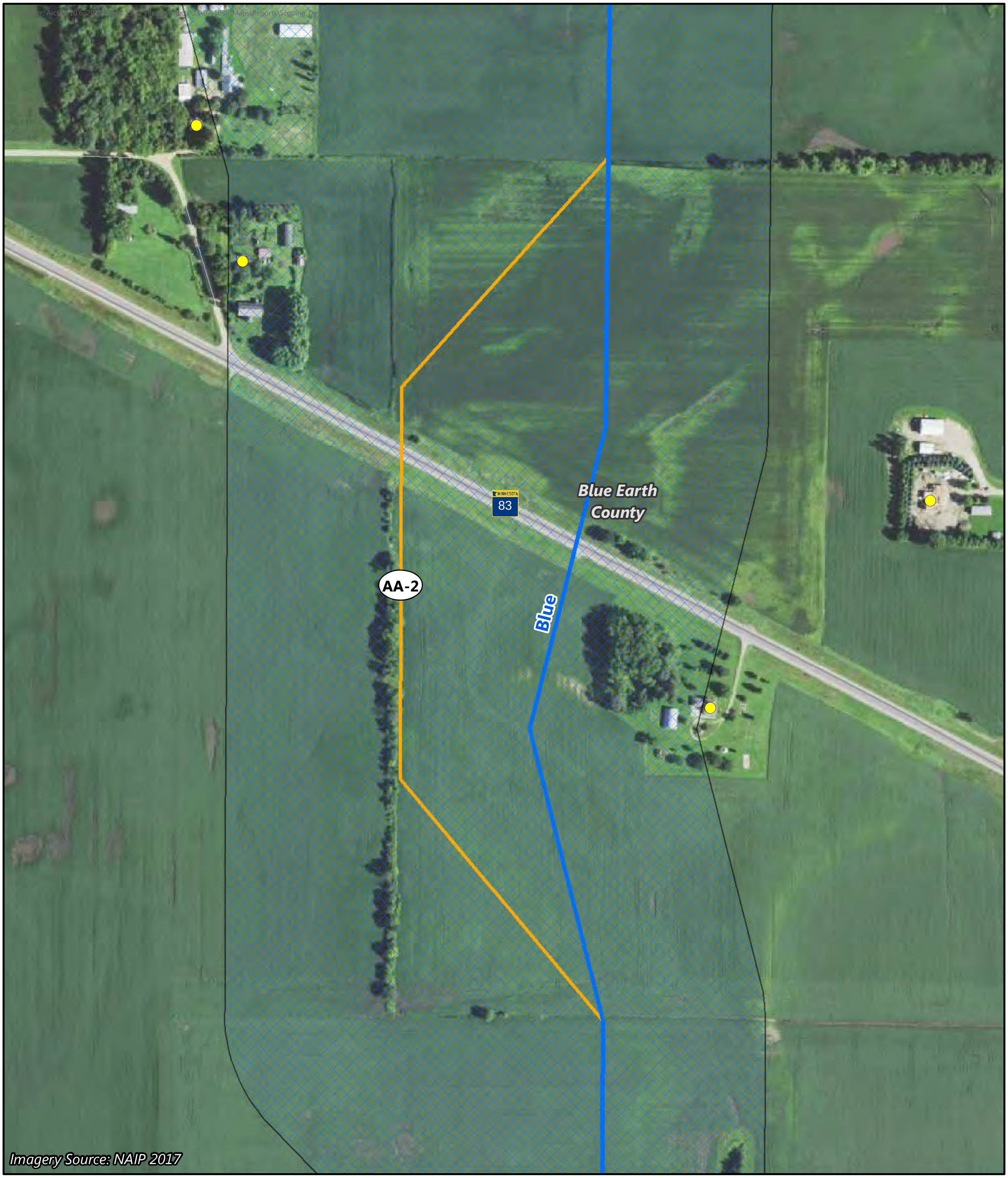
ROUTE SEGMENT Y
Scoping Decision
Huntley-Wilmarth 345kV Project

Route Segment
Route Segment Width
Alignment Alternative
Residence

Feet
0 600

Map 11 of 13

ALIGNMENT ALTERNATIVE 1
Scoping Decision
Huntley-Wilmarth 345kV Project

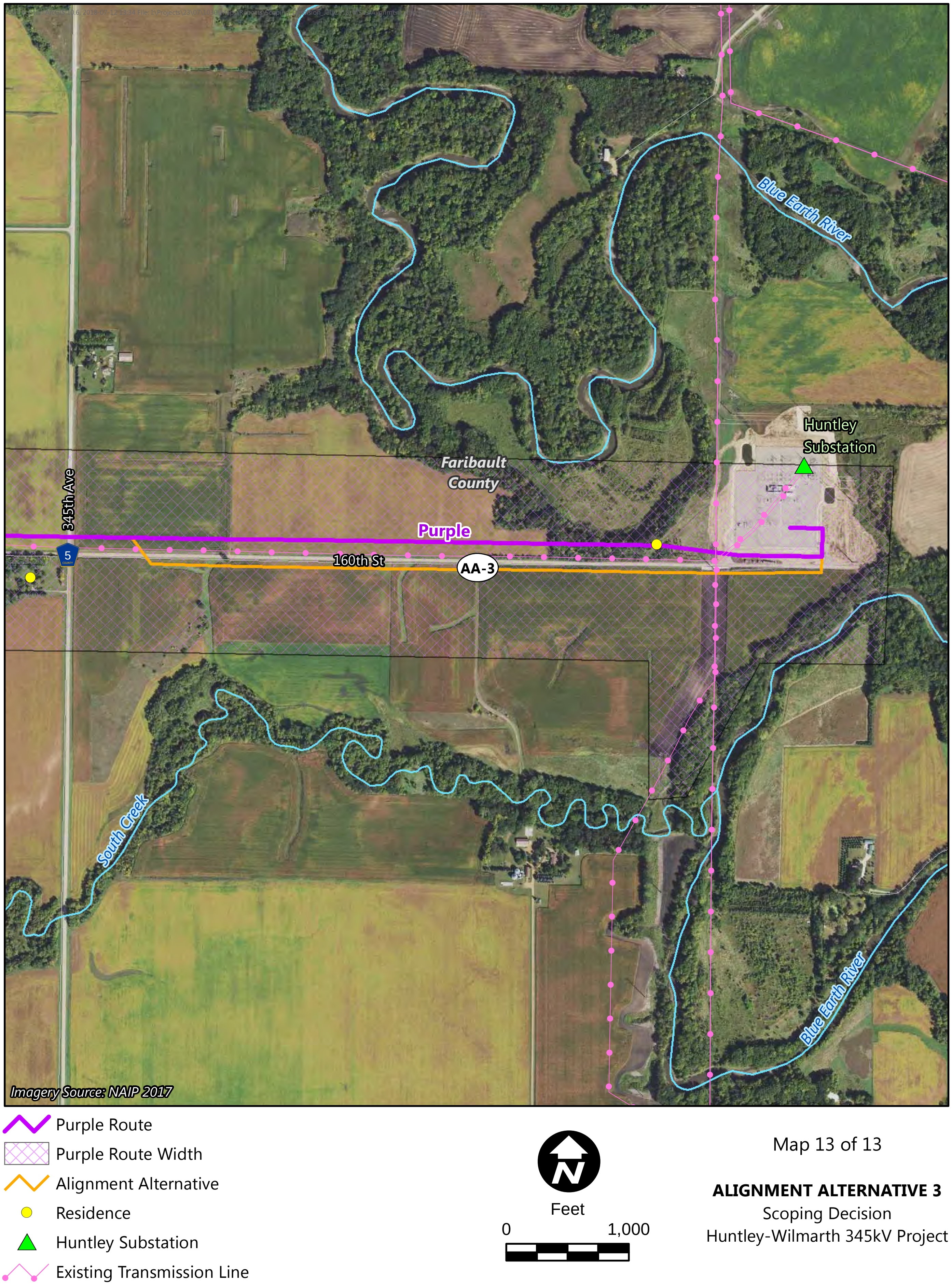


Blue Route
Blue Route Width
Alignment Alternative
Residence

Feet
0 400

Map 12 of 13

ALIGNMENT ALTERNATIVE 2
Scoping Decision
Huntley-Wilmarth 345kV Project



Map 13 of 13

ALIGNMENT ALTERNATIVE 3

Scoping Decision

Huntley-Wilmarth 345kV Project

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Xcel Energy			
Docket No.:	E002,ET6675/CN-17-184		
Response To:	MN Department of Commerce	Information Request No.	23
Requestor:	Matthew Landi / Steve Rakow		
Date Received:	August 1, 2018		

Question:

Topic:	Benefit-Cost Analysis of the Environmental Impact Statement Route Segments
Reference(s):	Environmental Impact Statement Scoping Decision dated July 17, 2018

The Minnesota Department of Commerce released an Environmental Impact Statement (EIS) Scoping Decision on July 17, 2018. Please provide the following information:

1. Do the additional routes, route segments, and alignment alternatives (EIS routes) to be included in the EIS due to the July 17, 2018 EIS Scoping Decision change the high or low end of the cost estimate for the Project?
    a. If the range of cost estimates does change as a result of the EIS routes, please provide the same level of benefit-cost analysis as was done for the Project and its alternatives.
2. For any future additional route segments proposed by the Applicants, please provide benefit-cost analysis if the additional route segments change the high or low end of the cost estimate for the Project.

Response:

1. Yes, certain routes, route segments, and alignment alternatives that will be included in the EIS change both the high and low end of the cost estimate for the Project.
    a. Please see **Attachment A**.

2. The Applicants agree to provide benefit-cost analysis to the extent they propose additional route segments that change the high or low end of the cost estimate for the Project.

Preparer:	Grant Stevenson, Xcel Energy
Title:	Senior Project Manager
Department:	Transmission Project Management North
Telephone:	612-330-6330
Date:	August 13, 2018

DOC IR 23: Huntley - Wilmarth Low and High Estimates as Revised by Scoping Segments (2016$)

This analysis calculates new lowest and highest cost bookends for each route estimate assuming the original route would be modified to the greatest extent possible by applicable scoping segments. Totals are rounded to the nearest $100,000 and segments to the nearest $10,000.

Summary

Lowest Cost	Highest Cost
$104.8 million	$160.7 million
Purple Route, single circuit H-frame	Purple-E-Red Route, double and single circuit monopole
2.18 Benefit/Cost (MTEP17)	1.42 Benefit/Cost (MTEP17)

High and Low by Route

	Purple		Green		Red		Blue		Purple-E-Red	
	Low	High	Low	High	Low	High	Low	High	Low	High
Project Cost (millions, 2016$)	$ 104.8	$ 147.3	$ 108.2	$ 124.8	$ 134.4	$ 143.8	$ 123.7	$ 142.5	$ 157.0	$ 160.7
Benefit-Cost Ratio, MTEP17	2.18	1.55	2.11	1.83	1.70	1.59	1.85	1.6	1.46	1.42

Details by Route

	Purple		Segment
	Low (SCH)	High (SCM + DC)	Design
Application	105,800,000	137,900,000	
F	(70,000)		SCM
H		4,040,000	SCM + DC
J	(930,000)		SCH
N		2,680,000	SCM
AA3		2,640,000	TC
	104,800,000	**147,300,000**	
MTEP17 B/C	**2.18**	**1.55**	

Segment F is SCM for its entire length due to concerns about fitting H frames near buildings in Judson

Segment Design Notes:
SCH: single circuit H-frame
SCM: single circuit monopole
DC: double circuit
TC: triple circuit

	Green		Segment
	Low (SCH)	High (SCM)	Design
Application	109,000,000	121,300,000	
A		2,130,000	SCM + DC
B	(790,000)		SCH
O		1,320,000	SCM
	108,200,000	**124,800,000**	
MTEP17 B/C	**2.11**	**1.83**	

	Red		Segment
	Low (SCH + DC)	High (SCM + DC)	Design
Application	135,200,000	138,000,000	
A		2,130,000	SCM + DC
B	(790,000)		SCH
Q		3,200,000	DC
Y		440,000	DC
	134,400,000	**143,800,000**	
MTEP17 B/C	**1.70**	**1.59**	

	Blue		Segment
	Low (SCH + DC)	High (SCM + DC)	Design
Application	123,700,000	135,800,000	
G		1,960,000	SCM
P		1,550,000	SCM
Q		3,200,000	DC
	123,700,000	**142,500,000**	
MTEP17 B/C	**1.85**	**1.60**	

	Purple-E-Red		Segment
	Low (SCM + DC)	High (SCM + DC)	Design
Red DC Application	138,000,000	138,000,000	
E	19,040,000	19,040,000	SCM + DC
Y		440,000	DC
Q		3,200,000	DC
	157,000,000	**160,700,000**	
MTEP17 B/C	**1.46**	**1.42**	

Purple-E-Red was proposed by the local government task force to connect Purple double circuit to Red double circuit to reduce impacts to agriculture. In that spirit, Purple-E-Red is estimated only as single circuit and double circuit monopoles. Therefore, the base Purple-E-Red estimate is the Red double circuit estimate from the application modified by scoping segment E, which results in $157 million low cost (2016$.) Note that Segment E in this analysis does not match Segment E in the route application per EERA scoping estimate endpoint maps.

From: Ramler, Bryan J
To: Landi, Matthew (COMM)
Cc: Stevenson, Grant D
Subject: RE: Docket No. E002,ET6675/CN-17-184 Inquiry - Benefit-Cost Analysis of the Proposed Huntley-Wilmarth Transmission Line Project
Date: Thursday, September 20, 2018 9:39:24 AM
Attachments: image003.png

Matthew-

Grant Stevenson forwarded me your e-mail and asked me to respond as I provided the benefit-cost calculations in the application and information requests. Grant can answer questions regarding construction costs.

Thanks for the question. The present value (PV) benefit for the Huntley – Wilmarth 345 kV Project as calculated under the MTEP17 models is $275.83 and this same PV benefit number was utilized in the Applicants' response to DOC IRs No. 17, 18, and 23.

However, I note that the PV benefit for the 345 kV Project cannot be directly calculated from the table provided in DOC IR No. 23 Attachment A. This is because the cost values used in calculating PV Costs in the PV Benefit/PV Cost ratio take into account the revenue requirements of NSP and ITC, the discount rate, and the inflation rate over a 20 year period, in addition to the construction costs of the Project. The revenue requirement, discount rate, and inflation rates for the three MTEP17 futures are found in the Supplement DOC 17, Attachments B through D, columns 6 through 8. For each year in the present value period, 2022 to 2041, an annual cost is calculated. The present cost (i.e., route construction cost estimate) is multiplied by the inflation rate that is applicable for that given year and the annual revenue requirement for that year. That annual cost value is then converted to a present value annual cost by dividing the annual cost by the discount rate that is applicable for that given year. These annual values are then summed up to produce a 20-year PV Cost. In the instance of the low-end Purple Route construction cost estimate of $104.8M, the 20-year PV Cost is $126.6M which when multiplied by the B/C ratio of 2.18 produces a PV Benefit of $276M. For MTEP17, you can utilize a 20.76% adder to the construction cost estimate for each route/design for the annual revenue requirements, discount rate, and inflation rate, thereby producing an appropriate PV Cost to calculate the PV Benefit, but the adder for a different MTEP model year (e.g., MTEP18) would be different. This is the same methodology that MISO utilizes to calculate the PV Cost for projects as part of its MTEP analysis.

Please don't hesitate to reach out if you have further questions about these PV calculations. We're happy to help and we can set up an in-person meeting if it would be helpful to discuss additional questions.

Thank you,

Bryan Ramler
Xcel Energy | Responsible By Nature
Senior Engineer – Regional Transmission Planning Analytics
414 Nicollet Mall, Minneapolis, MN 55401
P: 612.330.5954
E: **Bryan.Ramler@xcelenergy.com**

From: Landi, Matthew (COMM) [mailto:matthew.landi@state.mn.us]
Sent: Monday, September 17, 2018 10:40 AM
To: Stevenson, Grant D
Cc: Rakow, Stephen (COMM)
Subject: Docket No. E002,ET6675/CN-17-184 Inquiry - Benefit-Cost Analysis of the Proposed Huntley-Wilmarth Transmission Line Project

Good afternoon Mr. Stevenson,

Thank you for providing me with your e-mail address. Below is an explanation of why I am contacting you regarding the benefit-cost analysis of the proposed 345 kV Huntley-Wilmarth transmission line project.

===

In review of the responses and supplemental responses of the information requests, in addition to information contained in the CN application, the Department is requesting some additional insight regarding the appropriate figures to use in our analysis of the proposed transmission line project and the alternatives.

In response to DOC IR No. 23, in Attachment A, you provided benefit-cost analysis of the 'Huntley-Wilmarth Low and High Estimates as Revised by Scoping Segments (2016$).'

High and Low by Route

	Purple		Green		Red		Blue		Purple-E-Red	
	Low	High	Low	High	Low	High	Low	High	Low	High
Project Cost (millions, 2016$)	$ 104.8	$ 147.3	$ 108.2	$ 124.8	$ 134.4	$ 143.8	$ 123.7	$ 142.5	$ 157.0	$ 160.7
Benefit-Cost Ratio, MTEP17	2.18	1.55	2.11	1.83	1.70	1.59	1.85	1.6	1.46	1.42

In addition to this information, you provided a breakdown of the costs of the various routes.

In the supplemental response to DOC IR No. 17, dated August 31, 2018, the applicants provided benefit-cost analysis of the Huntley-Wilmarth 345 kV given the range of project costs and calculated the Present Value Benefit ("PV Benefit") and the resulting Benefit-to-Cost Ratios ("BC Ratios") in Table 17, entitled 'Table 17-Second Revised: MTEP17 Analysis with Current Project Cost Estimates (2016$).' This table also appears in the supplemental response to DOC IR No. 18, dated August 31, 2018.

The tables is as follows:

Table 17-Second Revised
MTEP17 Analysis with Current Project Cost Estimates (2016$)

Project	Applicants' Project Cost Estimates (2016$ Millions)	Expected In-Service	PV Benefit (Million 2016$)				Benefit-to-Cost Ratios (Millions, 2016$)			
			AAT	EF	PR	Weighted	AAT	EF	PR	Weighted
Huntley – Wilmarth 345 kV	$105.8-$138.0	2022	816.04	13.92	138.01	275.83	4.90-6.39	0.08-0.11	0.83-1.08	1.66-2.16

Extrapolating from the Table in DOC IR No. 23, PV Benefits for each of the route options and low/high costs results in a figure approximately equal to $228.3 million (e.g., using purple, low $104.8 * 2.18 = $228.3), lower than the weighted PV Benefit of $275.83 million relied upon in the Application.

My question is as follows: which set of figures is appropriate to use, the data presented in response to DOC IR No. 23, or the data presented in the supplemental response to DOC IR Nos. 17 and 18?

Thank you for any insight you can provide.

Sincerely,

Matthew Landi
Minnesota Department of Commerce
Public Utility Rates Analyst | Division of Energy Resources
651-539-1823
mn.gov/commerce
85 7th Place East, Suite 280 | Saint Paul, MN 55101

COMMERCE DEPARTMENT

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☒ **Public Document**

Xcel Energy

Docket No.:	E002,ET6675/CN-17-184		
Response To:	MN Department of Commerce	Information Request No.	27
Requestor:	Matthew Landi / Steve Rakow / Mark Johnson		
Date Received:	September 25, 2018		

Question:

Topic: Annual Revenue Requirements
Reference(s): Supplemental Response to DOC IR No. 17, Attachment A, p. 6

Please provide support for the annual revenue requirement percentages found on page 6 of Attachment A of the Supplemental Response to DOC IR No. 17. Specifically, please provide support for the figures listed in the 'ITCM' and 'NSP' columns.

Response:

The annual revenue requirement percentages found on page 6 of Attachment A of the Applicants' Supplemental Response to DOC IR No. 17 are posted by MISO in accordance with Attachment GG of the MISO Tariff using Attachment O data as of March 2017. These rates are posted for each Transmission Owner for a 20-year period. The components of the Attachment O data are assumed to be held constant in future years using a 40-year straight line depreciation for all projects and Transmission Owners.

For each Transmission Owner, the rate is made up of: (1) the annual expense charge on the Attachment GG gross project costs; (2) the annual return charge on the Attachment GG net project cost; and (3) the annual depreciation (assuming all Attachment GG projects have a 40-year asset life). The sum of these three amounts is added to get the annual revenue requirement. The annual revenue requirement is then divided by the gross project costs to develop the annual return factor listed in the table on page 6.

The annual expense charge on the Attachment GG gross project cost is calculated as follows:

Annual expense charge on Attachment GG gross project cost = Attachment O Transmission O&M + General & Common Depreciation + Taxes Other Than Income. That total is then divided by Gross Transmission Plant.

The annual return charge on Attachment GG net project cost is calculated as follows:

Annual return charge on Attachment GG net project cost = Attachment O Total Income Taxes + Return on Rate Base. This total is divided by Net Transmission Plant.

The NSP and ITC percentages shown on the table on page 6 are calculated as described above based on information publicly posted to MISO. The Applicants used the average of the NSP and ITC percentages to calculate the benefit-to-cost ratio for the Huntley – Wilmarth 345 kV Project as these two companies will own the proposed Project.

Preparer:	Kyle Neidermire, Xcel Energy / Zachary Paquette, ITC Holdings
Title:	Regional Transmission Initiative /Manager
Department:	Strategic Transmission Initiatives / Rates
Telephone:	715-737-2367 / 248-946-3446
Date:	October 5, 2018

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Xcel Energy			
Docket No.:	E002,ET6675/CN-17-184		
Response To:	MN Department of Commerce	Information Request No.	20
Requestor:	Matthew Landi / Steve Rakow		
Date Received:	May 29, 2018		

Question:

Topic: Economic Analysis of the Project and Alternatives
Reference(s): Chapters 4 & 5; Appendixes G, I, & K

Please explain the data and assumptions used in Appendix I, including the sources, methodology, and justification for each of the components.

Response:

Appendix I was developed by ITC Midwest to evaluate externalities of different transmission line alternatives in Certificate of Need proceedings as required by the Minnesota Public Utilities Commission's November 25, 2014 Order Granting Certificate of Need with Conditions in Docket No. ET6675/CN-12-1053. The initial template was developed and submitted by ITC Midwest on October 7, 2015 to be applied to future Certificate of Need proceedings. This is the first docket where ITC Midwest has populated the template. The data applied in this evaluation included the routing cost estimates in the Certificate of Need Application for the Huntley-Wilmarth 345 kV Project (Project), financial assumptions, and externality values. The purpose of this analysis is to compare the benefits and net benefits, considering externalities, of the Project and a comparable 161 kV alternative. The variables, data sources, and methodology are described below.

Route/Design Cost Estimates

High, medium, and low cost route estimates for the Huntley – Wilmarth 345 kV Project were applied in this externalities analysis to provide a range of benefits for potential routes. Specifically, ITC Midwest utilized the cost estimates for Purple Route (single-circuit, H-Frame design), the Blue Route (double-circuit and single-circuit, monopole design), and the Green Route (single-circuit, monopole design).

The same externalities value were applied regardless of the route/design of the 345 kV Project. Only one cost estimate was developed for the 161 kV Huntley – Wilmarth alternative, that being the mid-range cost estimate along the Green Route.

Financial Assumptions

The Levelized Fixed Charge Rate of 12.9% is an average of ITC Midwest and Xcel Energy levelized fixed charge rates derived analogous to MISO's Schedule 26 - Indicative Annual Charge Rates. MISO's assumptions for the Indicative Annual Charge Rates except using a 63-year life include:

1) Annual Charge Rate calculated in accordance with Attachment GG of the Tariff using Attachment O data as of March 2017. It does not take into account changes to Attachment O that would result from tax reform legislation; and

2) Components of Annual Charge Rate based on Attachment O data assumed to remain constant in future years.

The inflation and discount rates replicate MISO's assumptions applied in the MTEP17 analysis:

1) Inflation Rate 2.50%;

2) Discount Rate 7.10%

Benefits

Total proposed project benefits are calculated as the sum of the public policy benefits and the economic benefits. The public policy benefit reflect the weighted PROMOD Emissions Cost Savings as derived by the change in tons of emissions for resources within MISO LRZ's 1, 2, and 3 reported by PROMOD multiplied by the Minnesota Public Utilities Commission approved externality values. The economic benefit reflects the weighted PROMOD APC savings as derived from traditional MISO North/Central APC savings methodology discussed in Applicants' response to DOC-DER IR No. 17 minus the change in emissions costs.

Benefits are derived from simulations of study years 2021, 2026, and 2031. For a 63-year evaluation period, the remaining years are interpolated between study years and extrapolated beyond the final study year. The weighted data and formulae are included in the live spreadsheet provided in response to DOC-DER IR No. 19.

The MISO MTEP17 models capture emission rates of SO2, NOx, and CO2 that were developed by Asea Brown Bovari (ABB) and are applied in the MTEP17 models by fuel type. Emissions of NOx and CO2 have prices applied in the unit commitment and dispatch process. Increased CO2 prices are necessary to create higher dispatch costs necessary to achieve the carbon reduction assumptions developed in the futures building process. These resulting emission costs become part of the unit production costs captured in the APC metric but do not match the Minnesota Public Utilities Commission's approved externality values *In the Matter of the Further Investigation into Environmental and Socioeconomic Costs Under Minnesota Statutes Section 216B.2422, Subdivision 3*, Docket No. E-999/CI-14-642, Order Updating Environmental Cost Values (Jan. 3, 2018) ("Externalities Order"). To avoid double counting of emissions reductions when considering externalities, the change in emission costs from PROMOD are removed from the APC benefit for all MISO North/Central resources. This reduced APC is identified as the 'modified APC'.

The public policy benefits are measured as the change in weighted tons of emissions multiplied by the externality costs contained in the Externalities Order for MISO LRZ's 1, 2, and 3. These LRZ's reasonably capture the range of resource locations identified in the Externalities Order as Urban, Metropolitan Fringe, Rural, and Within 200 Miles of Minnesota. The majority of the emission changes occurred with CO2. Therefore, high and low CO2 values were applied to provide a range of impacts. SO2 and NOx emission changes were relatively insignificant so these effluents, regardless of resource location, were valued at their median value for the rural location as a proxy. Higher or lower values can be incorporated into the calculations upon request but are assumed to be inconsequential. Appendix I contains the externality values applied, the weighted tons of emissions for each simulation, the emissions reduction for each alternative and the resulting change in externality costs.

The non-weighted simulation results for APC benefits, emissions cost benefits, and modified APC benefits for Huntley – Wilmarth 345 kV Project and the Huntley – Wilmarth 161 kV are shown in Table 1 below. Only the weighted values (i.e., the MISO MTEP17 Futures weightings) are applied in Appendix I. It was identified during the preparation of the response to this IR request that the emission prices between the Base Cases and Change Cases are different by fractions of a cent. As a result, this small price change multiplied by a large emissions tonnage may equate to a small increase in cost. These costs are reported by the ReportAgent tool in PROMOD and do not require any user computations. Emission cost increases of $805 to $111,301, as seen in Table 1 below, are assumed to be a reflection of this minor variation in emissions prices applied by PROMOD.

Table 1

		Economic Benefit Data ($)	Future	2021	2026	2031	
1	Huntley - Wilmarth 345 kV	Traditional MISO APC Benefits	EF	1,546,109	946,852	1,941,249	
2			PR	3,022,323	9,141,354	21,708,039	
3			AAT	2,891,317	58,045,943	131,912,380	
4			**Weighted**	**2,530,635**	**19,316,251**	**44,233,463**	
5		Emissions Cost Portion of APC Benefits	EF	(805)	(47,284)	(34,493)	
6			PR	(17,192)	(111,301)	205,204	
7			AAT	(15,692)	4,882,121	38,497,928	
8			**Weighted**	**(11,722)**	**1,206,834**	**10,087,006**	
9		Modified APC Benefits	EF	1,546,914	994,135	1,975,742	
10			PR	3,039,515	9,252,655	21,502,835	
11			AAT	2,907,010	53,163,822	93,414,452	
12			**Weighted**	**2,542,357**	**18,109,417**	**34,146,457**	**<-- applied in Appendix I**
13	Huntley - Wilmarth 161 kV	Traditional MISO APC Benefits	EF	678,634	1,236,437	1,241,221	
14			PR	2,766,678	7,133,553	19,457,765	
15			AAT	2,233,562	46,134,101	89,699,186	
16			**Weighted**	**1,980,774**	**15,445,589**	**32,073,406**	
17		Emissions Cost Portion of APC Benefits	EF	6,351	(31,977)	(17,416)	
18			PR	4,842	301,689	1,171,366	
19			AAT	(8,889)	3,487,398	28,244,964	
20			**Weighted**	**1,740**	**1,026,537**	**7,841,979**	
21		Modified APC Benefits	EF	672,284	1,268,414	1,258,636	
22			PR	2,761,835	6,831,864	18,286,400	
23			AAT	2,242,452	42,646,704	61,454,222	
24			**Weighted**	**1,979,035**	**14,419,053**	**24,231,427**	**<-- applied in Appendix I**

Analysis

The Huntley – Wilmarth 345 kV Project produces higher emission reductions than the 161 kV alternative. As a result, the 345 kV Project was identified to have more economic and public policy benefits than the 161 kV alternative. A range of net benefits is calculated for the three 345 kV Project route/design options and the 161 kV alternative applying high and low CO2 externality values. Each of the evaluated combinations of projects or routing estimates is evaluated by benefits and net benefits on page 2 of Appendix I.

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☒ **Public Document**

Xcel Energy			
Docket No.:	E002,ET6675/CN-17-184		
Response To:	MN Department of Commerce	Information Request No.	12
Requestor:	Matthew Landi / Steve Rakow		
Date Received:	May 1, 2018		

Question:

Topic: System Loss Savings
Reference(s): Application, Table 25, Sec. 5.1.1.2.4, pp. 110-112

In Table 25, the 161 kV Huntley-Wilmarth alternative is projected to reduce system losses during the summer peak by a greater amount than the proposed 345 kV Huntley-Wilmarth line. Please explain why this occurs.

Response:

Through the analysis performed by the Applicants with respect to system losses and the system reliability analysis performed by MISO as part of MTEP16, the Applicants determined that the actual power flows on a Huntley – Wilmarth transmission line during summer peak conditions are very low. During summer peak conditions, wind generation is assumed to be at a low level and thermal generation sources closer to areas of demand are dispatched at higher levels, leading to lower power flows over a transmission line connecting the Huntley and Wilmarth substations.

The physical characteristics of the two voltage levels have different requirements when operating in low loading conditions. More specifically, the reactive power requirements of a 345 kV transmission line are greater than the reactive power requirements of a typical 161 kV transmission line during such conditions. Low loading conditions also tend to have lower real power losses due to the low level of current flowing on those lines.

The total system losses, as identified in Table 25 of the Certificate of Need Application (Application) on page 111, are in terms of MVA losses which has both real and reactive power components. Due to the minimal real power losses, which would be lower on the 345 kV configuration, and the greater reactive power demands of 345 kV transmission lines as compared to typical 161 kV transmission line characteristics, the total system loss savings appears to be lower for the 345 kV transmission line than it does for the 161 kV alternative. As shown in the Application, at times of high wind generation, leading to high power flow on a Huntley – Wilmarth transmission line, the 345 kV configuration reduces system losses significantly more than the 161 kV alternative.

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Date:	May 11, 2018

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Xcel Energy
Docket No.: E002,ET6675/CN-17-184
Response To: MN Department of Commerce — Information Request No. 10
Requestor: Matthew Landi / Steve Rakow
Date Received: May 1, 2018 — **SUPPLEMENT**

Question:
Topic: Congestion Relief of the 161 kV Huntley-Wilmarth Alternative
Reference(s): Application, Sec. 5.1.1.2, p. 104

Support and explain the conclusion that the 161 kV Huntley-Wilmarth alternative relieves only 84% of the identified congestion and that it appears to be trending downward.

Response
The 84% is the year 2031 weighted reduction in branch congestion of the target constraint (the Huntley-Blue Earth – South Bend – Wilmarth line) measured in dollars after the transmission line alternative (Huntley – Wilmarth 161 kV alternative) is added to the MTEP17 PROMOD simulations. The observation that the Huntley – Wilmarth 161 kV alternative has a downward trending congestion relief is based on the study years 2021, 2026, and 2031 and the alternative providing congestion relief of 100%, 88% and 84%, respectively for those three years. Neither MISO nor the Applicants developed PROMOD models to perform an analysis beyond the year 2031. The congestion relief results for the Huntley – Wilmarth 161 kV alternative for three MTEP17 individual futures are shown in Table 1 below.

Table 1: Huntley – Wilmarth 161 kV Target Constraint Congestion Relief[1]

	EF (31%)	PR (43%)	AAT (26%)	Weighted
2021	99%	100%	100%	100%
2026	100%	92%	69%	88%
2031	88%	86%	78%	84%

1 Congestion relief is shown for three MTEP17 Futures: Existing Fleet (EF), Policy Regulations (PR), and Accelerated Alternative Technologies (AAT).

Supplement:

Applicants submit this supplemental response to correct the weighted congestion reduction percentage in the original response and stated on page 107 of the Certificate of Need Application. In calculating the weighted percentages for the 161 kV alternative, the MISO weighting formula for each Future was incorrectly applied to each Futures' congestion reduction percentage instead of the congestion reduction dollars meaning there were inconsistent denominators for the weighted percentages. This error was discovered while preparing Direct Testimony. Applicants recalculated the weighted percentages to correct this error. The updated weighted congestion reduction decreases from the values originally provided. Applicants updated the original response below with the updated values are underlined and the prior incorrect values are shown in strikethrough format:

The ~~84~~80% is the year 2031 weighted reduction in branch congestion of the target constraint (the Huntley-Blue Earth – South Bend – Wilmarth line) measured in dollars after the transmission line alternative (Huntley – Wilmarth 161 kV alternative) is added to the MTEP17 PROMOD simulations. The observation that the Huntley – Wilmarth 161 kV alternative has a downward trending congestion relief is based on the study years 2021, 2026, and 2031 and the alternative providing congestion relief of 100%, ~~88~~75% and ~~84~~80%, respectively for those three years. Neither MISO nor the Applicants developed PROMOD models to perform an analysis beyond the year 2031. The congestion relief results for the Huntley – Wilmarth 161 kV alternative for three MTEP17 individual futures are shown in Table 1 below.

Table 1: Huntley – Wilmarth 161 kV Target Constraint Congestion Relief[1]

	EF (31%)	PR (43%)	AAT (26%)	Weighted
2021	99%	100%	100%	100%
2026	100%	92%	69%	~~88~~75%
2031	88%	86%	78%	~~84~~80%

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Xcel Energy			
Docket No.:	E002,ET6675/CN-17-184		
Response To:	MN Department of Commerce	Information Request No.	11
Requestor:	Matthew Landi / Steve Rakow		
Date Received:	May 1, 2018		

Question:

Topic: Congestion Relief
Reference(s): Application, Sec. 5.1.1.2.2, pp. 107-108

The Petition states that the proposed 345 kV Huntley-Wilmarth line provides 100% of the congestion relief considering expected generation levels. What is the maximum amount of generation capacity that the proposed 345 kV Huntley-Wilmarth line can accommodate and still provide 100% congestion relief?

Response:

The amount of congestion relief that a proposed transmission line can provide is dependent on a multitude of factors, including but not limited to generation type, size and location of the generation sources, system demand growth and utilization rates, and fuel costs. All of these assumptions are thoroughly vetted and agreed upon by the MISO stakeholders as part of the MTEP Futures development process that is described starting on page 72 of the Certificate of Need (CON) Application .

Due to the large number of variables that impact the amount of congestion on the system, the Applicants can only definitively state that the proposed Huntley – Wilmarth 345 kV Project relieves 100 percent of the identified congestion in all of the MTEP16 and MTEP17 Futures through the end of the study period (2031). The assumptions of the most congested scenario, which is modeled in the MTEP17 Advanced Alternative Technologies Future, are shown below as well as on pages 88-92 of the CON Application.

MTEP17 Future	Advanced Alternative Technologies
System-wide Renewable Additions by 2031	51,600 MW
Total System-wide Capacity Additions by 2031	93,800 MW
System-wide Generation Retirement by 2031	40,618 MW
Demand and Energy Growth	High; 0.91% Energy, 0.92% Demand
Demand Side Program additions	EE: 8,900 MW; DSM: 6,900 MW
Carbon Reduction Goal (from 2005)	35%

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