Appendix G

Applicants' Summary of MISO's Analysis of Huntley-Wilmarth Project

Huntley to Wilmarth 345 kV Project Development: Summary of MISO Study Process

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I. Executive Summary

A. Introduction

Since at least 2008, transmission planners have documented congestion on the transmission system along the Minnesota/Iowa border. Over the past decade, this congestion has increased with the rise in wind generation development that has taken advantage of the proximity to the Twin Cities and high average wind speeds the area offers.[1] Congestion on the transmission system affects both the cost of energy, deliverability of energy, and the efficiency of the electrical system. Specifically, congestion prevents the lowest cost generation, primarily wind in this area, from being used to serve customers, resulting in overall higher costs of wholesale energy.

The Midcontinent Independent System Operator, Inc. (MISO) regularly studies how to reduce congestion on the transmission system within its footprint, and as part of the 2016 MISO Transmission Expansion Plan (MTEP16), the MISO Board of Directors approved a solution for the congestion on the Minnesota/Iowa border. The proposed solution is a new 345 kV transmission line between ITC Midwest's new Huntley Substation near Winnebago, Minnesota, and Xcel Energy's existing Wilmarth Substation north of Mankato, Minnesota (Huntley-Wilmarth Project or Project). After studying 23 transmission alternatives, MISO concluded that the Huntley-Wilmarth Project provided the best overall performance by eliminating 100 percent of the identified congestion in this area and providing an anticipated $210 million in adjusted production cost benefits on a present value basis over 20 years with a

[1] NREL 100 Meter Average Annual Wind Speed, *available at* http://www.nrel.gov/gis/images/100m_wind/awstwspd100onoff3-1.jpg.

weighted benefit to cost ratio of 1.51 to 1.86.[2] Due in part to its benefit-to-cost ratio, the Project was designated as a Market Efficiency Project (MEP).

This MISO Study Process Report (Report) provides a summary of the MISO analysis that resulted in the Huntley-Wilmarth Project being designated as a MEP. The Report describes the congestion problem, provides an overview of MISO's responsibilities and planning processes, and identifies the criteria for an MEP. The Report then details MISO's selection of the Huntley-Wilmarth Project and the analysis that demonstrates its benefits.

B. MISO Responsibilities

MISO is a regional transmission organization (RTO) which operates the transmission system and an energy market in parts of 15 states and the Canadian province of Manitoba. As an RTO, MISO is responsible for planning and operating the transmission system in a reliable manner. MISO also provides operational oversight and control, market operations, and oversees planning of the transmission systems of its member Transmission Owners (TOs). MISO has 48 TO members with more than 65,800 miles of transmission lines and $34.5 billion in transmission assets that are under MISO's functional control.[3] MISO also has 128 non-transmission owning members that fall into the following industry sectors: Independent Power Producers, Power Marketers, Municipal/Cooperatives/Transmission Dependent Utilities, Consumer Advocates, State Regulatory Agencies, Environmental Organizations, End Use Customers, Transmission Developers and Coordinating Members.[4]

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[2] MISO, *MTEP16 – MISO Transmission Expansion Plan* (2016) [hereinafter MTEP16] at 12, *available at* https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20Full%20Report.pdf or as Appendix F to this Application.

[3] *See* MISO, *Fact Sheet* (updated Mar. 2017), *available at* https://www.misoenergy.org/AboutUs/Pages/FactSheet.aspx.

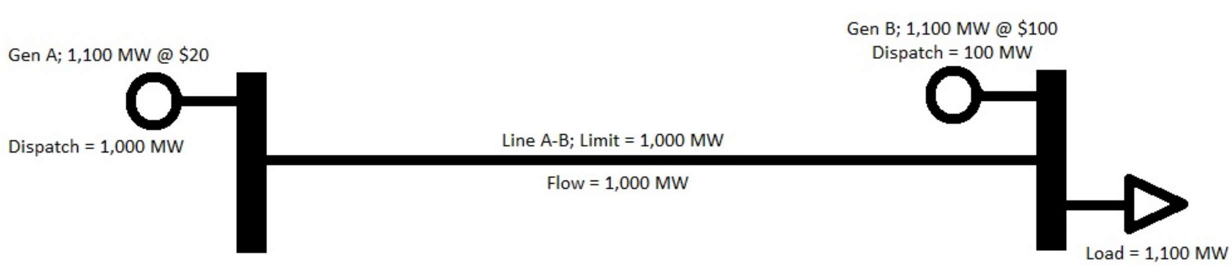
[4] A complete membership list of MISO members by stakeholder group is available at: https://www.misoenergy.org/Library/Repository/Communication%20Material/Corporate/Current%20Members%20by%20Sector.pdf.

In fulfilling its responsibility to operate an energy market in an efficient manner, MISO operates a day ahead and real-time energy market. Limits on transmission facilities can prevent MISO from dispatching the most efficient generation resources during all hours of the year, increasing wholesale energy costs. Currently, there is low cost energy being produced in Iowa and southern Minnesota that is unable to serve load centers, like the Twin Cities, due to transmission constraints in the area of the southern Minnesota/northern Iowa border that create congestion. More specifically, some energy cannot be delivered to load centers because the loading limits on certain system components preclude this additional energy from being transmitted along those facilities. As a result, more costly substitute energy from other areas (without transmission constraints) must be used to serve customers. These transmission constraints create inefficiencies in the wholesale energy market and increase costs.

Figure 1 is an illustration of how congestion affects the energy used and pricing in a single moment of time. The illustration assumes an energy need of 1,100 MW that could be supplied by two potential generators, one at a charge of $20 per MW and one at $100 per MW.

Figure 1

Congestion Illustration



In this theoretical intact system, Generator A could serve the entire 1,100 MW needed, but cannot do so because of the 1,000 MW limit on Line A-B. Instead, Generator A's dispatch is limited to 1,000 MW and Generator B will be called on to deliver the 100 MW balance. If Generator A were able to deliver the entire 1,100 MW it can generate, the energy cost would be $22,000 assuming no energy is lost during transmission. Due to system constraints, the total cost to deliver the 1,100 MW rises to $30,000 because 100 MW cannot be delivered, and replacement energy is required (1,000 MW X $20 for Generator A plus 100 MW X $100 for Generator B). In short, the congestion causes the overall cost of energy to increase $8,000 or 36 percent based on this simplified example. When there is no congestion, the lowest cost generator, regardless of fuel source, is the one that serves load.

A MEP is designed to address congestion to basically level the playing field for all generators to deliver their energy based on supply and demand, which in turn ensures that the energy market operates in the most efficient and cost-effective manner.

C. MISO Planning Process and MTEPs

One of MISO's responsibilities includes the development of the annual MTEP in collaboration with transmission owners and other stakeholders. The MTEP is developed in an 18-month overlapping cycle of model building, stakeholder input, reliability analysis, economic analysis, resource assessments, and drafting of the MTEP report. MISO adheres to the planning principles outlined in Federal Energy Regulatory Commission (FERC) Order Nos. 890[5] and 1000[6] in developing the MTEP. These FERC Orders require an open and transparent regional transmission planning process and include the requirement to plan for public policy objectives and for coordinated inter-regional planning and cost allocation. Consistent with these FERC directives, the MTEP process seeks to ensure the reliable operation of the

[5] FERC Order No. 890, 18 C.F.R. parts 35, 36 (2007), *available at* https://www.ferc.gov/whats-new/comm-meet/2007/021507/E-1.pdf.

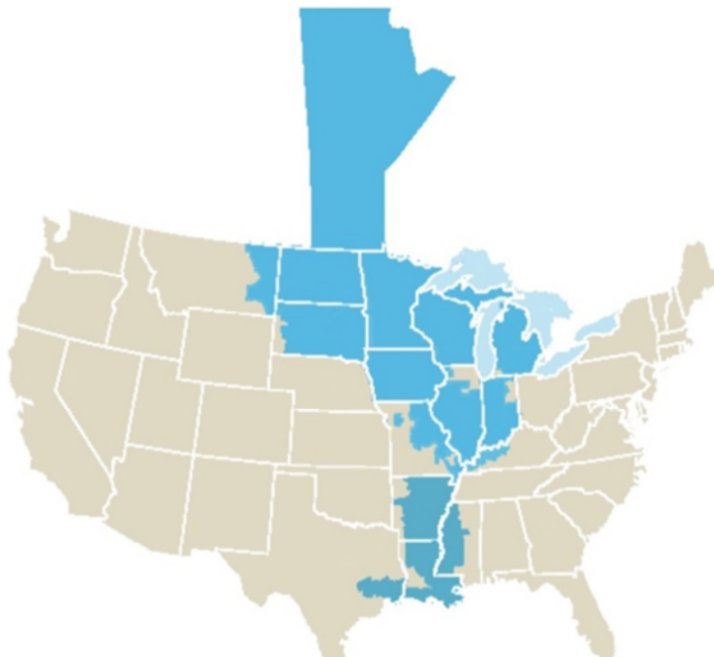
[6] FERC Order No. 1000, 18 C.F.R. part 35 (2011), *available at* https://www.ferc.gov/whats-new/comm-meet/2011/072111/E-6.pdf

transmission system, support the achievement of state and federal energy policy requirements, and enable a competitive energy market to benefit all customers.

The annual MTEP includes study work to identify projects necessary to ensure the reliability of the transmission system and a study aimed at identifying transmission projects that increase MISO customers' access to the lowest electric energy costs throughout the MISO energy market. A map of MISO's footprint is shown in **Figure 2**.

Figure 2

MISO Footprint



The Market Congestion Planning Study (MCPS) is a study conducted as part of the MTEP report that focuses exclusively on identifying congestion on the transmission system that limits access to the lowest-cost generation resources and evaluates transmission improvements that may relieve this congestion and increase market efficiency under a variety of different Future scenarios. The Future scenarios are developed through the stakeholder process to identify modeling assumptions for each Future, including but not limited to fuel prices, demand growth, and possible policy regulations.

The two types of projects that would result from the MCPS are the MEP and the "Other" type project, which can include lower cost or lower voltage economically justified projects. MEPs, such as the Huntley – Wilmarth Project, are defined in the MISO Open Access Transmission, Energy and Operating Markets Tariff (Tariff) as:

> Network Upgrades proposed by the Transmission Provider, Transmission Owner(s), ITC(s) [Independent Transmission Companies], Market Participant(s), or regulatory authorities as providing market efficiency benefits to one or more Market Participant(s), but not determined by the Transmission Provider to be Multi Value Projects and provide sufficient market efficiency benefits as determined by the Transmission Provider to justify inclusion into the MTEP.[7]

To qualify as an MEP, a project candidate must meet all of the following criteria:

1. Greater than 50 percent of the total cost of the candidate project must be attributed to facilities that operate at a 345 kV voltage level or higher;

2. The benefit-to-cost ratio of the candidate project must meet or exceed 1.25; and

3. The total project costs must exceed $5 million.

MISO utilizes the 1.25 threshold for the benefit-to-cost ratio because it captures the uncertainties associated with calculating future economic benefits of a transmission project while not setting the thresholds so high that projects with net benefits are not approved.

If a project candidate is found to be economically justifiable, but does not meet all of the MEP criteria, it can still be approved as an "Other" type project based on an economic justification. The full costs of "Other" projects are paid by customers in the transmission pricing zone where the facility is located. As discussed in greater

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[7] MISO, FERC Electric Tariff, Module A, §1.M (48.0.0).

detail below, MISO designated the Huntley – Wilmarth Project as an MEP because it met all three MEP criteria.

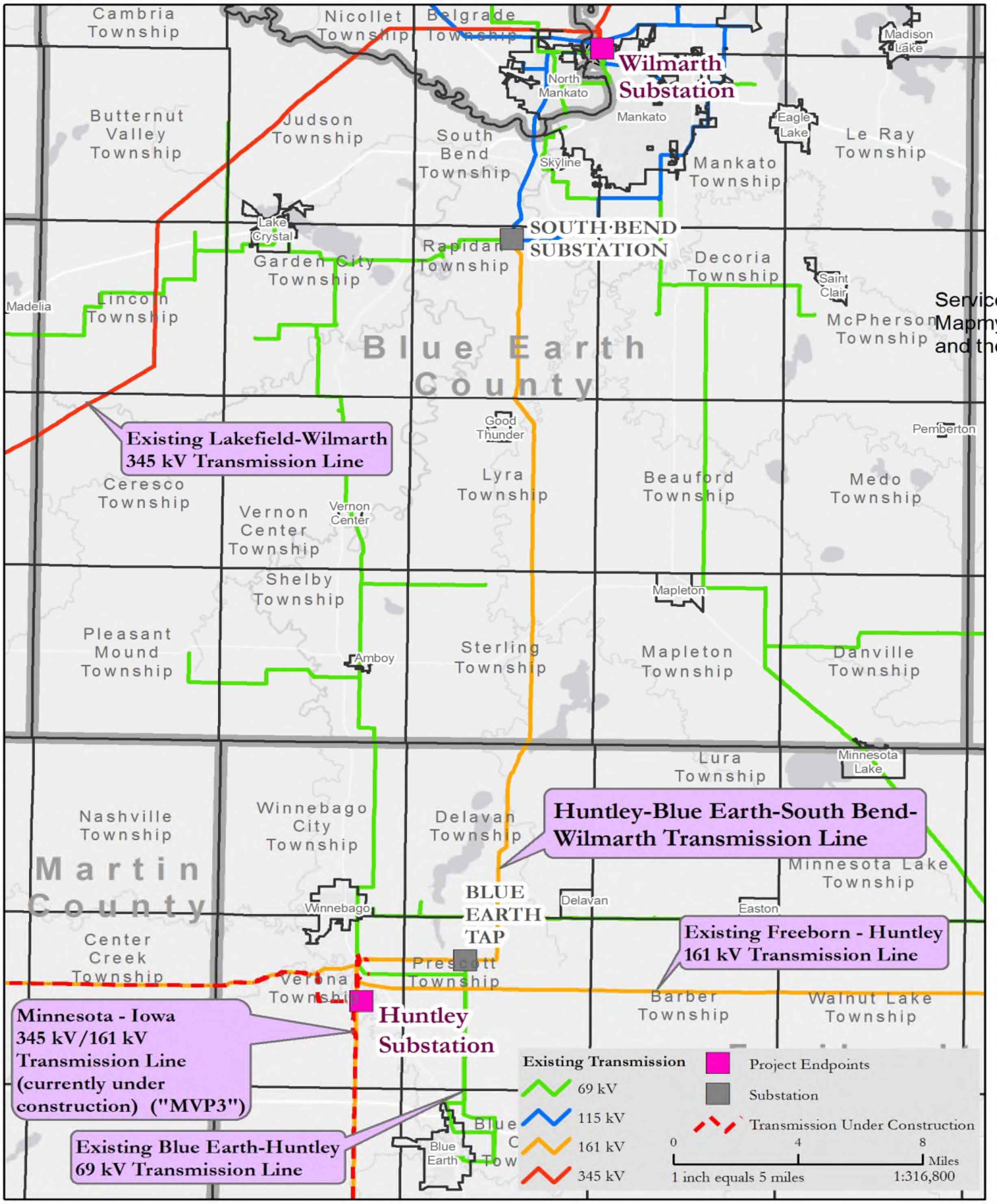
D. Prior MISO Studies of Congestion Near Minnesota/Iowa Border

MISO studies first publicly reported congestion as a problem in the border area of Minnesota/Iowa in 2009 in the MTEP08 Regional Generation Outlet Study (RGOS). At this time, these elements were considered a minor point of congestion as the amount of wind generation resources projected to be constructed in this area was far below the levels being seen today. The congestion identified in the Mankato/Blue Earth area on the Minnesota/Iowa border has been further studied in multiple subsequent MISO studies and MTEPs as described below.

In its 2011 Market Efficiency Analysis, MISO implemented a stand-alone analysis to identify and rank the top congested flowgates on the MISO system, appropriately named the "Top Congested Flowgate Study." A flowgate is defined as facility or group of facilities that may act as a constraint to power transfer on the Bulk Electric System. MISO identified congestion on the Huntley – Blue Earth – South Bend – Wilmarth line during the loss of the Lakefield Generating Station - Lakefield Junction 345 kV transmission line. This means that this line cannot carry the lower-cost renewable generation to the load centers; thus, it becomes necessary for higher cost generation located closer to load to be "redispatched" (i.e., increase output) or requested to commence operation. As a result of this congestion, the electrical systems are operated less efficiently and less cost-effectively. **Figure 3** shows the Huntley – Blue Earth – South Bend – Wilmarth 161 kV path.

Figure 3

Mankato Area Transmission System



This congestion was classified as the ninth most severely congested flowgate under existing conditions.[8] MTEP11 also included a portfolio of 17 high voltage projects. The Multi-Value Project (MVP) portfolio aimed, in part, at supporting states' renewable energy goals. Even after construction of the MVP portfolio, the study identified this flowgate as the 14th most severely congested flowgate.[9]

The next year, MISO's MTEP12 analysis indicated that this flowgate was congested between 10-20 percent of the total hours in the year analyzed, meaning 10-20 percent of the time, lower cost energy was available that was unable to be delivered to customers due to the congested nature of this portion of the transmission system.[10] Congestion was again confirmed in MTEP13 as the Mankato area transmission system was included on the list of the top 22 congested flowgates.[11]

In MTEP14,[12] the transmission lines in the Blue Earth area were again identified as a top congested flowgate on the MISO system, primarily due to future wind generation assumptions in the models. The congestion on this flowgate was regarded as a lower priority than those flowgates showing recent real time congestion during actual system operation.

In MTEP15,[13] the number of top congested flowgates decreased, but the Blue Earth area remained a major source of congestion on the MISO system. MTEP15 was the first to identify a new 345 kV transmission line between Huntley and Wilmarth as a potential solution to address this identified congestion. However, a 345 kV line between the Huntley and Wilmarth substations was not approved as part of

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[8] *Id.*

[9] *Id.*

[10] MISO, *MTEP 12 Report – Chapter 5.2 Top Congested Flowgate Study* (2014), *available at* https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP12.zip.

[11] MISO, *MTEP13 Report - Chapter 5.3: Market Efficiency Planning Study* at 73 (2014), *available at* https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP13.zip.

[12] MISO, *MTEP14 Report – Book 1: Transmission Studies, 5.3 Market Congestion Planning Study* (last visited Dec. 15, 2017), *available at* http://www.misomtep.org/market-congestion-planning-study/.

[13] MISO, *MTEP15 Report – Chapter 5.3: Market Congestion Planning Study* (last visited Jan. 10, 2018), *available at*: http://www.misomtep.org/market-congestion-planning-study-mtep15/.

MTEP15 because this proposal showed a low benefit in three of the four MTEP15 Futures and the weighted benefit-to-cost ratio did not reach the 1.25 MEP threshold.

E. MTEP16

As discussed above, the need being addressed by this Project is one that has long been identified and studied by MISO and its stakeholders. In the past few years, due to rapid expansion of wind development along the Minnesota/Iowa border, the congestion in this area has continued to worsen. This congestion has reached a point where, as part of the MTEP16 PROMOD analysis, the benefit-to-cost analysis justified approval of the Project as an MEP. This section provides an overview of MISO's MTEP16 analysis of the Project.

1. Model Development

As part of each MTEP cycle, MISO and its stakeholders develop reliability (Powerflow and Dynamics) and economic models to support the annual MTEP analysis. The economic models developed for the MTEP economic planning studies are forward-looking, hourly models based on future assumptions agreed on and approved thorough the stakeholder process. MISO MTEP16 Futures development commenced January 15, 2015 at the MTEP16 Futures Development workshop. The five futures that resulted from this process were defined as: Business As Usual (BAU), High Demand (HD), Low Demand (LD), Regional Clean Power Plan (CPP) Compliance (RCPP), and Sub-regional CPP Compliance (SRCPP). The key characteristics are summarized in **Figure 4**.

Figure 4

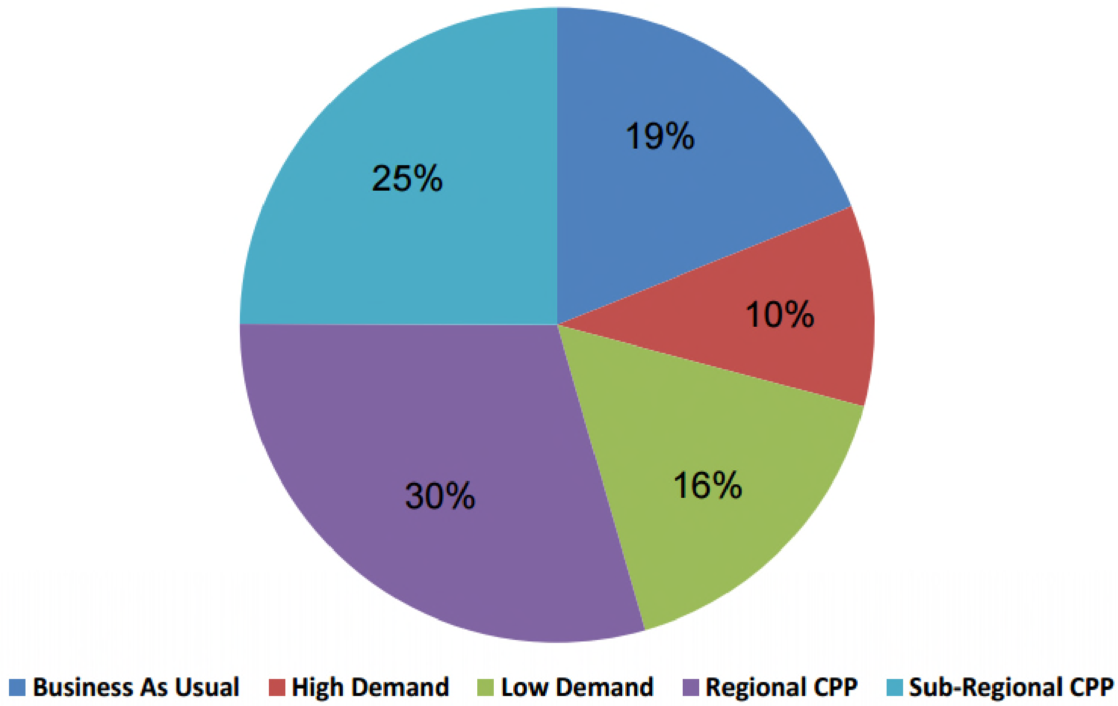
MTEP16 Key Characteristics

Future	Demand and Energy Growth	Retirement Level* (GW)	Peak Natural Gas Price (2015 $/MMBtu)	Incremental Renewables (GW) N/C: North/Central S: South	CO_2 Cost (2015 $/ton
Business as Usual	0.9%	No Additional	$4.30	N/C: 4.2 Wind/ 1.4 Solar S: 0 Wind/ 0 Solar	N/A
High Demand	1.6%	Age-related	$4.30	N/C: 7.2 Wind/ 1.6 Solar S: 0 Wind/ 0 Solar	N/A
Low Demand	0.2%	Age-related	$3.44	N/C: 2.4 Wind/ 1.3 Solar S: 0 Wind/ 0 Solar	N/A
Regional CPP Compliance	0.9%	14 GW coal + age-related	$5.16	N/C: 4.2 Wind/ 1.4 Solar S: 0 Wind/ 0 Solar + economically chosen wind/solar based on cost maturity curves	$25 / ton
Sub-Regional CPP Compliance	0.9%	20 GW coal + age-related	$5.16	N/C: 4.2 Wind/ 1.4 Solar S: 0 Wind/ 0 Solar + economically chosen wind/solar based on cost maturity curves	$40 / ton

MISO also assigned weights to each of these futures through a stakeholder process. The weighting is intended to represent the likelihood each one of the futures is likely to occur. For these MTEP16 Futures, the weighting is shown in **Figure 5**.

Figure 5

MTEP16 Futures Weighting



As shown in the diagram above, the Regional CPP was the highest weighted future at 30%, with the Sub-Regional CPP Future slightly lower at 25%. The remaining three futures, Business As Usual, Low Demand and High Demand, received lower weights at 19%, 16%, and 10%, respectively. This distribution of weights depicts the collective thought of the MISO stakeholders that additional development of renewable energy sources and potential impacts of public policies are a more likely future scenario than any variation of energy demand levels without such changes.

Once the futures were finalized in September 2015, the MISO Generation Expansion and Siting process commenced. As shown in the table above, each of the individual futures utilizes different generation capacity, generation retirement, fuel price, and policy regulations to determine a cost effective generation expansion scenario to meet regional generation capacity needs not being met by the existing generation fleet that would not be affected by the assumptions being made in the Future scenario. This generation expansion analysis is performed using the assumptions agreed upon during the first stage of the Futures development process, which are then incorporated into the MISO generation expansion model using the Electric Generation Expansion Analysis System (EGEAS),[14] which determines a cost effective way to meet the region's generation capacity requirements in each of the Future scenarios.

The following tables and images show the magnitude of generation expansion and retirements assumed in each of the five MTEP16 Futures. The following diagrams depict the project generation fleet capacity changes and energy production produced as a result of the Futures assumptions being analyzed in the scope of a least cost generation expansion analysis. As shown below in **Figure 6** and **Figure 7**, when renewable energy becomes a more economical way to meet all capacity and environmental requirements, the system wide capacity expansion and energy usage shift substantially away from larger thermal generation and start to favor renewable energy and more efficient and flexible natural gas fueled generation.

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[14] MISO, *MTEP16 EGEAS Results* (Aug. 21, 2015), *available at* https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2015/20150821/20150821%20EPUG%20Item%2005b%20MTEP16%20EGEAS%20Results.pdf.

Figure 6

MTEP16 Regional Resource Forecasting

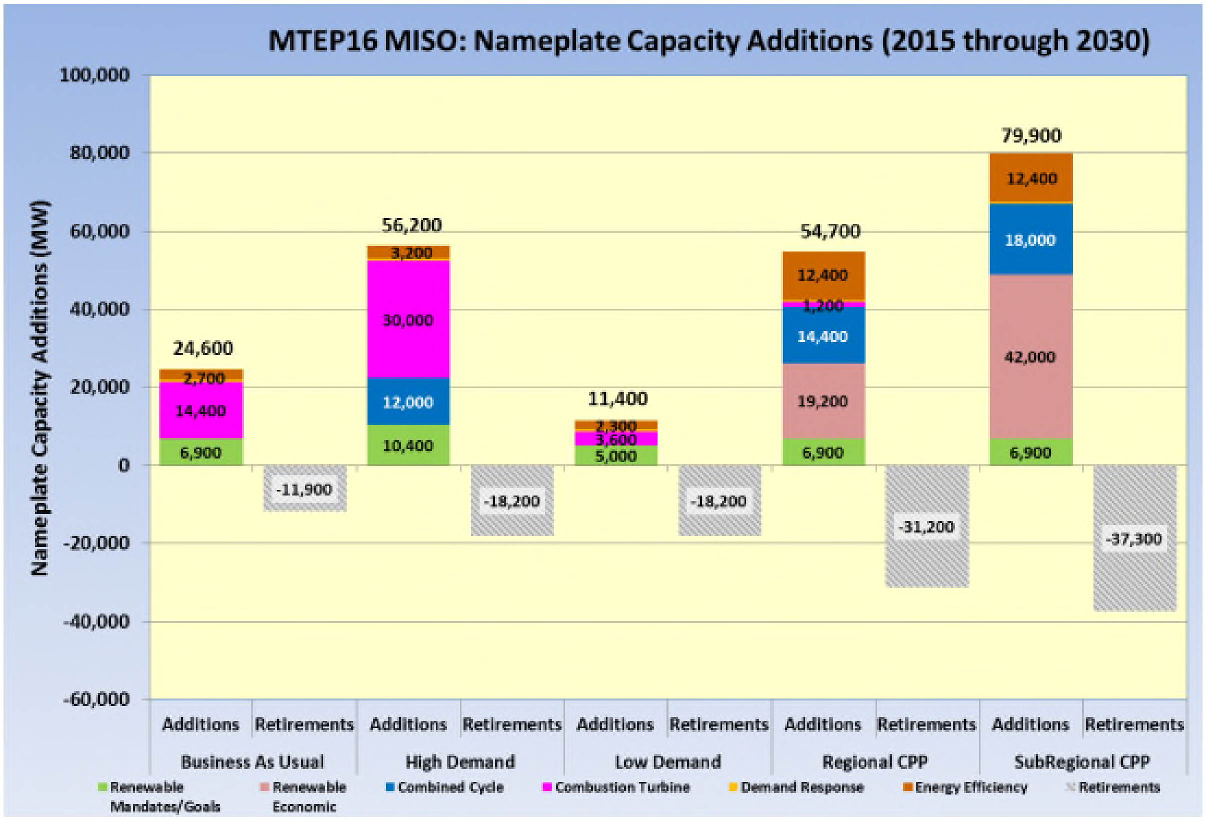
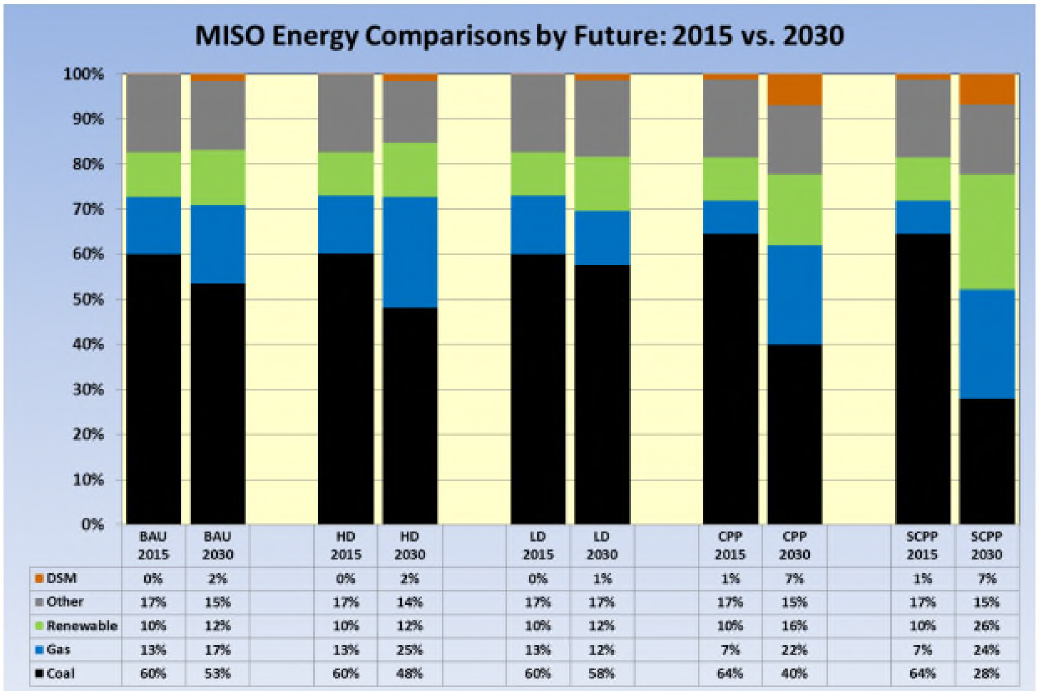


Figure 7

MTEP16 Futures Energy Utilization



	BAU 2015	BAU 2030	HD 2015	HD 2030	LD 2015	LD 2030	CPP 2015	CPP 2030	SCPP 2015	SCPP 2030
DSM	0%	2%	0%	2%	0%	1%	1%	7%	1%	7%
Other	17%	15%	17%	14%	17%	17%	17%	15%	17%	15%
Renewable	10%	12%	10%	12%	10%	12%	10%	16%	10%	26%
Gas	13%	17%	13%	25%	13%	12%	7%	22%	7%	24%
Coal	60%	53%	60%	48%	60%	58%	64%	40%	64%	28%

After a reasonable and cost-effective generation expansion is determined, MISO then proceeds to develop locations in which these new generation resources will be placed in the economic models in accordance with the rules established for siting of these Regional Resource Forecast (RRF) units.

This analysis resulted in specific generation assumptions for each of the Futures to be analyzed in the MCPS Study. Through this process, and as in prior MTEPs, the transmission system in the Mankato/Blue Earth area was identified as having congestion, including the Huntley – Blue Earth – South Bend – Wilmarth 161 kV line. Due to the ever increasing wind development in this area, the congestion increased on this flowgate to a level that warranted further analysis and identification of potential cost-effective solutions to resolve this congestion.

2. Alternatives Development

MISO and its stakeholders work collaboratively to identify potential transmission solutions to address the top congested flowgates. Potential solutions can be submitted by stakeholders or developed by MISO staff. To analyze the 23 possible transmission solutions for addressing congestion in the Minnesota/Iowa border area, MISO first conducted a screening analysis based on a one-year benefit/cost ratio. The benefits were based on APC calculations from the 15 year out models. The APC is the production cost adjusted for import/export revenues. The difference in APC between the base case and a case including the project candidate is the APC benefit provided by the project. The capital costs for each alternative were also estimated.

To compare the alternatives, a weighted one-year benefit-to-cost ratio for each alternative was computed using the Futures weights. The calculation for the Weighted APC Savings is shown below. This sum is divided by the cost for each alternative to calculate the benefit-to-cost ratio.

$$\text{Weighted APC Savings} = (\text{APC Savings}_{RCPP} * 0.3) + (\text{APC Savings}_{SRCPP} * 0.25) + (\text{APC Savings}_{BAU} * 0.19) + (\text{APC Savings}_{LD} * 0.16) + (\text{APC Savings}_{HD} * 0.1)$$

In this screening process, projects that showed a one-year benefit-to-cost ratio greater than or equal to 0.9 were carried forward for further analysis as a potential MEP.[15] Of the 23 alternatives proposed, 16 met this screening test. The 16 alternatives that MISO carried forward are in **Table 1**.

[15] MISO, *Project Candidate Identification Process* (Apr. 18, 2016), *available at* https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160418/20160418%20EPUG%20Item%2003%20Project%20Candidate%20Identification%20Process.pdf.

Table 1

Alternatives Meeting Screening Threshold

ID	Project Description	MISO Cost Estimate (2016 $M)	Flowgate(s) Addressed	Pass Screening
I-01	Huntley – Wilmarth 345 kV new circuit (double bundled 954 Cardinal ACSR)	$65.0	E	Y
I-02	Huntley – Wilmarth 345 kV new circuit (double bundled 1780 Chukar ACSR)	$70.0	E	Y
I-03	Huntley – Wilmarth 345 kV new circuit (2-795 ACSS)	$90.0	E	Y
I-04	Huntley – Wilmarth 345 kV new circuit (double bundled 1272 54/19 ACSR)	$67.0	E	Y
I-06	Huntley – South Bend – Wilmarth 345 kV new circuit; South Bend 161 kV substation upgraded to 345 kV and existing 161/115 kV transformer replaced by a 345/115 kV transformer, also retire Blue Earth – South Bend 161 kV	$107.0	E	Y
I-07	Huntley – Wilmarth – Cedar Mountain 345 kV new circuit	$214.0	E	Y
I-08	Huntley – South Bend – Wilmarth – Cedar Mountain 345 kV new circuit; South Bend 161 kV substation upgraded to 345 kV and existing 161/115 kV XFMR replaced by a 345/115 kV transformer, also retire Blue Earth – South Bend 161 kV	$231.0	E	Y
I-09	Lakefield Junction – Cedar Mountain 345 kV new circuit	$158.0	E	Y
I-10	Lakefield Junction – Cedar Mountain 345 kV; 3rd 345/161 kV Lakefield transformer	$167.0	E	Y
I-11	Huntley – West Owatonna – North Rochester 345 kV new circuit; West Owatonna 161 kV substation upgraded to 345 kV with a new 345/161 kV transformer	$229.0	E	Y
I-12	Huntley – N. Rochester 345 kV new circuit	$160.0	E	Y
I-13	Colby – Adams 345 kV new circuit	$99.0	E	Y
I-14	Huntley – South Bend 161 kV upgrade; South Bend – North Point – Wilmarth – Swan Lake – Ft. Ridgely – Franklin 115 kV upgrade; Franklin – Cedar Mountain 115 kV does not need to upgrade; South Bend 161/115 kV transformer replacement	$55.0	E	Y
I-15	Huntley – South Bend 161 kV reconductor, South Bend – Wilmarth 161 kV new circuit; Wilmarth substation 161 kV expansion with a 345/161 kV and a 161/115 kV transformer	$38.0	E	Y
I-16	Huntley – Loon Lake – West Owatonna 161 kV; Loon Lake substation 161 kV expansion with a 161/115 kV transformer	$59.0	E	Y
I-19	Freeborn – West Owatonna 161 kV new circuit	$27.0	E	Y

MISO then took the 16 alternatives and grouped them into four groups of solutions based on voltage level and design approach. The alternatives within each group were then ranked. The four groups and the top performer in the screening analysis for each group are listed below:

- ***Group 1***: projects (above 300 kV) that directly strengthened the Huntley/Lakefield to Wilmarth path. The best performer was the Huntley – Wilmarth Project, which was the lowest cost alternative and addressed 100 percent of the congestion.

- ***Group 2***: projects (above 300 kV) that strengthened the southeast transmission corridor into the Twin Cities. The best performer with the highest benefit-to-cost screening ratio was a new 345 kV circuit between Huntley and North Rochester.

- ***Group 3***: projects (less than 300 kV) that directly strengthened the Huntley/Lakefield to Wilmarth path. The best performer was a project that reconductored the existing 161 kV transmission line from Huntley to South Bend, added a new 161 kV transmission line from South Bend to Wilmarth and expanded the existing Wilmarth Substation to accommodate the additional 161 kV transmission line. This alternative had the highest benefit-to-cost screening ratio in the group.

- ***Group 4***: projects (less than 300 kV) that strengthened the southeast transmission corridor into the Twin Cities. The best performer was a project consisting of a new 161 kV transmission line between the existing Freeborn and West Owatonna substations. This alternative had the highest benefit-to-cost screening ratio in the group.

3. Initial Alternatives Screening

MISO performed a full 20-year Net Present Value (NPV) calculation for the best performer in each group to determine their initial benefit-to-cost ratio. This analysis utilized the 5-, 10-, and 15-year horizons for each of the five Futures developed for the MTEP16 cycle to develop the 20-year NPV. **Table 2** summarizes the results of this NPV analysis.

Table 2

Summary of NPV Analysis

ID	Transmission Solution	Top Down Cost Estimate (2016 $M)	Benefit-to-Cost Ratios						20-yr PV Benefit ($M)
			BAU	HD	LD	RCPP	SRCPP	Weighted	
I-02	Huntley – Wilmarth 345 kV new circuit (double bundled 1780 Chukar ACSR)	$100.9	0.51	1.29	0.12	1.71	6.72	2.44	$344
I-12	Huntley – N. Rochester 345 kV new circuit	$234.7	0.25	0.64	0.05	0.53	2.67	0.95	$288
I-15	Huntley - South Bend 161 kV reconductor, South Bend – Wilmarth 161 kV new circuit; Wilmarth Substation 161 kV expansion with a 345/161 kV and a 161/115 kV transformer	$48.4	0.42	1.32	0.09	1.81	5.15	2.06	$121
I-19	Freeborn – West Owatonna 161 kV new circuit	$40.8	0.60	1.68	0.11	0.97	12.62	3.75	$189

MISO then eliminated the Huntley – North Rochester 345 kV alternative because it had a weighted benefit-to-cost ratio of less than 1.0, meaning its costs exceed benefits.[16]

4. Updated Modeling and Analysis

MISO then refreshed its analysis to more accurately depict locations of recent wind generation additions. In the first set of MTEP16 Futures, the future wind generation sited in wind zone WI-B, which is meant to be in southwestern Wisconsin, was incorrectly modeled at the Freeborn Substation in southern Minnesota. When the wind generation was moved to the correct location, the benefits attributed to the Freeborn – West Owatonna 161 kV proposal significantly declined. In contrast, the

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[16] MISO, *Solution Screening and Preliminary Project Candidates – MN/IA* (Apr. 18, 2016), *available at* https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160418/20160418%20EPUG%20Item%2004c%20Screening%20and%20PV%20Analysis%20-%20MN%20IA.pdf.

Huntley – Wilmarth 345 kV Project maintained a high level of benefit. **Table 3** below shows the results obtained from the refreshed 20-year NPV analysis.[17]

Table 3

Revised NPV Analysis

ID	Transmission Solution	Top Down Cost Estimate (2016 $M)	Benefit-to-Cost Ratios						20-yr PV Benefit ($M)
			BAU	HD	LD	RCPP	SRCPP	Weighted	
I-2	Huntley – Wilmarth 345 kV new circuit	$100.9	0.48	1.22	0.14	1.39	4.85	1.87	$242
I-15	Huntley - South Bend 161 kV reconductor, South Bend – Wilmarth 161 kV new circuit; Wilmarth Substation 161 kV expansion with a 345/161 kV and a 161/115 kV transformer	$48.4	0.35	1.01	0.12	1.38	4.00	1.60	$95
I-19	Freeborn – West Owatonna 161 kV new circuit	$40.8	0.32	0.82	0.04	0.56	3.54	1.20	$60

MISO also analyzed the amount of the identified congestion that each project mitigated. As shown in **Table 4** below, while the two lower voltage 161 kV projects did provide economic benefits, they did not address all of the identified congestion. To eliminate all of the congestion, additional facilities would be required in addition to the 161 kV facilities.

17 MISO, *Robustness Testing – North/Central* (June 14, 2016), *available at* https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160614/20160614%20EPUG%20Item%2003%20Robustness%20Testing.pdf.

Table 4

Summary of Comparison of MTEP16 Alternatives

ID	Transmission Solution	B/C Above 1.0?	Highest B/C Ratio?	Highest 20-yr PV Benefit?	% Congestion Relief
I-2	Huntley – Wilmarth 345 kV new circuit (double bundled 1780 Chukar ACSR)	✓	✓	✓	100%
I-15	Huntley - South Bend 161 kV reconductor, South Bend – Wilmarth 161 kV new circuit; Wilmarth Substation 161 kV expansion with a 345/161 kV and a 161/115 kV transformer	✓	×	×	66%
I-19	Freeborn – West Owatonna 161 kV new circuit	✓	×	×	30%

5. Selection of Huntley-Wilmarth Project as MEP

In comparing these three alternatives, MISO eliminated the Freeborn-West Owatonna 161 kV circuit alternative because it relieved only 30 percent of the congestion. MISO determined that the I-15 project had a lower benefit-to-cost ratio and lower 20-year Present Value benefit than the Huntley –Wilmarth Project and did not relieve 100 percent of the congestion. Ultimately, MISO selected the Huntley – Wilmarth Project as the best overall solution because it resolves 100 percent of the congestion and had the highest benefit-to-cost ratio. MISO also determined that the Project was a robust solution because it maintained a benefit-to-cost ratio under a variety of different Futures. To further test the robustness of this solution, MISO conducted an economic sensitivity analysis and a reliability analysis.

MISO completed two sensitivity analyses based on the physical location of the future wind units and interconnection points assumed to be in the Futures and announced generation retirements. The first of these economic sensitivity analyses included a look at the impacts of the retirement and replacement of the large

Sherburne County Generation Station (Sherco) units 1 and 2 located northwest of the Twin Cities metro area. The units, which are 682 MW each, are planned to retire in 2023 and 2026, respectively. Specifically, MISO examined the retirement of these two large baseload generation sources northwest of the Twin Cities area, the largest urban area in Minnesota, and replaced this capacity with a 600 MW natural gas combined cycle generator and a 600 MW natural gas combustion turbine at the current Sherco location.

The second sensitivity tested whether the Project's benefits were sensitive to the location of forecasted wind generation additions meant to meet resource requirements external to MISO. To accomplish this second sensitivity, MISO removed the RRF generators, sited using the MTEP Futures siting guidelines, intended to meet non-MISO resource requirements. The result of these sensitivities showed that the Project maintains a high benefit-to-cost ratio under the generation location variations studied, with increased projected benefits in the Sherco replacement sensitivity. **Table 5** shows the sensitivity analysis results.

Table 5

Sensitivity Analysis Results

ID	MISO Cost Estimate (2016 $M)	Sensitivities	Benefit-to-Cost Ratios						20-yr PV Benefit ($M)
			BAU	HD	LD	RCPP	SRCPP	Weighted	
I-02	$100.9	Base Case	0.51	1.29	0.12	1.71	6.72	2.44	$344
		Sherco Retirement/ Replacement	0.70	1.84	0.30	1.71	6.72	2.55	$360
		External RRF Wind in IA Removal	0.51	1.29	0.12	0.91	4.50	1.64	$232

MISO also analyzed two alternatives that included the Huntley-Wilmarth 345 kV Project and additional 115 kV facilities. MISO evaluated where congestion would next develop on the system once the Project was in-service. The incremental benefit-to-cost ratio was analyzed for each alternative. **Table 6** shows the results of MISO's analysis which showed that the Huntley – Wilmarth 345 kV line by itself provided the highest benefit/cost ratio.

Table 6 also summarizes a generation interconnection queue sensitivity analysis MISO performed to look at the physical location of the future wind units assumed to be in the Futures. This generation interconnection queue sensitivity tested whether the Project's benefits were dependent on the location of forecasted wind generation additions. To accomplish the goal of this sensitivity, MISO replaced the RRF wind generators, sited using the MTEP Futures siting guidelines, with wind generation which was sited at the same location as wind generation interconnection requests that were in the final stage of the MISO Generator Interconnection Process. The results of this analysis showed that, with the level of wind likely to be interconnected based on historical interconnection trends, the benefits of the Project increase in all Futures.

Table 6

Huntley – Wilmarth Project Variations

ID	Transmission Solution	Model	MISO Cost Estimate (2016 $Millions)	Benefit to Cost Ratios						20-yr PV Benefit ($ Millions)
				BAU	HD	LD	RCPP	SRCPP	Weighted	
I-2	Huntley – Wilmarth 345 kV new circuit	Base	$88-108	0.43-0.52	1.16-1.42	0.10-0.13	1.32-1.62	3.63-4.45	1.51-1.86	$210
		Queue Wind Sensitivity		1.39-1.71	2.40-2.95	0.69-0.85	2.45-3.01	2.03-2.49	1.86-2.28	$251
I-2b	Huntley – Wilmarth 345 kV new circuit, Wilmarth to Swan Lake – Ft Ridgely 115 kV upgrade	Base	$113.3-133.3	0.37-0.43	1.12-1.31	0.09-0.10	1.15-1.35	3.31-3.90	1.36-1.60	$234
		Queue Wind Sensitivity		1.13-1.33	2.08-2.45	0.55-0.65	2.02-2.39	1.73-2.03	1.55-1.83	$259
I-2d	Freeborn – West Owatonna 161 kV new circuit	Base	$154.8-174.8	0.27-0.31	0.92-1.04	0.08-0.10	0.98-1.11	3.03-3.43	1.21-1.36	$272
		Queue Wind Sensitivity		0.86-0.97	1.74-1.97	0.44-0.50	1.68-1.90	1.55-1.76	1.30-1.47	$285

For reliability, MISO conducted studies to assess whether there would be any reliability issues resulting from the construction of the Huntley-Wilmarth Project. This was referred to as a "No-Harm test." Through this analysis, MISO found that there were no additional reliability needs created by the inclusion of the Huntley-Wilmarth 345 kV Project in the MISO transmission system.

F. <u>Conclusion</u>

The transmission system around the Minnesota/Iowa border has long experienced congestion that reduces the ability of the transmission system to deliver the lowest cost renewable energy available to meet customer demand. The MTEP16 planning process again identified this congestion as creating inefficiency in the energy market and through its stakeholder process, MISO evaluated 23 transmission alternatives to relieve the congestion. The Huntley-Wilmarth 345 kV Project emerged as the solution that would relieve 100 percent of the congestion and provide the highest weighted benefit-to-cost ratio. The Project also showed these benefits in generator sensitivity analyses and did not create any reliability issues on the system. Based on this performance, the MISO Board of Directors approved the Project as an MEP in the MTEP16.

The balance of this Report discusses MISO's MTEP process and analysis of the Huntley-Wilmarth Project in greater detail.

II. MISO MTEP Process

A. Overview of MTEP Process

MISO's annual planning cycle includes a reliability analysis, a resource assessment, and an economic analysis. Each is described below.

In the reliability analysis, MISO examines the reliability of the system from multiple perspectives to confirm that the transmission system has adequate capacity to provide reliable electric service to customers. The MTEP reliability assessment begins with MISO building a series of study cases. Using these models, MISO staff performs and independent reliability analysis of the transmission system to ensure that the system meets or exceeds all Federal, State, and local planning requirements. At the same time that MISO is evaluating system reliability, individual transmission owners are evaluating the reliability of their local transmission systems and identifying necessary projects to meet reliability concerns. Finally, MISO staff coordinates with all stakeholders including area transmission planners to verify needs, identify alternative solutions, and identify where transmission system upgrades are needed.

In the resource adequacy analysis,[18] MISO performs an annual assessment of the system capabilities to meet the demand in the near term as well as long-term projections. This process is implemented partially through Loss of Load Expectation

[18] MTEP16 Report Resource Adequacy: https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20Book%202%20Resource%20Adequacy.pdf.

(LOLE) analysis performed by MISO annually. Through this study, MISO determines the capacity reserve requirements on a sub-regional level, looking at the Local Resource Zone capabilities.

In the economic analysis, MISO seeks to identify and analyze solutions to MISO transmission system inefficiencies that could be addressed through expansion of the transmission system. This includes an analysis of the capital costs of transmission projects as well as the projected costs of energy (production cost) and generation capacity. To ensure that the transmission projects identified to address these system inefficiencies are the most robust, MISO analyzes these projects under a variety of possible economic and policy scenarios or "Futures." One of the analyses is the Market Congestion Planning Study (MCPS). The goal of this study is to identify transmission projects that offer MISO customers better access to the lowest electric energy costs throughout the MISO energy market. In essence, the study examines where congestion on the transmission system may limit access to the lowest-cost generation resources and evaluates transmission improvements that may relieve this congestion and increase market efficiency under a variety of different future scenarios.

B. Security Constrained Economic Dispatch (SCED) and Congestion Overview

In operating the transmission system, MISO uses a Security Constrained Economic Dispatch, or SCED. Generally speaking, SCED is an optimization process that MISO uses to ensure that electricity demand is met using the lowest cost of energy given the operational and reliability limitations of the transmission system and generation resources. SCED can be broken into two parts. The first part, Security Constrained, requires that MISO maintain the flow of power on the transmission system so that if an event were to happen that changes how the power is flowing on the system, such as a transmission line being out-of-service, the transmission system will stay within its identified limits.

The second portion of this procedure is the Economic Dispatch portion. This refers to how the generation resources in the MISO system are called on to provide energy to meet current load. Because SCED is based on economics, the lowest cost sources of energy are called upon first. Combining these two ideas, the procedure is meant to call upon the cheapest sources of energy that can reliably deliver their energy to customers. One important thing to note is since the transmission system may not be able to react fast enough to maintain reliability after an event; the Security Constrained Economic Dispatch of generation resources is constantly in place and could limit the availability of lower cost energy sources even in ideal conditions. MISO's ability to dispatch the lowest cost energy is also affected by congestion.

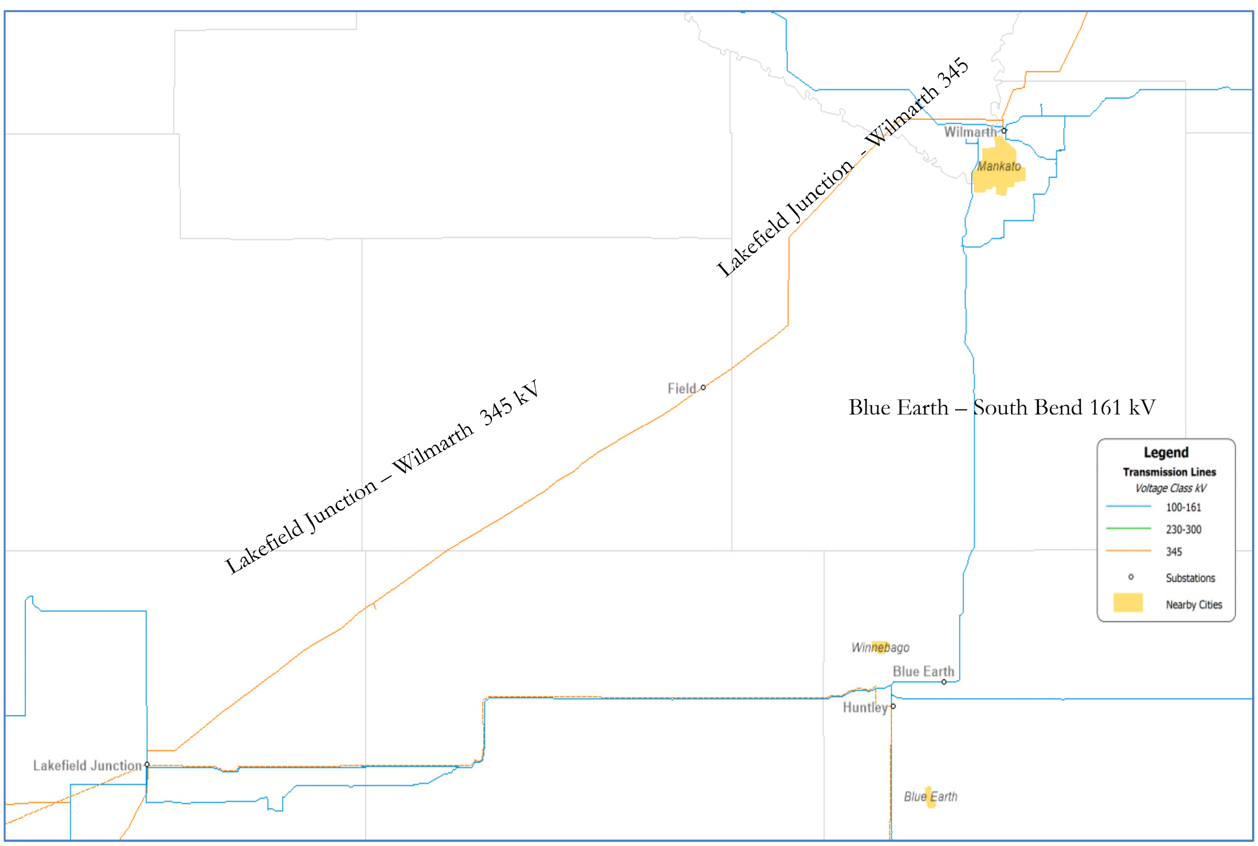
Congestion happens when either the generators of electricity want to put more power on a line than the existing transmission facilities are able to accommodate or when consumers of electricity want to use more power than can be delivered from the most cost-effective generators. Congestion, in its most basic form, simply means that there is insufficient transmission to deliver all of the lowest cost power to customers and as a result the electrical system is not operating as efficiently as it could be.

One important distinction to make is that congestion does not mean there is a system issue that is required to be fixed to ensure the reliability of the transmission system. System reliability issues are identified, analyzed and implemented through a very robust process governed by Federal, State, and local industry standards and requirements.

With the continued development of wind generation in southwestern Minnesota and northern Iowa, MISO has identified a significant amount of congestion near the border of Minnesota and Iowa. This identified congestion limits the ability of the transmission system to deliver this low cost wind generation to customers. In particular, there is a significant amount of congestion on the existing Huntley – Blue Earth 161 kV line near the border of Minnesota and Iowa. The congestion identified is based on the event of losing any portion of the 345 kV line between the Lakefield Junction Substation and the Wilmarth Substation. If there is an event that causes the loss of any portion of the Lakefield Junction – Wilmarth 345 kV line, the energy flowing on that path will try to divert to the lower capacity 161 kV line from the Blue Earth Substation to the Huntley Substation. *See* **Figure 8** below. Since this 161 kV line does not have the ability to carry nearly as much power as the larger 345 kV line, the MISO market can only call on the low cost wind resources to the point where the power flowing on that path will not exceed the limitation of this lower capacity 161 kV transmission line. Due to this congestion, all of this lower cost energy cannot be delivered to the greater MISO transmission system, and any power produced above those limits cannot be allowed to reach customers. As the level of wind generation increases in this area, this congestion will only worsen over time.

Figure 8

Blue Earth – South Bend 161 kV Line



C. MCPS Study Process

The Market Congestion Planning Study (MCPS) is the process that MISO undertook to develop the Huntley-Wilmarth Project and is part of the annual MTEP. The MCPS follows a seven-step process which is described below.

Step 1: Model Development

The first step is to review current industry trends and develop a group of future scenarios that will provide sufficient accuracy while covering a wide enough range of possible situations to adequately project the potential impact of changes to the future transmission system. These Futures are the models used to identify potential inefficiencies in the transmission system and determine the projected benefit of addressing that inefficiency with transmission improvements. Included in this is the development of modeling assumptions. MISO and the MISO stakeholders develop and agree to a set of modeling assumptions, including but not limited to fuel prices, demand growth, and possible policy regulations.

Step 2: Generation expansion siting and transmission system integration

Step two is to take the results of the first step looking at the most cost-effective generation expansion and find plausible locations to site those generation resources. Since this is looking at more of the electrical system configuration, the most up-to-date transmission system topology models are also incorporated at this time. The siting of additional generation, referred to as Regional Resource Forecast (RRF) units.

Step 3: Initial Analysis and Solution Development

The third step in the MISO seven-step process is to develop the production cost models using the PROMOD software and analyze the future transmission system for each scenario developed to determine any potential issues or inefficiencies that could be addressed by expansion of the transmission system.

Production cost models and analysis is the primary method for assessing the economic health of the transmission system and determining potential economic benefit of transmission expansion. The primary tool used to perform this analysis is PROMOD. PROMOD is a computer software-based power system analysis tool that uses an hour-by-hour look at the potential system conditions, emulating the MISO day-ahead market mechanisms to determine the system inefficiencies for that given scenario.

The initial production cost analysis performed during the MISO Market Congestion Planning Study process is to identify the top congested flowgates,[19] representing potential inefficiencies in delivering energy within the MISO market due to transmission constraints. The top congested flowgate analysis identified these inefficiencies based on both historical and projected system congestion and prioritizes those inefficiencies by severity.

MISO uses the identified top congested flowgates to develop a list of top issues for which transmission system solutions will be analyzed. These flowgates are ranked by the weighted average of their severity to avoid the unreasonable identification of a single inefficiency resulting from a single future scenario, or system assumption. MISO then solicits proposals to alleviate the identified congestion.

Step 4: Testing of Conceptual Transmission for Robustness

Once the open solicitation period has elapsed, MISO moves into the fourth of the seven-step planning process which includes several iterations testing the submitted transmission solutions for robustness and viability.

MISO tests the submitted transmission system solutions by performing a screening analysis to identify the most cost-effective solutions to relieve the congestion. This screening analysis uses a single year adjusted production cost (APC) savings for the 15-year out model compared to the calculated average costs for that single year to determine each project's screening index. *See* **Figure 9** below. To be

[19] A flowgate is defined as a transmission system element, or group of transmission system elements through which power flows due to interchange transactions. In the context of the MISO seven-step process, a flowgate is the point at which congestion on the transmission system has been identified.

considered an economically viable project, each system solution must meet or exceed a 0.9 screening index to move forward in this analysis.

Figure 9

Adjusted Project Cost Savings (one year)

$$\textit{Screening Index} = \frac{\textit{APC Savings}}{\textit{Solution Cost} \times \textit{MISO Aggregate Annual Charge Rate}}$$

System solutions that do not meet or exceed this 0.9 threshold are removed from this study process, but are included in future MCPS studies to reassess their economic viability.

<u>Step 5: Consolidation and Sequencing of Transmission Plans</u>

Once a list of projects meeting or exceeding the initial screening analysis is determined, these system solutions are divided up into groups according to the system inefficiency that solution addresses. These projects then move into an iterative process to compare each of them against the other similar solutions to determine a small group of best-fit solutions that will move forward as project candidates. The criteria used in this iterative process is the benefit-to-cost ratio, total benefits projected, level of congestion mitigated, and transmission system impacts.

The candidate projects are then subjected to an analysis testing the assumptions used in the future scenarios. Throughout the initial analyses of the candidate projects, specific assumptions can be identified that could substantially impact the project benefits. To ensure all benefits projected for recommended economic projects are likely to be realized, MISO varies these critical assumptions to ensure small changes in size, location or other factors in the assumptions being made as part of the future scenarios are not artificially increasing the attractiveness of the candidate project(s). If a project is found to be overly reliant on single assumptions or aspects of the production cost models, it will no longer be recommended as a candidate project.

This project would then be retained and reevaluated in future MTEP cycles to determine if the benefit projected for that project has become more likely.

Step 6: Evaluation of Conceptual Transmission for Reliability

As part of this process, a system reliability analysis is performed for each of the remaining system solutions. The reliability analysis uses a no-harm test to determine the impact of the project candidate on the thermal and voltage stability of the system under select NERC Category B and C contingencies.[20] A project candidate passes the reliability no-harm test if there is no degradation of the system reliability with the addition of the project.

Step 7: Cost Allocation

The final step in the MISO seven-step process is the determination of eligibility for cost allocation. If the project candidate is still being considered after multiple layers and iterations of screening and robustness testing, MISO will apply the thresholds for the defined project types to determine how this project candidate will proceed. The two types of projects types that would result from the MCPS process are the MEP and the "Other" type project, which includes economically justified projects.

MEPs are cost allocated 80 percent to the Local Resource Zones commensurate with expected benefit and the remaining 20 percent are allocated to each pricing zone based on MISO load share. To qualify as a MEP, a project candidate must meet all of the following criteria:

i. Greater than 50 percent of the total cost of the candidate project must be attributed to facilities that operate at a 345 kV voltage level or higher;
ii. The benefit to cost ratio of the candidate project must meet or exceed 1.25; and

[20] The following NERC categories of contingencies are evaluated: (1) Category P0 when the system is under normal conditions; (2) Category P1 contingencies resulting in the loss of a single element; (3) Category P2 contingencies resulting in the loss of two or more elements due to a single event.

iii. The total project costs must exceed $5 million.

If a project candidate is found to be economically justifiable, but does not meet one or more of the MEP criteria, it can still be approved as an "Other" type project based on an economic justification if agreed upon by the local transmission owner. If the local transmission owner agrees to the approval of an "Other" economic project, the full costs of those projects are allocated to that transmission owner's pricing zone.

D. Pre-MTEP16 Studies of Congestion Near Minnesota/Iowa Border

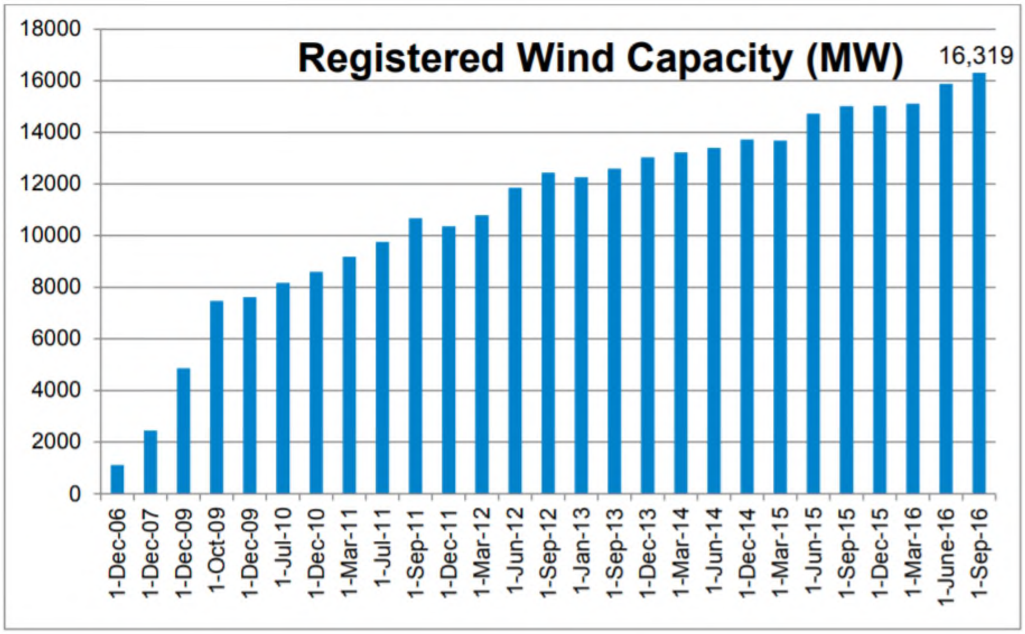
Multiple MISO studies since 2008 have identified congestion in the southern Minnesota/Iowa border area. Due to the models utilizing assumptions that are updated annually, it is expected that any congestion identified will move between system elements or disappearing completely from year to year and model to model. For the proposed Huntley - Wilmarth Project, this movement stays extremely localized throughout many MTEP cycles, only moving to system elements directly adjacent to the Blue Earth area congestion identified in the MTEP16 analysis, showing that this point of congestion will continually appear and most likely become more severe in the future if additional transmission facilities are not constructed.

1. MTEP08 Regional Generation Outlet Study (RGOS)

In 2008, MISO began the process of developing the first Multi-Value Project (MVP) portfolio. The development of this portfolio studied the impacts on the MISO system of increased renewable energy generation due to state Renewable Portfolio Standards being implemented by states in the MISO footprint at the time. **Figure 10** shows the growth in registered wind capacity from 2006 to 2016.

Figure 10

Nameplate Wind Capacity Register for MISO



During this analysis, the congestion on the same transmission elements, the low-voltage parallel path on the Huntley to Blue Earth to South Bend to Wilmarth line was first reported. At the time, these elements were considered a minor point of congestion as the wind generation resources projected to be in this area were far below the levels being seen today.

2. MTEP11 – Year of the MVP Portfolio Approval

In 2011, the final year of development for the first MVP portfolio, MISO implemented an analysis to identify and rank the top congested flowgates on the MISO system, appropriately named the "Top Congested Flowgate" analysis. Three sources were used to identify the flowgates with the most congestion: historical real-time market data, day-ahead market data, and forward-looking 2016 and 2021 MTEP11 production cost models. Flowgate congestion was measured and ranked in terms of number of binding hours and total shadow prices. Binding hours are the number of hours an element is congested. A shadow price is the savings in dollars from relieving a constraint by 1 MW. From this analysis,[21] MISO identified congestion in the Blue Earth area for the loss of the Lakefield – Lakefield Junction 345 kV transmission line as the 14th most severely congested flowgate in terms of binding hours if the MVP portfolio were not constructed in service and the 9th most severe congestion after implementation of the MVP portfolio. This shows that the identified congestion in the Blue Earth area would persist with or without previously identified transmission projects.

3. MTEP12 – First post-MVP approval analysis

The MTEP12 analysis[22] identified congestion in the same Blue Earth area as in the MTEP11 analysis. In the MTEP12 identification, MISO's analysis indicated that this flowgate was congested between 10 to 20 percent of the total hours in the year analyzed, meaning 10 to 20 percent of the time period between November 2011 and October 2012, cheaper energy was available that was unable to be delivered to customers due to the congested nature of this portion of the transmission system.[23]

4. MTEP13

During the MTEP13 analysis, congestion in this area was found to be on the Lakefield Junction – Lakefield Generating Station 345 kV line.[24] In the prior two MTEP cycles (MTEP11 and MTEP12), as well as the remaining MTEP cycles between MTEP14 and MTEP16, the Lakefield Junction – Lakefield Generating Station – Wilmarth 345 kV line was the outaged element in the flowgate definition. This means that, with the exception of MTEP13, congestion was found to be caused by the loss of this 345 kV path between the Lakefield Junction and Wilmarth substations, in the MTEP13 analysis, the congested facility was the 345 kV path

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[21] MISO, *Market Efficiency Analysis: 2011 Top Congested Flowgate Study* at 33 (May 2012), *available at* https://www.misoenergy.org/Library/Repository/Study/MTEP/2011%20Market%20Efficiency%20Analysis.pdf.

[22] MISO, *MTEP 12 Report – Chapter 5.2 Top Congested Flowgate Study* (2014), *available at* https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP12.zip.

[23] *Id.*

[24] The Lakefield Junction – Lakefield Generating Station 345 kV line is the first half of the Lakefield Junction – Wilmarth 345 kV line.

itself.[25] While this is different than the previous two cycles, the Blue Earth area is likely the second limiting element in the event of the Lakefield – Lakefield Junction 345 kV line being taken out of service in the MTEP13 analysis. Although this shows a shift in the actual element that is congested, the Huntley – Wilmarth 345 kV line would also mitigate this point of congestion by creating a secondary, high-capacity path between the Lakefield Junction area and the Wilmarth Substation.

5. MTEP14

In the MTEP14[26] cycle, the Blue Earth area was identified as a top congested flowgate on the MISO system. Since this congestion was primarily due to future wind generation assumptions in the MTEP14 models, the congestion on this flowgate was regarded as a lower priority than those flowgates showing higher levels of historical congestion during actual system operation.

The MTEP14 cycle was the first to identify mitigation options for the congestion in southern Minnesota. During that cycle, a project to upgrade the existing 161 kV system between Blue Earth and Winnebago was submitted. Since the first threshold for a project idea to be considered as a potential economic project is a 0.9 benefit to cost ratio, the 0.61 benefit-to-cost ratio projected for this project in the 2014 analysis meant this project did not move forward as a candidate economic project. This cycle also analyzed two different 345 kV solutions, including the a Huntley-Wilmarth 345 kV line but neither alternative made it beyond the initial screening.

6. MTEP15

At the time of MTEP15's analysis, additional new 345 kV lines were added in Minnesota and Iowa due to the completion or anticipated completion of the

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[25] MISO*, MTEP13 Report - Chapter 5.3: Market Efficiency Planning Study* at 73 (2014), *available at* https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP13.zip.

[26] MISO, *MTEP14 Report – Book 1: Transmission Studies, 5.3 Market Congestion Planning Study* (last accessed Dec. 15, 2017), *available at* http://www.misomtep.org/market-congestion-planning-study/.

CapX2020 transmission projects as well as several MVP projects. In addition, MISO implemented new dispatch and system operation methods that reduced overall congestion on the MISO transmission system. Despite these improvements and new transmission facilities, MTEP15 again identified the Blue Earth area as a major source of congestion on the MISO system.[27]

Due to this continued congestion, the MTEP15 study again looked at rebuilding the existing Winnebago to Blue Earth 161 kV. However this rebuild failed to provide enough benefit to move beyond the screening analysis. MTEP15 also examined a new 345 kV line between Huntley and Wilmarth substations. However, a 345 kV line between the Huntley and Wilmarth substations was not approved as part of MTEP15 because this proposal's weighted benefit-to-cost ratio did not reach the 1.25 MEP threshold.

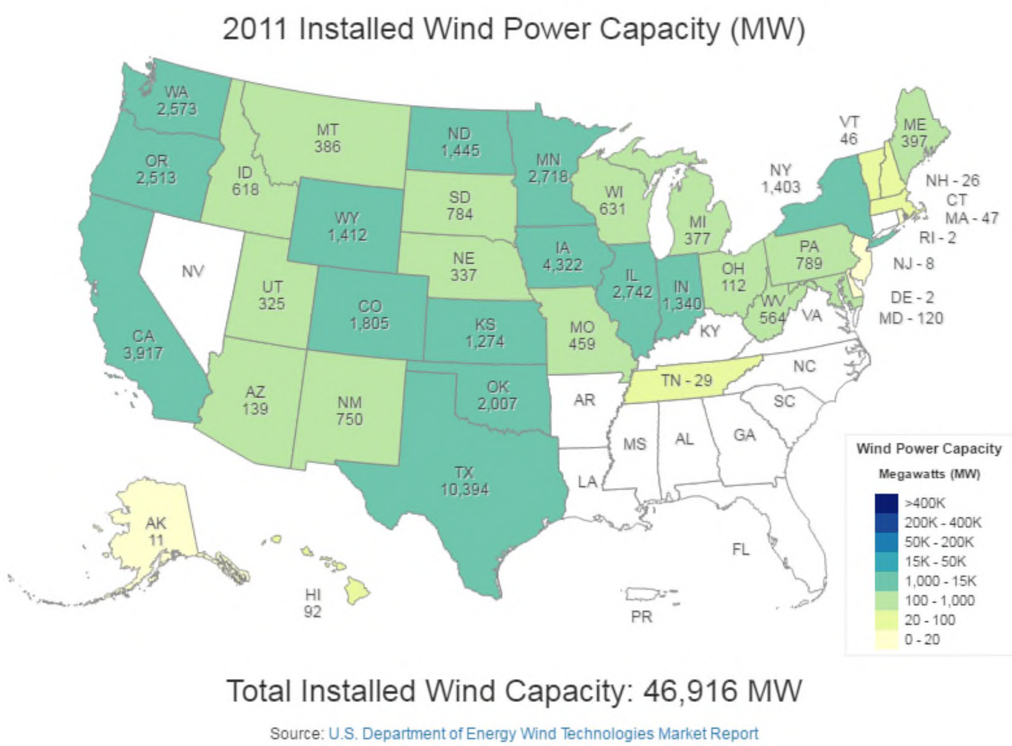
E. Changing Energy Mix

Over the years, the amount of installed wind generation substantially increased not only in Minnesota and Iowa, but across the country. **Figure 11** and **Figure 12** show the levels installed generation in 2011 and 2016, respectively. Much of this new wind generation is being developed in southwestern Minnesota and northern Iowa due to this area having one of the highest annual average wind speeds in the country as well as being electrically close to the two largest areas of energy usage in the Midwest, Minneapolis-St. Paul and Chicago. **Figure 13** shows the amount of potential wind capacity in the United States, indicating that the amount of wind generation can reasonably be expected to increase over time.

[27] MTEP15 Report – Chapter 5.3: Market Congestion Planning Study: http://www.misomtep.org/market-congestion-planning-study-mtep15/.

Figure 11

2011 Installed Wind Power Capacity[28]

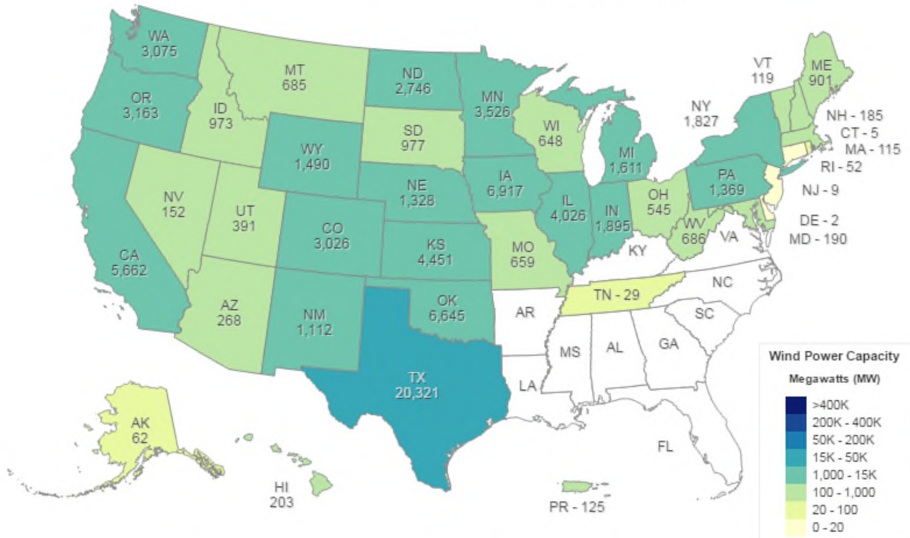


[28] U.S. DOE Installed Wind Capacity: http://apps2.eere.energy.gov/wind/windexchange/wind_installed_capacity.asp.

Figure 12

2016 Installed Wind Power Capacity

Q4 2016 Installed Wind Power Capacity (MW)



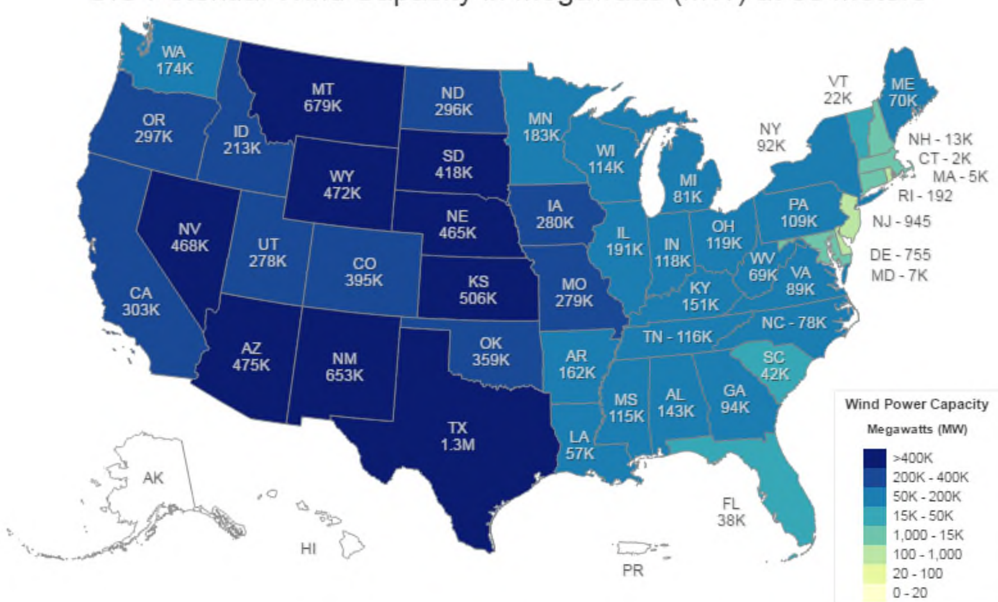
Total Installed Wind Capacity: 82,171 MW

Source: American Wind Energy Association Q4 2016 Market Report

Figure 13

United States Wind Potential

U.S Potential Wind Capacity in Megawatts (MW) at 80 Meters



Total Potential Wind Capacity: 10,640,080 MW

Source: AWS Truepower, NREL

The generation sources within the MISO footprint have evolved and continue to evolve based on economics of different generation sources as well as environmental regulations. In the past ten years, there has been a significant increase in wind generation as well as coal generator retirements. As a result of the Mercury and Air Toxics Standards, which sets standards for emissions from coal plants, approximately 10 GW of coal capacity in the MISO footprint have recently retired or converted to another fuel source. **Figure 14** and **Figure 15** show how the energy mix has shifted to reduce reliance on coal and to increase reliance on gas and renewables.

Figure 14

MISO Energy Mix 2009-2016

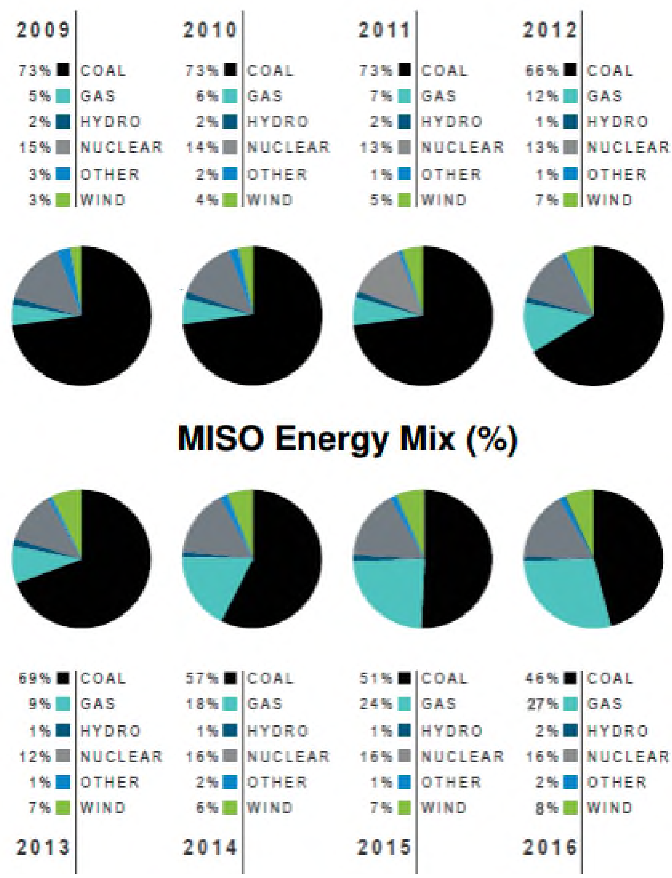


Figure 15

Planned Capacity Additions[29]

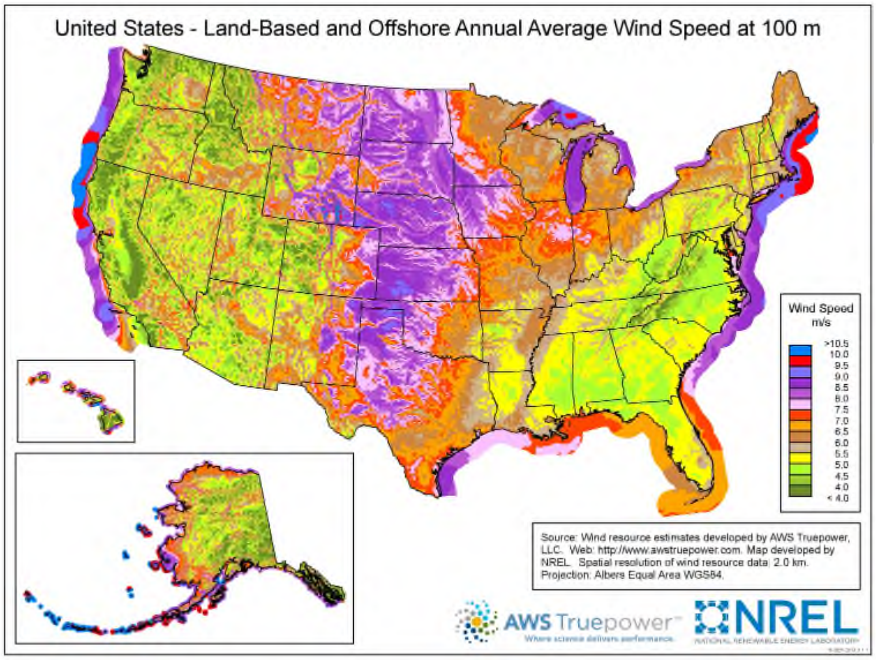
	Planned Generating Capacity Changes, by Energy Source, 2015-2019						
	Generator Additions		Generator Retirements		Net Capacity Additions		
Energy Source	Number of Generators	Net Summer Capacity (MW)	Number of Generators	Net Summer Capacity (MW)	Number of Generators	Net Summer Capacity (MW)
Coal	6	694	178	28,892	-173	-28,198
Petroleum	31	59	72	1,622	-41	-1,563
Natural Gas	389	54,893	131	7,887	258	47,006
Other Gases	3	403	--	--	3	403
Nuclear	3	3,322	1	610	2	2,712
Hydroelectric Conventional	66	1,088	22	433	44	655
Wind	198	21,624	6	60	192	21,564
Solar Thermal and Photovoltaic	627	13,220	1	1	626	13,219
Wood and Wood-Derived Fuels	5	199	6	37	-1	162.7
Geothermal	8	192	--	--	8	191.8
Other Biomass	57	263	32	52	25	211
Hydroelectric Pumped Storage	--	--	--	--	--	--
Other Energy Sources	20	579	2	1	18	578
U.S. Total	**1,412**	**96,536**	**451**	**39,594**	**961**	**56,942**

At the same time, the declining capital cost for wind in addition to tax credits for these resources have increased the number of new wind generation sources. The Dakotas, Minnesota and Iowa have particularly good wind resources that are driving further development. Specifically, **Figure 16** shows that these states have areas with much higher wind speeds than other parts of the country.

29 MTEP16 at Section 9.3 Generation Statistics.

Figure 16

Map of Average Wind Speed



III. <u>MTEP16 Summary and the Selection of Huntley – Wilmarth Project</u>

A. <u>MTEP16 Futures Model Development and Weighting[30] (Step 1)</u>

1. Futures Model Development

The MISO MTEP16 futures development was initiated on January 15, 2015 at the MTEP16 Futures Development workshop. During this workshop, MISO presented their thoughts on the direction for the MTEP16 Futures. These Futures were defined as: Business As Usual (BAU), High Demand (HD), Low Demand (LD), Regional Clean Power Plan (CPP) Compliance (RCPP), and Sub-regional CPP Compliance (SRCPP).

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[30] MTEP16 Futures Development Workshop: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/Workshops%20and%20Special%20Meetings/2015/MTEP16%20Futures%20Development%20Workshops/20150115/20150115%20MTEP16%20Futures%20Development%20Workshop%20Presentation.pdf.

a. MTEP16 Business As Usual (BAU) Future

As in many other MTEP analyses, the Business As Usual Future is developed to emulate historical trends and project those trends into the five-, ten- and 15-year models developed for the MTEP economic analysis. Since this is considered by many to be the "control" future, as it is not intended to deviate from historical system trends, it is typically used to buffer more impactful assumptions made in other Futures scenarios. MISO's MTEP16 BAU Future narrative is as follows:

> The baseline, or Business as Usual, future captures all current policies and trends in place at the time of futures development and assumes they continue, unchanged, throughout the duration of the study period. All applicable EPA regulations governing electric power generation, transmission and distribution are modeled. Demand and energy growth rates are modeled at a level equivalent to the 50/50 forecasts submitted into the Module E Capacity Tracking (MECT) tool. All current state-level Renewable Portfolio Standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates are modeled. To capture the expected effects of environmental regulations on the coal fleet, a total of 12.6 GW of coal unit retirements are modeled.[31]

b. MTEP16 High Demand (HD) Future

To analyze the effects of economic activity and energy usage above and beyond the normal demand forecast utilized in the BAU Future, the MTEP16 High Demand (HD) Future implements very similar assumptions as were used in the BAU Future, with the additional energy usage to be supplied by a slightly higher level of renewable generation. MISO's MTEP16 HD Future narrative is as follows:

> The High Demand future captures the effects of increased economic growth resulting in higher energy costs and medium – high gas prices. The magnitude of demand and energy growth is determined by using the upper bound of the Load Forecast Uncertainty metric and also includes forecasted load increases in the South region. All current state-level Renewable Portfolio

[31] MTEP16 at 98-99.

> Standard (RPS) and Energy Efficiency Resource Standard (EERS) mandates are modeled. All existing EPA regulations governing electric power generation, transmission and distribution are incorporated. To capture the expected effects of environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, including retired units or announced retirements. Additional, age-related retirements are captured using 60 years as a cutoff for non-coal thermal units and 100 years for conventional hydroelectric.[32]

c. MTEP16 Low Demand (LD) Future

Similar to the HD Future, the MTEP16 Low Demand (LD) Future is meant to analyze the effects of economic activity and energy usage lower the normal demand forecast utilized in the BAU Future. The MTEP16 LD Future implements very similar assumptions as were used in the BAU Future, with the lower energy usage reflected in lower levels of renewable generation investment and slightly lower fuel prices. MISO's MTEP16 LD Future narrative is as follows:

> The Low Demand future captures the effects of reduced economic growth resulting in lower energy costs and medium – low gas prices. The magnitude of demand and energy growth is determined by using the lower bound of the Load Forecast Uncertainty metric. All current state-level RPS and EERS mandates are modeled. All applicable EPA regulations governing electric power generation, transmission and distribution are modeled. To capture the expected effects of environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, including retired units or announced retirements. Additional, age-related retirements are captured using 60 years as a cutoff for non-coal thermal units and 100 years for conventional hydroelectric.[33]

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[32] MTEP16 at 99.

[33] MTEP16 at 99.

d. MTEP16 Regional Clean Power Plan Compliance (RCPP) Future

The final two MTEP16 Futures looked at the impacts of complying with a major policy driver at the time, the Clean Power Plan. The Regional Clean Power Plan Compliance (RCPP) Future was intended to analyze the impacts of complying with the requirements of the Clean Power Plan on a MISO region-wide scale. This approach for compliance utilized the current MISO energy market and planning polices to maximize the efficiency of potential renewable energy credits that could be traded between sub-regions and states. MISO's MTEP16 RCPP Future narrative is as follows:

> The Regional Clean Power Plan future focuses on several key items from a footprint wide level which combine to result in significant carbon reductions over the course of the study period. Assumptions are consistent with previous CPP sensitivity analysis, and include the following:
>
> - To capture the expected effects of existing environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, including units which have either already retired or publicly announced they will retire.
> - 14 GW of additional coal unit retirements, coupled with a $25/ton carbon cost, state mandates for renewables, and half of the EE annual growth used by the EPA, result in a significant reduction in carbon emissions by 2030.
> - Additional, age-related retirements are captured using 60 years of age as a cutoff for non-coal thermal units and 100 years for conventional hydroelectric.
> - Solar and wind include an economic maturity curve to reflect declining costs over time.
> - Demand and energy growth rates are modeled at levels as reported in Module E.[34]

[34] MTEP16 at 99.

e. MTEP16 Sub-regional Clean Power Plan Compliance (SRCPP) Future

The Sub-regional Clean Power Plan Compliance (SRCPP) Future was intended to analyze the impacts of complying with the requirements of the Clean Power Plan if the states within MISO developed plans utilizing different compliance paths, in this case some states choosing rate-based compliance and some states choosing mass-based compliance. This approach for compliance represents a more state-centric compliance approach that favors each individual state's goals instead of utilizing the current MISO energy market and planning polices to maximize the efficiency of potential renewable energy credits that could be traded between sub-regions and states. MISO's MTEP16 SRCPP Future narrative is as follows:

> The Sub-Regional Clean Power Plan future focuses on several key items from a zonal or state level which combine to result in significant carbon reductions over the course of the study period. Assumptions are consistent with previous CPP sensitivity analysis, and include the following:
>
> - To capture the expected effects of existing environmental regulations on the coal fleet, 12.6 GW of coal unit retirements are modeled, including units which have either already retired or publicly announced they will retire.
> - 20 GW of additional coal unit retirements, coupled with a $40/ton carbon cost, state mandates for renewables, and half of the EE annual growth used by the EPA, result in a significant reduction in carbon emissions by 2030.
> - Additional, age-related retirements are captured using 60 years of age as a cutoff for non-coal thermal units and 100 years for conventional hydroelectric.
> - Solar and wind include an economic maturity curve to reflect declining costs over time.
> - Demand and energy growth rates are modeled at levels as reported in Module E.[35]

[35] MTEP16 at 99-100.

A summary of all five MTEP16 futures is provided in **Figure 17** below. The figure shows the three main differences in the assumptions going into the Futures: growth levels, gas prices and carbon costs/coal retirements.

Figure 17

MTEP16 Futures Matrix

Future	Demand and Energy Growth	Retirement Level* (GW)	Peak Natural Gas Price (2015 $/MMBtu)	Incremental Renewables (GW) N/C: North/Central S: South	CO_2 Cost (2015 $/ton
Business as Usual	0.9%	No Additional	$4.30	N/C: 4.2 Wind/ 1.4 Solar S: 0 Wind/ 0 Solar	N/A
High Demand	1.6%	Age-related	$4.30	N/C: 7.2 Wind/ 1.6 Solar S: 0 Wind/ 0 Solar	N/A
Low Demand	0.2%	Age-related	$3.44	N/C: 2.4 Wind/ 1.3 Solar S: 0 Wind/ 0 Solar	N/A
Regional CPP Compliance	0.9%	14 GW coal + age-related	$5.16	N/C: 4.2 Wind/ 1.4 Solar S: 0 Wind/ 0 Solar + economically chosen wind/solar based on cost maturity curves	$25 / ton
Sub-Regional CPP Compliance	0.9%	20 GW coal + age-related	$5.16	N/C: 4.2 Wind/ 1.4 Solar S: 0 Wind/ 0 Solar + economically chosen wind/solar based on cost maturity curves	$40 / ton

*12 GW of MATS related coal-retirements are assumed in all Futures Age-related retirement assumption applies to non-coal generation only.

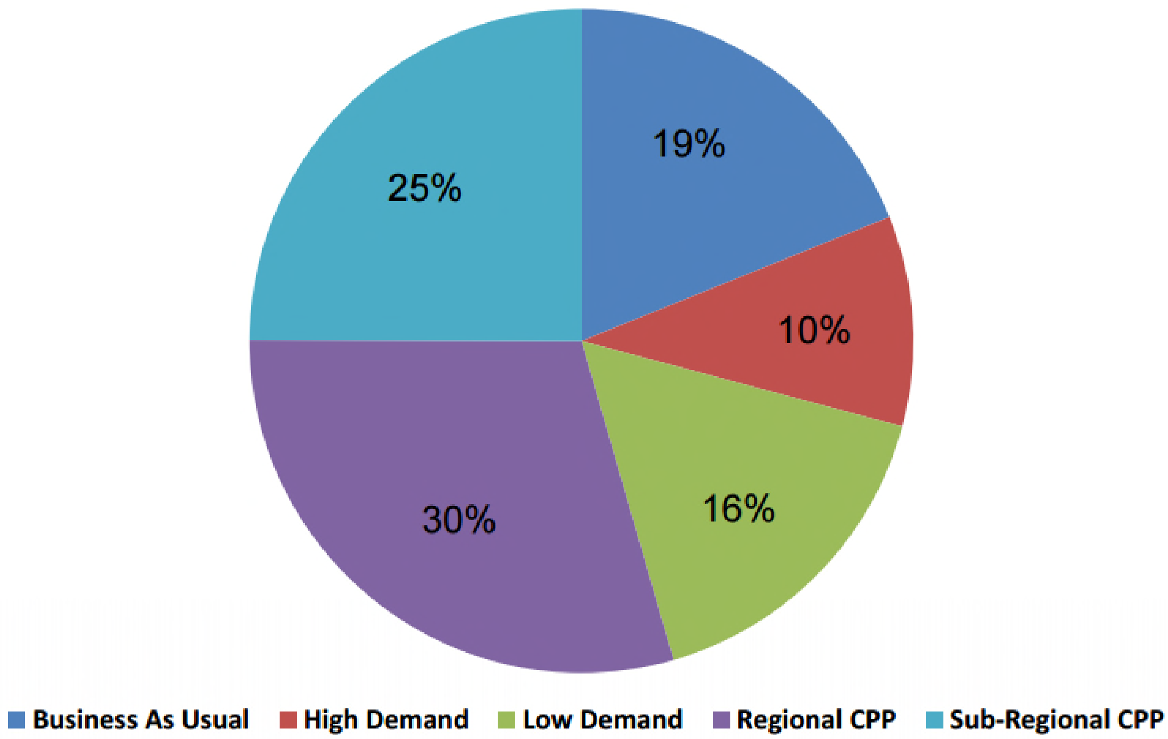
2. MTEP16 Future Weighting[36]

In the MTEP process, the economic Futures are assigned weights representing the perceived likelihood at the time of the weighting discussions for each of the Future scenarios to be realized. There are several voting sectors of the Planning Advisory Committee that vote for the weights for each future and provide a justification for the vote. The MTEP16 weights are shown in **Figure 18**.

[36] MTEP16 Futures Weights: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/PAC/2015/20150916/20150916%20PAC%20Item%2002b%20MTEP16%20Futures%20Weighting.pdf.

Figure 18

MTEP16 Futures Weighting



As shown in the diagram above, the Regional CPP was the highest weighted Future at 30%, with the Sub-Regional CPP Future slightly lower at 25%. The remaining three Futures, Business As Usual, Low Demand and High Demand, received lower weights at 19%, 16% and 10%, respectively. This distribution of weights depicts the thought of the MISO stakeholders that additional development of renewable energy sources and potential impacts of public policies are a more likely future scenario than any variation of energy demand levels without such changes. The equation below shows how the weights are used in determining project benefit.

$$\textit{Weighted APC Savings} = (\textit{APC Savings}_{RCPP} * 0.3) + (\textit{APC Savings}_{SRCPP} * 0.25) + (\textit{APC Savings}_{BAU} * 0.19) + (\textit{APC Savings}_{LD} * 0.16) + (\textit{APC Savings}_{HD} * 0.1)$$

To determine the benefit-to-cost ratio for each alternative, this weighted benefit is divided by the alternative's cost.

B. MTEP16 Generation Expansion Siting[37] (Step 2)

Each of the individual MTEP16 Futures utilizes different generation capacity, generation retirement, fuel price, and policy regulations to determine a cost-effective generation expansion scenario to meet regional generation capacity needs. This generation expansion analysis is performed using the assumptions agreed upon during the first stage of the Futures development process, which are then incorporated into the MISO generation expansion model using the Electric Generation Expansion Analysis System (EGEAS), which determines a cost-effective way to meet the regions generation capacity requirements in each of the Future scenarios. The following tables and images show the magnitude generation expansion and retirements assumed in each of the five MTEP16 futures. The following diagrams depict the projected generation fleet capacity changes and energy production produced as a result of the Futures assumptions being analyzed in the scope of a least cost generation expansion analysis. As shown below, when renewable energy becomes a more efficient way to meet all capacity and environmental requirements, the system-wide capacity expansion and energy usage shift substantially away from larger thermal generation and start to favor renewable energy and more efficient and flexible natural gas fueled generation. *See* **Figure 19** and **Figure 20**.

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[37] MTEP16 EGEAS Results: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2015/20150821/20150821%20EPUG%20Item%2005b%20MTEP16%20EGEAS%20Results.pdf.

Figure 19

MTEP16 Regional Resource Forecasting

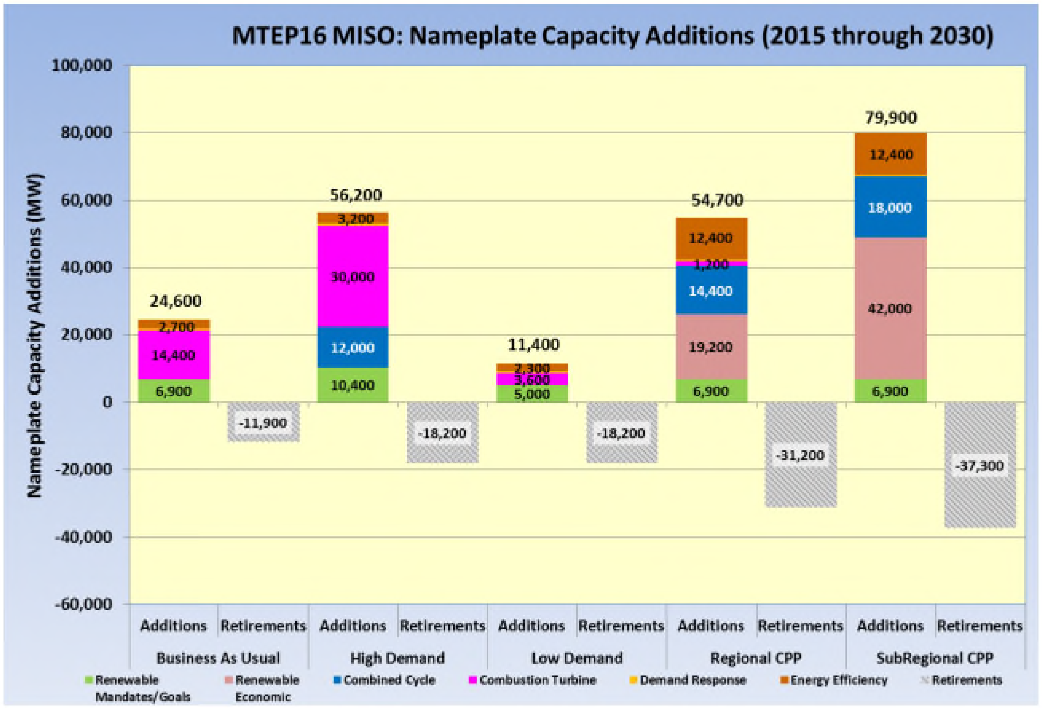
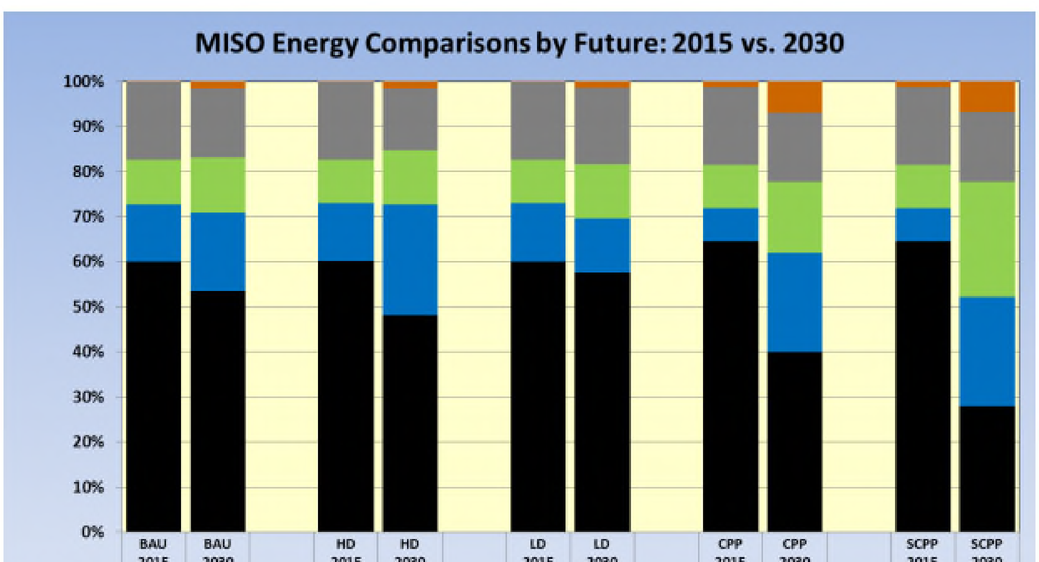


Figure 20

MTEP16 Futures Energy Utilization

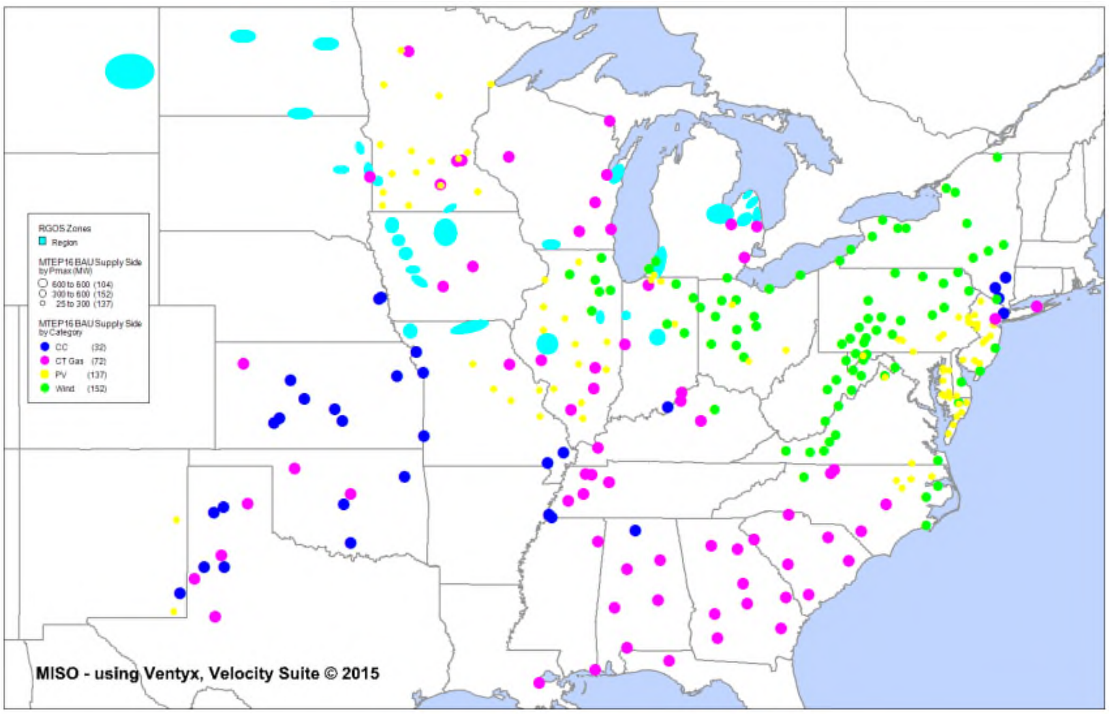


	BAU 2015	BAU 2030	HD 2015	HD 2030	LD 2015	LD 2030	CPP 2015	CPP 2030	SCPP 2015	SCPP 2030
DSM	0%	2%	0%	2%	0%	1%	1%	7%	1%	7%
Other	17%	15%	17%	14%	17%	17%	17%	15%	17%	15%
Renewable	10%	12%	10%	12%	10%	12%	10%	16%	10%	26%
Gas	13%	17%	13%	25%	13%	12%	7%	22%	7%	24%
Coal	60%	53%	60%	48%	60%	58%	64%	40%	64%	28%

After a reasonable and cost-effective generation expansion was determined, MISO then developed locations in which these new generation resources will be placed in the economic models. This process follows the rules established for siting of these Regional Resource Forecast (RRF) units.[38] **Figure 21**, **Figure 22**, **Figure 23**, **Figure 24** and **Figure 25** show the generation assumptions associated with each of the MTEP16 futures.

Figure 21

MTEP16 Business As Usual Generation Expansion Siting



[38] MTEP16 at Appendix E2 available at: https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20E2%20EGEAS_Assumptions.pdf.

Figure 22

MTEP16 High Demand Generation Expansion Siting

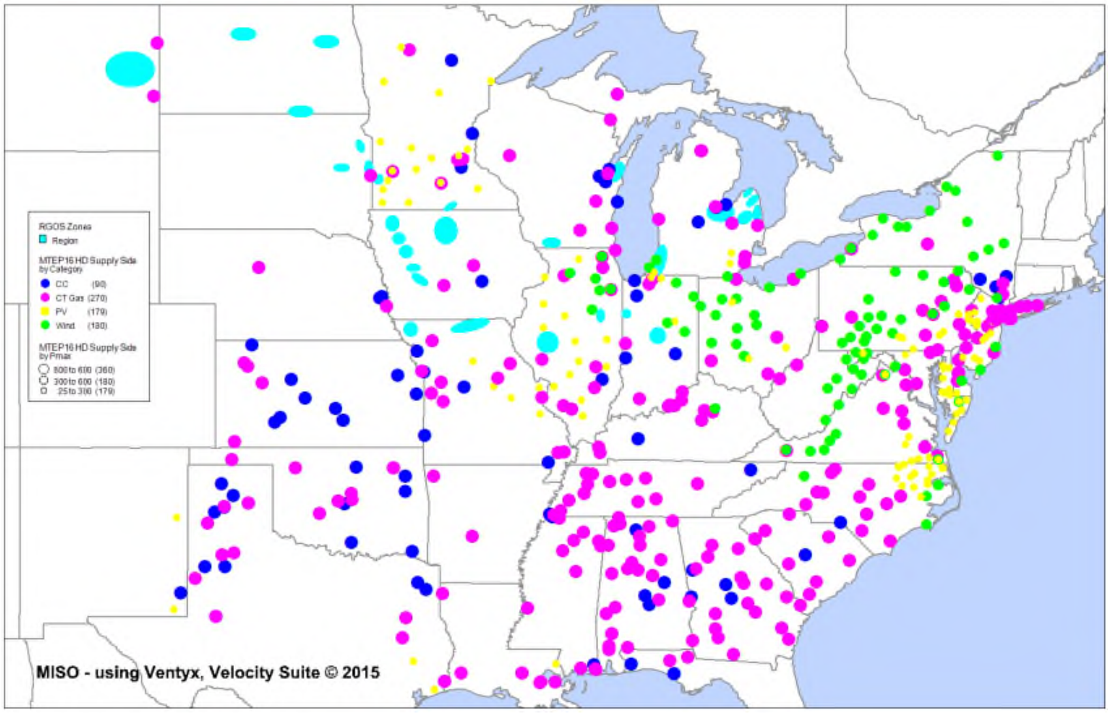


Figure 23

MTEP16 Low Demand Generation Expansion Siting

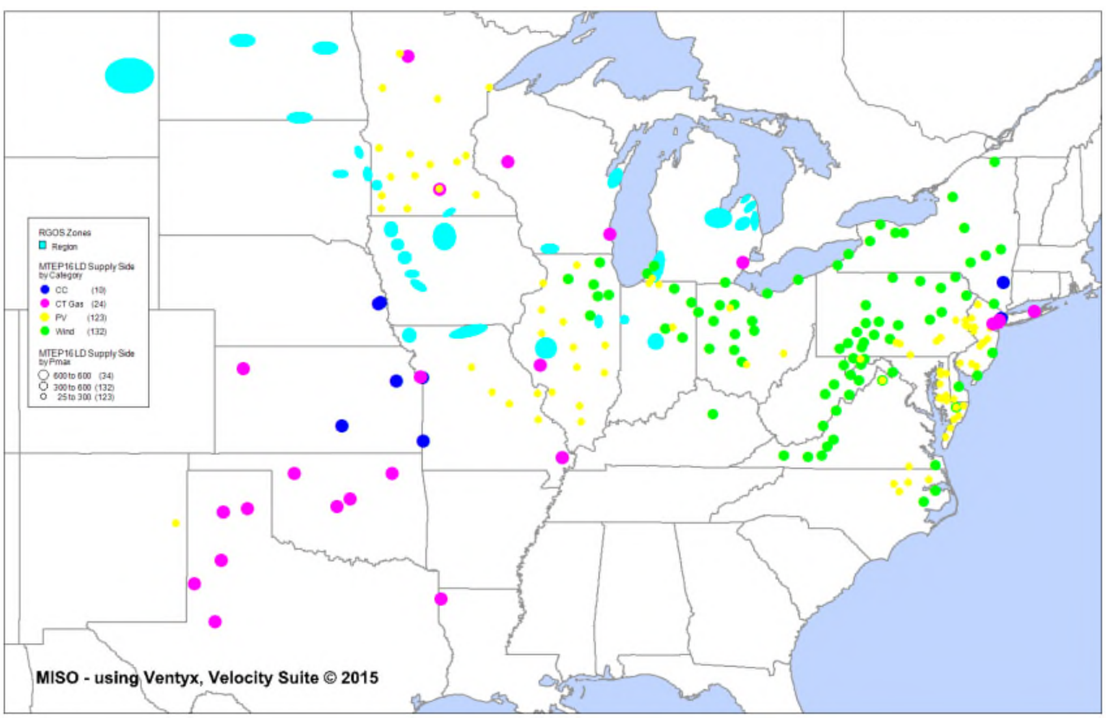


Figure 24

MTEP16 Regional CPP Compliance Generation Expansion Siting

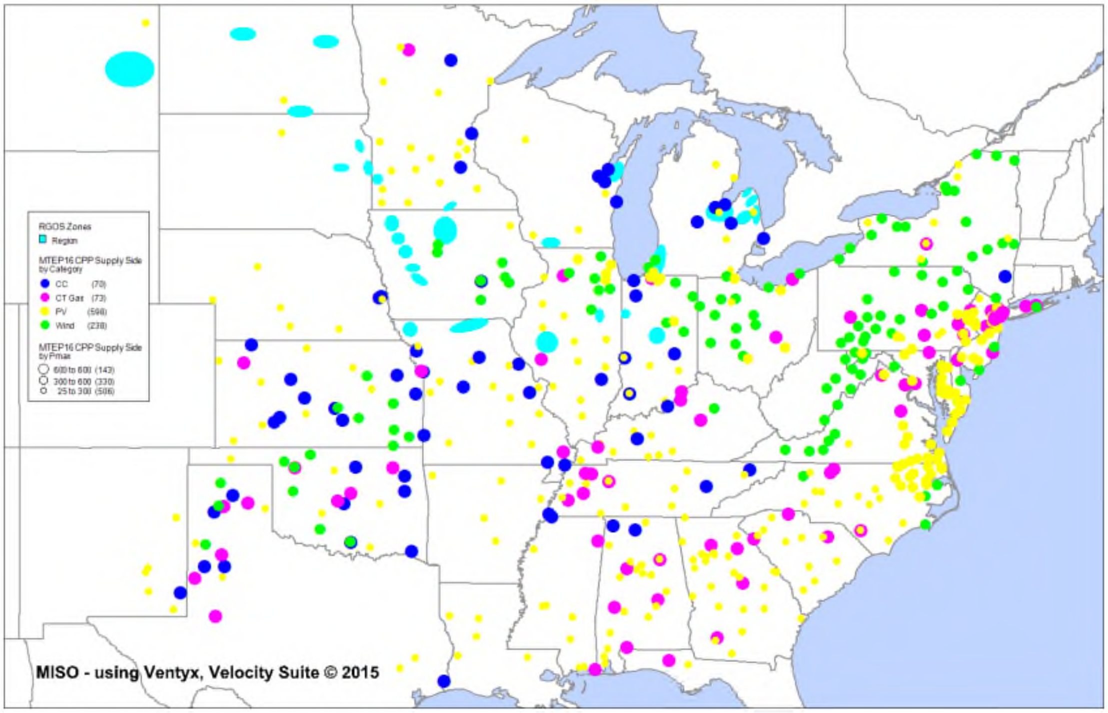
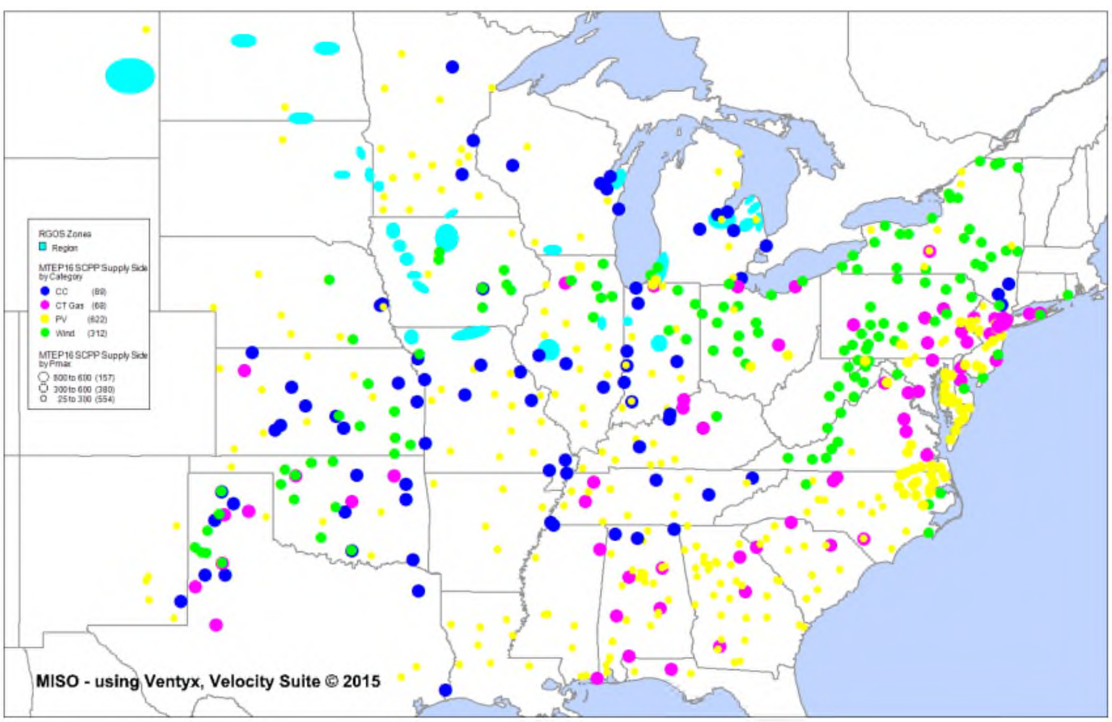


Figure 25

MTEP16 Sub-regional CPP Compliance Generation Expansion Siting



C. MTEP16 Initial Analysis and Solution Development [39] (Step 3)

The top congested flowgate analysis identifies system congestion trends based on both the historical market data and forecasted congestion. The analysis identifies and prioritizes highly congested flowgates within the MISO market footprint and on the seams. The flowgates of interest are those with historical congestion and are projected to limit constraints throughout the 15-year study period. MISO finds these flowgates by examining:[40]

- Historical day-ahead, real-time and market-to-market congestion
- Projected congestion identified through out-year production cost model simulations
- The magnitude and frequency of congestion identified under these two metrics signals where transmission investments should be made.

Figure 26 shows the six elements that were monitored for the congestion study in the MISO North/Central Region.

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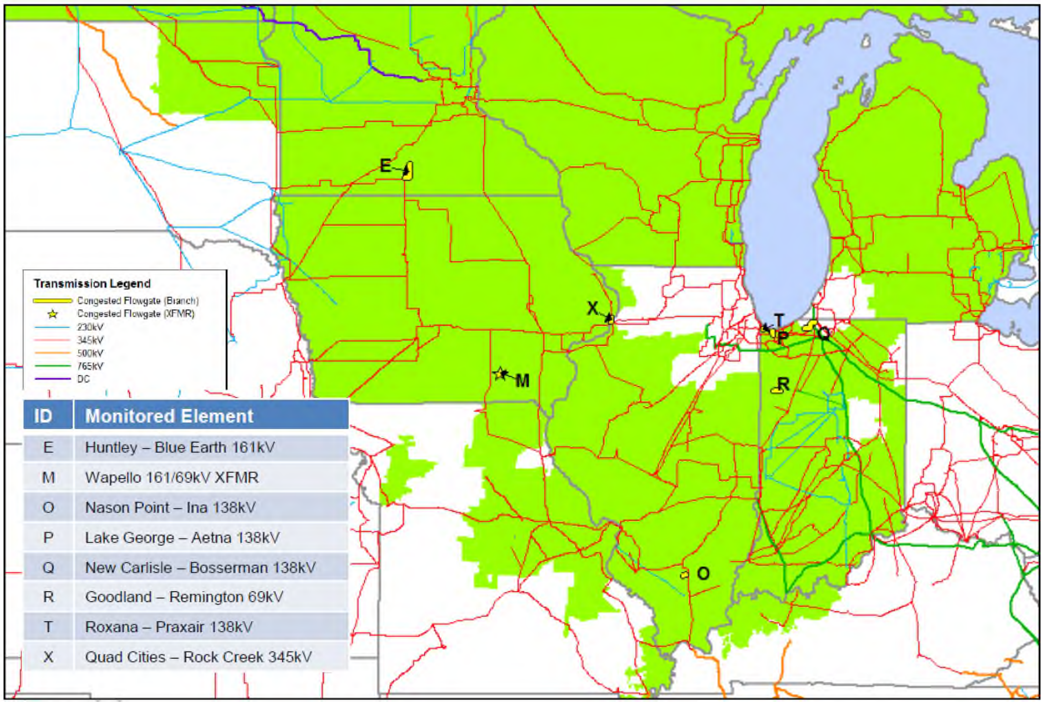
[39] MTEP16 MCPS North/Central Need Identification: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2015/20151211/20151211%20EPUG%20Item%2004%20MCPS%20North%20Central%20Need%20Identifcation.pdf.

[40] MTEP16 Report, page 97: https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20Book%201%20Transmission%20Planning.pdf.

Figure 26

Monitored Elements



The determination of the Top Congested flowgates in the MISO region is analyzed using the shadow price calculated for a given element. The shadow price indicates the cost savings that would be realized by relieving a single megawatt on the constrained element. While this does not have a direct correlation to the extent of the identified congestion or the costs associated with that congestion, it does provide a method for comparing the potential impacts of mitigating the congestion on a system element on a like-for-like basis without requiring a predefined, complete solution to the identified congestion. For example, in the table below, increasing the rating on the Quad Cities – Rock Creek 345 kV transmission line by a single megawatt was shown to provide 98.7 $k/MW-year. There is no direct correlation between $k/MW-year used as the unit designation for a shadow price calculation and $/MWh used during the production cost calculation, the shadow price is merely an indicator to the potential level of congestion that could occur due to that constraint. *See* **Figure 27**.

Figure 27

MTEP16 Congestion Analysis West Region

ID	Monitored Element	Contingency Element(s)	Area (From - To)	2030 Total Annual Shadow Price (k$/MW-year)				
				BAU	HD	LD	RCPP	SRCPP
E	Huntley – Blue Earth 161kV	Wilmarth – Fieldon 345kV	ALTW – NSP	225.2	576.3	64.4	1,173.2	2,318.2
M	Wapello 161/69kV XFMR	Wapello 161/69kV XFMR	ALTW - ALTW	185.0	284.4	1.2	40.3	31.3
X	Quad Cities – Rock Creek 345kV*^Δ^	Quad Cities – Sub 91 345kV No Outage	COMED - ALTW	98.7	90.7	42.4	7.8	4.6

**Shadow Price is used as an indication of congestion and cannot be directly correlated with congestion costs

Once these congested flowgates were identified, MISO solicited potential solutions to relieve the congestion identified in the study. The proposals included 23 unique project submissions, 20 of which were directly identified to address the congestion identified in southern Minnesota.

D. <u>Testing of Conceptual Transmission for Robustness (Step 4)</u>

MISO ran a screening analysis on the 23 submitted projects. Of those 23 projects, 16 submissions exceeded 0.9 benefit-to-cost ratio screening threshold.

A complete listing of all 23 projects analyzed in MTEP16 to address the monitored elements is provided in **Figure 28**. The 16 that passed the screening review have a "y" in the right-hand column.

Figure 28

Alternatives Evaluated in MTEP16 Screening Process

ID	Project Description	Cost Estimate (2016 $M)	Flowgate(s) Addressed	Pass Screening
I-01	Huntley - Wilmarth 345kV new circuit (double bundled 954 Cardinal ACSR)	65.0	E	Y
I-02	Huntley - Wilmarth 345kV new circuit (double bundled 1780 Chukar ACSR)	70.0	E	Y
I-03	Huntley - Wilmarth 345kV new circuit (2-795 ACSS)	90.0	E	Y
I-04	Huntley - Wilmarth 345kV new circuit (double bundled 1272 54/19 ACSR)	67.0	E	Y
I-06	Huntley - South Bend - Wilmarth 345kV new circuit; South Bend 161kV substation upgraded to 345kV and existing 161/115kV XFMR replaced by a 345/115kV XFMR, also retire Blue Earth – South Bend 161kV.	107.0	E	Y
I-07	Huntley - Wilmarth - Cedar Mountain 345kV new circuit	214.0	E	Y
I-08	Huntley - South Bend - Wilmarth - Cedar Mountain 345kV new circuit; South Bend 161kV substation upgraded to 345kV and existing 161/115kV XFMR replaced by a 345/115kV XFMR, also retire Blue Earth – South Bend 161kV.	231.0	E	Y
I-09	Lakefield Junction - Cedar Mountain 345kV new circuit	158.0	E	Y
I-10	Lakefield Junction - Cedar Mountain 345kV new circuit; 3rd 345/161kV Lakefield XFMR	167.0	E	Y
I-11	Huntley - West Owatonna - North Rochester 345kV new circuit ; West Owatonna 161kV substation upgraded to 345kV with a new 345/161kV XFMR	229.0	E	Y
I-12	Huntley - NROC 345kV new circuit	160.0	E	Y
I-13	Colby - Adams 345kV new circuit	99.0	E	Y
I-14	Huntley - South Bend 161kV upgrade; South Bend – North Point – Wilmarth – Swan Lake – Ft Ridgely – Franklin 115kV upgrade. Franklin – Cedar Mountain 115kV does not need to upgrade; South Bend 161/115kV XFMR replacement	55.0	E	Y
I-15	Huntley - South Bend 161kV reconductor, South Bend - Wilmarth 161kV new circuit; Wilmarth substation 161kV expansion with a 345/161kV and a 161/115kV XFMR	38.0	E	Y
I-16	Huntley - Loon Lake - West Owatonna 161kV; Loon Lake substation 161kV expansion with a 161/115kV XFMR	59.0	E	Y
I-19	Freeborn - West Owatonna 161kV new circuit	27.0	E	Y
I-37	Hazel Creek - Quarry 345kV new circuit	219.0	E	N
I-38	Upgrade Wapello 161/69 kV Xfmrs. 1&2 to 336MVA	5.0	M	N
I-39	Tap Ottumwa - Wapello 161 kV near Air Base 69kV substation; Air Base substation 161kV expansion with a 161/69kV XFMR and 0.5 mile in-and-out 161kV circuit.	7.4	M	N
I-42	Add 3rd 131 MVA 161/69 kV Wapello XFMR	5.0	M	N
I-46	Adams - Killdeer 345kV new circuit	123.0	E	N
I-59	Hayward - West Owatonna 161kV new circuit	41.0	E	N
I-60	Wilmarth – Loon Lake – West Owatonna – N. Rochester 345kV new circuit; Loon Lake substation expansion to 345kV with a 345/115kV XFMR West Owatonna substation expansion to 345kV with a 345/161kV XFMR	209.0	E	N

These 16 projects moved into the next portion of the process which sorted these projects into groups addressing similar constraints, then analyzed for the full 20- year net present value benefit-to-cost ratio of the project as described in the next section.[41]

[41] Solution Screening and Preliminary Project Candidates: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160418/20160418%20EPUG%20Item%2004c%20Screening%20and%20PV%20Analysis%20-%20MN%20IA.pdf

E. Consolidation and Sequencing of Transmission Plans[42] and Further Robustness Testing (Step 5)

When the 16 project submissions that passed the screening threshold were reanalyzed to select candidates for the full Present Value analysis, MISO narrowed the selected project list to four groups of solutions based on voltage level and design approach, then ranked the individual submissions in each group by their screening index. The full Present Value analysis analyzes a potential project in each of the three model years (five, ten and fifteen years) then interpolates and extrapolates the results to estimate a projected benefit for each of the twenty years in the planning horizon. This benefit is then calculated in terms of present year dollars to ensure an equitable aggregation of the annual benefit projections. **Figure 29** below summarizes these four groups of projects. Additional discussion of each group follows.

Figure 29

Types of Alternatives Evaluated

Group	Solution Ideas	Voltage	Design Approach
1	I-01, I-02, I-03, I-04, I-06, I-07, I-08, I-09, I-10	345kV	Directly strengthen Huntley/Lakefield to Wilmarth path
2	I-11, I-12, I-13	345kV	Strengthen southeast transmission corridor into the Twin Cities
3	I-14, I-15	Below 345kV	Directly strengthen Huntley/Lakefield to Wilmarth path
4	I-16, I-19	Below 345kV	Strengthen southeast transmission corridor into the Twin Cities

1. Alternative Groups

a. Group 1: Projects I-01 through I-04, I-06 through I-10

This group of projects proposes the direct strengthening of the Huntley - Wilmarth transmission path with predominately 345 kV facilities, but are different configurations of that project. Based on the system requirements needed to completely mitigate the identified congestion and the stakeholder submitted cost of

[42] Solution Screening and Preliminary Project Candidates: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160418/20160418%20EPUG%20Item%2004c%20Screening%20and%20PV%20Analysis%20-%20MN%20IA.pdf.

the projects, MISO chose Project I-02, which consists of a new 345 kV circuit from Huntley to Wilmarth, to move forward with additional analysis. Of this project group, I-02 was the lowest cost alternative that still addressed 100 percent of the congestion.

b. Group 2: Project I-11 through I-13

This group of projects proposes to mitigate the identified congestion through strengthening of the southeast transmission path into the Twin Cities metro area. Although they are all different configurations, they address the identified congestion by connecting the 345 kV system in southern Minnesota and northern Iowa with the 345 kV system in southeastern Minnesota, which are currently only connected in eastern Iowa. Similar to Group 1, Project I-12, adding a new 345 kV circuit between Huntley and North Rochester, was selected for further analysis due to having the highest weighted benefit-to-cost screening ratio.

c. Group 3: Project I-14 and I-15

This group of projects are alternatives to Group 1, which directly strengthens the Huntley – Wilmarth transmission path, but is made up of solely sub-345 kV solutions, i.e., lower voltage solutions. Due to having the lowest cost and highest weighted screening index of Group 3, Project I-15, which included reconductoring of the existing 161 kV transmission line from Huntley to South Bend, adding an new 161 kV transmission line from South Bend to Wilmarth and expanding the existing Wilmarth substation to accommodate the additional 161 kV transmission line, was selected to move forward for further analysis.

d. Group 4: Project I-16 and I-19

As Group 3 were sub-345 kV alternatives to Group 1, Group 4 are sub-345 kV alternative to Group 2; these projects look to strengthen the southeast transmission path into the Twin Cities area with predominately sub-345 kV facilities. In this group, Project I-19, adding a new 161 kV transmission line between the existing Freeborn and West Owatonna substations, provided a much higher weighted screening index than similar alternatives, and as a results, Project I-19 was selected for further analysis.

After the four project candidates were chosen from the four groups, MISO performed a full 20-year Net Present Value (NPV) calculation to determine their initial benefit-to-cost ratio. This analysis utilized the five, 10- and 15-year horizons for each of the five Futures developed for the MTEP16 cycle. Once the values are obtained for the three study year of each Future, the benefits are then interpolated with the benefits between the study years and extrapolated for the benefits to the full 20-year study horizon. MISO then performs a NPV calculation on the projected benefits to ensure they are all represented in the study year's dollars (in this case 2016 dollars). **Figure 30** shows the NPV analysis.

Figure 30

Summary of NPV Analysis

ID	Transmission Solution	Top Down Cost Estimate (2016 $M)	Benefit to Cost Ratios						20-yr PV Benefit ($M)
			BAU	HD	LD	RCPP	SRCPP	Weighted	
I-02	Huntley - Wilmarth 345kV new circuit (double bundled 1780 Chukar ACSR)	100.9	0.51	1.29	0.12	1.71	6.72	2.44	344
I-12	Huntley - NROC 345kV new circuit	234.7	0.25	0.64	0.05	0.53	2.67	0.95	288
I-15	Huntley - South Bend 161kV reconductor, South Bend - Wilmarth 161kV new circuit; Wilmarth substation 161kV expansion with a 345/161kV and a 161/115kV XFMR	48.4	0.42	1.32	0.09	1.81	5.15	2.06	121
I-19	Freeborn - West Owatonna 161kV new circuit	40.8	0.60	1.68	0.11	0.97	12.62	3.75	189

Given the results of the Present Value analysis shown above, MISO again reduced the project list by removing any project that did not meet or exceed the 1.0 benefit-to-cost ratio threshold. This eliminated Project I-12, adding a new 345 kV transmission line between Huntley and North Rochester, and left only the proposed Huntley – Wilmarth 345 kV solution, which was projected to have a 2.44 benefit to cost ratio, and two 161 kV solutions: (1) Project I-15 upgrading the existing facilities and adding a new 161 kV transmission line between South Bend and Wilmarth, showing a 2.06 benefit to cost ratio; and (2) Project I-19 adding a new 161 kV transmission line between the Freeborn and West Owatonna substations, showing a 3.75 benefit to cost ratio.[43]

After this initial Present Value analysis was completed, MISO refreshed their analysis to account for incorrectly modeled wind generation. In the first set of MTEP16 Future, the future wind generation sited in wind zone WI-B, which is meant to be in southwestern Wisconsin, was incorrectly modeled at the Freeborn substation in southern Minnesota due to an unaccounted for bus number change. Due to the relocation of wind generation, the benefits attributed to the Freeborn to West Owatonna 161 kV proposal (Project I-19) drastically declined. While this alternative was greatly affected by this model correction, the Huntley - Wilmarth 345 kV project maintained a high level of benefit. **Figure 31** below shows the results obtained from the refreshed 20-year Net Present Value analysis.[44]

Figure 31

Revised NPV Analysis

ID	Transmission Solution	Top Down Cost Estimate (2016 $M)	Benefit to Cost Ratios						20-yr PV Benefit ($M)
			BAU	HD	LD	RCPP	SRCP P	Weighted	
I-2	Huntley - Wilmarth 345kV new circuit	100.9	0.48	1.22	0.14	1.39	4.85	1.87	242
I-15	Huntley - South Bend 161kV reconductor, South Bend - Wilmarth 161kV new circuit; Wilmarth substation 161kV expansion with a 345/161kV and a 161/115kV XFMR	48.4	0.35	1.01	0.12	1.38	4.00	1.60	95
I-19	Freeborn - West Owatonna 161kV new circuit	40.8	0.32	0.82	0.04	0.56	3.54	1.20	60

[43] Solution Screening and Preliminary Project Candidates: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160418/20160418%20EPUG%20Item%2004c%20Screening%20and%20PV%20Analysis%20-%20MN%20IA.pdf.

[44] Robustness Testing – North/Central: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160614/20160614%20EPUG%20Item%2003%20Robustness%20Testing.pdf.

During this part of the analysis, MISO also analyzed the amount of the identified congestion that is mitigated by the proposed projects. As shown in **Figure 32** below, while the two lower voltage project did provide economic benefits, they did not address all of the identified congestion, and would likely require additional near-term mitigation. Specifically, Project I-15 alleviated 66 percent of the identified congestion and Project I-19 only alleviated 30 percent of the identified congestion.

Figure 32

Congestion Relief Provided by Top Three Alternatives

ID	Transmission Solution	B/C above 1.0?	Highest B/C Ratio?	Highest 20-yr PV Benefit ?	% Congestion Relief of FG E
I-2	Huntley - Wilmarth 345kV new circuit (double bundled 1780 Chukar ACSR)	✓	✓	✓	100%
I-15	Huntley - South Bend 161kV reconductor, South Bend - Wilmarth 161kV new circuit; Wilmarth substation 161kV expansion with a 345/161kV and a 161/115kV XFMR	✓	×	×	66%
I-19	Freeborn - West Owatonna 161kV new circuit	✓	×	×	30%

During this part of the process, MISO performed an updated Net Present Value analysis. This refreshed Net Present Value analysis was performed due to a modeling error discovered which erroneously sited additional generation at the Freeborn substation in southeast Minnesota. This generation was part of the WI-B wind generation siting zone, and was intended to be located in southwestern Wisconsin. This error was due to a recent bus number change in base the model which was not accounted for in the initial analysis. This model correction reduced the benefit-to-cost ratios of Projects I-2, I-15, and I-18 to 1.87, 1.60 and 1.20, respectively.

In comparing these three alternatives, MISO eliminated the Freeborn-West Owatonna 161 kV circuit alternative because it relieved only 30 percent of the congestion. MISO determined that the I-15 project had a lower benefit-to-cost ratio and lower 20-year Present Value benefit than the Huntley –Wilmarth Project and did not relieve 100 percent of the congestion. Ultimately, MISO selected the Huntley – Wilmarth Project as the best overall solution because it resolves 100 percent of the congestion and had the highest benefit-to-cost ratio.

2. Further Robustness Testing

a. Economic Sensitivity Analysis[45]

MISO completed two economic sensitivity analyses based on the physical location of the future wind units and interconnection points assumed to be in the Futures and announced generation retirements.

The first of these economic sensitivity analyses included a look at the impacts of the retirement and replacement of the large Sherburne County Generation Station (Sherco) units 1 and 2 located northwest of the Twin Cities metro area. The units, which are 682 MW each, are planned to retire in 2023 and 2026, respectively. Specifically, MISO examined the retirement of these two large baseload generation sources northwest of the Twin Cities area, the largest urban area in Minnesota, and replaced this capacity with a 600 MW natural gas combined cycle generator and a 600 MW natural gas combustion turbine at the current Sherco location.

The second economic sensitivity tested whether the Project's benefits were sensitive to the location of forecasted wind generation additions meant to meet resource requirements external to MISO. To accomplish this second sensitivity, MISO removed the RRF generators, sited using the MTEP Futures siting guidelines, intended to meet non-MISO resource requirements. The result of these sensitivities

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[45] MISO, *Robustness Testing – North/Central* (June 14, 2016), *available at* https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160614/20160614%20EPUG%20Item%2003%20Robustness%20Testing.pdf.

showed that the Project maintains a high benefit-to-cost ratio under the generation location variations studied, with increased projected benefits in the Sherco replacement sensitivity. **Table 7** shows the sensitivity analysis results.

Table 7

Sensitivity Analysis Results

ID	Top Down Cost Estimate (2016 $M)	Sensitivities	Benefit to Cost Ratios						20-yr PV Benefit ($M)
			BAU	HD	LD	RCPP	SRCPP	Weighted	
I-02	100.9	Base Case	0.51	1.29	0.12	1.71	6.72	2.44	344
		Sherco Retirement	0.70	1.84	0.30	1.71	6.72	2.55	360
		External RRF Wind in IA Removal	0.51	1.29	0.12	0.91	4.50	1.64	232

MISO also analyzed two alternatives that included the Huntley – Wilmarth 345 kV Project and additional 115 kV facilities. MISO evaluated where congestion would next develop on the system once the Project was in service. The incremental benefit-to-cost ratio was analyzed for each alternative. **Table 8** shows the results of MISO's analysis which showed that the Huntley – Wilmarth 345 kV line by itself provided the highest benefit-to-cost ratio.

Table 8 also summarizes a generation interconnection queue sensitivity analysis MISO performed to look at the physical location of the future wind units assumed to be in future scenarios. This generation interconnection queue sensitivity tested whether the Project's benefits were dependent on the location of forecasted wind generation additions. To accomplish the goal of this sensitivity, MISO replaced the RRF wind generators, sited using the MTEP Futures siting guidelines, with wind generation which was sited at the same location as wind generation interconnection requests that were in the final stage of the MISO Generator Interconnection Process. This results of this analysis showed that, with the level of wind likely to be interconnected based on historical interconnection trends, the benefits of the Project increase in all Futures. The analysis indicated increase economic benefits when more precise generator locations were included in the modeling.

Table 8

Huntley – Wilmarth Project Variations

ID	Transmission Solution	Model	Cost Estimate (2016 $M)	Benefit-to-Cost Ratios						20-yr PV Benefit ($M)
				BAU	HD	LD	RCPP	SRCPP	Weighted	
I-2	Huntley – Wilmarth 345 kV new circuit	Base	88-108	0.43-0.52	1.16-1.42	0.10-0.13	1.32-1.62	3.63-4.45	1.51-1.86	210
		Queue Wind Sensitivity		1.39-1.71	2.40-2.95	0.69-0.85	2.45-3.01	2.03-2.49	1.86-2.28	251
I-2b	Huntley – Wilmarth 345 kV new circuit, Wilmarth to Swan Lake – Ft Ridgeley 115 kV upgrade	Base	113.3-133.3	0.37-0.43	1.12-1.31	0.09-0.10	1.15-1.35	3.31-3.90	1.36-1.60	234
		Queue Wind Sensitivity		1.13-1.33	2.08-2.45	0.55-0.65	2.02-2.39	1.73-2.03	1.55-1.83	259
I-2d	Huntley – Wilmarth 345 kV new circuit, Wilmarth – Swan Lake – Ft Ridgeley 115 kV upgrade Add 2nd Helena – Scott County 345 kV circuit, Scott Co – Scott Co Tap 115 kV upgrade	Base	154.8-174.8	0.27-0.31	0.92-1.04	0.08-0.10	0.98-1.11	3.03-3.43	1.21-1.36	272
		Queue Wind Sensitivity		0.86-0.97	1.74-1.97	0.44-0.50	1.68-1.90	1.55-1.76	1.30-1.47	285

F. Reliability Analysis[46] (Step 6)

The final analysis performed for the candidate economic project is the reliability "No-Harm test." The intent of this analysis is to determine whether the inclusion of the candidate economic project creates any additional reliability issues to the system. This includes a subset of the NERC TPL-001-4 requirements to be tested, with any additional costs that would be required to mitigate reliability issues caused by the Huntley – Wilmarth project, if any, to be added to the candidate project costs. Through this analysis, MISO found that there were no additional reliability needs created by the inclusion of the Huntley-Wilmarth 345 kV Project in the MISO transmission system.

46 MCPS North-Central Reliability Analysis: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/EPUG/2016/20160614/20160614%20EPUG%20Item%2004%20Reliability%20Analysis.pdf.

G. Cost Allocation (Step 7)

The last step in the MCPS process was cost allocation. The preferred alternative, Huntley-Wilmarth Project, qualified for cost sharing as an MEP. It met the MEP criteria of having greater than 50 percent of the total cost of the project attributed to facilities that operate at 345 kV or above, with a cost exceeding $5 million, and having a benefit-to-cost ratio of 1.25 or above at the time of the analysis and MISO Board approval in MTEP16.

IV. Conclusion

In Iowa and southern Minnesota, low cost energy has not been able to reach load centers, like the Twin Cities, due to congestion on the electrical system. Since 2008, MISO has been studying means of alleviating this congestion. In MTEP16, MISO evaluated 23 proposed alternatives and identified the Huntley-Wilmarth Project as the best alternative to address the congestion. The Project: (1) will relieve 100 percent of the congestion; (2) will provide $210 million in production cost benefits on a present value basis over 20 years based on MTEP16 models; and (3) has a weighted benefit to cost ratio of 1.51 to 1.86 based on MTEP16 models.[47] Based on this MTEP16 study work, the MISO Board of Directors approved the Huntley – Wilmarth 345 kV Project as an MEP and inclusion in Appendix A of MTEP16.

[47] MTEP16 at 112.

Appendix H

Xcel Energy Demand-Side Management Data

Pursuant to Minn. R. 7849.0290, a Certificate of Need application must provide information related to an applicant's energy conservation and efficiency programs and a quantification of the impact of these conservation and efficiency programs on forecast data. ITC Midwest LLC requested, and was granted a full exemption from this rule because it has no end-use customers and therefore cannot affect customers' energy consumption levels.[1] Below is energy conservation and efficiency program information for Xcel Energy:

A. The name of the committee, department, or individual responsible for the applicant's energy conservation and efficiency programs, including load management;

Shawn White, Manager, DSM Regulatory Strategy and Planning, is responsible for Xcel Energy's energy conservation and efficiency programs, including load management.

B. A list of the applicant's energy conservation and efficiency goals and objectives;

Xcel Energy's energy conservation and efficiency goals and objectives are to provide customers with many options for saving energy. In our 2017-2019 Triennial Plan, Docket No. E,G002/CIP-16-115, Xcel Energy established a goal of saving 1,300 GWh of electric energy and 270 MW of energy demand between 2017 and 2019. The Triennial Plan was designed to achieve electric savings equal to 1.5 percent of retail sales in each year of the three years of the 2017-2019 Triennial. This goal is consistent with our last resource plan, Docket No. E002/RP-15-21, and Minnesota Statute section 216B.241, subd. 1c(b), to have an average annual energy savings level of 434 GWh for all planning years.

In Xcel Energy's last resource plan, the Commission also required Xcel Energy to acquire no less than 400 MW of additional demand response by 2023 and to evaluate in its next resource plan (to be filed on February 1, 2019) combinations of supply-side, demand-side, and transmission solutions that could in the aggregate meet post-

[1] *In the Matter of the Application of Northern States Power Company and ITC Midwest LLC, for a Certificate of Need for the Huntley to Wilmarth 345 kV Transmission Line Project*, Docket No. E002, ET6675/CN-17-184, ORDER (Sep. 1, 2017).

retirement (of baseload fleet) energy and capacity needs as well as contribute to grid support.[2]

C. A description of the specific energy conservation and efficiency programs the applicant has considered, a list of those that have been implemented, and the reasons why the other programs have not been implemented;

A full list of programs Xcel Energy considered and implemented and the Company's rationale for doing so is available in the Company's 2017-2019 Triennial Plan, Docket No. E,G002/CIP-16-115, which was subsequently approved by the Department of Commerce in a Decision dated November 3, 2016. Xcel Energy's 2017-2019 Triennial Plan[3] and the Department's Decision approving the plan[4] are hereby incorporated into this appendix by reference.

D. A description of the major accomplishments that have been made by the applicant with respect to energy conservation and efficiency;

Between 1990 and 2016 , Xcel Energy has invested of $1.4 billion (nominal) resulting in 8,477 GWh of electric energy savings and 3,312 MW of electric demand savings.

In recent years, Minnesota utilities have been recognized nationwide for their long lasting commitment to DSM, innovative programs, and delivering value to the customers they serve. In October 2015, the Department issued a study prepared by Cadmus that analyzed the economic impact on DSM for 2008-2013. This study assessed the impacts of DSM on several facets of Minnesota's economy and concluded that for every dollar invested in DSM, $4.00 to $4.30 is generated in new economic activity, energy savings, and environmental benefits. Xcel Energy in

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[2] *In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan*, Docket No. E002/RP-15-21, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS (hereinafter RESOURCE PLAN ORDER) at Order Points 10 and 14(b) (Jan. 11, 2017).

[3] *In the Matter of Xcel Energy's 2017-2019 Electric and Natural Gas CIP Plan*, Docket No. E,G002/CIP-16-115, XCEL ENERGY'S 2017-2019 TRIENNIAL PLAN (June 1, 2016), available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={06627D3D-422A-46BF-B285-31F2FF19AADD}&documentTitle=20166-121880-01.

[4] *In the Matter of Xcel Energy's 2017-2019 Electric and Natural Gas CIP Plan*, Docket No. E,G002/CIP-16-115, DECISION BEFORE THE DEPUTY COMMISSION OF THE MINNESOTA DEPARTMENT OF COMMERCE (Nov. 3, 2016), available at https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={03FFA254-C01A-4018-A6CE-44DC58FFC416}&documentTitle=201611-126260-06.

particular has been recognized for outstanding DSM performance. For instance, in July 2014 Ceres ranked 32 of the largest utilities on renewable energy and energy efficiency. Xcel Energy was ranked second for renewable energy and fifth in cumulative annual energy efficiency. Additionally, in 2012, Xcel Energy was honored with the Energy Star Award for Sustained Excellence for continuing to exhibit exceptional leadership year after year. Lastly, the American Council for an Energy Efficient Economy (ACEEE) ranked Minnesota's DSM programs as 10th best in the country in its October 2015 State Energy Efficiency Scorecard.

E. A description of the applicant's future plans through the forecast years with respect to energy conservation and efficiency; and

In the Company's most recent Resource Plan, Docket No. E002/RP-15-21, the Commission approved an average annual energy savings level of 434 GWh for all planning years.[5] The Company will continue to design its Conservation Improvement Program in a manner designed to achieve this goal.

F. A quantification of the manner by which these programs affect or help determine the forecast provided in response to part 7849.0270, subpart 2, a list of their total costs by program, and a discussion of their expected effects in reducing the need for new generation and transmission facilities.

The Company's 2017-2019 Triennial Plan is designed to reduce the annual growth in electric sales by 1.5 percent each year. The Company's 2017-2019 Triennial filing, which was incorporated by reference in question C, above, contains a list of the total costs for each program.

The Huntley-Wilmarth Project is not needed to support growing peak demand or to meet energy demands. Rather, the Huntley-Wilmarth 345 kV transmission line, identified by the Midcontinent Independent System Operator , Inc. (MISO) as a Market Efficiency Project (MEP), will benefit customers in the broader MISO region as well as customers in southwestern Minnesota and the Twin Cities metropolitan area by relieving congestion on the regional electric system, allowing greater and more

[5] RESOURCE PLAN ORDER at Order Point 10.

efficient access to lower cost renewable energy. Given that the need for this Project is not driven by peak demand or energy demand, the Commission granted the Applicants' request for exemption from certain forecasting data for Applicants' service areas and systems as required by Minnesota Rule 7849.0270, Subp. 2. Rather, Applicants committed to provide forecast information utilized by MISO in studying, planning, and analyzing the Project as part of its MISO Transmission Expansion Plan (MTEP) for 2016 (MTEP16).

MISO's annual planning process develops multiple future scenarios to study transmission needs under a variety of policy, economic, and social futures. Each future contains assumptions about future fuel costs, environmental regulations, demand and energy levels, and available technology. For MTEP16's five future scenarios, the impact of DSM programs were scaled to reflect state-level energy efficiency and/or demand response mandates or goals. To calculate the effective demand and energy growth rates, which are ultimately input into the production cost models, MISO nets out only the impact of the energy efficiency programs from the baseline demand and energy growth rates. As shown in the table below, the resulting growth rates for various futures range from 0 to 1.43 percent for demand and 0.11 percent to 1.53 percent for energy.

Table 1
MTEP 16 Effective Demand and Energy Growth Rates

	Baseline Growth Rates		Effective Growth Rates	
Future Scenario	**Demand**	**Energy**	**Demand**	**Energy**
Business as Usual	**0.75%**	**0.82%**	**0.65%**	**0.76%**
High Demand	**1.55%**	**1.61%**	**1.43%**	**1.53%**
Low Demand	**0.11%**	**0.19%**	**0.00%**	**0.11%**
Regional CPP	**0.75%**	**0.82%**	**0.27%**	**0.46%**
Sub-Regional CPP	**0.75%**	**0.82%**	**0.27%**	**0.46%**

Moreover, in conjunction with the 2017-2019 Triennial Plan, Xcel Energy worked with the Department and other electric utilities in the state to perform a DSM

Avoided Transmission and Distribution Study (DSM T&D Study).[6] This study performed an analysis to determine the level of future transmission (and distribution) projects that could be avoided of deferred due to future DSM achievement. As the Huntley-Wilmarth Project is an economic project driven by relieving congestion, not a reliability project driven by increased demand, conservation and demand-side management programs are not effective alternatives to meet the identified need. As a result, the Huntley to Wilmarth Project was not included in the DSM T&D Study.

[6] This report was filed on July 31, 2017 in Docket No. E999/CIP-16-541.

Appendix I

ITC Midwest's Cost of Alternatives, Including Commission Externalities Values

Appendix I was prepared by ITC Midwest to evaluate alternatives in a Certificate of Need proceeding before the Minnesota Public Utilities Commission. Appendix I was created to comply with the Commission's November 25, 2014 order in Docket No. ET6675/CN-12-1053 for ITC Midwest to develop a spreadsheet to calculate the cost of alternatives, including the Commission's CO_2 internal cost and externality values.

SUMMARY[1]

Alternative	Route	Total Capital Cost (2016$)	Present Value (base year 2016)			Net Benefits[2]
			Revenue Requirement ($)	Economic Benefit ($)	Public Policy Benefit ($)[2]	
Preferred Project: Huntley - Wilmarth 345 kV	Low Cost: Purple Route (West Route), Single-Circuit Parallel H-frame	$ 105,820,000	$ 156,130,593	$ 470,716,689	$ 100,677,763 to $ 455,788,663	$ 415,263,859 to $ 770,374,759
	High Cost: Blue Route (East Route), Double-Circuit Monopole and Single Circuit Monopole	$ 138,020,000	$ 203,639,619			$ 367,754,834 to $ 722,865,735
	Midrange Cost: Green Route (Middle Route), Single Circuit Parallel Monopole	$ 121,320,000	$ 178,999,845			$ 392,394,608 to $ 747,505,509
Alternative: Huntley - Wilmarth 161 kV	Midrange Cost: Green Route (Middle Route), Single Circuit Monopole Design	$ 80,900,000	$ 119,362,738	$ 339,693,909	$ 75,134,571 to $ 331,485,787	$ 295,465,743 to $ 551,816,959

1. Total project benefits are calculated as the sum of economic benefit and public policy benefit. The economic benefit reported here is a modification to the weighted Adjusted Production Cost benefits. The modification eliminates embedded CO2 and NOx costs which were included in MISO's base cases. MISO developed the cases which include emissions fees as VOM costs in the unit commitment and dispatch process. The emission fees, which resulted in higher dispatch costs, were necessary in order to achieve the carbon reduction assumptions developed in the futures building process. The emission fees do not match the Commision's approved Externality values. Therefore, a modification to the APC is required to subtract out the emission fees and to apply the externality costs in order to prevent double counting of public policy benefits. These indicative Public Policy benefits are calculated as the value of emission reductions for MISO Local Resource Zones (LRZs) 1, 2, and 3 multiplied by the appropriate externality value. Emissions from these zones have the potential to impact the State of Minnesota. Therefore, the total benefit is a summation of the modified APC and the externality benefits for MISO LRZs 1, 2 and 3. The net benefits is a present value of the total benefits minus the present value of the costs. The evaluation period is the 63 year life of the Project for a base year of 2016.

2. Range presented to capture both low and high CO2 Externality Values. Remaining effluents valued at median of rural subregion values. Additional details on externality values can be found in the Externality Costs tab.

Inputs

Inflation Rate	2.50%	[a]
Discount Rate	7.10%	[b]
Levelized Fixed Charge Rate [1]	12.90%	[c]

[1] The Levelized Fixed Charge Rate is an average of ITCM and NSP 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:

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

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

Average MNPUC Externality and Internal Cost Values ($/short ton)

2014 <-- Base Year for Externality Cost Inflation

2014 Inflation Adjusted Values ($/short ton)

	*SO2**	*NOx**
Low	$ 3,427	$ 1,985
Median	$ 6,159	$ 4,762
High	$ 8,352	$ 6,370

2020 Annual Values for CO2 (2015$ per net short ton) **

	CO2
Low	$9.05
High	$42.46

	*SO2**	*NOx**	*CO2 Low***	*CO2 High***
2021	$ 7,321	$ 5,661	10.73	$ 50.28
2026	$ 8,283	$ 6,404	13.49	$ 62.80
2031	$ 9,372	$ 7,246	16.77	$ 77.74

* Median values for 'Rural' subregion presented in Docket No. E-999/CI-14-643 applied to appropriate year

** Externality Costs for CO2 are also presented in Docket No. E999-CI-14-643 Order 010318, Table 5. These match the values reported in the Fourth Affidavit of Anne E. Smith, Ph.D., Table B. The values are reported here in nominal dollars. Additional details can be found in the in next tab.

Note: Externality values for $PM_{2.5}$, PM_{10}, CO, and PB also exist but these effluents were not modeled in MTEP cases.

Annual Emissions (short tons) for MISO LRZ's 1,2,3

	SO2	*NOx*	*CO2*
Base Case			
2021	63,083	108,185	124,739,498
2026	49,485	91,629	110,711,475
2031	39,509	83,149	107,111,812
Preferred Option: Huntley-Wilmarth 345 kV			
2021	62,978	108,101	124,580,450
2026	49,428	91,497	110,371,853
2031	39,488	83,116	106,669,047
Alternative: Huntley-Wilmarth 161 kV			
2021	63,024	108,131	124,663,217
2026	49,433	91,539	110,500,964
2031	39,490	83,117	106,795,489

Annual Emissions Costs ($)

	SO2	*NOx*	*CO2 Low*	*CO2 High*
Base Case				
2021	$ 461,841,363	$ 612,385,884	$ 1,338,454,813	$ 6,271,901,955
2026	$ 409,890,596	$ 586,823,350	$ 1,493,497,803	$ 6,952,680,655
2031	$ 370,268,387	$ 602,496,347	$ 1,796,265,079	$ 8,326,872,228
Preferred Option: Huntley-Wilmarth 345 kV				
2021	$ 461,069,978	$ 611,906,655	$ 1,336,748,224	$ 6,263,905,003
2026	$ 409,417,029	$ 585,982,652	$ 1,488,916,300	$ 6,931,352,381
2031	$ 370,065,967	$ 602,254,418	$ 1,788,839,919	$ 8,292,451,717
Alternative: Huntley-Wilmarth 161 kV				
2021	$ 461,405,022	$ 612,080,109	$ 1,337,636,324	$ 6,268,066,575
2026	$ 409,462,827	$ 586,247,679	$ 1,490,658,004	$ 6,939,460,538
2031	$ 370,083,238	$ 602,259,494	$ 1,790,960,344	$ 8,302,281,285

Total Annual Emissions Costs

	Applying Low CO2	Applying High CO2
Base Case		
2021	$ 2,412,682,060	$ 7,346,129,203
2026	$ 2,490,211,749	$ 7,949,394,601
2031	$ 2,769,029,813	$ 9,299,636,962
Preferred Option: Huntley-Wilmarth 345 kV		
2021	$ 2,409,724,856	$ 7,336,881,636
2026	$ 2,484,315,980	$ 7,926,752,061
2031	$ 2,761,160,304	$ 9,264,772,102
Alternative: Huntley-Wilmarth 161 kV		
2021	$ 2,411,121,455	$ 7,341,551,706
2026	$ 2,486,368,510	$ 7,935,171,044
2031	$ 2,763,303,075	$ 9,274,624,016

Annual Emissions Benefit (short tons) for MISO LRZ's 1,2,3

	SO2	*NOx*	*CO2*
Preferred Option: Huntley-Wilmarth 345 kV			
2021	105	85	159,048
2026	57	131	339,622
2031	22	33	442,764
Alternative: Huntley-Wilmarth 161 kV			
2021	60	54	76,280
2026	52	90	210,511
2031	20	33	316,323

Annual Emissions Cost Benefits ($)

	SO2	*NOx*	*CO2 Low*	*CO2 High*
Preferred Option: Huntley-Wilmarth 345 kV				
2021	$ 771,386	$ 479,229	$ 1,706,589	$ 7,996,952
2026	$ 473,567	$ 840,699	$ 4,581,503	$ 21,328,274
2031	$ 202,420	$ 241,929	$ 7,425,160	$ 34,420,511
Alternative: Huntley-Wilmarth 161 kV				
2021	$ 436,341	$ 305,775	$ 818,489	$ 3,835,380
2026	$ 427,769	$ 575,672	$ 2,839,799	$ 13,220,117
2031	$ 185,149	$ 236,853	$ 5,304,735	$ 24,590,943

Total Annual Emissions Benefits ($)

	Applying Low CO2	Applying High CO2
Preferred Option: Huntley-Wilmarth 345 kV		
2021	$ 2,957,204	$ 9,247,567
2026	$ 5,895,769	$ 22,642,540
2031	$ 7,869,509	$ 34,864,860
Alternative: Huntley-Wilmarth 161 kV		
2021	$ 1,560,606	$ 4,577,497
2026	$ 3,843,239	$ 14,223,557
2031	$ 5,726,738	$ 25,012,946

CO_2 Externality Details

Annual Values (2017-2050) of CO_2 in (2015$ per net short ton)

Year	Low	High
2017	8.44	39.76
2018	8.64	40.66
2019	8.85	41.56
2020	9.05	42.46
2021	9.25	43.36
2022	9.46	44.26
2023	9.66	45.16
2024	9.87	46.06
2025	10.07	46.96
2026	10.28	47.86
2027	10.48	48.77
2028	10.69	49.67
2029	10.89	50.57
2030	11.1	51.47
2031	11.3	52.37
2032	11.51	53.27
2033	11.71	54.17
2034	11.92	55.07
2035	12.12	55.97
2036	12.33	56.87
2037	12.53	57.77
2038	12.74	58.67
2039	12.94	59.58
2040	13.15	60.48
2041	13.35	61.38
2042	13.56	62.28
2043	13.79	63.18
2044	13.97	64.08
2045	14.17	64.98
2046	14.38	65.88
2047	14.58	66.78
2048	14.79	67.68
2049	14.99	68.58
2050	15.2	69.48

Annual Values (2017-2050) of CO_2 in (nominal $ per net short ton)

Year	Low	High
2017	8.87	41.77
2018	9.30	43.79
2019	9.77	45.87
2020	10.24	48.04
2021	**10.73**	**50.28**
2022	11.24	52.61
2023	11.77	55.02
2024	12.33	57.52
2025	12.89	60.11
2026	**13.49**	**62.80**
2027	14.09	65.59
2028	14.74	68.47
2029	15.39	71.45
2030	16.08	74.54
2031	**16.77**	**77.74**
2032	17.51	81.06
2033	18.26	84.49
2034	19.06	88.04
2035	19.86	91.71
2036	20.71	95.52
2037	21.57	99.46
2038	22.48	103.53
2039	23.40	107.76
2040	24.38	112.13
2041	25.37	116.64
2042	26.41	121.31
2043	27.53	126.14
2044	28.59	131.13
2045	29.72	136.30
2046	30.92	141.64
2047	32.13	147.17
2048	33.41	152.88
2049	34.71	158.78
2050	36.07	164.89

Low CO2 Values

Project Description	**Preferred Option: Huntley - Wilmarth 345 kV with Low CO2 Values**	
Base Year	2016	
Expected In Service Date (ISD)	2022	
Base Year Cost ($)	$105,820,000	Purple Route (West Route), Single-Circuit Parallel H-frame

Year	Economic Benefits ($)					Public Policy Benefits ($)		
	PROMOD APC Savings ($) [7]	Transmission Loss Energy Savings ($) [2]	Transmission Loss Capacity Savings ($) [3]	Other Economic Benefits ($) [4]	Total Economic Benefits ($)	PROMOD Emissions Cost Savings ($)	Other PP Benefits ($) [5]	Total Public Policy Benefits ($)
2021	$ 2,542,357				$ 2,542,357	$ 2,957,204		$ 2,957,204
2026	$ 18,109,417				$ 18,109,417	$ 5,895,769		$ 5,895,769
2031	$ 34,146,457				$ 34,146,457	$ 7,869,509		$ 7,869,509

Year [1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($) [6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2017		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	PROMOD Model Year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	Interpolation	$ 122,718,758	$ 15,830,720	$ 10,489,719	$ 5,655,769	$ -	$ 3,544,917	$ 9,200,686	$ 6,096,540	$ 4,393,179	$ 4,393,179	$ 3,747,614	$ 2,348,926
2023	Interpolation	$ -	$ 15,830,720	$ 9,794,322	$ 8,769,181	$ -	$ 4,132,630	$ 12,901,811	$ 7,982,233	$ 1,812,089	$ 6,205,268	$ 5,425,412	$ 2,556,820
2024	Interpolation	$ -	$ 15,830,720	$ 9,145,025	$ 11,882,593	$ -	$ 4,720,343	$ 16,602,936	$ 9,591,116	$ (446,091)	$ 5,759,177	$ 6,864,288	$ 2,726,828
2025	Interpolation	$ -	$ 15,830,720	$ 8,538,772	$ 18,109,417	$ -	$ 5,895,769	$ 24,005,186	$ 12,947,915	$ (4,409,143)	$ 1,350,034	$ 9,767,856	$ 3,180,059
2026	PROMOD Model Year	$ -	$ 15,830,720	$ 7,972,710	$ 18,109,417	$ -	$ 5,895,769	$ 24,005,186	$ 12,089,557	$ (4,116,847)	$ (2,766,813)	$ 9,120,314	$ 2,969,243
2027	Interpolation	$ -	$ 15,830,720	$ 7,444,173	$ 21,316,825	$ -	$ 6,290,517	$ 27,607,342	$ 12,981,965	$ (5,537,791)	$ (8,304,604)	$ 10,023,937	$ 2,958,027
2028	Interpolation	$ -	$ 15,830,720	$ 6,950,675	$ 24,524,233	$ -	$ 6,685,265	$ 31,209,498	$ 13,702,920	$ (6,752,245)	$ (15,056,849)	$ 10,767,671	$ 2,935,249
2029	Interpolation	$ -	$ 15,830,720	$ 6,489,893	$ 27,731,641	$ -	$ 7,080,013	$ 34,811,654	$ 14,271,234	$ (7,781,341)	$ (22,838,190)	$ 11,368,743	$ 2,902,491
2030	Interpolation	$ -	$ 15,830,720	$ 6,059,657	$ 34,146,457	$ -	$ 7,869,509	$ 42,015,966	$ 16,082,804	$ (10,023,146)	$ (32,861,337)	$ 13,070,526	$ 3,012,278
2031	PROMOD Model Year	$ -	$ 15,830,720	$ 5,657,943	$ 34,068,127	$ -	$ 8,030,313	$ 42,098,440	$ 15,046,100	$ (9,388,157)	$ (42,249,493)	$ 12,176,044	$ 2,870,056
2032	Extrapolation	$ -	$ 15,830,720	$ 5,282,860	$ 37,228,537	$ -	$ 8,521,544	$ 45,750,081	$ 15,267,233	$ (9,984,373)	$ (52,233,866)	$ 12,423,513	$ 2,843,719
2033	Extrapolation	$ -	$ 15,830,720	$ 4,932,643	$ 40,388,947	$ -	$ 9,012,774	$ 49,401,721	$ 15,392,922	$ (10,460,280)	$ (62,694,146)	$ 12,584,661	$ 2,808,261
2034	Extrapolation	$ -	$ 15,830,720	$ 4,605,642	$ 43,549,357	$ -	$ 9,504,005	$ 53,053,362	$ 15,434,851	$ (10,829,209)	$ (73,523,354)	$ 12,669,844	$ 2,765,007
2035	Extrapolation	$ -	$ 15,830,720	$ 4,300,319	$ 46,709,767	$ -	$ 9,995,235	$ 56,705,002	$ 15,403,571	$ (11,103,252)	$ (84,626,606)	$ 12,688,426	$ 2,715,145
2036	Extrapolation	$ -	$ 15,830,720	$ 4,015,238	$ 49,870,177	$ -	$ 10,486,466	$ 60,356,643	$ 15,308,606	$ (11,293,369)	$ (95,919,975)	$ 12,648,863	$ 2,659,743
2037	Extrapolation	$ -	$ 15,830,720	$ 3,749,055	$ 53,030,587	$ -	$ 10,977,696	$ 64,008,283	$ 15,158,537	$ (11,409,482)	$ (107,329,457)	$ 12,558,783	$ 2,599,754
2038	Extrapolation	$ -	$ 15,830,720	$ 3,500,518	$ 56,190,996	$ -	$ 11,468,927	$ 67,659,923	$ 14,961,087	$ (11,460,569)	$ (118,790,026)	$ 12,425,057	$ 2,536,030
2039	Extrapolation	$ -	$ 15,830,720	$ 3,268,457	$ 59,351,406	$ -	$ 11,960,158	$ 71,311,564	$ 14,723,197	$ (11,454,740)	$ (130,244,766)	$ 12,253,868	$ 2,469,330
2040	Extrapolation	$ -	$ 15,830,720	$ 3,051,781	$ 62,511,816	$ -	$ 12,451,388	$ 74,963,204	$ 14,451,098	$ (11,399,317)	$ (141,644,083)	$ 12,050,771	$ 2,400,327
2041	Extrapolation	$ -	$ 15,830,720	$ 2,849,469	$ 65,672,226	$ -	$ 12,942,619	$ 78,614,845	$ 14,150,370	$ (11,300,901)	$ (152,944,984)	$ 11,820,748	$ 2,329,622
2042	Extrapolation	$ -	$ 15,830,720	$ 2,660,568	$ 68,832,636	$ -	$ 13,433,849	$ 82,266,485	$ 13,826,005	$ (11,165,436)	$ (164,110,421)	$ 11,568,263	$ 2,257,742
2043	Extrapolation	$ -	$ 15,830,720	$ 2,484,191	$ 71,993,046	$ -	$ 13,925,080	$ 85,918,126	$ 13,482,458	$ (10,998,267)	$ (175,108,688)	$ 11,297,305	$ 2,185,154
2044	Extrapolation	$ -	$ 15,830,720	$ 2,319,506	$ 75,153,456	$ -	$ 14,416,310	$ 89,569,766	$ 13,123,699	$ (10,804,193)	$ (185,912,881)	$ 11,011,431	$ 2,112,268
2045	Extrapolation	$ -	$ 15,830,720	$ 2,165,738	$ 78,313,866	$ -	$ 14,907,541	$ 93,221,407	$ 12,753,254	$ (10,587,515)	$ (196,500,396)	$ 10,713,812	$ 2,039,442
2046	Extrapolation	$ -	$ 15,830,720	$ 2,022,165	$ 81,474,276	$ -	$ 15,398,771	$ 96,873,047	$ 12,374,249	$ (10,352,084)	$ (206,852,480)	$ 10,407,260	$ 1,966,989
2047	Extrapolation	$ -	$ 15,830,720	$ 1,888,109	$ 84,634,686	$ -	$ 15,890,002	$ 100,524,688	$ 11,989,447	$ (10,101,338)	$ (216,953,818)	$ 10,094,267	$ 1,895,179
2048	Extrapolation	$ -	$ 15,830,720	$ 1,762,940	$ 87,795,096	$ -	$ 16,381,232	$ 104,176,328	$ 11,601,282	$ (9,838,342)	$ (226,792,159)	$ 9,777,035	$ 1,824,246
2049	Extrapolation	$ -	$ 15,830,720	$ 1,646,069	$ 90,955,506	$ -	$ 16,872,463	$ 107,827,969	$ 11,211,891	$ (9,565,822)	$ (236,357,982)	$ 9,457,502	$ 1,754,389
2050	Extrapolation	$ -	$ 15,830,720	$ 1,536,946	$ 94,115,916	$ -	$ 17,363,693	$ 111,479,609	$ 10,823,144	$ (9,286,198)	$ (245,644,179)	$ 9,137,367	$ 1,685,777
2051	Extrapolation	$ -	$ 15,830,720	$ 1,435,057	$ 97,276,326	$ -	$ 17,854,924	$ 115,131,250	$ 10,436,665	$ (9,001,608)	$ (254,645,787)	$ 8,818,113	$ 1,618,551
2052	Extrapolation	$ -	$ 15,830,720	$ 1,339,923	$ 100,436,736	$ -	$ 18,346,154	$ 118,782,890	$ 10,053,862	$ (8,713,940)	$ (263,359,727)	$ 8,501,032	$ 1,552,831
2053	Extrapolation	$ -	$ 15,830,720	$ 1,251,095	$ 103,597,146	$ -	$ 18,837,385	$ 122,434,531	$ 9,675,947	$ (8,424,853)	$ (271,784,579)	$ 8,187,237	$ 1,488,710
2054	Extrapolation	$ -	$ 15,830,720	$ 1,168,156	$ 106,757,556	$ -	$ 19,328,615	$ 126,086,171	$ 9,303,954	$ (8,135,798)	$ (279,920,378)	$ 7,877,687	$ 1,426,267
2055	Extrapolation	$ -	$ 15,830,720	$ 1,090,715	$ 109,917,966	$ -	$ 19,819,846	$ 129,737,811	$ 8,938,759	$ (7,848,043)	$ (287,768,421)	$ 7,573,198	$ 1,365,560
2056	Extrapolation	$ -	$ 15,830,720	$ 1,018,408	$ 113,078,376	$ -	$ 20,311,076	$ 133,389,452	$ 8,581,094	$ (7,562,686)	$ (295,331,107)	$ 7,274,459	$ 1,306,634
2057	Extrapolation	$ -	$ 15,830,720	$ 950,895	$ 116,238,785	$ -	$ 20,802,307	$ 137,041,092	$ 8,231,567	$ (7,280,672)	$ (302,611,779)	$ 6,982,047	$ 1,249,520
2058	Extrapolation	$ -	$ 15,830,720	$ 887,857	$ 119,399,195	$ -	$ 21,293,537	$ 140,692,733	$ 7,890,670	$ (7,002,813)	$ (309,614,593)	$ 6,696,435	$ 1,194,236
2059	Extrapolation	$ -	$ 15,830,720	$ 828,998	$ 122,559,605	$ -	$ 21,784,768	$ 144,344,373	$ 7,558,796	$ (6,729,798)	$ (316,344,391)	$ 6,418,006	$ 1,140,790

Year [1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($) [6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2060	Extrapolation	$ -	$ 15,830,720	$ 774,041	$ 125,720,015	$ -	$ 22,275,999	$ 147,996,014	$ 7,236,246	$ (6,462,205)	$ (322,806,596)	$ 6,147,064	$ 1,089,182
2061	Extrapolation	$ -	$ 15,830,720	$ 722,727	$ 128,880,425	$ -	$ 22,767,229	$ 151,647,654	$ 6,923,242	$ (6,200,515)	$ (329,007,110)	$ 5,883,839	$ 1,039,403
2062	Extrapolation	$ -	$ 15,830,720	$ 674,815	$ 132,040,835	$ -	$ 23,258,460	$ 155,299,295	$ 6,619,937	$ (5,945,121)	$ (334,952,231)	$ 5,628,499	$ 991,437
2063	Extrapolation	$ -	$ 15,830,720	$ 630,080	$ 135,201,245	$ -	$ 23,749,690	$ 158,950,935	$ 6,326,419	$ (5,696,339)	$ (340,648,571)	$ 5,381,156	$ 945,263
2064	Extrapolation	$ -	$ 15,830,720	$ 588,310	$ 138,361,655	$ -	$ 24,240,921	$ 162,602,576	$ 6,042,725	$ (5,454,415)	$ (346,102,986)	$ 5,141,871	$ 900,854
2065	Extrapolation	$ -	$ 15,830,720	$ 549,309	$ 141,522,065	$ -	$ 24,732,151	$ 166,254,216	$ 5,768,841	$ (5,219,533)	$ (351,322,518)	$ 4,910,662	$ 858,179
2066	Extrapolation	$ -	$ 15,830,720	$ 512,893	$ 144,682,475	$ -	$ 25,223,382	$ 169,905,857	$ 5,504,715	$ (4,991,821)	$ (356,314,339)	$ 4,687,512	$ 817,203
2067	Extrapolation	$ -	$ 15,830,720	$ 478,892	$ 147,842,885	$ -	$ 25,714,612	$ 173,557,497	$ 5,250,255	$ (4,771,363)	$ (361,085,702)	$ 4,472,367	$ 777,888
2068	Extrapolation	$ -	$ 15,830,720	$ 447,145	$ 151,003,295	$ -	$ 26,205,843	$ 177,209,138	$ 5,005,341	$ (4,558,196)	$ (365,643,898)	$ 4,265,146	$ 740,194
2069	Extrapolation	$ -	$ 15,830,720	$ 417,502	$ 154,163,705	$ -	$ 26,697,073	$ 180,860,778	$ 4,769,825	$ (4,352,323)	$ (369,996,221)	$ 4,065,745	$ 704,079
2070	Extrapolation	$ -	$ 15,830,720	$ 389,825	$ 157,324,115	$ -	$ 27,188,304	$ 184,512,418	$ 4,543,538	$ (4,153,714)	$ (374,149,934)	$ 3,874,038	$ 669,500
2071	Extrapolation	$ -	$ 15,830,720	$ 363,982	$ 160,484,525	$ -	$ 27,679,534	$ 188,164,059	$ 4,326,291	$ (3,962,310)	$ (378,112,244)	$ 3,689,880	$ 636,411
2072	Extrapolation	$ -	$ 15,830,720	$ 339,852	$ 163,644,935	$ -	$ 28,170,765	$ 191,815,699	$ 4,117,881	$ (3,778,029)	$ (381,890,272)	$ 3,513,114	$ 604,767
2073	Extrapolation	$ -	$ 15,830,720	$ 317,322	$ 166,805,345	$ -	$ 28,661,995	$ 195,467,340	$ 3,918,090	$ (3,600,767)	$ (385,491,039)	$ 3,343,568	$ 574,522
2074	Extrapolation	$ -	$ 15,830,720	$ 296,286	$ 169,965,755	$ -	$ 29,153,226	$ 199,118,980	$ 3,726,691	$ (3,430,405)	$ (388,921,444)	$ 3,181,062	$ 545,629
2075	Extrapolation	$ -	$ 15,830,720	$ 276,644	$ 173,126,164	$ -	$ 29,644,456	$ 202,770,621	$ 3,543,450	$ (3,266,805)	$ (392,188,249)	$ 3,025,408	$ 518,042
2076	Extrapolation	$ -	$ 15,830,720	$ 258,305	$ 176,286,574	$ -	$ 30,135,687	$ 206,422,261	$ 3,368,126	$ (3,109,821)	$ (395,298,070)	$ 2,876,411	$ 491,714
2077	Extrapolation	$ -	$ 15,830,720	$ 241,181	$ 179,446,984	$ -	$ 30,626,917	$ 210,073,902	$ 3,200,475	$ (2,959,294)	$ (398,257,364)	$ 2,733,874	$ 466,601
2078	Extrapolation	$ -	$ 15,830,720	$ 225,192	$ 182,607,394	$ -	$ 31,118,148	$ 213,725,542	$ 3,040,250	$ (2,815,057)	$ (401,072,421)	$ 2,597,593	$ 442,656
2079	Extrapolation	$ -	$ 15,830,720	$ 210,264	$ 185,767,804	$ -	$ 31,609,378	$ 217,377,183	$ 2,887,203	$ (2,676,939)	$ (403,749,360)	$ 2,467,367	$ 419,836
2080	Extrapolation	$ -	$ 15,830,720	$ 196,325	$ 188,928,214	$ -	$ 32,100,609	$ 221,028,823	$ 2,741,087	$ (2,544,762)	$ (406,294,122)	$ 2,342,991	$ 398,095
2081	Extrapolation	$ -	$ 15,830,720	$ 183,310	$ 192,088,624	$ -	$ 32,591,839	$ 224,680,464	$ 2,601,655	$ (2,418,345)	$ (408,712,468)	$ 2,224,263	$ 377,393
2082	Extrapolation	$ -	$ 15,830,720	$ 171,157	$ 195,249,034	$ -	$ 33,083,070	$ 228,332,104	$ 2,468,664	$ (2,297,506)	$ (411,009,974)	$ 2,110,979	$ 357,685
2083	Extrapolation	$ -	$ 15,830,720	$ 159,811	$ 198,409,444	$ -	$ 33,574,301	$ 231,983,745	$ 2,341,871	$ (2,182,060)	$ (413,192,034)	$ 2,002,939	$ 338,932
2084	Extrapolation	$ -	$ 15,830,720	$ 149,216	$ 201,569,854	$ -	$ 34,065,531	$ 235,635,385	$ 2,221,041	$ (2,071,824)	$ (415,263,859)	$ 1,899,947	$ 321,093
				156,130,593								$ 470,716,689	$ 100,677,763

[1] Assumed 63 year life for transmission line.

[2] From PROMOD or other Production Cost modeling software.

[3] From PSS/E or other Powerflow modeling software.

[4] Other Economic benefits may include avoided Economic Project Costs, Congestion/Load Cost Savings, Mitigation of Transmission Outage Costs etc.

[5] Other Public Policy Benefits may include Avoided Public Policy project benefits, Renewable Investment Benefit, production cost savings by untrapping renewable generation etc.

[6] Reliability benefits based upon Avoided Reliability Project Costs in a future year

[7] MISO's MTEP17 futures apply carbon fees in the base cases to achieve emission reduction target assumptions, this reported APC is modified to eliminate the value of reduced emissions

Low CO2 Values

Project Description	Preferred Option: Huntley - Wilmarth 345 kV with Low CO2 Values
Base Year	2016
Expected In Service Date (ISD)	2022
Base Year Cost ($)	$121,320,000 Green Route (Middle Route), Single Circuit Parallel Monopole

Year	Economic Benefits ($)					Public Policy Benefits ($)		
	PROMOD APC Savings ($) [7]	Transmission Loss Energy Savings ($) [2]	Transmission Loss Capacity Savings ($) [3]	Other Economic Benefits ($) [4]	Total Economic Benefits ($)	PROMOD Emissions Cost Savings ($)	Other PP Benefits ($) [5]	Total Public Policy Benefits ($)
2021	$ 2,542,357				$ 2,542,357	$ 2,957,204		$ 2,957,204
2026	$ 18,109,417				$ 18,109,417	$ 5,895,769		$ 5,895,769
2031	$ 34,146,457				$ 34,146,457	$ 7,869,509		$ 7,869,509

Year [1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($) [6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2017		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	PROMOD Model Year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	Interpolation	$ 140,694,005	$ 18,149,527	$ 12,026,202	$ 5,655,769	$ -	$ 3,544,917	$ 9,200,686	$ 6,096,540	$ 5,929,662	$ 5,929,662	$ 3,747,614	$ 2,348,926
2023	Interpolation	$ -	$ 18,149,527	$ 11,228,946	$ 8,769,181	$ -	$ 4,132,630	$ 12,901,811	$ 7,982,233	$ 3,246,714	$ 9,176,376	$ 5,425,412	$ 2,556,820
2024	Interpolation	$ -	$ 18,149,527	$ 10,484,544	$ 11,882,593	$ -	$ 4,720,343	$ 16,602,936	$ 9,591,116	$ 893,428	$ 10,069,804	$ 6,864,288	$ 2,726,828
2025	Interpolation	$ -	$ 18,149,527	$ 9,789,490	$ 18,109,417	$ -	$ 5,895,769	$ 24,005,186	$ 12,947,915	$ (3,158,425)	$ 6,911,378	$ 9,767,856	$ 3,180,059
2026	PROMOD Model Year	$ -	$ 18,149,527	$ 9,140,514	$ 18,109,417	$ -	$ 5,895,769	$ 24,005,186	$ 12,089,557	$ (2,949,043)	$ 3,962,335	$ 9,120,314	$ 2,969,243
2027	Interpolation	$ -	$ 18,149,527	$ 8,534,560	$ 21,316,825	$ -	$ 6,290,517	$ 27,607,342	$ 12,981,965	$ (4,447,405)	$ (485,069)	$ 10,023,937	$ 2,958,027
2028	Interpolation	$ -	$ 18,149,527	$ 7,968,777	$ 24,524,233	$ -	$ 6,685,265	$ 31,209,498	$ 13,702,920	$ (5,734,144)	$ (6,219,213)	$ 10,767,671	$ 2,935,249
2029	Interpolation	$ -	$ 18,149,527	$ 7,440,501	$ 27,731,641	$ -	$ 7,080,013	$ 34,811,654	$ 14,271,234	$ (6,830,733)	$ (13,049,946)	$ 11,368,743	$ 2,902,491
2030	Interpolation	$ -	$ 18,149,527	$ 6,947,247	$ 34,146,457	$ -	$ 7,869,509	$ 42,015,966	$ 16,082,804	$ (9,135,557)	$ (22,185,504)	$ 13,070,526	$ 3,012,278
2031	PROMOD Model Year	$ -	$ 18,149,527	$ 6,486,691	$ 34,068,127	$ -	$ 8,030,313	$ 42,098,440	$ 15,046,100	$ (8,559,408)	$ (30,744,912)	$ 12,176,044	$ 2,870,056
2032	Extrapolation	$ -	$ 18,149,527	$ 6,056,668	$ 37,228,537	$ -	$ 8,521,544	$ 45,750,081	$ 15,267,233	$ (9,210,565)	$ (39,955,477)	$ 12,423,513	$ 2,843,719
2033	Extrapolation	$ -	$ 18,149,527	$ 5,655,152	$ 40,388,947	$ -	$ 9,012,774	$ 49,401,721	$ 15,392,922	$ (9,737,770)	$ (49,693,247)	$ 12,584,661	$ 2,808,261
2034	Extrapolation	$ -	$ 18,149,527	$ 5,280,254	$ 43,549,357	$ -	$ 9,504,005	$ 53,053,362	$ 15,434,851	$ (10,154,596)	$ (59,847,843)	$ 12,669,844	$ 2,765,007
2035	Extrapolation	$ -	$ 18,149,527	$ 4,930,209	$ 46,709,767	$ -	$ 9,995,235	$ 56,705,002	$ 15,403,571	$ (10,473,362)	$ (70,321,206)	$ 12,688,426	$ 2,715,145
2036	Extrapolation	$ -	$ 18,149,527	$ 4,603,370	$ 49,870,177	$ -	$ 10,486,466	$ 60,356,643	$ 15,308,606	$ (10,705,236)	$ (81,026,442)	$ 12,648,863	$ 2,659,743
2037	Extrapolation	$ -	$ 18,149,527	$ 4,298,198	$ 53,030,587	$ -	$ 10,977,696	$ 64,008,283	$ 15,158,537	$ (10,860,339)	$ (91,886,781)	$ 12,558,783	$ 2,599,754
2038	Extrapolation	$ -	$ 18,149,527	$ 4,013,257	$ 56,190,996	$ -	$ 11,468,927	$ 67,659,923	$ 14,961,087	$ (10,947,830)	$ (102,834,611)	$ 12,425,057	$ 2,536,030
2039	Extrapolation	$ -	$ 18,149,527	$ 3,747,205	$ 59,351,406	$ -	$ 11,960,158	$ 71,311,564	$ 14,723,197	$ (10,975,992)	$ (113,810,603)	$ 12,253,868	$ 2,469,330
2040	Extrapolation	$ -	$ 18,149,527	$ 3,498,791	$ 62,511,816	$ -	$ 12,451,388	$ 74,963,204	$ 14,451,098	$ (10,952,307)	$ (124,762,910)	$ 12,050,771	$ 2,400,327
2041	Extrapolation	$ -	$ 18,149,527	$ 3,266,845	$ 65,672,226	$ -	$ 12,942,619	$ 78,614,845	$ 14,150,370	$ (10,883,525)	$ (135,646,435)	$ 11,820,748	$ 2,329,622
2042	Extrapolation	$ -	$ 18,149,527	$ 3,050,275	$ 68,832,636	$ -	$ 13,433,849	$ 82,266,485	$ 13,826,005	$ (10,775,729)	$ (146,422,164)	$ 11,568,263	$ 2,257,742
2043	Extrapolation	$ -	$ 18,149,527	$ 2,848,063	$ 71,993,046	$ -	$ 13,925,080	$ 85,918,126	$ 13,482,458	$ (10,634,395)	$ (157,056,559)	$ 11,297,305	$ 2,185,154
2044	Extrapolation	$ -	$ 18,149,527	$ 2,659,256	$ 75,153,456	$ -	$ 14,416,310	$ 89,569,766	$ 13,123,699	$ (10,464,443)	$ (167,521,002)	$ 11,011,431	$ 2,112,268
2045	Extrapolation	$ -	$ 18,149,527	$ 2,482,965	$ 78,313,866	$ -	$ 14,907,541	$ 93,221,407	$ 12,753,254	$ (10,270,288)	$ (177,791,291)	$ 10,713,812	$ 2,039,442
2046	Extrapolation	$ -	$ 18,149,527	$ 2,318,362	$ 81,474,276	$ -	$ 15,398,771	$ 96,873,047	$ 12,374,249	$ (10,055,887)	$ (187,847,178)	$ 10,407,260	$ 1,966,989
2047	Extrapolation	$ -	$ 18,149,527	$ 2,164,670	$ 84,634,686	$ -	$ 15,890,002	$ 100,524,688	$ 11,989,447	$ (9,824,777)	$ (197,671,954)	$ 10,094,267	$ 1,895,179
2048	Extrapolation	$ -	$ 18,149,527	$ 2,021,167	$ 87,795,096	$ -	$ 16,381,232	$ 104,176,328	$ 11,601,282	$ (9,580,115)	$ (207,252,069)	$ 9,777,035	$ 1,824,246
2049	Extrapolation	$ -	$ 18,149,527	$ 1,887,178	$ 90,955,506	$ -	$ 16,872,463	$ 107,827,969	$ 11,211,891	$ (9,324,714)	$ (216,576,783)	$ 9,457,502	$ 1,754,389
2050	Extrapolation	$ -	$ 18,149,527	$ 1,762,071	$ 94,115,916	$ -	$ 17,363,693	$ 111,479,609	$ 10,823,144	$ (9,061,073)	$ (225,637,856)	$ 9,137,367	$ 1,685,777
2051	Extrapolation	$ -	$ 18,149,527	$ 1,645,257	$ 97,276,326	$ -	$ 17,854,924	$ 115,131,250	$ 10,436,665	$ (8,791,408)	$ (234,429,264)	$ 8,818,113	$ 1,618,551
2052	Extrapolation	$ -	$ 18,149,527	$ 1,536,188	$ 100,436,736	$ -	$ 18,346,154	$ 118,782,890	$ 10,053,862	$ (8,517,674)	$ (242,946,938)	$ 8,501,032	$ 1,552,831
2053	Extrapolation	$ -	$ 18,149,527	$ 1,434,349	$ 103,597,146	$ -	$ 18,837,385	$ 122,434,531	$ 9,675,947	$ (8,241,598)	$ (251,188,536)	$ 8,187,237	$ 1,488,710
2054	Extrapolation	$ -	$ 18,149,527	$ 1,339,262	$ 106,757,556	$ -	$ 19,328,615	$ 126,086,171	$ 9,303,954	$ (7,964,693)	$ (259,153,229)	$ 7,877,687	$ 1,426,267
2055	Extrapolation	$ -	$ 18,149,527	$ 1,250,478	$ 109,917,966	$ -	$ 19,819,846	$ 129,737,811	$ 8,938,759	$ (7,688,281)	$ (266,841,510)	$ 7,573,198	$ 1,365,560
2056	Extrapolation	$ -	$ 18,149,527	$ 1,167,580	$ 113,078,376	$ -	$ 20,311,076	$ 133,389,452	$ 8,581,094	$ (7,413,514)	$ (274,255,024)	$ 7,274,459	$ 1,306,634
2057	Extrapolation	$ -	$ 18,149,527	$ 1,090,177	$ 116,238,785	$ -	$ 20,802,307	$ 137,041,092	$ 8,231,567	$ (7,141,390)	$ (281,396,414)	$ 6,982,047	$ 1,249,520
2058	Extrapolation	$ -	$ 18,149,527	$ 1,017,906	$ 119,399,195	$ -	$ 21,293,537	$ 140,692,733	$ 7,890,670	$ (6,872,765)	$ (288,269,179)	$ 6,696,435	$ 1,194,236

Year [1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($) [6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2059	Extrapolation	$ -	$ 18,149,527	$ 950,425	$ 122,559,605	$ -	$ 21,784,768	$ 144,344,373	$ 7,558,796	$ (6,608,370)	$ (294,877,549)	$ 6,418,006	$ 1,140,790
2060	Extrapolation	$ -	$ 18,149,527	$ 887,419	$ 125,720,015	$ -	$ 22,275,999	$ 147,996,014	$ 7,236,246	$ (6,348,827)	$ (301,226,376)	$ 6,147,064	$ 1,089,182
2061	Extrapolation	$ -	$ 18,149,527	$ 828,589	$ 128,880,425	$ -	$ 22,767,229	$ 151,647,654	$ 6,923,242	$ (6,094,653)	$ (307,321,029)	$ 5,883,839	$ 1,039,403
2062	Extrapolation	$ -	$ 18,149,527	$ 773,659	$ 132,040,835	$ -	$ 23,258,460	$ 155,299,295	$ 6,619,937	$ (5,846,277)	$ (313,167,306)	$ 5,628,499	$ 991,437
2063	Extrapolation	$ -	$ 18,149,527	$ 722,371	$ 135,201,245	$ -	$ 23,749,690	$ 158,950,935	$ 6,326,419	$ (5,604,048)	$ (318,771,355)	$ 5,381,156	$ 945,263
2064	Extrapolation	$ -	$ 18,149,527	$ 674,483	$ 138,361,655	$ -	$ 24,240,921	$ 162,602,576	$ 6,042,725	$ (5,368,242)	$ (324,139,597)	$ 5,141,871	$ 900,854
2065	Extrapolation	$ -	$ 18,149,527	$ 629,769	$ 141,522,065	$ -	$ 24,732,151	$ 166,254,216	$ 5,768,841	$ (5,139,072)	$ (329,278,669)	$ 4,910,662	$ 858,179
2066	Extrapolation	$ -	$ 18,149,527	$ 588,020	$ 144,682,475	$ -	$ 25,223,382	$ 169,905,857	$ 5,504,715	$ (4,916,695)	$ (334,195,365)	$ 4,687,512	$ 817,203
2067	Extrapolation	$ -	$ 18,149,527	$ 549,038	$ 147,842,885	$ -	$ 25,714,612	$ 173,557,497	$ 5,250,255	$ (4,701,217)	$ (338,896,581)	$ 4,472,367	$ 777,888
2068	Extrapolation	$ -	$ 18,149,527	$ 512,640	$ 151,003,295	$ -	$ 26,205,843	$ 177,209,138	$ 5,005,341	$ (4,492,700)	$ (343,389,281)	$ 4,265,146	$ 740,194
2069	Extrapolation	$ -	$ 18,149,527	$ 478,656	$ 154,163,705	$ -	$ 26,697,073	$ 180,860,778	$ 4,769,825	$ (4,291,169)	$ (347,680,451)	$ 4,065,745	$ 704,079
2070	Extrapolation	$ -	$ 18,149,527	$ 446,924	$ 157,324,115	$ -	$ 27,188,304	$ 184,512,418	$ 4,543,538	$ (4,096,614)	$ (351,777,064)	$ 3,874,038	$ 669,500
2071	Extrapolation	$ -	$ 18,149,527	$ 417,296	$ 160,484,525	$ -	$ 27,679,534	$ 188,164,059	$ 4,326,291	$ (3,908,995)	$ (355,686,060)	$ 3,689,880	$ 636,411
2072	Extrapolation	$ 1	$ 18,149,527	$ 389,632	$ 163,644,935	$ 1	$ 28,170,765	$ 191,815,700	$ 4,117,881	$ (3,728,249)	$ (359,414,308)	$ 3,513,114	$ 604,767
2073	Extrapolation	$ 2	$ 18,149,527	$ 363,802	$ 166,805,345	$ 2	$ 28,661,995	$ 195,467,342	$ 3,918,090	$ (3,554,287)	$ (362,968,596)	$ 3,343,568	$ 574,522
2074	Extrapolation	$ 3	$ 18,149,527	$ 339,685	$ 169,965,755	$ 3	$ 29,153,226	$ 199,118,983	$ 3,726,691	$ (3,387,006)	$ (366,355,602)	$ 3,181,062	$ 545,629
2075	Extrapolation	$ 4	$ 18,149,527	$ 317,166	$ 173,126,164	$ 4	$ 29,644,456	$ 202,770,625	$ 3,543,450	$ (3,226,284)	$ (369,581,886)	$ 3,025,408	$ 518,042
2076	Extrapolation	$ 5	$ 18,149,527	$ 296,140	$ 176,286,574	$ 5	$ 30,135,687	$ 206,422,266	$ 3,368,126	$ (3,071,986)	$ (372,653,871)	$ 2,876,411	$ 491,714
2077	Extrapolation	$ 6	$ 18,149,527	$ 276,508	$ 179,446,984	$ 6	$ 30,626,917	$ 210,073,908	$ 3,200,475	$ (2,923,967)	$ (375,577,838)	$ 2,733,874	$ 466,601
2078	Extrapolation	$ 7	$ 18,149,527	$ 258,177	$ 182,607,394	$ 7	$ 31,118,148	$ 213,725,549	$ 3,040,250	$ (2,782,072)	$ (378,359,910)	$ 2,597,593	$ 442,656
2079	Extrapolation	$ 8	$ 18,149,527	$ 241,062	$ 185,767,804	$ 8	$ 31,609,378	$ 217,377,191	$ 2,887,203	$ (2,646,141)	$ (381,006,051)	$ 2,467,367	$ 419,836
2080	Extrapolation	$ 9	$ 18,149,527	$ 225,081	$ 188,928,214	$ 9	$ 32,100,609	$ 221,028,832	$ 2,741,087	$ (2,516,006)	$ (383,522,057)	$ 2,342,991	$ 398,095
2081	Extrapolation	$ 10	$ 18,149,527	$ 210,160	$ 192,088,624	$ 10	$ 32,591,839	$ 224,680,474	$ 2,601,655	$ (2,391,495)	$ (385,913,552)	$ 2,224,263	$ 377,393
2082	Extrapolation	$ 11	$ 18,149,527	$ 196,228	$ 195,249,034	$ 11	$ 33,083,070	$ 228,332,115	$ 2,468,664	$ (2,272,436)	$ (388,185,988)	$ 2,110,979	$ 357,685
2083	Extrapolation	$ 12	$ 18,149,527	$ 183,219	$ 198,409,444	$ 12	$ 33,574,301	$ 231,983,757	$ 2,341,871	$ (2,158,652)	$ (390,344,641)	$ 2,002,939	$ 338,932
2084	Extrapolation	$ 13	$ 18,149,527	$ 171,073	$ 201,569,854	$ 13	$ 34,065,531	$ 235,635,398	$ 2,221,041	$ (2,049,968)	$ (392,394,608)	$ 1,899,947	$ 321,093
				178,999,845								$ 470,716,689	$ 100,677,763

[1] Assumed 63 year life for transmission line.

[2] From PROMOD or other Production Cost modeling software.

[3] From PSS/E or other Powerflow modeling software.

[4] Other Economic benefits may include avoided Economic Project Costs, Congestion/Load Cost Savings, Mitigation of Transmission Outage Costs etc.

[5] Other Public Policy Benefits may include Avoided Public Policy project benefits, Renewable Investment Benefit, production cost savings by untrapping renewable generation etc.

[6] Reliability benefits based upon Avoided Reliability Project Costs in a future year

[7] MISO's MTEP17 futures apply carbon fees in the base cases to achieve emission reduction target assumptions, this reported APC is modified to eliminate the value of reduced emissions

Low CO2 Values

Project Description	Preferred Option: Huntley - Wilmarth 345 kV with Low CO2 Values	
Base Year	2016	
Expected In Service Date (ISD)	2022	
Base Year Cost ($)	$138,020,000	Blue Route (East Route), Double-Circuit Monopole and Single Circuit Monopole

Year	Economic Benefits ($)					Public Policy Benefits ($)		
	PROMOD APC Savings ($) [7]	Transmission Loss Energy Savings ($) [2]	Transmission Loss Capacity Savings ($) [3]	Other Economic Benefits ($) [4]	Total Economic Benefits ($)	PROMOD Emissions Cost Savings ($)	Other PP Benefits ($) [5]	Total Public Policy Benefits ($)
2021	$ 2,542,357				$ 2,542,357	$ 2,957,204		$ 2,957,204
2026	$ 18,109,417				$ 18,109,417	$ 5,895,769		$ 5,895,769
2031	$ 34,146,457				$ 34,146,457	$ 7,869,509		$ 7,869,509

Year [1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($) [6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2017		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	PROMOD Model Year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	Interpolation	$ 160,060,886	$ 20,647,854	$ 13,681,638	$ 5,655,769	$ -	$ 3,544,917	$ 9,200,686	$ 6,096,540	$ 7,585,099	$ 7,585,099	$ 3,747,614	$ 2,348,926
2023	Interpolation	$ -	$ 20,647,854	$ 12,774,639	$ 8,769,181	$ -	$ 4,132,630	$ 12,901,811	$ 7,982,233	$ 4,792,406	$ 12,377,505	$ 5,425,412	$ 2,556,820
2024	Interpolation	$ -	$ 20,647,854	$ 11,927,767	$ 11,882,593	$ -	$ 4,720,343	$ 16,602,936	$ 9,591,116	$ 2,336,652	$ 14,714,156	$ 6,864,288	$ 2,726,828
2025	Interpolation	$ -	$ 20,647,854	$ 11,137,038	$ 18,109,417	$ -	$ 5,895,769	$ 24,005,186	$ 12,947,915	$ (1,810,877)	$ 12,903,279	$ 9,767,856	$ 3,180,059
2026	PROMOD Model Year	$ -	$ 20,647,854	$ 10,398,728	$ 18,109,417	$ -	$ 5,895,769	$ 24,005,186	$ 12,089,557	$ (1,690,829)	$ 11,212,450	$ 9,120,314	$ 2,969,243
2027	Interpolation	$ -	$ 20,647,854	$ 9,709,363	$ 21,316,825	$ -	$ 6,290,517	$ 27,607,342	$ 12,981,965	$ (3,272,601)	$ 7,939,849	$ 10,023,937	$ 2,958,027
2028	Interpolation	$ -	$ 20,647,854	$ 9,065,699	$ 24,524,233	$ -	$ 6,685,265	$ 31,209,498	$ 13,702,920	$ (4,637,222)	$ 3,302,627	$ 10,767,671	$ 2,935,249
2029	Interpolation	$ -	$ 20,647,854	$ 8,464,705	$ 27,731,641	$ -	$ 7,080,013	$ 34,811,654	$ 14,271,234	$ (5,806,530)	$ (2,503,903)	$ 11,368,743	$ 2,902,491
2030	Interpolation	$ -	$ 20,647,854	$ 7,903,552	$ 34,146,457	$ -	$ 7,869,509	$ 42,015,966	$ 16,082,804	$ (8,179,251)	$ (10,683,154)	$ 13,070,526	$ 3,012,278
2031	PROMOD Model Year	$ -	$ 20,647,854	$ 7,379,601	$ 34,068,127	$ -	$ 8,030,313	$ 42,098,440	$ 15,046,100	$ (7,666,499)	$ (18,349,654)	$ 12,176,044	$ 2,870,056
2032	Extrapolation	$ -	$ 20,647,854	$ 6,890,383	$ 37,228,537	$ -	$ 8,521,544	$ 45,750,081	$ 15,267,233	$ (8,376,849)	$ (26,726,503)	$ 12,423,513	$ 2,843,719
2033	Extrapolation	$ -	$ 20,647,854	$ 6,433,598	$ 40,388,947	$ -	$ 9,012,774	$ 49,401,721	$ 15,392,922	$ (8,959,324)	$ (35,685,827)	$ 12,584,661	$ 2,808,261
2034	Extrapolation	$ -	$ 20,647,854	$ 6,007,094	$ 43,549,357	$ -	$ 9,504,005	$ 53,053,362	$ 15,434,851	$ (9,427,756)	$ (45,113,584)	$ 12,669,844	$ 2,765,007
2035	Extrapolation	$ -	$ 20,647,854	$ 5,608,865	$ 46,709,767	$ -	$ 9,995,235	$ 56,705,002	$ 15,403,571	$ (9,794,706)	$ (54,908,290)	$ 12,688,426	$ 2,715,145
2036	Extrapolation	$ -	$ 20,647,854	$ 5,237,035	$ 49,870,177	$ -	$ 10,486,466	$ 60,356,643	$ 15,308,606	$ (10,071,571)	$ (64,979,861)	$ 12,648,863	$ 2,659,743
2037	Extrapolation	$ -	$ 20,647,854	$ 4,889,856	$ 53,030,587	$ -	$ 10,977,696	$ 64,008,283	$ 15,158,537	$ (10,268,681)	$ (75,248,543)	$ 12,558,783	$ 2,599,754
2038	Extrapolation	$ -	$ 20,647,854	$ 4,565,692	$ 56,190,996	$ -	$ 11,468,927	$ 67,659,923	$ 14,961,087	$ (10,395,395)	$ (85,643,938)	$ 12,425,057	$ 2,536,030
2039	Extrapolation	$ -	$ 20,647,854	$ 4,263,017	$ 59,351,406	$ -	$ 11,960,158	$ 71,311,564	$ 14,723,197	$ (10,460,180)	$ (96,104,118)	$ 12,253,868	$ 2,469,330
2040	Extrapolation	$ -	$ 20,647,854	$ 3,980,408	$ 62,511,816	$ -	$ 12,451,388	$ 74,963,204	$ 14,451,098	$ (10,470,690)	$ (106,574,807)	$ 12,050,771	$ 2,400,327
2041	Extrapolation	$ -	$ 20,647,854	$ 3,716,534	$ 65,672,226	$ -	$ 12,942,619	$ 78,614,845	$ 14,150,370	$ (10,433,835)	$ (117,008,643)	$ 11,820,748	$ 2,329,622
2042	Extrapolation	$ -	$ 20,647,854	$ 3,470,153	$ 68,832,636	$ -	$ 13,433,849	$ 82,266,485	$ 13,826,005	$ (10,355,851)	$ (127,364,494)	$ 11,568,263	$ 2,257,742
2043	Extrapolation	$ -	$ 20,647,854	$ 3,240,106	$ 71,993,046	$ -	$ 13,925,080	$ 85,918,126	$ 13,482,458	$ (10,242,352)	$ (137,606,846)	$ 11,297,305	$ 2,185,154
2044	Extrapolation	$ -	$ 20,647,854	$ 3,025,309	$ 75,153,456	$ -	$ 14,416,310	$ 89,569,766	$ 13,123,699	$ (10,098,390)	$ (147,705,236)	$ 11,011,431	$ 2,112,268
2045	Extrapolation	$ -	$ 20,647,854	$ 2,824,752	$ 78,313,866	$ -	$ 14,907,541	$ 93,221,407	$ 12,753,254	$ (9,928,502)	$ (157,633,738)	$ 10,713,812	$ 2,039,442
2046	Extrapolation	$ -	$ 20,647,854	$ 2,637,490	$ 81,474,276	$ -	$ 15,398,771	$ 96,873,047	$ 12,374,249	$ (9,736,759)	$ (167,370,497)	$ 10,407,260	$ 1,966,989
2047	Extrapolation	$ -	$ 20,647,854	$ 2,462,642	$ 84,634,686	$ -	$ 15,890,002	$ 100,524,688	$ 11,989,447	$ (9,526,804)	$ (176,897,301)	$ 10,094,267	$ 1,895,179
2048	Extrapolation	$ -	$ 20,647,854	$ 2,299,386	$ 87,795,096	$ -	$ 16,381,232	$ 104,176,328	$ 11,601,282	$ (9,301,896)	$ (186,199,197)	$ 9,777,035	$ 1,824,246
2049	Extrapolation	$ -	$ 20,647,854	$ 2,146,952	$ 90,955,506	$ -	$ 16,872,463	$ 107,827,969	$ 11,211,891	$ (9,064,939)	$ (195,264,137)	$ 9,457,502	$ 1,754,389
2050	Extrapolation	$ -	$ 20,647,854	$ 2,004,624	$ 94,115,916	$ -	$ 17,363,693	$ 111,479,609	$ 10,823,144	$ (8,818,520)	$ (204,082,656)	$ 9,137,367	$ 1,685,777
2051	Extrapolation	$ -	$ 20,647,854	$ 1,871,731	$ 97,276,326	$ -	$ 17,854,924	$ 115,131,250	$ 10,436,665	$ (8,564,934)	$ (212,647,590)	$ 8,818,113	$ 1,618,551
2052	Extrapolation	$ -	$ 20,647,854	$ 1,747,648	$ 100,436,736	$ -	$ 18,346,154	$ 118,782,890	$ 10,053,862	$ (8,306,214)	$ (220,953,805)	$ 8,501,032	$ 1,552,831
2053	Extrapolation	$ -	$ 20,647,854	$ 1,631,791	$ 103,597,146	$ -	$ 18,837,385	$ 122,434,531	$ 9,675,947	$ (8,044,157)	$ (228,997,961)	$ 8,187,237	$ 1,488,710
2054	Extrapolation	$ -	$ 20,647,854	$ 1,523,614	$ 106,757,556	$ -	$ 19,328,615	$ 126,086,171	$ 9,303,954	$ (7,780,340)	$ (236,778,301)	$ 7,877,687	$ 1,426,267
2055	Extrapolation	$ -	$ 20,647,854	$ 1,422,609	$ 109,917,966	$ -	$ 19,819,846	$ 129,737,811	$ 8,938,759	$ (7,516,149)	$ (244,294,451)	$ 7,573,198	$ 1,365,560
2056	Extrapolation	$ -	$ 20,647,854	$ 1,328,300	$ 113,078,376	$ -	$ 20,311,076	$ 133,389,452	$ 8,581,094	$ (7,252,794)	$ (251,547,245)	$ 7,274,459	$ 1,306,634
2057	Extrapolation	$ -	$ 20,647,854	$ 1,240,243	$ 116,238,785	$ -	$ 20,802,307	$ 137,041,092	$ 8,231,567	$ (6,991,324)	$ (258,538,569)	$ 6,982,047	$ 1,249,520
2058	Extrapolation	$ -	$ 20,647,854	$ 1,158,023	$ 119,399,195	$ -	$ 21,293,537	$ 140,692,733	$ 7,890,670	$ (6,732,647)	$ (265,271,216)	$ 6,696,435	$ 1,194,236
2059	Extrapolation	$ -	$ 20,647,854	$ 1,081,254	$ 122,559,605	$ -	$ 21,784,768	$ 144,344,373	$ 7,558,796	$ (6,477,542)	$ (271,748,758)	$ 6,418,006	$ 1,140,790

Year [1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($) [6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2060	Extrapolation	$ -	$ 20,647,854	$ 1,009,574	$ 125,720,015	$ -	$ 22,275,999	$ 147,996,014	$ 7,236,246	$ (6,226,672)	$ (277,975,430)	$ 6,147,064	$ 1,089,182
2061	Extrapolation	$ -	$ 20,647,854	$ 942,646	$ 128,880,425	$ -	$ 22,767,229	$ 151,647,654	$ 6,923,242	$ (5,980,596)	$ (283,956,025)	$ 5,883,839	$ 1,039,403
2062	Extrapolation	$ -	$ 20,647,854	$ 880,155	$ 132,040,835	$ -	$ 23,258,460	$ 155,299,295	$ 6,619,937	$ (5,739,781)	$ (289,695,807)	$ 5,628,499	$ 991,437
2063	Extrapolation	$ -	$ 20,647,854	$ 821,807	$ 135,201,245	$ -	$ 23,749,690	$ 158,950,935	$ 6,326,419	$ (5,504,612)	$ (295,200,419)	$ 5,381,156	$ 945,263
2064	Extrapolation	$ -	$ 20,647,854	$ 767,327	$ 138,361,655	$ -	$ 24,240,921	$ 162,602,576	$ 6,042,725	$ (5,275,398)	$ (300,475,817)	$ 5,141,871	$ 900,854
2065	Extrapolation	$ -	$ 20,647,854	$ 716,458	$ 141,522,065	$ -	$ 24,732,151	$ 166,254,216	$ 5,768,841	$ (5,052,383)	$ (305,528,200)	$ 4,910,662	$ 858,179
2066	Extrapolation	$ -	$ 20,647,854	$ 668,962	$ 144,682,475	$ -	$ 25,223,382	$ 169,905,857	$ 5,504,715	$ (4,835,753)	$ (310,363,953)	$ 4,687,512	$ 817,203
2067	Extrapolation	$ -	$ 20,647,854	$ 624,614	$ 147,842,885	$ -	$ 25,714,612	$ 173,557,497	$ 5,250,255	$ (4,625,640)	$ (314,989,593)	$ 4,472,367	$ 777,888
2068	Extrapolation	$ -	$ 20,647,854	$ 583,207	$ 151,003,295	$ -	$ 26,205,843	$ 177,209,138	$ 5,005,341	$ (4,422,134)	$ (319,411,727)	$ 4,265,146	$ 740,194
2069	Extrapolation	$ -	$ 20,647,854	$ 544,544	$ 154,163,705	$ -	$ 26,697,073	$ 180,860,778	$ 4,769,825	$ (4,225,281)	$ (323,637,008)	$ 4,065,745	$ 704,079
2070	Extrapolation	$ -	$ 20,647,854	$ 508,444	$ 157,324,115	$ -	$ 27,188,304	$ 184,512,418	$ 4,543,538	$ (4,035,094)	$ (327,672,102)	$ 3,874,038	$ 669,500
2071	Extrapolation	$ -	$ 20,647,854	$ 474,738	$ 160,484,525	$ -	$ 27,679,534	$ 188,164,059	$ 4,326,291	$ (3,851,553)	$ (331,523,655)	$ 3,689,880	$ 636,411
2072	Extrapolation	$ 1	$ 20,647,854	$ 443,266	$ 163,644,935	$ 1	$ 28,170,765	$ 191,815,700	$ 4,117,881	$ (3,674,615)	$ (335,198,270)	$ 3,513,114	$ 604,767
2073	Extrapolation	$ 2	$ 20,647,854	$ 413,881	$ 166,805,345	$ 2	$ 28,661,995	$ 195,467,342	$ 3,918,090	$ (3,504,209)	$ (338,702,479)	$ 3,343,568	$ 574,522
2074	Extrapolation	$ 3	$ 20,647,854	$ 386,443	$ 169,965,755	$ 3	$ 29,153,226	$ 199,118,983	$ 3,726,691	$ (3,340,248)	$ (342,042,727)	$ 3,181,062	$ 545,629
2075	Extrapolation	$ 4	$ 20,647,854	$ 360,825	$ 173,126,164	$ 4	$ 29,644,456	$ 202,770,625	$ 3,543,450	$ (3,182,625)	$ (345,225,352)	$ 3,025,408	$ 518,042
2076	Extrapolation	$ 5	$ 20,647,854	$ 336,904	$ 176,286,574	$ 5	$ 30,135,687	$ 206,422,266	$ 3,368,126	$ (3,031,221)	$ (348,256,573)	$ 2,876,411	$ 491,714
2077	Extrapolation	$ 6	$ 20,647,854	$ 314,570	$ 179,446,984	$ 6	$ 30,626,917	$ 210,073,908	$ 3,200,475	$ (2,885,905)	$ (351,142,478)	$ 2,733,874	$ 466,601
2078	Extrapolation	$ 7	$ 20,647,854	$ 293,716	$ 182,607,394	$ 7	$ 31,118,148	$ 213,725,549	$ 3,040,250	$ (2,746,534)	$ (353,889,011)	$ 2,597,593	$ 442,656
2079	Extrapolation	$ 8	$ 20,647,854	$ 274,245	$ 185,767,804	$ 8	$ 31,609,378	$ 217,377,191	$ 2,887,203	$ (2,612,958)	$ (356,501,970)	$ 2,467,367	$ 419,836
2080	Extrapolation	$ 9	$ 20,647,854	$ 256,064	$ 188,928,214	$ 9	$ 32,100,609	$ 221,028,832	$ 2,741,087	$ (2,485,023)	$ (358,986,992)	$ 2,342,991	$ 398,095
2081	Extrapolation	$ 10	$ 20,647,854	$ 239,089	$ 192,088,624	$ 10	$ 32,591,839	$ 224,680,474	$ 2,601,655	$ (2,362,566)	$ (361,349,558)	$ 2,224,263	$ 377,393
2082	Extrapolation	$ 11	$ 20,647,854	$ 223,239	$ 195,249,034	$ 11	$ 33,083,070	$ 228,332,115	$ 2,468,664	$ (2,245,425)	$ (363,594,983)	$ 2,110,979	$ 357,685
2083	Extrapolation	$ 12	$ 20,647,854	$ 208,440	$ 198,409,444	$ 12	$ 33,574,301	$ 231,983,757	$ 2,341,871	$ (2,133,432)	$ (365,728,415)	$ 2,002,939	$ 338,932
2084	Extrapolation	$ 13	$ 20,647,854	$ 194,622	$ 201,569,854	$ 13	$ 34,065,531	$ 235,635,398	$ 2,221,041	$ (2,026,419)	$ (367,754,834)	$ 1,899,947	$ 321,093
				203,639,619								$ 470,716,689	$ 100,677,763

[1] Assumed 63 year life for transmission line.

[2] From PROMOD or other Production Cost modeling software.

[3] From PSS/E or other Powerflow modeling software.

[4] Other Economic benefits may include avoided Economic Project Costs, Congestion/Load Cost Savings, Mitigation of Transmission Outage Costs etc.

[5] Other Public Policy Benefits may include Avoided Public Policy project benefits, Renewable Investment Benefit, production cost savings by untrapping renewable generation etc.

[6] Reliability benefits based upon Avoided Reliability Project Costs in a future year

[7] MISO's MTEP17 futures apply carbon fees in the base cases to achieve emission reduction target assumptions, this reported APC is modified to eliminate the value of reduced emissions

Low CO2 Values

Project Description	**Alternative: Huntley - Wilmarth 161 kV with Low CO2 Values**
Base Year	2016
Expected In Service Date (ISD)	2022
Base Year Cost ($)	$80,900,000 Green Route (Middle Route), Single Circuit Parallel Monopole

Year	Economic Benefits ($)					Public Policy Benefits ($)		
	PROMOD APC Savings ($) [7]	Transmission Loss Energy Savings ($) [2]	Transmission Loss Capacity Savings ($) [3]	Other Economic Benefits ($) [4]	Total Economic Benefits ($)	PROMOD Emissions Cost Savings ($)	Other PP Benefits ($) [5]	Total Public Policy Benefits ($)
2021	$ 1,979,035				$ 1,979,035	$ 1,560,606		$ 1,560,606
2026	$ 14,419,053				$ 14,419,053	$ 3,843,239		$ 3,843,239
2031	$ 24,231,427				$ 24,231,427	$ 5,726,738		$ 5,726,738

Year [1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($) [6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2017		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	PROMOD Model Year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	Interpolation	$ 93,819,198	$ 12,102,676	$ 8,019,450	$ 4,467,038	$ -	$ 2,017,132	$ 6,484,170	$ 4,296,528	$ 3,722,923	$ 3,722,923	$ 2,959,940	$ 1,336,588
2023	Interpolation	$ -	$ 12,102,676	$ 7,487,815	$ 6,955,042	$ -	$ 2,473,659	$ 9,428,701	$ 5,833,451	$ 1,654,364	$ 5,377,287	$ 4,303,021	$ 1,530,430
2024	Interpolation	$ -	$ 12,102,676	$ 6,991,424	$ 9,443,045	$ -	$ 2,930,186	$ 12,373,231	$ 7,147,717	$ (156,293)	$ 5,220,994	$ 5,455,020	$ 1,692,698
2025	Interpolation	$ -	$ 12,102,676	$ 6,527,940	$ 14,419,053	$ -	$ 3,843,239	$ 18,262,292	$ 9,850,313	$ (3,322,373)	$ 1,898,621	$ 7,777,347	$ 2,072,966
2026	PROMOD Model Year	$ -	$ 12,102,676	$ 6,095,183	$ 14,419,053	$ -	$ 3,843,239	$ 18,262,292	$ 9,197,305	$ (3,102,122)	$ (1,203,501)	$ 7,261,762	$ 1,935,543
2027	Interpolation	$ -	$ 12,102,676	$ 5,691,113	$ 16,381,528	$ -	$ 4,219,939	$ 20,601,466	$ 9,687,550	$ (3,996,437)	$ (5,199,937)	$ 7,703,183	$ 1,984,367
2028	Interpolation	$ -	$ 12,102,676	$ 5,313,831	$ 18,344,002	$ -	$ 4,596,639	$ 22,940,641	$ 10,072,375	$ (4,758,544)	$ (9,958,481)	$ 8,054,164	$ 2,018,212
2029	Interpolation	$ -	$ 12,102,676	$ 4,961,561	$ 20,306,477	$ -	$ 4,973,338	$ 25,279,816	$ 10,363,603	$ (5,402,043)	$ (15,360,524)	$ 8,324,755	$ 2,038,848
2030	Interpolation	$ -	$ 12,102,676	$ 4,632,643	$ 24,231,427	$ -	$ 5,726,738	$ 29,958,165	$ 11,467,338	$ (6,834,695)	$ (22,195,219)	$ 9,275,267	$ 2,192,071
2031	PROMOD Model Year	$ -	$ 12,102,676	$ 4,325,530	$ 24,669,368	$ -	$ 5,793,260	$ 30,462,628	$ 10,887,428	$ (6,561,898)	$ (28,757,117)	$ 8,816,901	$ 2,070,527
2032	Extrapolation	$ -	$ 12,102,676	$ 4,038,777	$ 26,894,607	$ -	$ 6,209,873	$ 33,104,480	$ 11,047,277	$ (7,008,500)	$ (35,765,616)	$ 8,974,984	$ 2,072,293
2033	Extrapolation	$ -	$ 12,102,676	$ 3,771,034	$ 29,119,846	$ -	$ 6,626,487	$ 35,746,333	$ 11,138,084	$ (7,367,050)	$ (43,132,667)	$ 9,073,358	$ 2,064,726
2034	Extrapolation	$ -	$ 12,102,676	$ 3,521,040	$ 31,345,085	$ -	$ 7,043,100	$ 38,388,185	$ 11,168,301	$ (7,647,261)	$ (50,779,928)	$ 9,119,247	$ 2,049,054
2035	Extrapolation	$ -	$ 12,102,676	$ 3,287,619	$ 33,570,325	$ -	$ 7,459,713	$ 41,030,038	$ 11,145,562	$ (7,857,943)	$ (58,637,871)	$ 9,119,176	$ 2,026,386
2036	Extrapolation	$ -	$ 12,102,676	$ 3,069,672	$ 35,795,564	$ -	$ 7,876,326	$ 43,671,890	$ 11,076,756	$ (8,007,083)	$ (66,644,954)	$ 9,079,037	$ 1,997,718
2037	Extrapolation	$ -	$ 12,102,676	$ 2,866,174	$ 38,020,803	$ -	$ 8,292,939	$ 46,313,742	$ 10,968,090	$ (8,101,916)	$ (74,746,870)	$ 9,004,143	$ 1,963,946
2038	Extrapolation	$ -	$ 12,102,676	$ 2,676,166	$ 40,246,042	$ -	$ 8,709,553	$ 48,955,595	$ 10,825,151	$ (8,148,985)	$ (82,895,855)	$ 8,899,279	$ 1,925,872
2039	Extrapolation	$ -	$ 12,102,676	$ 2,498,755	$ 42,471,281	$ -	$ 9,126,166	$ 51,597,447	$ 10,652,962	$ (8,154,208)	$ (91,050,062)	$ 8,768,747	$ 1,884,215
2040	Extrapolation	$ -	$ 12,102,676	$ 2,333,104	$ 44,696,521	$ -	$ 9,542,779	$ 54,239,300	$ 10,456,029	$ (8,122,925)	$ (99,172,987)	$ 8,616,411	$ 1,839,618
2041	Extrapolation	$ -	$ 12,102,676	$ 2,178,435	$ 46,921,760	$ -	$ 9,959,392	$ 56,881,152	$ 10,238,389	$ (8,059,953)	$ (107,232,941)	$ 8,445,736	$ 1,792,652
2042	Extrapolation	$ -	$ 12,102,676	$ 2,034,020	$ 49,146,999	$ -	$ 10,376,005	$ 59,523,005	$ 10,003,653	$ (7,969,633)	$ (115,202,573)	$ 8,259,823	$ 1,743,829
2043	Extrapolation	$ -	$ 12,102,676	$ 1,899,178	$ 51,372,238	$ -	$ 10,792,619	$ 62,164,857	$ 9,755,044	$ (7,855,866)	$ (123,058,439)	$ 8,061,443	$ 1,693,601
2044	Extrapolation	$ -	$ 12,102,676	$ 1,773,276	$ 53,597,478	$ -	$ 11,209,232	$ 64,806,710	$ 9,495,433	$ (7,722,158)	$ (130,780,597)	$ 7,853,065	$ 1,642,369
2045	Extrapolation	$ -	$ 12,102,676	$ 1,655,720	$ 55,822,717	$ -	$ 11,625,845	$ 67,448,562	$ 9,227,372	$ (7,571,653)	$ (138,352,250)	$ 7,636,886	$ 1,590,486
2046	Extrapolation	$ -	$ 12,102,676	$ 1,545,957	$ 58,047,956	$ -	$ 12,042,458	$ 70,090,414	$ 8,953,122	$ (7,407,165)	$ (145,759,415)	$ 7,414,857	$ 1,538,265
2047	Extrapolation	$ -	$ 12,102,676	$ 1,443,470	$ 60,273,195	$ -	$ 12,459,072	$ 72,732,267	$ 8,674,681	$ (7,231,211)	$ (152,990,626)	$ 7,188,704	$ 1,485,977
2048	Extrapolation	$ -	$ 12,102,676	$ 1,347,778	$ 62,498,435	$ -	$ 12,875,685	$ 75,374,119	$ 8,393,811	$ (7,046,033)	$ (160,036,659)	$ 6,959,949	$ 1,433,862
2049	Extrapolation	$ -	$ 12,102,676	$ 1,258,429	$ 64,723,674	$ -	$ 13,292,298	$ 78,015,972	$ 8,112,057	$ (6,853,627)	$ (166,890,286)	$ 6,729,931	$ 1,382,126
2050	Extrapolation	$ -	$ 12,102,676	$ 1,175,004	$ 66,948,913	$ -	$ 13,708,911	$ 80,657,824	$ 7,830,770	$ (6,655,766)	$ (173,546,053)	$ 6,499,823	$ 1,330,948
2051	Extrapolation	$ -	$ 12,102,676	$ 1,097,109	$ 69,174,152	$ -	$ 14,125,524	$ 83,299,677	$ 7,551,128	$ (6,454,019)	$ (180,000,071)	$ 6,270,647	$ 1,280,481
2052	Extrapolation	$ -	$ 12,102,676	$ 1,024,379	$ 71,399,392	$ -	$ 14,542,138	$ 85,941,529	$ 7,274,148	$ (6,249,769)	$ (186,249,841)	$ 6,043,292	$ 1,230,856
2053	Extrapolation	$ -	$ 12,102,676	$ 956,469	$ 73,624,631	$ -	$ 14,958,751	$ 88,583,382	$ 7,000,706	$ (6,044,237)	$ (192,294,077)	$ 5,818,522	$ 1,182,184
2054	Extrapolation	$ -	$ 12,102,676	$ 893,062	$ 75,849,870	$ -	$ 15,375,364	$ 91,225,234	$ 6,731,550	$ (5,838,488)	$ (198,132,566)	$ 5,596,995	$ 1,134,555
2055	Extrapolation	$ -	$ 12,102,676	$ 833,858	$ 78,075,109	$ -	$ 15,791,977	$ 93,867,086	$ 6,467,314	$ (5,633,456)	$ (203,766,022)	$ 5,379,269	$ 1,088,046
2056	Extrapolation	$ -	$ 12,102,676	$ 778,579	$ 80,300,349	$ -	$ 16,208,590	$ 96,508,939	$ 6,208,529	$ (5,429,950)	$ (209,195,972)	$ 5,165,812	$ 1,042,717
2057	Extrapolation	$ -	$ 12,102,676	$ 726,964	$ 82,525,588	$ -	$ 16,625,204	$ 99,150,791	$ 5,955,632	$ (5,228,668)	$ (214,424,640)	$ 4,957,016	$ 998,616
2058	Extrapolation	$ -	$ 12,102,676	$ 678,772	$ 84,750,827	$ -	$ 17,041,817	$ 101,792,644	$ 5,708,981	$ (5,030,210)	$ (219,454,850)	$ 4,753,201	$ 955,780

Year [1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($) [6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2059	Extrapolation	$ -	$ 12,102,676	$ 633,774	$ 86,976,066	$ -	$ 17,458,430	$ 104,434,496	$ 5,468,859	$ (4,835,085)	$ (224,289,936)	$ 4,554,624	$ 914,235
2060	Extrapolation	$ -	$ 12,102,676	$ 591,759	$ 89,201,305	$ -	$ 17,875,043	$ 107,076,349	$ 5,235,484	$ (4,643,725)	$ (228,933,661)	$ 4,361,486	$ 873,998
2061	Extrapolation	$ -	$ 12,102,676	$ 552,529	$ 91,426,545	$ -	$ 18,291,656	$ 109,718,201	$ 5,009,017	$ (4,456,488)	$ (233,390,148)	$ 4,173,939	$ 835,078
2062	Extrapolation	$ -	$ 12,102,676	$ 515,900	$ 93,651,784	$ -	$ 18,708,270	$ 112,360,054	$ 4,789,567	$ (4,273,667)	$ (237,663,815)	$ 3,992,091	$ 797,477
2063	Extrapolation	$ -	$ 12,102,676	$ 481,700	$ 95,877,023	$ -	$ 19,124,883	$ 115,001,906	$ 4,577,200	$ (4,095,501)	$ (241,759,316)	$ 3,816,009	$ 761,191
2064	Extrapolation	$ -	$ 12,102,676	$ 449,766	$ 98,102,262	$ -	$ 19,541,496	$ 117,643,759	$ 4,371,941	$ (3,922,175)	$ (245,681,491)	$ 3,645,729	$ 726,212
2065	Extrapolation	$ -	$ 12,102,676	$ 419,950	$ 100,327,502	$ -	$ 19,958,109	$ 120,285,611	$ 4,173,781	$ (3,753,831)	$ (249,435,322)	$ 3,481,256	$ 692,525
2066	Extrapolation	$ -	$ 12,102,676	$ 392,110	$ 102,552,741	$ -	$ 20,374,722	$ 122,927,463	$ 3,982,680	$ (3,590,570)	$ (253,025,891)	$ 3,322,567	$ 660,113
2067	Extrapolation	$ -	$ 12,102,676	$ 366,116	$ 104,777,980	$ -	$ 20,791,336	$ 125,569,316	$ 3,798,573	$ (3,432,458)	$ (256,458,349)	$ 3,169,619	$ 628,955
2068	Extrapolation	$ -	$ 12,102,676	$ 341,845	$ 107,003,219	$ -	$ 21,207,949	$ 128,211,168	$ 3,621,374	$ (3,279,529)	$ (259,737,878)	$ 3,022,347	$ 599,027
2069	Extrapolation	$ -	$ 12,102,676	$ 319,183	$ 109,228,459	$ -	$ 21,624,562	$ 130,853,021	$ 3,450,975	$ (3,131,792)	$ (262,869,670)	$ 2,880,672	$ 570,303
2070	Extrapolation	$ -	$ 12,102,676	$ 298,023	$ 111,453,698	$ -	$ 22,041,175	$ 133,494,873	$ 3,287,253	$ (2,989,230)	$ (265,858,900)	$ 2,744,499	$ 542,754
2071	Extrapolation	$ -	$ 12,102,676	$ 278,266	$ 113,678,937	$ -	$ 22,457,789	$ 136,136,726	$ 3,130,073	$ (2,851,806)	$ (268,710,707)	$ 2,613,720	$ 516,352
2072	Extrapolation	$ -	$ 12,102,676	$ 259,819	$ 115,904,176	$ 1	$ 22,874,402	$ 138,778,579	$ 2,979,285	$ (2,719,466)	$ (271,430,173)	$ 2,488,220	$ 491,065
2073	Extrapolation	$ -	$ 12,102,676	$ 242,595	$ 118,129,416	$ 2	$ 23,291,015	$ 141,420,433	$ 2,834,734	$ (2,592,139)	$ (274,022,312)	$ 2,367,872	$ 466,862
2074	Extrapolation	$ -	$ 12,102,676	$ 226,512	$ 120,354,655	$ 3	$ 23,707,628	$ 144,062,286	$ 2,696,255	$ (2,469,743)	$ (276,492,054)	$ 2,252,546	$ 443,710
2075	Extrapolation	$ -	$ 12,102,676	$ 211,496	$ 122,579,894	$ 4	$ 24,124,241	$ 146,704,139	$ 2,563,679	$ (2,352,182)	$ (278,844,237)	$ 2,142,104	$ 421,575
2076	Extrapolation	$ -	$ 12,102,676	$ 197,475	$ 124,805,133	$ 5	$ 24,540,855	$ 149,345,993	$ 2,436,831	$ (2,239,355)	$ (281,083,592)	$ 2,036,405	$ 400,425
2077	Extrapolation	$ -	$ 12,102,676	$ 184,384	$ 127,030,373	$ 6	$ 24,957,468	$ 151,987,846	$ 2,315,534	$ (2,131,150)	$ (283,214,742)	$ 1,935,307	$ 380,227
2078	Extrapolation	$ -	$ 12,102,676	$ 172,161	$ 129,255,612	$ 7	$ 25,374,081	$ 154,629,700	$ 2,199,610	$ (2,027,449)	$ (285,242,191)	$ 1,838,663	$ 360,947
2079	Extrapolation	$ -	$ 12,102,676	$ 160,748	$ 131,480,851	$ 8	$ 25,790,694	$ 157,271,553	$ 2,088,880	$ (1,928,132)	$ (287,170,323)	$ 1,746,328	$ 342,552
2080	Extrapolation	$ -	$ 12,102,676	$ 150,091	$ 133,706,090	$ 9	$ 26,207,307	$ 159,913,407	$ 1,983,165	$ (1,833,073)	$ (289,003,397)	$ 1,658,155	$ 325,010
2081	Extrapolation	$ -	$ 12,102,676	$ 140,141	$ 135,931,329	$ 10	$ 26,623,921	$ 162,555,260	$ 1,882,285	$ (1,742,144)	$ (290,745,541)	$ 1,573,997	$ 308,288
2082	Extrapolation	$ -	$ 12,102,676	$ 130,851	$ 138,156,569	$ 11	$ 27,040,534	$ 165,197,114	$ 1,786,065	$ (1,655,215)	$ (292,400,755)	$ 1,493,711	$ 292,355
2083	Extrapolation	$ -	$ 12,102,676	$ 122,176	$ 140,381,808	$ 12	$ 27,457,147	$ 167,838,967	$ 1,694,331	$ (1,572,155)	$ (293,972,910)	$ 1,417,152	$ 277,179
2084	Extrapolation	$ -	$ 12,102,676	$ 114,077	$ 142,607,047	$ 13	$ 27,873,760	$ 170,480,820	$ 1,606,910	$ (1,492,833)	$ (295,465,743)	$ 1,344,179	$ 262,731
				119,362,738								$ 339,693,909	$ 75,134,571

[1] Assumed 63 year life for transmission line.

[2] From PROMOD or other Production Cost modeling software.

[3] From PSS/E or other Powerflow modeling software.

[4] Other Economic benefits may include avoided Economic Project Costs, Congestion/Load Cost Savings, Mitigation of Transmission Outage Costs etc.

[5] Other Public Policy Benefits may include Avoided Public Policy project benefits, Renewable Investment Benefit, production cost savings by untrapping renewable generation etc.

[6] Reliability benefits based upon Avoided Reliability Project Costs in a future year

[7] MISO's MTEP17 futures apply carbon fees in the base cases to achieve emission reduction target assumptions, this reported APC is modified to eliminate the value of reduced emissions

High CO2 Values

Project Description	Preferred Option: Huntley - Wilmarth 345 kV with High CO2 Values
Base Year	2016
Expected In Service Date (ISD)	2022
Base Year Cost ($)	$105,820,000 Purple Route (West Route), Single-Circuit Parallel H-frame

Year	Economic Benefits ($)					Public Policy Benefits ($)		
	PROMOD APC Savings ($) [7]	Transmission Loss Energy Savings ($) [2]	Transmission Loss Capacity Savings ($) [3]	Other Economic Benefits ($) [4]	Total Economic Benefits ($)	PROMOD Emissions Cost Savings ($)	Other PP Benefits ($) [5]	Total Public Policy Benefits ($)
2021	$ 2,542,357				$ 2,542,357	$ 9,247,567		$ 9,247,567
2026	$ 18,109,417				$ 18,109,417	$ 22,642,540		$ 22,642,540
2031	$ 34,146,457				$ 34,146,457	$ 34,864,860		$ 34,864,860

Year [1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($) [6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2017		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	PROMOD Model Year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	Interpolation	$ 122,718,758	$ 15,830,720	$ 10,489,719	$ 5,655,769	$ -	$ 11,926,562	$ 17,582,331	$ 11,650,368	$ (1,160,649)	$ (1,160,649)	$ 3,747,614	$ 7,902,754
2023	Interpolation	$ -	$ 15,830,720	$ 9,794,322	$ 8,769,181	$ -	$ 14,605,556	$ 23,374,738	$ 14,461,737	$ (4,667,415)	$ (5,828,064)	$ 5,425,412	$ 9,036,324
2024	Interpolation	$ -	$ 15,830,720	$ 9,145,025	$ 11,882,593	$ -	$ 17,284,551	$ 29,167,144	$ 16,849,156	$ (7,704,131)	$ (13,532,195)	$ 6,864,288	$ 9,984,868
2025	Interpolation	$ -	$ 15,830,720	$ 8,538,772	$ 18,109,417	$ -	$ 22,642,540	$ 40,751,957	$ 21,980,787	$ (13,442,015)	$ (26,974,209)	$ 9,767,856	$ 12,212,931
2026	PROMOD Model Year	$ -	$ 15,830,720	$ 7,972,710	$ 18,109,417	$ -	$ 22,642,540	$ 40,751,957	$ 20,523,610	$ (12,550,901)	$ (39,525,110)	$ 9,120,314	$ 11,403,297
2027	Interpolation	$ -	$ 15,830,720	$ 7,444,173	$ 21,316,825	$ -	$ 25,087,004	$ 46,403,829	$ 21,820,748	$ (14,376,575)	$ (53,901,685)	$ 10,023,937	$ 11,796,811
2028	Interpolation	$ -	$ 15,830,720	$ 6,950,675	$ 24,524,233	$ -	$ 27,531,468	$ 52,055,701	$ 22,855,706	$ (15,905,031)	$ (69,806,716)	$ 10,767,671	$ 12,088,035
2029	Interpolation	$ -	$ 15,830,720	$ 6,489,893	$ 27,731,641	$ -	$ 29,975,932	$ 57,707,573	$ 23,657,546	$ (17,167,653)	$ (86,974,368)	$ 11,368,743	$ 12,288,803
2030	Interpolation	$ -	$ 15,830,720	$ 6,059,657	$ 34,146,457	$ -	$ 34,864,860	$ 69,011,317	$ 26,416,040	$ (20,356,383)	$ (107,330,751)	$ 13,070,526	$ 13,345,515
2031	PROMOD Model Year	$ -	$ 15,830,720	$ 5,657,943	$ 34,068,127	$ -	$ 35,060,302	$ 69,128,429	$ 24,706,693	$ (19,048,750)	$ (126,379,501)	$ 12,176,044	$ 12,530,650
2032	Extrapolation	$ -	$ 15,830,720	$ 5,282,860	$ 37,228,537	$ -	$ 37,622,031	$ 74,850,568	$ 24,978,340	$ (19,695,479)	$ (146,074,981)	$ 12,423,513	$ 12,554,826
2033	Extrapolation	$ -	$ 15,830,720	$ 4,932,643	$ 40,388,947	$ -	$ 40,183,760	$ 80,572,707	$ 25,105,389	$ (20,172,746)	$ (166,247,727)	$ 12,584,661	$ 12,520,728
2034	Extrapolation	$ -	$ 15,830,720	$ 4,605,642	$ 43,549,357	$ -	$ 42,745,490	$ 86,294,846	$ 25,105,819	$ (20,500,176)	$ (186,747,903)	$ 12,669,844	$ 12,435,974
2035	Extrapolation	$ -	$ 15,830,720	$ 4,300,319	$ 46,709,767	$ -	$ 45,307,219	$ 92,016,986	$ 24,995,858	$ (20,695,539)	$ (207,443,442)	$ 12,688,426	$ 12,307,432
2036	Extrapolation	$ -	$ 15,830,720	$ 4,015,238	$ 49,870,177	$ -	$ 47,868,948	$ 97,739,125	$ 24,790,143	$ (20,774,905)	$ (228,218,347)	$ 12,648,863	$ 12,141,280
2037	Extrapolation	$ -	$ 15,830,720	$ 3,749,055	$ 53,030,587	$ -	$ 50,430,677	$ 103,461,264	$ 24,501,851	$ (20,752,796)	$ (248,971,144)	$ 12,558,783	$ 11,943,068
2038	Extrapolation	$ -	$ 15,830,720	$ 3,500,518	$ 56,190,996	$ -	$ 52,992,407	$ 109,183,403	$ 24,142,835	$ (20,642,317)	$ (269,613,461)	$ 12,425,057	$ 11,717,779
2039	Extrapolation	$ -	$ 15,830,720	$ 3,268,457	$ 59,351,406	$ -	$ 55,554,136	$ 114,905,542	$ 23,723,740	$ (20,455,282)	$ (290,068,743)	$ 12,253,868	$ 11,469,872
2040	Extrapolation	$ -	$ 15,830,720	$ 3,051,781	$ 62,511,816	$ -	$ 58,115,865	$ 120,627,682	$ 23,254,108	$ (20,202,327)	$ (310,271,070)	$ 12,050,771	$ 11,203,337
2041	Extrapolation	$ -	$ 15,830,720	$ 2,849,469	$ 65,672,226	$ -	$ 60,677,594	$ 126,349,821	$ 22,742,482	$ (19,893,013)	$ (330,164,083)	$ 11,820,748	$ 10,921,734
2042	Extrapolation	$ -	$ 15,830,720	$ 2,660,568	$ 68,832,636	$ -	$ 63,239,324	$ 132,071,960	$ 22,196,494	$ (19,535,926)	$ (349,700,009)	$ 11,568,263	$ 10,628,231
2043	Extrapolation	$ -	$ 15,830,720	$ 2,484,191	$ 71,993,046	$ -	$ 65,801,053	$ 137,794,099	$ 21,622,948	$ (19,138,757)	$ (368,838,766)	$ 11,297,305	$ 10,325,644
2044	Extrapolation	$ -	$ 15,830,720	$ 2,319,506	$ 75,153,456	$ -	$ 68,362,782	$ 143,516,238	$ 21,027,898	$ (18,708,392)	$ (387,547,158)	$ 11,011,431	$ 10,016,467
2045	Extrapolation	$ -	$ 15,830,720	$ 2,165,738	$ 78,313,866	$ -	$ 70,924,511	$ 149,238,378	$ 20,416,715	$ (18,250,976)	$ (405,798,135)	$ 10,713,812	$ 9,702,903
2046	Extrapolation	$ -	$ 15,830,720	$ 2,022,165	$ 81,474,276	$ -	$ 73,486,241	$ 154,960,517	$ 19,794,153	$ (17,771,989)	$ (423,570,123)	$ 10,407,260	$ 9,386,894
2047	Extrapolation	$ -	$ 15,830,720	$ 1,888,109	$ 84,634,686	$ -	$ 76,047,970	$ 160,682,656	$ 19,164,408	$ (17,276,299)	$ (440,846,422)	$ 10,094,267	$ 9,070,141
2048	Extrapolation	$ -	$ 15,830,720	$ 1,762,940	$ 87,795,096	$ -	$ 78,609,699	$ 166,404,795	$ 18,531,167	$ (16,768,227)	$ (457,614,649)	$ 9,777,035	$ 8,754,132
2049	Extrapolation	$ -	$ 15,830,720	$ 1,646,069	$ 90,955,506	$ -	$ 81,171,429	$ 172,126,934	$ 17,897,662	$ (16,251,592)	$ (473,866,241)	$ 9,457,502	$ 8,440,159
2050	Extrapolation	$ -	$ 15,830,720	$ 1,536,946	$ 94,115,916	$ -	$ 83,733,158	$ 177,849,074	$ 17,266,710	$ (15,729,764)	$ (489,596,005)	$ 9,137,367	$ 8,129,343
2051	Extrapolation	$ -	$ 15,830,720	$ 1,435,057	$ 97,276,326	$ -	$ 86,294,887	$ 183,571,213	$ 16,640,758	$ (15,205,701)	$ (504,801,706)	$ 8,818,113	$ 7,822,644
2052	Extrapolation	$ -	$ 15,830,720	$ 1,339,923	$ 100,436,736	$ -	$ 88,856,616	$ 189,293,352	$ 16,021,915	$ (14,681,992)	$ (519,483,698)	$ 8,501,032	$ 7,520,883
2053	Extrapolation	$ -	$ 15,830,720	$ 1,251,095	$ 103,597,146	$ -	$ 91,418,346	$ 195,015,491	$ 15,411,989	$ (14,160,894)	$ (533,644,592)	$ 8,187,237	$ 7,224,752
2054	Extrapolation	$ -	$ 15,830,720	$ 1,168,156	$ 106,757,556	$ -	$ 93,980,075	$ 200,737,630	$ 14,812,518	$ (13,644,363)	$ (547,288,955)	$ 7,877,687	$ 6,934,831
2055	Extrapolation	$ -	$ 15,830,720	$ 1,090,715	$ 109,917,966	$ -	$ 96,541,804	$ 206,459,770	$ 14,224,797	$ (13,134,082)	$ (560,423,037)	$ 7,573,198	$ 6,651,599
2056	Extrapolation	$ -	$ 15,830,720	$ 1,018,408	$ 113,078,376	$ -	$ 99,103,533	$ 212,181,909	$ 13,649,902	$ (12,631,493)	$ (573,054,530)	$ 7,274,459	$ 6,375,442
2057	Extrapolation	$ -	$ 15,830,720	$ 950,895	$ 116,238,785	$ -	$ 101,665,263	$ 217,904,048	$ 13,088,714	$ (12,137,820)	$ (585,192,350)	$ 6,982,047	$ 6,106,668
2058	Extrapolation	$ -	$ 15,830,720	$ 887,857	$ 119,399,195	$ -	$ 104,226,992	$ 223,626,187	$ 12,541,945	$ (11,654,088)	$ (596,846,438)	$ 6,696,435	$ 5,845,510
2059	Extrapolation	$ -	$ 15,830,720	$ 828,998	$ 122,559,605	$ -	$ 106,788,721	$ 229,348,326	$ 12,010,147	$ (11,181,149)	$ (608,027,587)	$ 6,418,006	$ 5,592,141

Year [1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($) [6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2060	Extrapolation	$ -	$ 15,830,720	$ 774,041	$ 125,720,015	$ -	$ 109,350,450	$ 235,070,466	$ 11,493,740	$ (10,719,699)	$ (618,747,286)	$ 6,147,064	$ 5,346,676
2061	Extrapolation	$ -	$ 15,830,720	$ 722,727	$ 128,880,425	$ -	$ 111,912,180	$ 240,792,605	$ 10,993,018	$ (10,270,291)	$ (629,017,577)	$ 5,883,839	$ 5,109,180
2062	Extrapolation	$ -	$ 15,830,720	$ 674,815	$ 132,040,835	$ -	$ 114,473,909	$ 246,514,744	$ 10,508,174	$ (9,833,358)	$ (638,850,935)	$ 5,628,499	$ 4,879,675
2063	Extrapolation	$ -	$ 15,830,720	$ 630,080	$ 135,201,245	$ -	$ 117,035,638	$ 252,236,883	$ 10,039,301	$ (9,409,221)	$ (648,260,156)	$ 5,381,156	$ 4,658,145
2064	Extrapolation	$ -	$ 15,830,720	$ 588,310	$ 138,361,655	$ -	$ 119,597,367	$ 257,959,022	$ 9,586,413	$ (8,998,103)	$ (657,258,259)	$ 5,141,871	$ 4,444,542
2065	Extrapolation	$ -	$ 15,830,720	$ 549,309	$ 141,522,065	$ -	$ 122,159,097	$ 263,681,162	$ 9,149,451	$ (8,600,142)	$ (665,858,401)	$ 4,910,662	$ 4,238,788
2066	Extrapolation	$ -	$ 15,830,720	$ 512,893	$ 144,682,475	$ -	$ 124,720,826	$ 269,403,301	$ 8,728,294	$ (8,215,401)	$ (674,073,802)	$ 4,687,512	$ 4,040,782
2067	Extrapolation	$ -	$ 15,830,720	$ 478,892	$ 147,842,885	$ -	$ 127,282,555	$ 275,125,440	$ 8,322,767	$ (7,843,875)	$ (681,917,677)	$ 4,472,367	$ 3,850,400
2068	Extrapolation	$ -	$ 15,830,720	$ 447,145	$ 151,003,295	$ -	$ 129,844,284	$ 280,847,579	$ 7,932,648	$ (7,485,504)	$ (689,403,181)	$ 4,265,146	$ 3,667,502
2069	Extrapolation	$ -	$ 15,830,720	$ 417,502	$ 154,163,705	$ -	$ 132,406,014	$ 286,569,718	$ 7,557,677	$ (7,140,175)	$ (696,543,356)	$ 4,065,745	$ 3,491,932
2070	Extrapolation	$ -	$ 15,830,720	$ 389,825	$ 157,324,115	$ -	$ 134,967,743	$ 292,291,858	$ 7,197,560	$ (6,807,735)	$ (703,351,091)	$ 3,874,038	$ 3,323,522
2071	Extrapolation	$ -	$ 15,830,720	$ 363,982	$ 160,484,525	$ -	$ 137,529,472	$ 298,013,997	$ 6,851,975	$ (6,487,993)	$ (709,839,084)	$ 3,689,880	$ 3,162,095
2072	Extrapolation	$ -	$ 15,830,720	$ 339,852	$ 163,644,935	$ -	$ 140,091,201	$ 303,736,136	$ 6,520,578	$ (6,180,726)	$ (716,019,810)	$ 3,513,114	$ 3,007,464
2073	Extrapolation	$ -	$ 15,830,720	$ 317,322	$ 166,805,345	$ -	$ 142,652,931	$ 309,458,275	$ 6,203,007	$ (5,885,684)	$ (721,905,494)	$ 3,343,568	$ 2,859,439
2074	Extrapolation	$ -	$ 15,830,720	$ 296,286	$ 169,965,755	$ -	$ 145,214,660	$ 315,180,414	$ 5,898,885	$ (5,602,599)	$ (727,508,093)	$ 3,181,062	$ 2,717,823
2075	Extrapolation	$ -	$ 15,830,720	$ 276,644	$ 173,126,164	$ -	$ 147,776,389	$ 320,902,554	$ 5,607,824	$ (5,331,180)	$ (732,839,273)	$ 3,025,408	$ 2,582,416
2076	Extrapolation	$ -	$ 15,830,720	$ 258,305	$ 176,286,574	$ -	$ 150,338,118	$ 326,624,693	$ 5,329,430	$ (5,071,125)	$ (737,910,398)	$ 2,876,411	$ 2,453,019
2077	Extrapolation	$ -	$ 15,830,720	$ 241,181	$ 179,446,984	$ -	$ 152,899,848	$ 332,346,832	$ 5,063,302	$ (4,822,121)	$ (742,732,519)	$ 2,733,874	$ 2,329,428
2078	Extrapolation	$ -	$ 15,830,720	$ 225,192	$ 182,607,394	$ -	$ 155,461,577	$ 338,068,971	$ 4,809,037	$ (4,583,845)	$ (747,316,364)	$ 2,597,593	$ 2,211,444
2079	Extrapolation	$ -	$ 15,830,720	$ 210,264	$ 185,767,804	$ -	$ 158,023,306	$ 343,791,110	$ 4,566,232	$ (4,355,969)	$ (751,672,332)	$ 2,467,367	$ 2,098,865
2080	Extrapolation	$ -	$ 15,830,720	$ 196,325	$ 188,928,214	$ -	$ 160,585,035	$ 349,513,250	$ 4,334,485	$ (4,138,161)	$ (755,810,493)	$ 2,342,991	$ 1,991,494
2081	Extrapolation	$ -	$ 15,830,720	$ 183,310	$ 192,088,624	$ -	$ 163,146,765	$ 355,235,389	$ 4,113,397	$ (3,930,087)	$ (759,740,580)	$ 2,224,263	$ 1,889,134
2082	Extrapolation	$ -	$ 15,830,720	$ 171,157	$ 195,249,034	$ -	$ 165,708,494	$ 360,957,528	$ 3,902,573	$ (3,731,416)	$ (763,471,996)	$ 2,110,979	$ 1,791,594
2083	Extrapolation	$ -	$ 15,830,720	$ 159,811	$ 198,409,444	$ -	$ 168,270,223	$ 366,679,667	$ 3,701,624	$ (3,541,813)	$ (767,013,809)	$ 2,002,939	$ 1,698,685
2084	Extrapolation	$ -	$ 15,830,720	$ 149,216	$ 201,569,854	$ -	$ 170,831,952	$ 372,401,806	$ 3,510,167	$ (3,360,950)	$ (770,374,759)	$ 1,899,947	$ 1,610,220
				156,130,593								$ 470,716,689	$ 455,788,663

[1] Assumed 63 year life for transmission line.

[2] From PROMOD or other Production Cost modeling software.

[3] From PSS/E or other Powerflow modeling software.

[4] Other Economic benefits may include avoided Economic Project Costs, Congestion/Load Cost Savings, Mitigation of Transmission Outage Costs etc.

[5] Other Public Policy Benefits may include Avoided Public Policy project benefits, Renewable Investment Benefit, production cost savings by untrapping renewable generation etc.

[6] Reliability benefits based upon Avoided Reliability Project Costs in a future year

[7] MISO's MTEP17 futures apply carbon fees in the base cases to achieve emission reduction target assumptions, this reported APC is modified to eliminate the value of reduced emissions

High CO2 Values

Project Description	Preferred Option: Huntley - Wilmarth 345 kV with High CO2 Values
Base Year	2016
Expected In Service Date (ISD)	2022
Base Year Cost ($)	$121,320,000 Green Route (Middle Route), Single Circuit Parallel Monopole

Year	Economic Benefits ($)					Public Policy Benefits ($)		
	PROMOD APC Savings ($) [7]	Transmission Loss Energy Savings ($) [2]	Transmission Loss Capacity Savings ($) [3]	Other Economic Benefits ($) [4]	Total Economic Benefits ($)	PROMOD Emissions Cost Savings ($)	Other PP Benefits ($) [5]	Total Public Policy Benefits ($)
2021	$ 2,542,357				$ 2,542,357	$ 9,247,567		$ 9,247,567
2026	$ 18,109,417				$ 18,109,417	$ 22,642,540		$ 22,642,540
2031	$ 34,146,457				$ 34,146,457	$ 34,864,860		$ 34,864,860

Year [1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($) [6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2017		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	PROMOD Model Year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	Interpolation	$ 140,694,005	$ 18,149,527	$ 12,026,202	$ 5,655,769	$ -	$ 11,926,562	$ 17,582,331	$ 11,650,368	$ 375,834	$ 375,834	$ 3,747,614	$ 7,902,754
2023	Interpolation	$ -	$ 18,149,527	$ 11,228,946	$ 8,769,181	$ -	$ 14,605,556	$ 23,374,738	$ 14,461,737	$ (3,232,790)	$ (2,856,956)	$ 5,425,412	$ 9,036,324
2024	Interpolation	$ -	$ 18,149,527	$ 10,484,544	$ 11,882,593	$ -	$ 17,284,551	$ 29,167,144	$ 16,849,156	$ (6,364,612)	$ (9,221,568)	$ 6,864,288	$ 9,984,868
2025	Interpolation	$ -	$ 18,149,527	$ 9,789,490	$ 18,109,417	$ -	$ 22,642,540	$ 40,751,957	$ 21,980,787	$ (12,191,297)	$ (21,412,865)	$ 9,767,856	$ 12,212,931
2026	PROMOD Model Year	$ -	$ 18,149,527	$ 9,140,514	$ 18,109,417	$ -	$ 22,642,540	$ 40,751,957	$ 20,523,610	$ (11,383,097)	$ (32,795,962)	$ 9,120,314	$ 11,403,297
2027	Interpolation	$ -	$ 18,149,527	$ 8,534,560	$ 21,316,825	$ -	$ 25,087,004	$ 46,403,829	$ 21,820,748	$ (13,286,188)	$ (46,082,150)	$ 10,023,937	$ 11,796,811
2028	Interpolation	$ -	$ 18,149,527	$ 7,968,777	$ 24,524,233	$ -	$ 27,531,468	$ 52,055,701	$ 22,855,706	$ (14,886,930)	$ (60,969,080)	$ 10,767,671	$ 12,088,035
2029	Interpolation	$ -	$ 18,149,527	$ 7,440,501	$ 27,731,641	$ -	$ 29,975,932	$ 57,707,573	$ 23,657,546	$ (16,217,045)	$ (77,186,124)	$ 11,368,743	$ 12,288,803
2030	Interpolation	$ -	$ 18,149,527	$ 6,947,247	$ 34,146,457	$ -	$ 34,864,860	$ 69,011,317	$ 26,416,040	$ (19,468,794)	$ (96,654,918)	$ 13,070,526	$ 13,345,515
2031	PROMOD Model Year	$ -	$ 18,149,527	$ 6,486,691	$ 34,068,127	$ -	$ 35,060,302	$ 69,128,429	$ 24,706,693	$ (18,220,002)	$ (114,874,920)	$ 12,176,044	$ 12,530,650
2032	Extrapolation	$ -	$ 18,149,527	$ 6,056,668	$ 37,228,537	$ -	$ 37,622,031	$ 74,850,568	$ 24,978,340	$ (18,921,672)	$ (133,796,592)	$ 12,423,513	$ 12,554,826
2033	Extrapolation	$ -	$ 18,149,527	$ 5,655,152	$ 40,388,947	$ -	$ 40,183,760	$ 80,572,707	$ 25,105,389	$ (19,450,237)	$ (153,246,828)	$ 12,584,661	$ 12,520,728
2034	Extrapolation	$ -	$ 18,149,527	$ 5,280,254	$ 43,549,357	$ -	$ 42,745,490	$ 86,294,846	$ 25,105,819	$ (19,825,564)	$ (173,072,393)	$ 12,669,844	$ 12,435,974
2035	Extrapolation	$ -	$ 18,149,527	$ 4,930,209	$ 46,709,767	$ -	$ 45,307,219	$ 92,016,986	$ 24,995,858	$ (20,065,649)	$ (193,138,042)	$ 12,688,426	$ 12,307,432
2036	Extrapolation	$ -	$ 18,149,527	$ 4,603,370	$ 49,870,177	$ -	$ 47,868,948	$ 97,739,125	$ 24,790,143	$ (20,186,773)	$ (213,324,814)	$ 12,648,863	$ 12,141,280
2037	Extrapolation	$ -	$ 18,149,527	$ 4,298,198	$ 53,030,587	$ -	$ 50,430,677	$ 103,461,264	$ 24,501,851	$ (20,203,653)	$ (233,528,467)	$ 12,558,783	$ 11,943,068
2038	Extrapolation	$ -	$ 18,149,527	$ 4,013,257	$ 56,190,996	$ -	$ 52,992,407	$ 109,183,403	$ 24,142,835	$ (20,129,578)	$ (253,658,046)	$ 12,425,057	$ 11,717,779
2039	Extrapolation	$ -	$ 18,149,527	$ 3,747,205	$ 59,351,406	$ -	$ 55,554,136	$ 114,905,542	$ 23,723,740	$ (19,976,534)	$ (273,634,580)	$ 12,253,868	$ 11,469,872
2040	Extrapolation	$ -	$ 18,149,527	$ 3,498,791	$ 62,511,816	$ -	$ 58,115,865	$ 120,627,682	$ 23,254,108	$ (19,755,317)	$ (293,389,897)	$ 12,050,771	$ 11,203,337
2041	Extrapolation	$ -	$ 18,149,527	$ 3,266,845	$ 65,672,226	$ -	$ 60,677,594	$ 126,349,821	$ 22,742,482	$ (19,475,637)	$ (312,865,534)	$ 11,820,748	$ 10,921,734
2042	Extrapolation	$ -	$ 18,149,527	$ 3,050,275	$ 68,832,636	$ -	$ 63,239,324	$ 132,071,960	$ 22,196,494	$ (19,146,218)	$ (332,011,752)	$ 11,568,263	$ 10,628,231
2043	Extrapolation	$ -	$ 18,149,527	$ 2,848,063	$ 71,993,046	$ -	$ 65,801,053	$ 137,794,099	$ 21,622,948	$ (18,774,885)	$ (350,786,637)	$ 11,297,305	$ 10,325,644
2044	Extrapolation	$ -	$ 18,149,527	$ 2,659,256	$ 75,153,456	$ -	$ 68,362,782	$ 143,516,238	$ 21,027,898	$ (18,368,642)	$ (369,155,279)	$ 11,011,431	$ 10,016,467
2045	Extrapolation	$ -	$ 18,149,527	$ 2,482,965	$ 78,313,866	$ -	$ 70,924,511	$ 149,238,378	$ 20,416,715	$ (17,933,750)	$ (387,089,029)	$ 10,713,812	$ 9,702,903
2046	Extrapolation	$ -	$ 18,149,527	$ 2,318,362	$ 81,474,276	$ -	$ 73,486,241	$ 154,960,517	$ 19,794,153	$ (17,475,792)	$ (404,564,821)	$ 10,407,260	$ 9,386,894
2047	Extrapolation	$ -	$ 18,149,527	$ 2,164,670	$ 84,634,686	$ -	$ 76,047,970	$ 160,682,656	$ 19,164,408	$ (16,999,738)	$ (421,564,559)	$ 10,094,267	$ 9,070,141
2048	Extrapolation	$ -	$ 18,149,527	$ 2,021,167	$ 87,795,096	$ -	$ 78,609,699	$ 166,404,795	$ 18,531,167	$ (16,510,000)	$ (438,074,559)	$ 9,777,035	$ 8,754,132
2049	Extrapolation	$ -	$ 18,149,527	$ 1,887,178	$ 90,955,506	$ -	$ 81,171,429	$ 172,126,934	$ 17,897,662	$ (16,010,484)	$ (454,085,043)	$ 9,457,502	$ 8,440,159
2050	Extrapolation	$ -	$ 18,149,527	$ 1,762,071	$ 94,115,916	$ -	$ 83,733,158	$ 177,849,074	$ 17,266,710	$ (15,504,640)	$ (469,589,682)	$ 9,137,367	$ 8,129,343
2051	Extrapolation	$ -	$ 18,149,527	$ 1,645,257	$ 97,276,326	$ -	$ 86,294,887	$ 183,571,213	$ 16,640,758	$ (14,995,500)	$ (484,585,183)	$ 8,818,113	$ 7,822,644
2052	Extrapolation	$ -	$ 18,149,527	$ 1,536,188	$ 100,436,736	$ -	$ 88,856,616	$ 189,293,352	$ 16,021,915	$ (14,485,727)	$ (499,070,909)	$ 8,501,032	$ 7,520,883
2053	Extrapolation	$ -	$ 18,149,527	$ 1,434,349	$ 103,597,146	$ -	$ 91,418,346	$ 195,015,491	$ 15,411,989	$ (13,977,640)	$ (513,048,549)	$ 8,187,237	$ 7,224,752
2054	Extrapolation	$ -	$ 18,149,527	$ 1,339,262	$ 106,757,556	$ -	$ 93,980,075	$ 200,737,630	$ 14,812,518	$ (13,473,257)	$ (526,521,806)	$ 7,877,687	$ 6,934,831
2055	Extrapolation	$ -	$ 18,149,527	$ 1,250,478	$ 109,917,966	$ -	$ 96,541,804	$ 206,459,770	$ 14,224,797	$ (12,974,319)	$ (539,496,125)	$ 7,573,198	$ 6,651,599
2056	Extrapolation	$ -	$ 18,149,527	$ 1,167,580	$ 113,078,376	$ -	$ 99,103,533	$ 212,181,909	$ 13,649,902	$ (12,482,322)	$ (551,978,447)	$ 7,274,459	$ 6,375,442
2057	Extrapolation	$ -	$ 18,149,527	$ 1,090,177	$ 116,238,785	$ -	$ 101,665,263	$ 217,904,048	$ 13,088,714	$ (11,998,538)	$ (563,976,985)	$ 6,982,047	$ 6,106,668
2058	Extrapolation	$ -	$ 18,149,527	$ 1,017,906	$ 119,399,195	$ -	$ 104,226,992	$ 223,626,187	$ 12,541,945	$ (11,524,039)	$ (575,501,024)	$ 6,696,435	$ 5,845,510

Year [1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($) [6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2059	Extrapolation	$ -	$ 18,149,527	$ 950,425	$ 122,559,605	$ -	$ 106,788,721	$ 229,348,326	$ 12,010,147	$ (11,059,722)	$ (586,560,746)	$ 6,418,006	$ 5,592,141
2060	Extrapolation	$ -	$ 18,149,527	$ 887,419	$ 125,720,015	$ -	$ 109,350,450	$ 235,070,466	$ 11,493,740	$ (10,606,321)	$ (597,167,066)	$ 6,147,064	$ 5,346,676
2061	Extrapolation	$ -	$ 18,149,527	$ 828,589	$ 128,880,425	$ -	$ 111,912,180	$ 240,792,605	$ 10,993,018	$ (10,164,430)	$ (607,331,496)	$ 5,883,839	$ 5,109,180
2062	Extrapolation	$ -	$ 18,149,527	$ 773,659	$ 132,040,835	$ -	$ 114,473,909	$ 246,514,744	$ 10,508,174	$ (9,734,515)	$ (617,066,011)	$ 5,628,499	$ 4,879,675
2063	Extrapolation	$ -	$ 18,149,527	$ 722,371	$ 135,201,245	$ -	$ 117,035,638	$ 252,236,883	$ 10,039,301	$ (9,316,930)	$ (626,382,940)	$ 5,381,156	$ 4,658,145
2064	Extrapolation	$ -	$ 18,149,527	$ 674,483	$ 138,361,655	$ -	$ 119,597,367	$ 257,959,022	$ 9,586,413	$ (8,911,930)	$ (635,294,871)	$ 5,141,871	$ 4,444,542
2065	Extrapolation	$ -	$ 18,149,527	$ 629,769	$ 141,522,065	$ -	$ 122,159,097	$ 263,681,162	$ 9,149,451	$ (8,519,682)	$ (643,814,553)	$ 4,910,662	$ 4,238,788
2066	Extrapolation	$ -	$ 18,149,527	$ 588,020	$ 144,682,475	$ -	$ 124,720,826	$ 269,403,301	$ 8,728,294	$ (8,140,275)	$ (651,954,827)	$ 4,687,512	$ 4,040,782
2067	Extrapolation	$ -	$ 18,149,527	$ 549,038	$ 147,842,885	$ -	$ 127,282,555	$ 275,125,440	$ 8,322,767	$ (7,773,729)	$ (659,728,556)	$ 4,472,367	$ 3,850,400
2068	Extrapolation	$ -	$ 18,149,527	$ 512,640	$ 151,003,295	$ -	$ 129,844,284	$ 280,847,579	$ 7,932,648	$ (7,420,008)	$ (667,148,564)	$ 4,265,146	$ 3,667,502
2069	Extrapolation	$ -	$ 18,149,527	$ 478,656	$ 154,163,705	$ -	$ 132,406,014	$ 286,569,718	$ 7,557,677	$ (7,079,021)	$ (674,227,586)	$ 4,065,745	$ 3,491,932
2070	Extrapolation	$ -	$ 18,149,527	$ 446,924	$ 157,324,115	$ -	$ 134,967,743	$ 292,291,858	$ 7,197,560	$ (6,750,636)	$ (680,978,222)	$ 3,874,038	$ 3,323,522
2071	Extrapolation	$ -	$ 18,149,527	$ 417,296	$ 160,484,525	$ -	$ 137,529,472	$ 298,013,997	$ 6,851,975	$ (6,434,679)	$ (687,412,900)	$ 3,689,880	$ 3,162,095
2072	Extrapolation	$ 1	$ 18,149,527	$ 389,632	$ 163,644,935	$ 1	$ 140,091,201	$ 303,736,137	$ 6,520,578	$ (6,130,946)	$ (693,543,846)	$ 3,513,114	$ 3,007,464
2073	Extrapolation	$ 2	$ 18,149,527	$ 363,802	$ 166,805,345	$ 2	$ 142,652,931	$ 309,458,277	$ 6,203,007	$ (5,839,205)	$ (699,383,051)	$ 3,343,568	$ 2,859,439
2074	Extrapolation	$ 3	$ 18,149,527	$ 339,685	$ 169,965,755	$ 3	$ 145,214,660	$ 315,180,417	$ 5,898,885	$ (5,559,200)	$ (704,942,251)	$ 3,181,062	$ 2,717,823
2075	Extrapolation	$ 4	$ 18,149,527	$ 317,166	$ 173,126,164	$ 4	$ 147,776,389	$ 320,902,558	$ 5,607,824	$ (5,290,658)	$ (710,232,909)	$ 3,025,408	$ 2,582,416
2076	Extrapolation	$ 5	$ 18,149,527	$ 296,140	$ 176,286,574	$ 5	$ 150,338,118	$ 326,624,698	$ 5,329,430	$ (5,033,290)	$ (715,266,199)	$ 2,876,411	$ 2,453,019
2077	Extrapolation	$ 6	$ 18,149,527	$ 276,508	$ 179,446,984	$ 6	$ 152,899,848	$ 332,346,838	$ 5,063,302	$ (4,786,794)	$ (720,052,993)	$ 2,733,874	$ 2,329,428
2078	Extrapolation	$ 7	$ 18,149,527	$ 258,177	$ 182,607,394	$ 7	$ 155,461,577	$ 338,068,978	$ 4,809,037	$ (4,550,860)	$ (724,603,853)	$ 2,597,593	$ 2,211,444
2079	Extrapolation	$ 8	$ 18,149,527	$ 241,062	$ 185,767,804	$ 8	$ 158,023,306	$ 343,791,118	$ 4,566,232	$ (4,325,170)	$ (728,929,023)	$ 2,467,367	$ 2,098,865
2080	Extrapolation	$ 9	$ 18,149,527	$ 225,081	$ 188,928,214	$ 9	$ 160,585,035	$ 349,513,259	$ 4,334,485	$ (4,109,404)	$ (733,038,427)	$ 2,342,991	$ 1,991,494
2081	Extrapolation	$ 10	$ 18,149,527	$ 210,160	$ 192,088,624	$ 10	$ 163,146,765	$ 355,235,399	$ 4,113,397	$ (3,903,237)	$ (736,941,665)	$ 2,224,263	$ 1,889,134
2082	Extrapolation	$ 11	$ 18,149,527	$ 196,228	$ 195,249,034	$ 11	$ 165,708,494	$ 360,957,539	$ 3,902,573	$ (3,706,345)	$ (740,648,010)	$ 2,110,979	$ 1,791,594
2083	Extrapolation	$ 12	$ 18,149,527	$ 183,219	$ 198,409,444	$ 12	$ 168,270,223	$ 366,679,679	$ 3,701,624	$ (3,518,405)	$ (744,166,415)	$ 2,002,939	$ 1,698,685
2084	Extrapolation	$ 13	$ 18,149,527	$ 171,073	$ 201,569,854	$ 13	$ 170,831,952	$ 372,401,819	$ 3,510,167	$ (3,339,094)	$ (747,505,509)	$ 1,899,947	$ 1,610,220
				178,999,845								$ 470,716,689	$ 455,788,663

[1] Assumed 63 year life for transmission line.

[2] From PROMOD or other Production Cost modeling software.

[3] From PSS/E or other Powerflow modeling software.

[4] Other Economic benefits may include avoided Economic Project Costs, Congestion/Load Cost Savings, Mitigation of Transmission Outage Costs etc.

[5] Other Public Policy Benefits may include Avoided Public Policy project benefits, Renewable Investment Benefit, production cost savings by untrapping renewable generation etc.

[6] Reliability benefits based upon Avoided Reliability Project Costs in a future year

[7] MISO's MTEP17 futures apply carbon fees in the base cases to achieve emission reduction target assumptions, this reported APC is modified to eliminate the value of reduced emissions

High CO2 Values

Project Description	Preferred Option: Huntley - Wilmarth 345 kV with High CO2 Values
Base Year	2016
Expected In Service Date (ISD)	2022
Base Year Cost ($)	$138,020,000 Blue Route (East Route), Double-Circuit Monopole and Single Circuit Monopole

Year	Economic Benefits ($)					Public Policy Benefits ($)		
	PROMOD APC Savings ($) [7]	Transmission Loss Energy Savings ($) [2]	Transmission Loss Capacity Savings ($) [3]	Other Economic Benefits ($) [4]	Total Economic Benefits ($)	PROMOD Emissions Cost Savings ($)	Other PP Benefits ($) [5]	Total Public Policy Benefits ($)
2021	$ 2,542,357				$ 2,542,357	$ 9,247,567		$ 9,247,567
2026	$ 18,109,417				$ 18,109,417	$ 22,642,540		$ 22,642,540
2031	$ 34,146,457				$ 34,146,457	$ 34,864,860		$ 34,864,860

Year [1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($) [6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2017		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	PROMOD Model Year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	Interpolation	$ 160,060,886	$ 20,647,854	$ 13,681,638	$ 5,655,769	$ -	$ 11,926,562	$ 17,582,331	$ 11,650,368	$ 2,031,271	$ 2,031,271	$ 3,747,614	$ 7,902,754
2023	Interpolation	$ -	$ 20,647,854	$ 12,774,639	$ 8,769,181	$ -	$ 14,605,556	$ 23,374,738	$ 14,461,737	$ (1,687,098)	$ 344,173	$ 5,425,412	$ 9,036,324
2024	Interpolation	$ -	$ 20,647,854	$ 11,927,767	$ 11,882,593	$ -	$ 17,284,551	$ 29,167,144	$ 16,849,156	$ (4,921,388)	$ (4,577,215)	$ 6,864,288	$ 9,984,868
2025	Interpolation	$ -	$ 20,647,854	$ 11,137,038	$ 18,109,417	$ -	$ 22,642,540	$ 40,751,957	$ 21,980,787	$ (10,843,749)	$ (15,420,964)	$ 9,767,856	$ 12,212,931
2026	PROMOD Model Year	$ -	$ 20,647,854	$ 10,398,728	$ 18,109,417	$ -	$ 22,642,540	$ 40,751,957	$ 20,523,610	$ (10,124,882)	$ (25,545,847)	$ 9,120,314	$ 11,403,297
2027	Interpolation	$ -	$ 20,647,854	$ 9,709,363	$ 21,316,825	$ -	$ 25,087,004	$ 46,403,829	$ 21,820,748	$ (12,111,385)	$ (37,657,232)	$ 10,023,937	$ 11,796,811
2028	Interpolation	$ -	$ 20,647,854	$ 9,065,699	$ 24,524,233	$ -	$ 27,531,468	$ 52,055,701	$ 22,855,706	$ (13,790,008)	$ (51,447,240)	$ 10,767,671	$ 12,088,035
2029	Interpolation	$ -	$ 20,647,854	$ 8,464,705	$ 27,731,641	$ -	$ 29,975,932	$ 57,707,573	$ 23,657,546	$ (15,192,841)	$ (66,640,081)	$ 11,368,743	$ 12,288,803
2030	Interpolation	$ -	$ 20,647,854	$ 7,903,552	$ 34,146,457	$ -	$ 34,864,860	$ 69,011,317	$ 26,416,040	$ (18,512,488)	$ (85,152,569)	$ 13,070,526	$ 13,345,515
2031	PROMOD Model Year	$ -	$ 20,647,854	$ 7,379,601	$ 34,068,127	$ -	$ 35,060,302	$ 69,128,429	$ 24,706,693	$ (17,327,093)	$ (102,479,661)	$ 12,176,044	$ 12,530,650
2032	Extrapolation	$ -	$ 20,647,854	$ 6,890,383	$ 37,228,537	$ -	$ 37,622,031	$ 74,850,568	$ 24,978,340	$ (18,087,956)	$ (120,567,618)	$ 12,423,513	$ 12,554,826
2033	Extrapolation	$ -	$ 20,647,854	$ 6,433,598	$ 40,388,947	$ -	$ 40,183,760	$ 80,572,707	$ 25,105,389	$ (18,671,791)	$ (139,239,408)	$ 12,584,661	$ 12,520,728
2034	Extrapolation	$ -	$ 20,647,854	$ 6,007,094	$ 43,549,357	$ -	$ 42,745,490	$ 86,294,846	$ 25,105,819	$ (19,098,724)	$ (158,338,133)	$ 12,669,844	$ 12,435,974
2035	Extrapolation	$ -	$ 20,647,854	$ 5,608,865	$ 46,709,767	$ -	$ 45,307,219	$ 92,016,986	$ 24,995,858	$ (19,386,994)	$ (177,725,126)	$ 12,688,426	$ 12,307,432
2036	Extrapolation	$ -	$ 20,647,854	$ 5,237,035	$ 49,870,177	$ -	$ 47,868,948	$ 97,739,125	$ 24,790,143	$ (19,553,107)	$ (197,278,234)	$ 12,648,863	$ 12,141,280
2037	Extrapolation	$ -	$ 20,647,854	$ 4,889,856	$ 53,030,587	$ -	$ 50,430,677	$ 103,461,264	$ 24,501,851	$ (19,611,995)	$ (216,890,229)	$ 12,558,783	$ 11,943,068
2038	Extrapolation	$ -	$ 20,647,854	$ 4,565,692	$ 56,190,996	$ -	$ 52,992,407	$ 109,183,403	$ 24,142,835	$ (19,577,144)	$ (236,467,372)	$ 12,425,057	$ 11,717,779
2039	Extrapolation	$ -	$ 20,647,854	$ 4,263,017	$ 59,351,406	$ -	$ 55,554,136	$ 114,905,542	$ 23,723,740	$ (19,460,722)	$ (255,928,095)	$ 12,253,868	$ 11,469,872
2040	Extrapolation	$ -	$ 20,647,854	$ 3,980,408	$ 62,511,816	$ -	$ 58,115,865	$ 120,627,682	$ 23,254,108	$ (19,273,699)	$ (275,201,794)	$ 12,050,771	$ 11,203,337
2041	Extrapolation	$ -	$ 20,647,854	$ 3,716,534	$ 65,672,226	$ -	$ 60,677,594	$ 126,349,821	$ 22,742,482	$ (19,025,948)	$ (294,227,742)	$ 11,820,748	$ 10,921,734
2042	Extrapolation	$ -	$ 20,647,854	$ 3,470,153	$ 68,832,636	$ -	$ 63,239,324	$ 132,071,960	$ 22,196,494	$ (18,726,340)	$ (312,954,082)	$ 11,568,263	$ 10,628,231
2043	Extrapolation	$ -	$ 20,647,854	$ 3,240,106	$ 71,993,046	$ -	$ 65,801,053	$ 137,794,099	$ 21,622,948	$ (18,382,842)	$ (331,336,924)	$ 11,297,305	$ 10,325,644
2044	Extrapolation	$ -	$ 20,647,854	$ 3,025,309	$ 75,153,456	$ -	$ 68,362,782	$ 143,516,238	$ 21,027,898	$ (18,002,589)	$ (349,339,513)	$ 11,011,431	$ 10,016,467
2045	Extrapolation	$ -	$ 20,647,854	$ 2,824,752	$ 78,313,866	$ -	$ 70,924,511	$ 149,238,378	$ 20,416,715	$ (17,591,963)	$ (366,931,477)	$ 10,713,812	$ 9,702,903
2046	Extrapolation	$ -	$ 20,647,854	$ 2,637,490	$ 81,474,276	$ -	$ 73,486,241	$ 154,960,517	$ 19,794,153	$ (17,156,664)	$ (384,088,140)	$ 10,407,260	$ 9,386,894
2047	Extrapolation	$ -	$ 20,647,854	$ 2,462,642	$ 84,634,686	$ -	$ 76,047,970	$ 160,682,656	$ 19,164,408	$ (16,701,766)	$ (400,789,906)	$ 10,094,267	$ 9,070,141
2048	Extrapolation	$ -	$ 20,647,854	$ 2,299,386	$ 87,795,096	$ -	$ 78,609,699	$ 166,404,795	$ 18,531,167	$ (16,231,781)	$ (417,021,687)	$ 9,777,035	$ 8,754,132
2049	Extrapolation	$ -	$ 20,647,854	$ 2,146,952	$ 90,955,506	$ -	$ 81,171,429	$ 172,126,934	$ 17,897,662	$ (15,750,710)	$ (432,772,396)	$ 9,457,502	$ 8,440,159
2050	Extrapolation	$ -	$ 20,647,854	$ 2,004,624	$ 94,115,916	$ -	$ 83,733,158	$ 177,849,074	$ 17,266,710	$ (15,262,086)	$ (448,034,483)	$ 9,137,367	$ 8,129,343
2051	Extrapolation	$ -	$ 20,647,854	$ 1,871,731	$ 97,276,326	$ -	$ 86,294,887	$ 183,571,213	$ 16,640,758	$ (14,769,027)	$ (462,803,509)	$ 8,818,113	$ 7,822,644
2052	Extrapolation	$ -	$ 20,647,854	$ 1,747,648	$ 100,436,736	$ -	$ 88,856,616	$ 189,293,352	$ 16,021,915	$ (14,274,267)	$ (477,077,776)	$ 8,501,032	$ 7,520,883
2053	Extrapolation	$ -	$ 20,647,854	$ 1,631,791	$ 103,597,146	$ -	$ 91,418,346	$ 195,015,491	$ 15,411,989	$ (13,780,198)	$ (490,857,974)	$ 8,187,237	$ 7,224,752
2054	Extrapolation	$ -	$ 20,647,854	$ 1,523,614	$ 106,757,556	$ -	$ 93,980,075	$ 200,737,630	$ 14,812,518	$ (13,288,904)	$ (504,146,878)	$ 7,877,687	$ 6,934,831
2055	Extrapolation	$ -	$ 20,647,854	$ 1,422,609	$ 109,917,966	$ -	$ 96,541,804	$ 206,459,770	$ 14,224,797	$ (12,802,188)	$ (516,949,066)	$ 7,573,198	$ 6,651,599
2056	Extrapolation	$ -	$ 20,647,854	$ 1,328,300	$ 113,078,376	$ -	$ 99,103,533	$ 212,181,909	$ 13,649,902	$ (12,321,602)	$ (529,270,668)	$ 7,274,459	$ 6,375,442
2057	Extrapolation	$ -	$ 20,647,854	$ 1,240,243	$ 116,238,785	$ -	$ 101,665,263	$ 217,904,048	$ 13,088,714	$ (11,848,472)	$ (541,119,140)	$ 6,982,047	$ 6,106,668
2058	Extrapolation	$ -	$ 20,647,854	$ 1,158,023	$ 119,399,195	$ -	$ 104,226,992	$ 223,626,187	$ 12,541,945	$ (11,383,922)	$ (552,503,061)	$ 6,696,435	$ 5,845,510
2059	Extrapolation	$ -	$ 20,647,854	$ 1,081,254	$ 122,559,605	$ -	$ 106,788,721	$ 229,348,326	$ 12,010,147	$ (10,928,893)	$ (563,431,955)	$ 6,418,006	$ 5,592,141

Year [1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($) [6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2060	Extrapolation	$ -	$ 20,647,854	$ 1,009,574	$ 125,720,015	$ -	$ 109,350,450	$ 235,070,466	$ 11,493,740	$ (10,484,165)	$ (573,916,120)	$ 6,147,064	$ 5,346,676
2061	Extrapolation	$ -	$ 20,647,854	$ 942,646	$ 128,880,425	$ -	$ 111,912,180	$ 240,792,605	$ 10,993,018	$ (10,050,372)	$ (583,966,492)	$ 5,883,839	$ 5,109,180
2062	Extrapolation	$ -	$ 20,647,854	$ 880,155	$ 132,040,835	$ -	$ 114,473,909	$ 246,514,744	$ 10,508,174	$ (9,628,018)	$ (593,594,511)	$ 5,628,499	$ 4,879,675
2063	Extrapolation	$ -	$ 20,647,854	$ 821,807	$ 135,201,245	$ -	$ 117,035,638	$ 252,236,883	$ 10,039,301	$ (9,217,494)	$ (602,812,005)	$ 5,381,156	$ 4,658,145
2064	Extrapolation	$ -	$ 20,647,854	$ 767,327	$ 138,361,655	$ -	$ 119,597,367	$ 257,959,022	$ 9,586,413	$ (8,819,086)	$ (611,631,091)	$ 5,141,871	$ 4,444,542
2065	Extrapolation	$ -	$ 20,647,854	$ 716,458	$ 141,522,065	$ -	$ 122,159,097	$ 263,681,162	$ 9,149,451	$ (8,432,993)	$ (620,064,083)	$ 4,910,662	$ 4,238,788
2066	Extrapolation	$ -	$ 20,647,854	$ 668,962	$ 144,682,475	$ -	$ 124,720,826	$ 269,403,301	$ 8,728,294	$ (8,059,332)	$ (628,123,416)	$ 4,687,512	$ 4,040,782
2067	Extrapolation	$ -	$ 20,647,854	$ 624,614	$ 147,842,885	$ -	$ 127,282,555	$ 275,125,440	$ 8,322,767	$ (7,698,153)	$ (635,821,568)	$ 4,472,367	$ 3,850,400
2068	Extrapolation	$ -	$ 20,647,854	$ 583,207	$ 151,003,295	$ -	$ 129,844,284	$ 280,847,579	$ 7,932,648	$ (7,349,442)	$ (643,171,010)	$ 4,265,146	$ 3,667,502
2069	Extrapolation	$ -	$ 20,647,854	$ 544,544	$ 154,163,705	$ -	$ 132,406,014	$ 286,569,718	$ 7,557,677	$ (7,013,133)	$ (650,184,143)	$ 4,065,745	$ 3,491,932
2070	Extrapolation	$ -	$ 20,647,854	$ 508,444	$ 157,324,115	$ -	$ 134,967,743	$ 292,291,858	$ 7,197,560	$ (6,689,116)	$ (656,873,259)	$ 3,874,038	$ 3,323,522
2071	Extrapolation	$ -	$ 20,647,854	$ 474,738	$ 160,484,525	$ -	$ 137,529,472	$ 298,013,997	$ 6,851,975	$ (6,377,237)	$ (663,250,496)	$ 3,689,880	$ 3,162,095
2072	Extrapolation	$ 1	$ 20,647,854	$ 443,266	$ 163,644,935	$ 1	$ 140,091,201	$ 303,736,137	$ 6,520,578	$ (6,077,312)	$ (669,327,808)	$ 3,513,114	$ 3,007,464
2073	Extrapolation	$ 2	$ 20,647,854	$ 413,881	$ 166,805,345	$ 2	$ 142,652,931	$ 309,458,277	$ 6,203,007	$ (5,789,126)	$ (675,116,934)	$ 3,343,568	$ 2,859,439
2074	Extrapolation	$ 3	$ 20,647,854	$ 386,443	$ 169,965,755	$ 3	$ 145,214,660	$ 315,180,417	$ 5,898,885	$ (5,512,442)	$ (680,629,376)	$ 3,181,062	$ 2,717,823
2075	Extrapolation	$ 4	$ 20,647,854	$ 360,825	$ 173,126,164	$ 4	$ 147,776,389	$ 320,902,558	$ 5,607,824	$ (5,247,000)	$ (685,876,375)	$ 3,025,408	$ 2,582,416
2076	Extrapolation	$ 5	$ 20,647,854	$ 336,904	$ 176,286,574	$ 5	$ 150,338,118	$ 326,624,698	$ 5,329,430	$ (4,992,526)	$ (690,868,901)	$ 2,876,411	$ 2,453,019
2077	Extrapolation	$ 6	$ 20,647,854	$ 314,570	$ 179,446,984	$ 6	$ 152,899,848	$ 332,346,838	$ 5,063,302	$ (4,748,732)	$ (695,617,633)	$ 2,733,874	$ 2,329,428
2078	Extrapolation	$ 7	$ 20,647,854	$ 293,716	$ 182,607,394	$ 7	$ 155,461,577	$ 338,068,978	$ 4,809,037	$ (4,515,321)	$ (700,132,954)	$ 2,597,593	$ 2,211,444
2079	Extrapolation	$ 8	$ 20,647,854	$ 274,245	$ 185,767,804	$ 8	$ 158,023,306	$ 343,791,118	$ 4,566,232	$ (4,291,987)	$ (704,424,942)	$ 2,467,367	$ 2,098,865
2080	Extrapolation	$ 9	$ 20,647,854	$ 256,064	$ 188,928,214	$ 9	$ 160,585,035	$ 349,513,259	$ 4,334,485	$ (4,078,421)	$ (708,503,363)	$ 2,342,991	$ 1,991,494
2081	Extrapolation	$ 10	$ 20,647,854	$ 239,089	$ 192,088,624	$ 10	$ 163,146,765	$ 355,235,399	$ 4,113,397	$ (3,874,308)	$ (712,377,671)	$ 2,224,263	$ 1,889,134
2082	Extrapolation	$ 11	$ 20,647,854	$ 223,239	$ 195,249,034	$ 11	$ 165,708,494	$ 360,957,539	$ 3,902,573	$ (3,679,334)	$ (716,057,005)	$ 2,110,979	$ 1,791,594
2083	Extrapolation	$ 12	$ 20,647,854	$ 208,440	$ 198,409,444	$ 12	$ 168,270,223	$ 366,679,679	$ 3,701,624	$ (3,493,184)	$ (719,550,189)	$ 2,002,939	$ 1,698,685
2084	Extrapolation	$ 13	$ 20,647,854	$ 194,622	$ 201,569,854	$ 13	$ 170,831,952	$ 372,401,819	$ 3,510,167	$ (3,315,545)	$ (722,865,735)	$ 1,899,947	$ 1,610,220
				203,639,619								$ 470,716,689	$ 455,788,663

[1] Assumed 63 year life for transmission line.

[2] From PROMOD or other Production Cost modeling software.

[3] From PSS/E or other Powerflow modeling software.

[4] Other Economic benefits may include avoided Economic Project Costs, Congestion/Load Cost Savings, Mitigation of Transmission Outage Costs etc.

[5] Other Public Policy Benefits may include Avoided Public Policy project benefits, Renewable Investment Benefit, production cost savings by untrapping renewable generation etc.

[6] Reliability benefits based upon Avoided Reliability Project Costs in a future year

[7] MISO's MTEP17 futures apply carbon fees in the base cases to achieve emission reduction target assumptions, this reported APC is modified to eliminate the value of reduced emissions

High CO2 Values

Project Description	**Alternative: Huntley - Wilmarth 161 kV with High CO2 Values**
Base Year	2016
Expected In Service Date (ISD)	2022
Base Year Cost ($)	$80,900,000 Green Route (Middle Route), Single Circuit Parallel Monopole

Year	Economic Benefits ($)					Public Policy Benefits ($)		
	PROMOD APC Savings ($) [7]	Transmission Loss Energy Savings ($) [2]	Transmission Loss Capacity Savings ($) [3]	Other Economic Benefits ($) [4]	Total Economic Benefits ($)	PROMOD Emissions Cost Savings ($)	Other PP Benefits ($) [5]	Total Public Policy Benefits ($)
2021	$ 1,979,035				$ 1,979,035	$ 4,577,497		$ 4,577,497
2026	$ 14,419,053				$ 14,419,053	$ 14,223,557		$ 14,223,557
2031	$ 24,231,427				$ 24,231,427	$ 25,012,946		$ 25,012,946

Year [1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($) [6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2017		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2018		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2019		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2020		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2021	PROMOD Model Year	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2022	Interpolation	$ 93,819,198	$ 12,102,676	$ 8,019,450	$ 4,467,038	$ -	$ 6,506,709	$ 10,973,747	$ 7,271,401	$ 748,049	$ 748,049	$ 2,959,940	$ 4,311,462
2023	Interpolation	$ -	$ 12,102,676	$ 7,487,815	$ 6,955,042	$ -	$ 8,435,921	$ 15,390,963	$ 9,522,248	$ (2,034,433)	$ (1,286,384)	$ 4,303,021	$ 5,219,227
2024	Interpolation	$ -	$ 12,102,676	$ 6,991,424	$ 9,443,045	$ -	$ 10,365,133	$ 19,808,178	$ 11,442,707	$ (4,451,283)	$ (5,737,666)	$ 5,455,020	$ 5,987,687
2025	Interpolation	$ -	$ 12,102,676	$ 6,527,940	$ 14,419,053	$ -	$ 14,223,557	$ 28,642,610	$ 15,449,248	$ (8,921,308)	$ (14,658,974)	$ 7,777,347	$ 7,671,901
2026	PROMOD Model Year	$ -	$ 12,102,676	$ 6,095,183	$ 14,419,053	$ -	$ 14,223,557	$ 28,642,610	$ 14,425,068	$ (8,329,886)	$ (22,988,860)	$ 7,261,762	$ 7,163,306
2027	Interpolation	$ -	$ 12,102,676	$ 5,691,113	$ 16,381,528	$ -	$ 16,381,435	$ 32,762,962	$ 15,406,322	$ (9,715,209)	$ (32,704,069)	$ 7,703,183	$ 7,703,139
2028	Interpolation	$ -	$ 12,102,676	$ 5,313,831	$ 18,344,002	$ -	$ 18,539,313	$ 36,883,315	$ 16,194,081	$ (10,880,249)	$ (43,584,318)	$ 8,054,164	$ 8,139,917
2029	Interpolation	$ -	$ 12,102,676	$ 4,961,561	$ 20,306,477	$ -	$ 20,697,190	$ 41,003,667	$ 16,809,685	$ (11,848,125)	$ (55,432,443)	$ 8,324,755	$ 8,484,930
2030	Interpolation	$ -	$ 12,102,676	$ 4,632,643	$ 24,231,427	$ -	$ 25,012,946	$ 49,244,373	$ 18,849,682	$ (14,217,039)	$ (69,649,481)	$ 9,275,267	$ 9,574,415
2031	PROMOD Model Year	$ -	$ 12,102,676	$ 4,325,530	$ 24,669,368	$ -	$ 24,822,391	$ 49,491,759	$ 17,688,493	$ (13,362,962)	$ (83,012,443)	$ 8,816,901	$ 8,871,592
2032	Extrapolation	$ -	$ 12,102,676	$ 4,038,777	$ 26,894,607	$ -	$ 26,865,936	$ 53,760,543	$ 17,940,400	$ (13,901,622)	$ (96,914,066)	$ 8,974,984	$ 8,965,416
2033	Extrapolation	$ -	$ 12,102,676	$ 3,771,034	$ 29,119,846	$ -	$ 28,909,481	$ 58,029,327	$ 18,081,170	$ (14,310,136)	$ (111,224,202)	$ 9,073,358	$ 9,007,811
2034	Extrapolation	$ -	$ 12,102,676	$ 3,521,040	$ 31,345,085	$ -	$ 30,953,026	$ 62,298,111	$ 18,124,432	$ (14,603,392)	$ (125,827,594)	$ 9,119,247	$ 9,005,185
2035	Extrapolation	$ -	$ 12,102,676	$ 3,287,619	$ 33,570,325	$ -	$ 32,996,571	$ 66,566,895	$ 18,082,495	$ (14,794,876)	$ (140,622,470)	$ 9,119,176	$ 8,963,319
2036	Extrapolation	$ -	$ 12,102,676	$ 3,069,672	$ 35,795,564	$ -	$ 35,040,115	$ 70,835,679	$ 17,966,465	$ (14,896,793)	$ (155,519,263)	$ 9,079,037	$ 8,887,428
2037	Extrapolation	$ -	$ 12,102,676	$ 2,866,174	$ 38,020,803	$ -	$ 37,083,660	$ 75,104,463	$ 17,786,351	$ (14,920,177)	$ (170,439,440)	$ 9,004,143	$ 8,782,208
2038	Extrapolation	$ -	$ 12,102,676	$ 2,676,166	$ 40,246,042	$ -	$ 39,127,205	$ 79,373,247	$ 17,551,159	$ (14,874,993)	$ (185,314,433)	$ 8,899,279	$ 8,651,880
2039	Extrapolation	$ -	$ 12,102,676	$ 2,498,755	$ 42,471,281	$ -	$ 41,170,750	$ 83,642,032	$ 17,268,982	$ (14,770,228)	$ (200,084,661)	$ 8,768,747	$ 8,500,235
2040	Extrapolation	$ -	$ 12,102,676	$ 2,333,104	$ 44,696,521	$ -	$ 43,214,295	$ 87,910,816	$ 16,947,085	$ (14,613,981)	$ (214,698,642)	$ 8,616,411	$ 8,330,674
2041	Extrapolation	$ -	$ 12,102,676	$ 2,178,435	$ 46,921,760	$ -	$ 45,257,840	$ 92,179,600	$ 16,591,974	$ (14,413,538)	$ (229,112,180)	$ 8,445,736	$ 8,146,237
2042	Extrapolation	$ -	$ 12,102,676	$ 2,034,020	$ 49,146,999	$ -	$ 47,301,385	$ 96,448,384	$ 16,209,466	$ (14,175,446)	$ (243,287,626)	$ 8,259,823	$ 7,949,643
2043	Extrapolation	$ -	$ 12,102,676	$ 1,899,178	$ 51,372,238	$ -	$ 49,344,930	$ 100,717,168	$ 15,804,756	$ (13,905,578)	$ (257,193,204)	$ 8,061,443	$ 7,743,313
2044	Extrapolation	$ -	$ 12,102,676	$ 1,773,276	$ 53,597,478	$ -	$ 51,388,475	$ 104,985,952	$ 15,382,468	$ (13,609,192)	$ (270,802,396)	$ 7,853,065	$ 7,529,403
2045	Extrapolation	$ -	$ 12,102,676	$ 1,655,720	$ 55,822,717	$ -	$ 53,432,020	$ 109,254,736	$ 14,946,710	$ (13,290,991)	$ (284,093,387)	$ 7,636,886	$ 7,309,824
2046	Extrapolation	$ -	$ 12,102,676	$ 1,545,957	$ 58,047,956	$ -	$ 55,475,564	$ 113,523,521	$ 14,501,126	$ (12,955,169)	$ (297,048,556)	$ 7,414,857	$ 7,086,269
2047	Extrapolation	$ -	$ 12,102,676	$ 1,443,470	$ 60,273,195	$ -	$ 57,519,109	$ 117,792,305	$ 14,048,932	$ (12,605,462)	$ (309,654,019)	$ 7,188,704	$ 6,860,228
2048	Extrapolation	$ -	$ 12,102,676	$ 1,347,778	$ 62,498,435	$ -	$ 59,562,654	$ 122,061,089	$ 13,592,964	$ (12,245,186)	$ (321,899,205)	$ 6,959,949	$ 6,633,015
2049	Extrapolation	$ -	$ 12,102,676	$ 1,258,429	$ 64,723,674	$ -	$ 61,606,199	$ 126,329,873	$ 13,135,709	$ (11,877,280)	$ (333,776,484)	$ 6,729,931	$ 6,405,778
2050	Extrapolation	$ -	$ 12,102,676	$ 1,175,004	$ 66,948,913	$ -	$ 63,649,744	$ 130,598,657	$ 12,679,342	$ (11,504,337)	$ (345,280,822)	$ 6,499,823	$ 6,179,519
2051	Extrapolation	$ -	$ 12,102,676	$ 1,097,109	$ 69,174,152	$ -	$ 65,693,289	$ 134,867,441	$ 12,225,754	$ (11,128,644)	$ (356,409,466)	$ 6,270,647	$ 5,955,106
2052	Extrapolation	$ -	$ 12,102,676	$ 1,024,379	$ 71,399,392	$ -	$ 67,736,834	$ 139,136,225	$ 11,776,582	$ (10,752,204)	$ (367,161,670)	$ 6,043,292	$ 5,733,290
2053	Extrapolation	$ -	$ 12,102,676	$ 956,469	$ 73,624,631	$ -	$ 69,780,379	$ 143,405,009	$ 11,333,235	$ (10,376,766)	$ (377,538,436)	$ 5,818,522	$ 5,514,713
2054	Extrapolation	$ -	$ 12,102,676	$ 893,062	$ 75,849,870	$ -	$ 71,823,924	$ 147,673,794	$ 10,896,914	$ (10,003,853)	$ (387,542,288)	$ 5,596,995	$ 5,299,919
2055	Extrapolation	$ -	$ 12,102,676	$ 833,858	$ 78,075,109	$ -	$ 73,867,468	$ 151,942,578	$ 10,468,637	$ (9,634,779)	$ (397,177,067)	$ 5,379,269	$ 5,089,368
2056	Extrapolation	$ -	$ 12,102,676	$ 778,579	$ 80,300,349	$ -	$ 75,911,013	$ 156,211,362	$ 10,049,253	$ (9,270,674)	$ (406,447,741)	$ 5,165,812	$ 4,883,441
2057	Extrapolation	$ -	$ 12,102,676	$ 726,964	$ 82,525,588	$ -	$ 77,954,558	$ 160,480,146	$ 9,639,467	$ (8,912,502)	$ (415,360,244)	$ 4,957,016	$ 4,682,451
2058	Extrapolation	$ -	$ 12,102,676	$ 678,772	$ 84,750,827	$ -	$ 79,998,103	$ 164,748,930	$ 9,239,848	$ (8,561,076)	$ (423,921,320)	$ 4,753,201	$ 4,486,647

Year[1]	Source	Transmission Investment	Annual Rev Req ($)	PVRR ($)	Economic Benefits ($)	Reliability Benefits ($)[6]	Public Policy Benefits ($)	Total Benefits ($)	Total Benefits PV ($)	Net PVRR ($)	Net Cumulative PVRR ($)	PV of Economic Benefits	PV of Public Policy Benefits
		[1]	[2]	[3]	[4]	[5]	[6]	[7] = [4]+[5]+[6]	[8]	[9] = [3] - [8]	[10]	[11]	[12]
2059	Extrapolation	$ -	$ 12,102,676	$ 633,774	$ 86,976,066	$ -	$ 82,041,648	$ 169,017,714	$ 8,850,850	$ (8,217,076)	$ (432,138,396)	$ 4,554,624	$ 4,296,226
2060	Extrapolation	$ -	$ 12,102,676	$ 591,759	$ 89,201,305	$ -	$ 84,085,193	$ 173,286,498	$ 8,472,821	$ (7,881,062)	$ (440,019,458)	$ 4,361,486	$ 4,111,334
2061	Extrapolation	$ -	$ 12,102,676	$ 552,529	$ 91,426,545	$ -	$ 86,128,738	$ 177,555,283	$ 8,106,015	$ (7,553,486)	$ (447,572,944)	$ 4,173,939	$ 3,932,076
2062	Extrapolation	$ -	$ 12,102,676	$ 515,900	$ 93,651,784	$ -	$ 88,172,283	$ 181,824,067	$ 7,750,607	$ (7,234,707)	$ (454,807,651)	$ 3,992,091	$ 3,758,516
2063	Extrapolation	$ -	$ 12,102,676	$ 481,700	$ 95,877,023	$ -	$ 90,215,828	$ 186,092,851	$ 7,406,697	$ (6,924,997)	$ (461,732,648)	$ 3,816,009	$ 3,590,687
2064	Extrapolation	$ -	$ 12,102,676	$ 449,766	$ 98,102,262	$ -	$ 92,259,373	$ 190,361,635	$ 7,074,322	$ (6,624,556)	$ (468,357,203)	$ 3,645,729	$ 3,428,593
2065	Extrapolation	$ -	$ 12,102,676	$ 419,950	$ 100,327,502	$ -	$ 94,302,917	$ 194,630,419	$ 6,753,465	$ (6,333,515)	$ (474,690,719)	$ 3,481,256	$ 3,272,209
2066	Extrapolation	$ -	$ 12,102,676	$ 392,110	$ 102,552,741	$ -	$ 96,346,462	$ 198,899,203	$ 6,444,059	$ (6,051,949)	$ (480,742,668)	$ 3,322,567	$ 3,121,492
2067	Extrapolation	$ -	$ 12,102,676	$ 366,116	$ 104,777,980	$ -	$ 98,390,007	$ 203,167,987	$ 6,145,996	$ (5,779,880)	$ (486,522,548)	$ 3,169,619	$ 2,976,377
2068	Extrapolation	$ -	$ 12,102,676	$ 341,845	$ 107,003,219	$ -	$ 100,433,552	$ 207,436,771	$ 5,859,132	$ (5,517,287)	$ (492,039,835)	$ 3,022,347	$ 2,836,784
2069	Extrapolation	$ -	$ 12,102,676	$ 319,183	$ 109,228,459	$ -	$ 102,477,097	$ 211,705,556	$ 5,583,291	$ (5,264,109)	$ (497,303,943)	$ 2,880,672	$ 2,702,619
2070	Extrapolation	$ -	$ 12,102,676	$ 298,023	$ 111,453,698	$ -	$ 104,520,642	$ 215,974,340	$ 5,318,274	$ (5,020,251)	$ (502,324,194)	$ 2,744,499	$ 2,573,775
2071	Extrapolation	$ -	$ 12,102,676	$ 278,266	$ 113,678,937	$ -	$ 106,564,187	$ 220,243,124	$ 5,063,857	$ (4,785,591)	$ (507,109,786)	$ 2,613,720	$ 2,450,137
2072	Extrapolation	$ -	$ 12,102,676	$ 259,819	$ 115,904,176	$ 1	$ 108,607,732	$ 224,511,909	$ 4,819,800	$ (4,559,981)	$ (511,669,766)	$ 2,488,220	$ 2,331,580
2073	Extrapolation	$ -	$ 12,102,676	$ 242,595	$ 118,129,416	$ 2	$ 110,651,277	$ 228,780,694	$ 4,585,847	$ (4,343,252)	$ (516,013,018)	$ 2,367,872	$ 2,217,975
2074	Extrapolation	$ -	$ 12,102,676	$ 226,512	$ 120,354,655	$ 3	$ 112,694,821	$ 233,049,479	$ 4,361,731	$ (4,135,218)	$ (520,148,236)	$ 2,252,546	$ 2,109,185
2075	Extrapolation	$ -	$ 12,102,676	$ 211,496	$ 122,579,894	$ 4	$ 114,738,366	$ 237,318,264	$ 4,147,175	$ (3,935,679)	$ (524,083,915)	$ 2,142,104	$ 2,005,072
2076	Extrapolation	$ -	$ 12,102,676	$ 197,475	$ 124,805,133	$ 5	$ 116,781,911	$ 241,587,050	$ 3,941,898	$ (3,744,423)	$ (527,828,338)	$ 2,036,405	$ 1,905,493
2077	Extrapolation	$ -	$ 12,102,676	$ 184,384	$ 127,030,373	$ 6	$ 118,825,456	$ 245,855,835	$ 3,745,612	$ (3,561,228)	$ (531,389,566)	$ 1,935,307	$ 1,810,305
2078	Extrapolation	$ -	$ 12,102,676	$ 172,161	$ 129,255,612	$ 7	$ 120,869,001	$ 250,124,620	$ 3,558,027	$ (3,385,866)	$ (534,775,432)	$ 1,838,663	$ 1,719,364
2079	Extrapolation	$ -	$ 12,102,676	$ 160,748	$ 131,480,851	$ 8	$ 122,912,546	$ 254,393,405	$ 3,378,852	$ (3,218,104)	$ (537,993,537)	$ 1,746,328	$ 1,632,524
2080	Extrapolation	$ -	$ 12,102,676	$ 150,091	$ 133,706,090	$ 9	$ 124,956,091	$ 258,662,190	$ 3,207,797	$ (3,057,705)	$ (541,051,242)	$ 1,658,155	$ 1,549,642
2081	Extrapolation	$ -	$ 12,102,676	$ 140,141	$ 135,931,329	$ 10	$ 126,999,636	$ 262,930,975	$ 3,044,571	$ (2,904,430)	$ (543,955,672)	$ 1,573,997	$ 1,470,574
2082	Extrapolation	$ -	$ 12,102,676	$ 130,851	$ 138,156,569	$ 11	$ 129,043,181	$ 267,199,760	$ 2,888,890	$ (2,758,039)	$ (546,713,711)	$ 1,493,711	$ 1,395,179
2083	Extrapolation	$ -	$ 12,102,676	$ 122,176	$ 140,381,808	$ 12	$ 131,086,726	$ 271,468,545	$ 2,740,469	$ (2,618,293)	$ (549,332,004)	$ 1,417,152	$ 1,323,318
2084	Extrapolation	$ -	$ 12,102,676	$ 114,077	$ 142,607,047	$ 13	$ 133,130,270	$ 275,737,331	$ 2,599,032	$ (2,484,955)	$ (551,816,959)	$ 1,344,179	$ 1,254,853
				119,362,738								$ 339,693,909	$ 331,485,787

[1] Assumed 63 year life for transmission line.

[2] From PROMOD or other Production Cost modeling software.

[3] From PSS/E or other Powerflow modeling software.

[4] Other Economic benefits may include avoided Economic Project Costs, Congestion/Load Cost Savings, Mitigation of Transmission Outage Costs etc.

[5] Other Public Policy Benefits may include Avoided Public Policy project benefits, Renewable Investment Benefit, production cost savings by untrapping renewable generation etc.

[6] Reliability benefits based upon Avoided Reliability Project Costs in a future year

[7] MISO's MTEP17 futures apply carbon fees in the base cases to achieve emission reduction target assumptions, this reported APC is modified to eliminate the value of reduced emissions

Appendix J

Cost Allocation Information

Year One Project Revenue Requirements Summary

Amounts in dollars (2016)
Tax assumptions include 35% corporate tax rate

	LOW (West Parallel H)			HIGH (161 DC + SC Mono)		
	Line (A)	Subs (B)	Total	Line (A)	Sub (B)	Total
NSPM retail rates revenue requirement	6,361,950		6,361,950	8,271,858		8,271,858
NSPM Substation (Wilmarth) retail rate revenue requirement		372,077	372,077		372,077	372,077
TOTAL NSP retail rate revenue requirement	**6,361,950**	**372,077**	**6,734,027**	**8,271,858**	**372,077**	**8,643,935**
NSP line MISO Attachment GG Revenue Requirement	6,917,950		6,917,950	9,154,785		9,154,785
NSP substation MISO Attachment GG Revenue Requirement		387,481	387,481		387,481	387,481
NSP Total MISO Attachment GG Revenue Requirement	6,917,950	387,481	7,305,431	9,154,785	387,481	9,542,266
ITC line MISO Attachment GG Revenue Requirement	8,357,760		8,357,760	11,032,908		11,032,908
ITC substation MISO Attachment GG Revenue Requirement		414,040	414,040		414,040	414,040
ITC Total MISO Attachment Revenue Requirement	8,357,760	414,040	8,771,801	11,032,908	414,040	11,446,948
TOTAL MISO Attachment GG REVENUE REQUIREMENT	**15,275,710**	**801,521**	**16,077,231**	**20,187,693**	**801,521**	**20,989,215**

Allocation of MISO Attachment GG Revenue Requirement to State of MN load

Zone	HNT-WLM allocation	Estimated % of revenue in MN	% of Project ATRR in MN rates	HNT-WLM allocation	Estimated % of revenue in MN	% of Project ATRR in MN rates
ITCM	20.3%	11.9%	2.4%	20.3%	11.9%	2.4%
GRE	3%	98%	3%	3%	98%	3%
MP	4%	82%	3%	4%	82%	3%
NSP	20%	73%	14%	20%	73%	14%
OTP	3%	51%	2%	3%	51%	2%
SMP	1%	100%	1%	1%	100%	1%
Total	51%		25%	51%		25%
Net Cost to MN Jurisdiction			$ 4,073,870			$ 5,318,536

Calculation to NSP loads:

	Line (A)	Subs (B)	Total	Line (A)	Subs (B)	Total
TOTAL NSP retail rate revenue requirement	6,361,950	372,077	6,734,027	8,271,858	372,077	8,643,935
Less: NSP MISO Attachment GG Revenue Requirement	(6,917,950)	(387,481)	(7,305,431)	(9,154,785)	(387,481)	(9,542,266)
Add: NSP Load ratio share of total MISO Attachment Revenue Requirement (16.96%)	2,591,480	135,976	2,727,456	3,424,784	135,976	3,560,760
Net cost - NSP Companies	2,035,481	120,572	**2,156,053**	2,541,857	120,572	**2,662,429**
FERC Interchange Agreement allocator to NSPM			83.94%			83.94%
Demand Allocator - MN Jurisdiction			87.21%			87.21%
Net cost to MN Jurisdiction			**1,578,319**			**1,949,007**

NSP Companies load ratio share of Pricing Zones in Schedule 26

Zone	Sch 26 - Trans Expansion Plan 12CP Avg Load (2016)	Divisor (2016)	Load Ratio Share
ITCM	5.6	2,945	0.19%
DPC	114.8	879	13.07%
GRE	58.8	1,068	5.51%
MP	0.5	1,660	0.03%
NSP	6,241.0	7,844	79.56%
OTP	292.2	1,312	22.26%

Huntley-Wilmarth Allocation to NSP Companies load

Pricing Zone	Huntley Wilmarth PZ Allocation %	NSP Sch 26 PZ Load Ratio Share	NSP Share of PZ Allocated Costs
ITCM	20.30%	0.19%	0.04%
DPC	2.20%	13.07%	0.29%
GRE	2.70%	5.51%	0.15%
MP	4.20%	0.03%	0.00%
NSP	19.80%	79.56%	15.75%
OTP	3.30%	22.26%	0.73%
Total NSP Companies retail load			16.96%

Appendix K

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

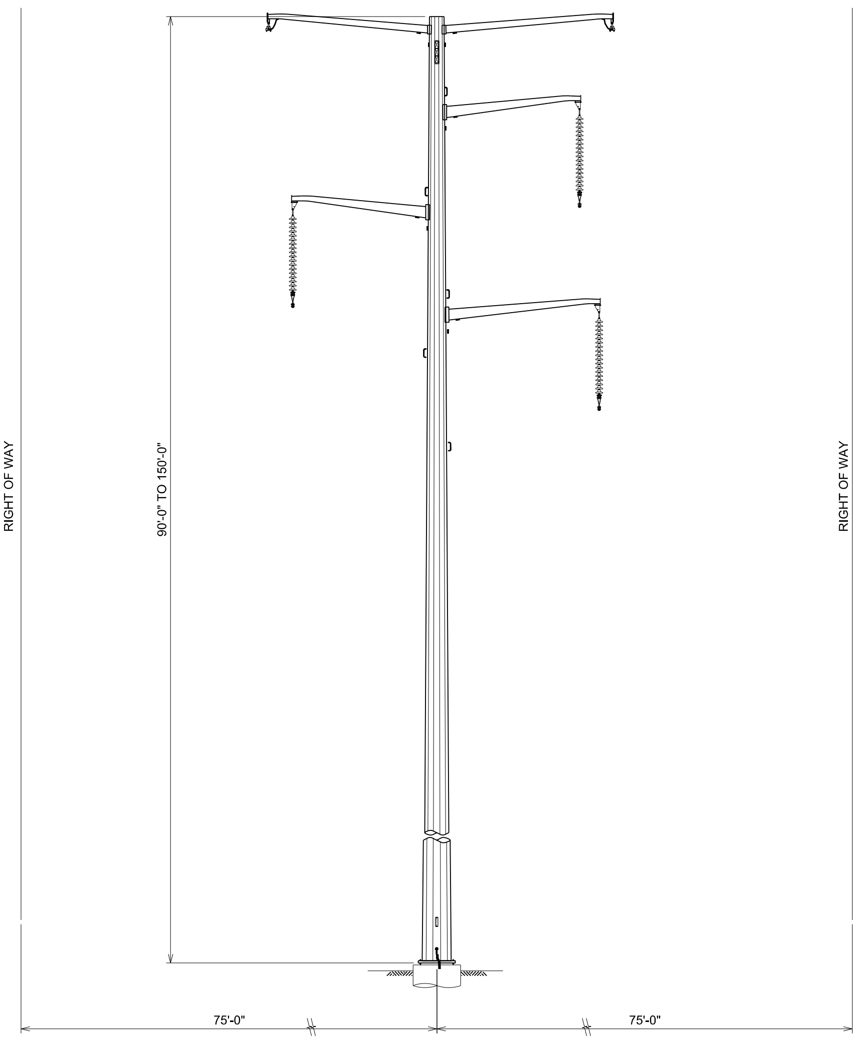
Benefit to Cost Ratios under MTEP17 for Applicants' Proposed Route/Designs

	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 Monopolse 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	**2.14**	**1.86**	**1.64**	**2.08**	**1.87**	**1.67**	**1.64**	**1.83**	**1.67**

Appendix L

Technical Diagrams of Typical 345 kV Structures

SC DAVIT MONOPOLE.DGN



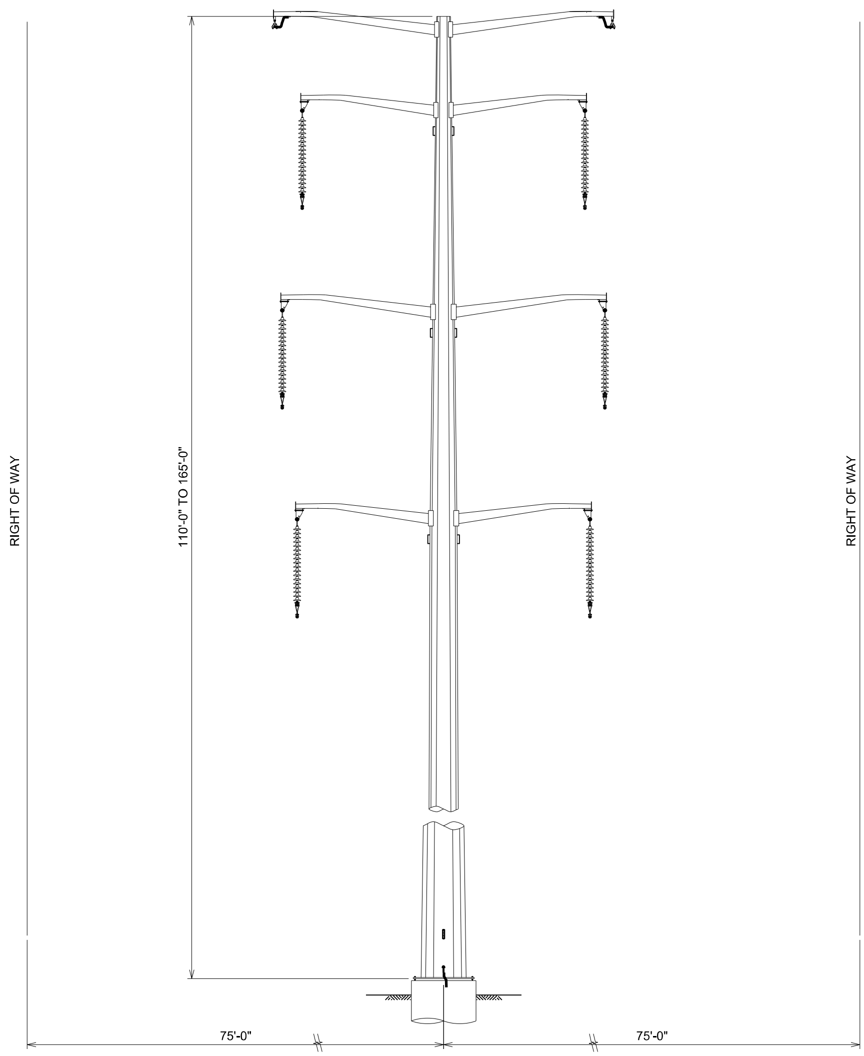
SINGLE CIRCUIT MONOPOLE 345kV

Xcel Energy®

SCALE

REV

10/19/2017 2:14:28 PM



DOUBLE CIRCUIT MONOPOLE 345kV

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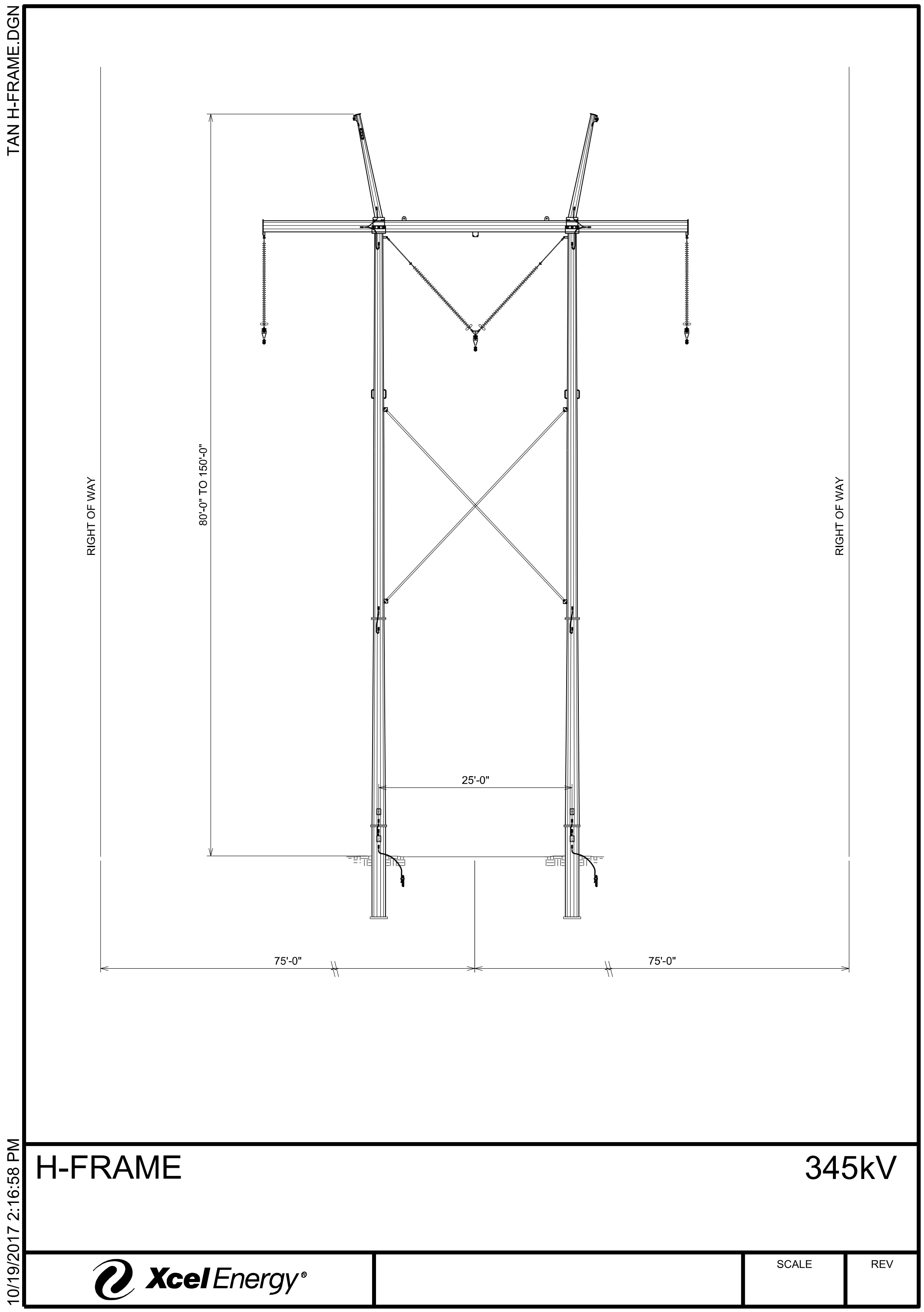
Xcel Energy®

		SCALE	REV

Appendix L
Huntley-Wilmarth Project
Certificate of Need Application
E002, ET6675/CN-17-184



Appendix L
Huntley-Wilmarth Project
Certificate of Need Application
E002, ET6675/CN-17-184

Appendix M

Mankato Area Substation Load Data

Mankato Area Substation Historic and Projected Peak Load Data

	Historical Peak Load (KVA)					Forecasted Load (KVA)				
Substation	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2022**	**2025**	**2027**
Dome Pipeline	1,152	1,248	1,344	1,440	1,488	1,533	1,579	1,725	2,249	2,684
Summit	66,100	62,640	59,490	61,470	62,830	65,508	65,829	67,825	74,184	78,750
Sibley Park	46,090	42,810	44,380	44,680	43,270	45,398	45,718	46,694	49,749	51,896
Eastwood	48,700	47,040	50,410	54,070	50,640	52,090	52,702	57,140	57,803	58,473
St. James East	8,000	7,330	7,130	8,420	7,970	8,410	8,452	8,495	8,625	8,713
St. James Municipal	4,941	4,941	4,729	4,503	4,010	4,930	4,955	4,910	4,777	4,691
Rapidan	2,368	1,937	2,239	2,368	2,282	2,368	2,368	2,368	2,368	2,368
Mapleton	4,736	3,659	3,789	4,865	4,779	4,863	4,887	4,961	5,190	5,348
Minnesota Lake	1,678	1,333	1,438	1,356	1,491	1,678	1,678	1,678	1,678	1,678
Swan Lake	5,156	4,410	4,503	4,913	4,222	5,167	5,203	5,263	5,447	5,574
Lake Emily	6,935	7,706	6,239	5,991	5,543	7,725	7,764	7,695	7,492	7,359
Eagle Lake	5,334	5,001	5,163	5,601	5,008	5,635	5,663	5,610	5,454	5,352
Morristown	1,981	1,954	1,891	2,747	2,747	2,761	2,775	2,788	2,827	2,854
Fair Park	22,446	23,292	23,218	24,659	25,549	27,403	27,678	28,516	31,185	33,102
Faribault	24,190	23,110	22,730	24,250	22,690	24,423	24,546	25,243	27,455	29,036
West Faribault	14817	13473	13523	14136	13225	14,817	14,966	15,419	16,862	17,898
Waterville	14,433	14,171	14,634	15,200	15,530	17,087	17,410	15,273	15,274	15,275
TOTAL	**279,057**	**266,055**	**266,850**	**280,669**	**273,274**	**291,796**	**294,173**	**301,603**	**318,619**	**331,053**