APPENDIX F: TRANSMISSION PLANNING ACTIVITIES

Part 1: Minnesota Biennial Transmission Projects Report Summary

Background

Every two years, Minnesota Power (or "Company") participates with the other Minnesota Transmission Owners in the preparation and filing of the Minnesota Biennial Transmission Projects Report ("Biennial Report"). The Biennial Report is prepared pursuant to Minn. Stat. § 216B.2425, which requires any utility that owns or operates electric transmission facilities in the state of Minnesota to report on the status of its transmission system by November 1 of each odd numbered year. A major purpose of the Biennial Report is to provide information about all present and reasonably foreseeable transmission inadequacies that have been identified in the existing transmission system. An "inadequacy" is essentially a situation where the present transmission infrastructure is unable or unlikely to be able to perform in a consistently reliable fashion in compliance with regulatory standards in the reasonably foreseeable future. In addition to information about inadequacies and the projects proposed to address them, the Biennial Report provides information about the transmission planning process and about the utilities that own transmission lines in the state. The tenth Biennial Report (Docket No. E-999/M-19-205) was filed on October 31, 2019. This report, along with previous reports from 2001, 2003, 2005, 2007, 2009, 2011, 2013, 2015, and 2017, are publicly available on the internet.[1] The 2021 Biennial Report, which will include an updated list of inadequacies and proposed projects, will be filed by November 1, 2021.

Minnesota Power's Transmission Projects

For purposes of the Biennial Report, the state of Minnesota has been divided into six geographic Transmission Planning Zones. Of these six zones, Minnesota Power is located wholly in the Northeast Zone. Table 1 provides the current status of and background information about each of the present and reasonably foreseeable future inadequacies that Minnesota Power reported in the 2019 Biennial Report. Table 1 also includes information on future needs that have been identified by Minnesota Power since the filing of the 2019 Biennial Report. The future needs listed at the end of Table 1 with State (MPUC) Tracking Numbers beginning "2021" will be reported in the 2021 Biennial Report. There are several inadequacies for which projects have been completed and placed in service or the need profile has changed since the 2019 Biennial Report. Completed and cancelled projects since the filing of the 2019 Biennial Report are shown in Table 2.

In both tables, each project is identified by its State (MPUC) Tracking Number as well as its MISO Transmission Expansion Plan ("MTEP") project number. The MTEP project numbers are utilized by the Midcontinent Independent System Operator ("MISO") to identify and track projects in the compilation of the annual MTEP Report. The table also includes the MTEP Year, which identifies the specific year of the MTEP Report in which the project was approved in and its most recent Appendix. The MTEP Appendix classification indicates the status of the project in the regional planning process. For example, "2019/A" indicates that the project was in the MISO MTEP Appendix A and approved in 2019. The MTEP Appendix definitions are as follows:

- Appendix A – Projects recommended for approval
- Appendix B – Projects still in the planning and review process

[1] http://www.minnelectrans.com.

More information can be obtained on these projects by referring to the latest MTEP Report, available on the MISO website at http://www.misoenergy.org (Click on "Planning").

Table 1: Minnesota Power's Transmission Needs

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
2007-NE-N1	2014/B	2548	**Duluth 230 kV Project:** Add a second 230/115 kV transformer at the Hilltop Substation and upgrade an existing line from 115 kV to 230 kV between the Arrowhead and Hilltop Substations. **Location:** Duluth, St. Louis County. **Timing:** Need delayed by Hilltop 230 kV Reliability Project (*MTEP Project #20077*)
2013-NE-N16	2013/B	4295	**HVDC Valve Hall Replacement:** Modernization of existing Arrowhead & Square Butte HVDC converter stations, maintaining existing 550 MW capacity **Location:** Hermantown, St. Louis Co. & Center, ND **Timing:** Earliest in-service date 2027
2013-NE-N17	2014/B	3856	**HVDC 750 MW Upgrade:** Modernize & upgrade capacity of existing HVDC line & terminals to 750 MW. Alternative to Project No. 2013-NE-N16. **Location:** Hermantown, St. Louis Co. & Center, ND **Timing:** Earliest in-service date 2027
2015-NE-N2	2019/A	7913	**868 Line Upgrade:** Reconductor existing 115 kV line to increase capacity; Little Falls – St. Stephen Tap; **Location:** Morrison, Benton, and Stearns Cos. **Timing:** Planned in-service date 2021
2015-NE-N12	2014/B	3832	**Iron Range – Arrowhead 345 kV Line:** Add 500/345 kV transformers at Iron Range Substation and extend a 345 kV line from Iron Range Substation to existing Arrowhead Substation **Location:** Itasca and St. Louis Cos. **Timing:** Minnesota Power has no current plans to construct this project.
2015-NE-N14	2016/A	9622	**83 Line Upgrade:** Replace limiting 230 kV terminal equipment at the Boswell and Blackberry Substations **Location:** Itasca Co. **Timing:** Anticipated in-service date 2022
2015-NE-N18	2018/A	9202	**Swatara Pumping Station (X3A):** New tap in Riverton – Blackberry 230 kV Line & 230 kV breaker addition at Riverton Substation **Location:** Aitkin & Crow Wing Cos. **Timing:** Breaker addition completed in 2019; Tap construction planned for 2021.

2017-NE-N2	2016/A	10383	**Laskin – Tac Harbor Voltage Conversion:** Convert legacy 138 kV system to 115 kV between Laskin, Skibo, Hoyt Lakes, and Taconite Harbor Substations. **Location:** St. Louis & Cook Cos. **Timing:** Planned in-service date 2021
2017-NE-N3	2020/A	18110	**Little Falls Bus Reconfiguration:** Reconfigure Little Falls 115 kV bus connections to mitigate low voltage concerns. (replaces MTEP Project #9643) **Location:** Morrison Co. **Timing:** Anticipated in-service date 2025
2017-NE-N6	2019/A	10285	**Forbes Tie Breaker Addition:** Reconfigure Forbes 115 kV bus to install redundant tie breaker & replace aging 115 kV apparatus **Location:** St. Louis Co. **Timing:** Planned implementation in 2021-22
2017-NE-N21	2018/A	13504	**Laskin – Tac Harbor Transmission Line Upgrades:** Increase capacity of existing Laskin – Hoyt Lakes – Taconite Harbor transmission lines in coordination with Voltage Conversion Project (2017-NE-N2) **Location:** St. Louis & Cook Cos. **Timing:** Staged implementation in 2019-20-21
2017-NE-N23	2018/A	13485	**Mesaba Junction 115 kV Project:** New switching station, cap banks, and 115 kV line extension to support redundancy to North Shore Loop **Location:** Hoyt Lakes, St. Louis Co. **Timing:** Switching station complete by end of 2020, 115 kV line extension and interconnection staged with Voltage Conversion (2017-NE-N2) in 2021
2019-NE-N2	2019/A	15591	**Forbes 37 Line Upgrade:** Increase capacity of Forbes – 37 Line Tap 115 kV Line **Location:** St. Louis Co. **Timing:** Anticipated in-service date 2022
2019-NE-N3	2020/A	15592	**Hibbing 14 Line Upgrade:** Increase capacity of Hibbing – 14 Line Tap 115 kV Line **Location:** Hibbing, St. Louis Co. **Timing:** Planned in-service date 2021
2019-NE-N4	2020/A	15593	**25 Line Upgrade:** Increase capacity of Hibbing – Virginia 115 kV Line **Location:** St. Louis Co. **Timing:** Anticipated in-service date 2022
2019-NE-N5	2019/B	15594	**29 Line Upgrade:** Increase capacity of Boswell – Grand Rapids 115 kV Line **Location:** Cohasset & Grand Rapids, Itasca Co. **Timing:** Need & timing for this project to be reviewed in next MTEP cycle

2019-NE-N6	2019/A	15596	**Long Prairie Substation Modernization:** Age-related equipment replacements and site improvements at existing Long Prairie 115/34 kV Substation **Location:** Long Prairie, Todd Co. **Timing:** Staged implementation in 2021-22
2019-NE-N7	2019/A	15597	**Savanna Transformer:** Expand existing substation to accommodate a new distribution transformer. Retire 90-year-old Floodwood Substation. Rebuild nearby Meadowlands Substation. **Location:** Floodwood & Meadowlands, St. Louis Co **Timing:** Staged implementation in 2020-21
2019-NE-N8	2020/A	15598	**Badoura Transformer Replacement:** Replace existing Badoura 230/115 kV transformer and expand 230 kV substation to a ring bus. **Location:** Hubbard Co. **Timing:** Anticipated in-service date 2024
2019-NE-N10	2018/B 2018/B	16069 16070	**Babbitt Area 115 kV Project:** Rebuild & extend existing Embarrass – Babbitt 115 kV Line to Hoyt Lakes area **Location:** Babbitt & Hoyt Lakes, St. Louis Co. **Timing:** Anticipated in-service date 2025
2019-NE-N12	2020/B	17868	**Duluth 115 kV Loop:** New 115 kV line from Hilltop to Haines Road to Ridgeview Substations to support redundancy to Duluth and the North Shore Loop **Location:** Duluth, St. Louis Co. **Timing:** Anticipate staged implementation in 2024-25
2019-NE-N13	2020/A	17870	**National Breaker Replacements:** Age-related replacement of five 115 kV circuit breakers and associated equipment at National Substation **Location:** Hibbing, St Louis Co. **Timing:** Planned in-service date 2021
2019-NE-N14	2020/A	17871	**Laskin Breaker Replacements:** Age-related replacement of up to three 115 kV circuit breakers and associated equipment at Laskin Substation **Location:** Hoyt Lakes, St. Louis Co. **Timing:** Anticipated in-service date 2024
2021-NE-XX	2020/B	18058	**HVDC Line Hardening Project:** Structure replacements to improve HVDC line resiliency and restorability at critical infrastructure crossings **Location:** Various locations between Duluth, St. Louis Co., and Center, ND **Timing:** Staged implementation in coordination with HVDC Valve Hall Replacement (2013-NE-N16) or HVDC 750 MW Upgrade (2013-NE-N17)
2021-NE-XX	2020/A	18060	**8 Line Relocation:** Relocate and rebuild existing Fond Du Lac – Thomson 115 kV Line. **Location:** Carlton Co. **Timing:** Anticipated in-service date 2022

2021-NE-XX	2020/A	18064	**Hibbing Breaker Replacements:** Age-related replacement of three existing 115 kV circuit breakers and associated equipment at Hibbing Substation **Location:** Hibbing, St. Louis Co. **Timing:** Anticipated in-service date 2022-23
2021-NE-XX	2020/A	18065	**Verndale Breaker Replacements:** Age-related replacement of two existing 115 kV circuit breakers and associated equipment at Verndale Substation **Location:** Verndale, Wadena Co. **Timing:** Anticipated in-service date 2024-25
2021-NE-XX	2021/A	18066	**Badoura Breaker Replacements:** Age-related replacement of two existing 115 kV circuit breakers and associated equipment at Badoura Substation **Location:** Hubbard Co. **Timing:** Anticipated in-service date 2022
2021-NE-XX	2020/A	18109	**15th Ave West 115/34 kV Transformer:** Expand existing substation to accommodate a new distribution transformer to support downtown Duluth area **Location:** Duluth, St. Louis Co. **Timing:** Anticipated in-service date 2023
2021-NE-XX	2021/A	18945	**98 Line Asset Renewal:** Age & condition-related structure and hardware replacements on Iron Range – Arrowhead 230 kV Line **Location:** Itasca & St. Louis Cos. **Timing:** Planned in-service date 2021
2021-NE-XX	2021/A	20030	**LSPI Cap Bank Refurbishment:** Refurbish problematic capacitor bank with targeted updates **Location:** Duluth, St. Louis Co. **Timing:** Anticipated in-service date 2022
2021-NE-XX	2021/A	20032	**Canosia Rd Transformer Addition:** Expand existing substation to accommodate a new distribution transformer to support Cloquet & surrounding area **Location:** Esko, Carlton Co. **Timing:** Anticipated in-service date 2022
2021-NE-XX	2021/B	20071	**95 Line Asset Renewal:** Age & condition-related structure and hardware replacements on Boswell – Blackberry 230 kV Line **Location:** Itasca Co. **Timing:** Anticipated in-service date 2024
2021-NE-XX	2021/B	20074	**Tac Harbor Switching Station:** Construct new switching station to replace existing Taconite Harbor Substation **Location:** Cook Co. **Timing:** Anticipated in-service date 2023

2021-NE-XX	2021/A	20075	**Forbes 230 kV Asset Renewal:** Age-related replacement of one 230 kV circuit breaker, one 230 kV capacitor bank, and associated equipment at Forbes Substation **Location:** St. Louis Co. **Timing:** Anticipated in-service date 2022
2021-NE-XX	2021/A	20077	**Hilltop 230 kV Reliability Project:** Increase capacity of Hilltop 230/115 kV transformer, add breakers and sectionalize Arrowhead – Hilltop 230 kV Line **Location:** St. Louis Co. **Timing:** Anticipated in-service date 2024
2021-NE-XX	2021/B	20087	**Cloquet Substation Renewal:** Age-related replacement of two 115 kV circuit breakers and associated equipment at Cloquet Substation. **Location:** Cloquet, Carlton Co. **Timing:** Anticipated in-service date 2023-24

[TRADE SECRET DATA BEGINS [redacted]

MPUC Tracking Number	MTEP Year & Appendix	MTEP Project Number	Description
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]	

TRADE SECRET DATA ENDS]

Part 2: Great Northern Transmission Line

Background

Minnesota Power, in partnership with Manitoba Hydro, has constructed a new interconnection from southern Manitoba to northeastern Minnesota. The Great Northern Transmission Line ("GNTL") Project is the Minnesota portion of the new 500 kV interconnection between Manitoba and Minnesota. The purpose of the Great Northern Transmission Line Project is to efficiently provide Minnesota Power's customers and the Midwest region with clean, emission-free energy that will:

- Help meet the region's growing long-term energy demands;
- Advance Minnesota Power's *Energy**Forward*** strategy to increase its generation diversity and renewable portfolio;
- Strengthen system reliability; and
- Fulfill Minnesota Power's obligations under its power purchase agreements with Manitoba Hydro.

The GNTL facilitates 883 MW of incremental Manitoba – United States transfer capability, including 383 MW of hydropower and wind storage energy products to serve Minnesota Power's customers. Minnesota Power's 250 MW Power Purchase Agreement and 133 MW Renewable Energy Optimization Agreement with Manitoba Hydro both required that new transmission facilities be in place by June 1, 2020, to facilitate the transactions. The Manitoba hydropower purchases made possible by the GNTL provide Minnesota Power and other utilities in the Upper Midwest access to a predominantly emission-free energy supply that has a unique combination of baseload supply characteristics, price certainty, and resource optimization flexibility not available in comparable alternatives for meeting customer requirements.

Project Description

The GNTL Project includes approximately 225 miles of 500 kV transmission line between a point on the Minnesota – Manitoba border northwest of Roseau, Minn., and Minnesota Power's existing Blackberry Substation near Grand Rapids, Minn. The Project also includes the development of a new substation (Iron Range 500/230 kV Substation), located on the same site as the existing Blackberry Substation, as well as a 500 kV midline series capacitor bank station (Warroad River Series Compensation Station) located near Warroad, Minnesota.

Project Status

In anticipation of the GNTL Project's aggressive schedule and needing to meet a June 1, 2020, in-service date, Minnesota Power initiated a proactive public outreach program to key agency stakeholders and the public that started in August 2012 and continued through May 2015. Through this program, thousands of landowners, the public, and tribal, federal, state, and local agency stakeholders were engaged through a variety of means, including five rounds of voluntary public open house meetings held throughout the GNTL Project area.

On September 23, 2014, Minnesota Power, Manitoba Hydro, and MISO executed a Facilities Construction Agreement ("FCA") for the GNTL Project, setting forth the ownership and financial responsibilities for the Project, among other terms. Upon approval of the FCA by the Federal Energy Regulatory Commission ("FERC") on November 25, 2014, MISO considered the Project an approved project under the MISO tariff and moved the GNTL Project to Appendix A of the MTEP14 (Midcontinent Transmission Expansion Plan 2014). Subsequently, the

Minnesota Public Utilities Commission ("Commission") granted Minnesota Power a Certificate of Need (Docket No. E015/CN-12-1163) and Route Permit (Docket No. E015/TL-14-21) for the GNTL Project on May 14, 2015, and February 26, 2016, respectively. The final major approval – the United States Presidential Permit granting approval of the border crossing (DOE Docket No. PP-398) – was received from the United States Department of Energy on November 16, 2016.

Following receipt of the Presidential Permit, Minnesota Power began construction of the GNTL Project in early 2017. Construction continued through 2017, 2018, and 2019, ultimately culminating in placing the new 500 kV interconnection in-service on June 1, 2020 in satisfaction of the contractual agreements between Minnesota Power and Manitoba Hydro.

Part 3: Center – Arrowhead High Voltage Direct Current ("HVDC") Line

Background

In early 2010, Minnesota Power finalized its purchase of a 465 mile, +/- 250 kV HVDC line with converter stations located in Center, North Dakota, and Hermantown, Minnesota ("HVDC Line"). The line and its converter stations at the Center and Arrowhead substations were built in the 1970's to bring electricity from the coal-fired Milton R. Young 2 ("Young 2") generating station in Center, North Dakota, directly to Minnesota Power's customers. Minnesota Power's purchase of the HVDC Line in 2010 cleared the way for the line to be repurposed to facilitate the delivery of wind power generated in North Dakota directly to Minnesota Power's customers. Minnesota Power subsequently purchased and developed a portfolio of approximately 600 MW of North Dakota wind that now relies on the HVDC Line for reliable transmission deliverability. In recent years, Minnesota Power has been evaluating the need for modernization and capacity upgrades to extend the life and expand the usefulness of the HVDC Line. A brief discussion on the need for modernization of the HVDC converter stations and Minnesota Power's assessment of options for increasing the capacity and usefulness of the facility is provided below.

HVDC Modernization

The Center and Arrowhead HVDC converter stations were designed by General Electric ("GE") for a 30 year operating lifetime and as of 2021 they have been operating reliably for over 40 years. The main components of the HVDC converter stations include power electronics (thyristor valves) and their associated cooling system, converter transformers, smoothing reactors, harmonic filters and reactive resources to complete the conversion between alternating current ("AC") and direct current ("DC"). The original vendor, GE, left the HVDC business in the 1980s and in recent years it has been increasingly difficult to procure spare parts for the converter stations as the technology is becoming obsolete and the original designers are well into retirement. Minnesota Power has researched reverse engineering solutions to this technology issue, but has had limited results and thus spare and replacement parts for the converter stations remain limited. Modernizing the converter stations by replacing the thyristors, cooling system, converter transformers, smoothing reactors, harmonic filters, reactive resources, and control system will greatly reduce the likelihood of an extended outage due to component failures in the HVDC converter stations.

HVDC Capacity Upgrades

The modernization of the existing Center and Arrowhead HVDC converter stations presents a once-in-a-generation opportunity to consider enhancements to the long-term value of the HVDC system. At a time when there is increasing focus on long-term regional transmission needs and renewable energy integration, it is especially worthwhile to evaluate the costs and benefits of increasing the capacity and usefulness of the Center – Arrowhead HVDC corridor. Minnesota Power has assessed the capacity limitations associated with the existing HVDC Line and found that the total capacity of the HVDC Line may be reasonably increased from 550 MW to a maximum of 900 MW concurrently with modernization of the converter stations. Upgrades would also be needed along the 465-mile HVDC transmission line to achieve increased capacity above 550 MW. Depending on the long-term value outlook, a lower total capacity such as 750 MW may ultimately prove to be the most cost-effective and efficient solution for Minnesota Power's customers. Modern HVDC technology at the converter stations would also enhance HVDC dispatch capability and allow energy to flow in both west to east and east to west directions, adding new flexibility and optionality for the regional transmission system. More significant changes to the capacity, operating voltage, and converter technology of the HVDC system could also provide enhanced long-term value for Minnesota Power and the region, but would come at considerably higher cost. Minnesota Power is in the process of carefully considering the long-term value of the HVDC corridor both internally and with MISO in order to determine the best path forward for its customers and the region.

Current Status

Both the HVDC Modernization Project and the potential HVDC Capacity Upgrade Project are currently in the MISO MTEP Appendix B. At the request of Minnesota Power, MISO performed Transmission Service Request ("TSR") System Impact Studies on varying levels of increased HVDC capacity in 2019-2020 and provided Facilities Studies to the TSR customers documenting the associated costs. While the timing of the HVDC Modernization and Capacity Upgrade projects has been fluid in recent years due to Minnesota Power's ongoing assessment of the risks, value proposition, and opportunities associated with the projects, Minnesota Power presently anticipates proceeding with an HVDC converter station modernization and upgrade project to be completed and placed in service by the end of 2027.

Part 4: Generator Interconnection Network Upgrade Assumptions

Background

Transmission network upgrade costs realized through the MISO definitive planning phase ("DPP") generator interconnection process are difficult to accurately predict. In order to provide a reasonable range of generator interconnection network upgrade cost assumptions for the purpose of modeling new resources in the IRP, Minnesota Power's Transmission Planning and Resource Planning disciplines collaboratively devised a methodology based on historical network upgrade costs reported in recent DPP cycles. This methodology is intended to establish generic assumptions for IRP modeling purposes, and is not meant to be predictive of the actual network upgrades or costs associated with any specific (individual) future generation project. An overview of the methodology behind the generator interconnection network upgrade cost assumptions used for IRP modeling is provided below.

Methodology

To begin development of a methodology, Minnesota Power reviewed several recent MISO DPP cycles that employed MISO's present generator interconnection study practices and modeling assumptions. Specific DPP cycles included in the analysis were from the MISO West region only, between February 2016 – April 2018 to align with MISO's change to a three-phase system impact study. DPP network upgrades identified in each of the three phases of these cycles were categorized and grouped into the following three general network upgrade cost types:

- **C1 - Base MISO Network Upgrade Costs:** Steady State Thermal & Voltage, Transient Stability, Short Circuit, NRIS Network Upgrades, TOIF Network Upgrades, TO-Owned Direct Assigned, (Disregard Shared Network Upgrade Costs), Local Planning Criteria except GRE.
- **C2 - Backbone Network Upgrade Costs:** Backbone/Base Case Network Upgrades, MWEX Voltage Stability, GRE Local Planning Criteria. These types typically involve EHV transmission lines at a substantial project cost.
- **C3 - Affected Systems Network Upgrade Costs:** All Affected Systems costs, including PJM and SPP.

Subsequently, the costs for each type were linked to the generation projects they were allocated to in the DPP cycle in order to calculate a rate ($/kW) for network upgrades by generation project. The decision of each of the generation projects to continue, withdraw, or modify their interconnection request in light of the assigned transmission network upgrade costs at each phase of the study process was also evaluated. Based on this assessment, the network upgrade costs at the time a generation project either withdrew or proceeded to a Generator Interconnection Agreement were combined and weighted to come up with a generic network upgrade rate ($/MW) by fuel type. Weightings applied at each decision point are borrowed from the 2020 OMS-MISO Survey used for accredited capacity projections to ensure consistency between processes and methodologies relying on generator queue uncertainty for future planning. The fuel-type rates for each of the three cost types (C1, C2, and C3) were then used to develop two different projections of interconnection costs for use when modeling new solar and wind resources in the IRP. The Base Cost Assumptions combines the C1, C2, and C3 cost buckets. The Low Interconnection Cost Sensitivity Assumption is represented by adding the C1 and C2 cost groups, but excluding the C3 cost bucket. The upgrades required and included in the C3 cost bucket are determined through Affected System Studies performed by third parties (i.e. not MISO). These costs have been volatile for many projects over the past few cycles leading to some uncertainty on how to approach them. There is also added difficulty estimating these costs because the studies resulting in these upgrades do not always use MISO base models.

The cost ranges for wind and solar resources are shown in Table 3. The cost rates calculated were assumed to be in 2020 dollars and were escalated by 2.5 percent per year for use in the IRP modeling scenarios.

Table 3: Generator Interconnection Cost Assumptions

	Base Interconnection ($/kW)	Low Sensitivity ($/kW)
New Wind	$491	$343
New Solar	$192	$66

Part 5: CapX 2050 Transmission Vision Report Overview

Background

Minnesota Power, in collaboration with the nine other CapX2020 utilities, announced in 2019 a plan to study how a concerted effort to reduce carbon emissions from the generation of electricity could affect the transmission system that serves Minnesota, eastern South Dakota and North Dakota, western Wisconsin, and the surrounding areas. The resulting CapX2050 Transmission Vision Report ("CapX2050 Report") focused on how transitioning away from traditional dispatchable generating resources and increasing reliance on intermittent renewable (non-dispatchable) generating resources would affect the operation of the transmission grid in the coming decades. While not intended to identify specific new transmission projects, the CapX2050 Report highlighted the need for additional grid infrastructure, either in the form of new high voltage lines or the development of new advanced technologies.

Findings

The CapX2050 Report highlighted four key areas, or findings, that are necessary to continue operating a safe, reliable, and affordable grid:

- Dispatchable resources support the electric grid in ways that non-dispatchable resources presently cannot. They provide physical attributes that help maintain a stable and reliable grid. As dispatchable resources are retired, it will be essential that new and existing generation and transmission technologies are deployed with the ability to provide grid support in the appropriate locations to ensure reliability is maintained.
- The ability for System Operators to meet real-time operational demands will become more challenging as dispatchable resources are retired and their corresponding ancillary services are lost and therefore, we will need to develop new tools and operating procedures to address the challenges.
- More transmission system infrastructure will be needed in the Upper Midwest to accommodate the transition of resources while maintaining the reliability of the transmission system.
- Non-dispatchable resources alone will be incapable of meeting all consumer energy requirements at all times. Dispatchable resources and/or energy storage with capacity for multi-day support will be needed.

As an example, the CapX2050 Report specifically cites Minnesota Power's experience with fleet transition in the North Shore Loop area and the need to implement transmission solutions, including a static synchronous compensator ("STATCOM"), to support system reliability with traditional dispatchable resources offline. A detailed discussion of Minnesota Power's fleet transition experience in the North Shore Loop and other areas is provided in Part 6 below.

Future Work & Next Steps

Understanding and highlighting the critical issues of a transitioning power system will provide the basis for more extensive studies in the future. Minnesota Power will be deeply involved in these studies on its own, in partnership with its CapX2020 fellow members, and with its regional transmission operator MISO. Collectively, we are committed to a long-term transmission vision that will facilitate a greater utilization of non-dispatchable resources while ensuring reliable, safe, and affordable energy is provided to the consumers we serve.

The CapX2050 Report is publicly available at http://www.capx2020.com/

Part 6: Fleet Transition Experience with Small Coal Unit Closures

This section provides an update on transmission system impacts and projects implemented as a result of previous small coal unit fleet transition decisions at Laskin Energy Center, Taconite Harbor Energy Center, and Boswell Energy Center Units 1 and 2. The discussion focuses on specific transmission projects needed to mitigate transmission system impacts from small coal unit closures, with added context around the underlying concepts that drive these needs. The understanding gained from our experience of implementing small coal unit closures on our system has been foundational to informing our understanding and expectations for the broader impacts from similar consideration of Boswell Energy Center Units 3 and 4. While those units and their area of impact are much larger than the small coal units discussed in this section, we believe that the same general concepts may be applied – albeit on a much larger scale – to understand and anticipate the impacts from shutting down Boswell Units 3 and 4. Our analysis of Boswell Unit 3 and 4 closures will be discussed in Part 7.

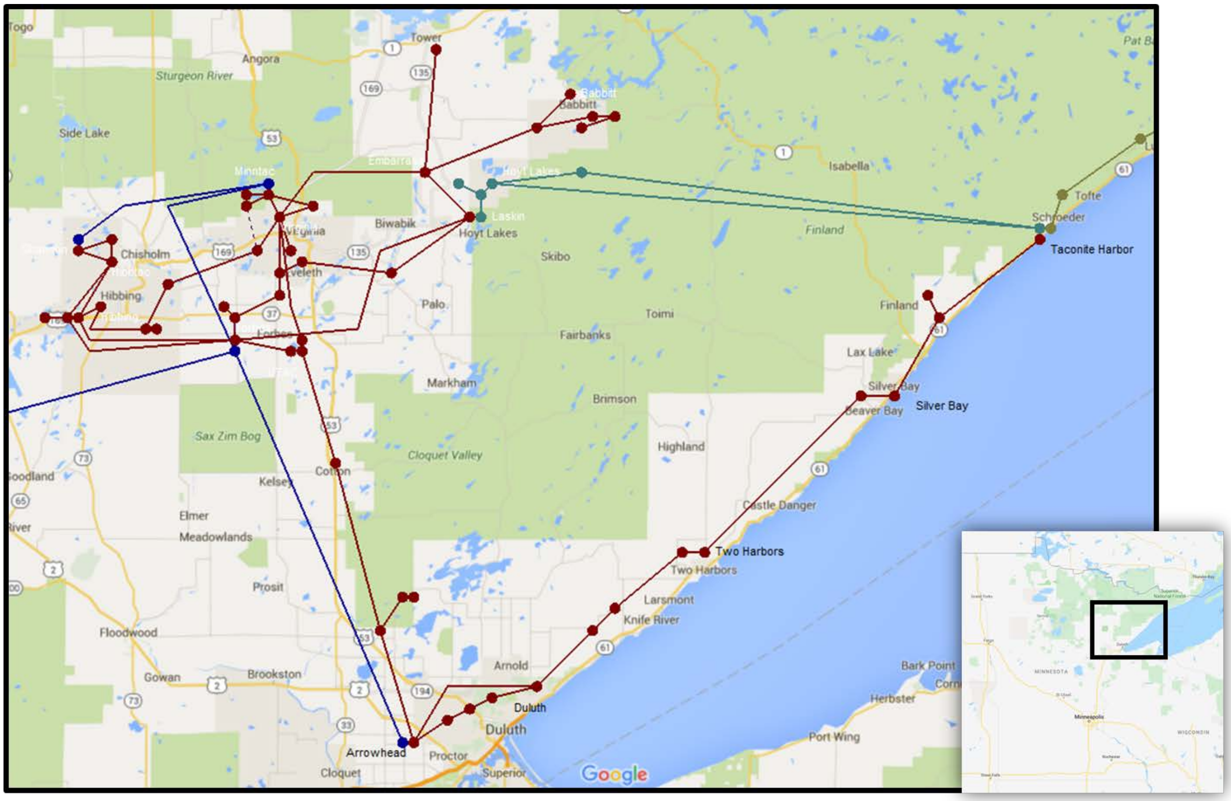
The initial discussion in this section will focus on the North Shore Loop transmission system, which includes the Laskin and Taconite Harbor Energy Centers. The impact of small coal unit closures on voltage support and system strength, local power delivery and redundancy in the North Shore Loop and the surrounding area will be illustrated, including fundamental concepts, specific projects implemented and a summary of project costs to date. Following the North Shore Loop discussion, a briefer discussion of the Grand Rapids Area and impacts from shutting down Boswell Energy Center Units 1 and 2 is also provided.

The North Shore Loop: Laskin & Taconite Harbor

Background

The North Shore Loop is a 140-mile system of 115 kV and 138 kV lines that extends approximately 70 miles along the North Shore of Lake Superior from east Duluth to the Taconite Harbor Energy Center near Schroeder, then turns west and extends approximately another 70 miles to the Laskin Energy Center near Hoyt Lakes. The North Shore Loop transmission system is used by Minnesota Power and Great River Energy to serve customers in an area extending from Duluth to the Canadian border to the eastern end of the Mesabi Iron Range, including east Duluth, Two Harbors, Silver Bay, Grand Marais, Hoyt Lakes, and the surrounding areas. The North Shore Loop transmission system is shown in Figure 1.

Figure 1: North Shore Loop Transmission System



Historically, the North Shore loop contained an abundance of coal-fired baseload generation, and the transmission system was designed from the mid-1900s onward to rely on the power and system support provided by the local baseload generators to serve customers. North Shore Loop coal-fired generators included Minnesota Power's Laskin Energy Center and Taconite Harbor Energy Center, as well as a large industrial cogeneration facility located in Silver Bay. The Silver Bay generators are owned by Silver Bay Power Company, a subsidiary of Cliffs Natural Resources Inc. Over a span of approximately five years beginning in 2015, all seven of the coal-fired generating units located at these three sites have been idled, retired, or converted to peaking operation. In 2015, the two units at the Laskin Energy Center were converted from coal-fired baseload units to peaking natural gas capacity units. Also in 2015, Minnesota Power retired one of the units at the Taconite Harbor Energy Center. In 2016, Minnesota Power idled the other two Taconite Harbor Energy Center units. Coal-fired operations at Taconite Harbor ceased by 2020 with full retirement scheduled for September 2021. In June 2016, Silver Bay Power Company began operating with one of the two Silver Bay units normally idled. Finally, in September 2019 Silver Bay Power Company idled both of the Silver Bay units. The cumulative impact of these operational changes has effectively decarbonized the North Shore Loop, leaving no baseload generators normally online.

The local baseload generators at Laskin Energy Center, Taconite Harbor Energy Center, and Silver Bay have, for decades, contributed to the reliability of the North Shore Loop transmission system by providing voltage support, power delivery capability, and redundancy, among other things. As a result of the rapid decarbonization of the North Shore Loop, several transmission projects throughout and adjacent to the North Shore Loop have been implemented since 2016 and several more projects are planned between 2020 and 2025. Below is a summary of the types of transmission impacts identified as a result of moving beyond baseload generation in the North Shore Loop and the projects Minnesota Power has implemented or is planning to implement to address these impacts.

Voltage Support & System Strength

Local baseload generators provide reactive power and voltage support to the local transmission system. Electric power generated in an alternating current power system includes the generation of both real power, measured in megawatts, as well as reactive power, measured in mega voltage amperes reactive ("MVAR"). Reactive power is required to maintain an appropriate system voltage, stabilize the system, and enable the delivery of real power. Generators provide a dynamic source of reactive power, able to ramp MVAR output up and down within the limits of the generator to regulate system voltage. This dynamic reactive support becomes particularly important for system reliability, as abrupt changes in the power system can result in rapid voltage collapse if there is not a fast-responding source of reactive power. Unlike real power, which can be transmitted over long distances with relatively minimal losses, reactive power tends to be consumed locally by loads and by the transmission system itself as transmission lines load up above their optimal power delivery capability. As more power is transferred on the transmission system, the reactive power needed to maintain appropriate system voltage increases. Without the local baseload generators in the North Shore Loop, the main sources of reactive power and voltage support have been lost. The resulting voltage support-related issues include increased difficulty regulating transmission system voltage, post-contingent high or low voltage conditions, and increased risk of voltage collapse.

To illustrate the voltage regulation impacts, Figure 2 below shows the Taconite Harbor 138 kV bus voltage for the second half of 2016. As noted on the figure, Taconite Harbor Unit 1 and Unit 2 were idled in October 2016. The impact of the transition of these generators on transmission system voltage regulation is noticeable. Without the local voltage regulation provided by the Taconite Harbor units, the transmission system voltage becomes less predictable – varying more rapidly and over a broader range than it did when the Taconite Harbor units were online and regulating the voltage. Without the voltage support and system strength from the generators, which acted like shock absorbers any time there was a significant change on the system, the transmission system voltage is also impacted more significantly by minute-to-minute and day-to-day changes, such as large motor starting or other changes in load, switching of fixed reactive support devices like capacitor banks, and events outside of the North Shore Loop transmission system.

Figure 2: Taconite Harbor 138 kV Bus Voltage, June – December 2016

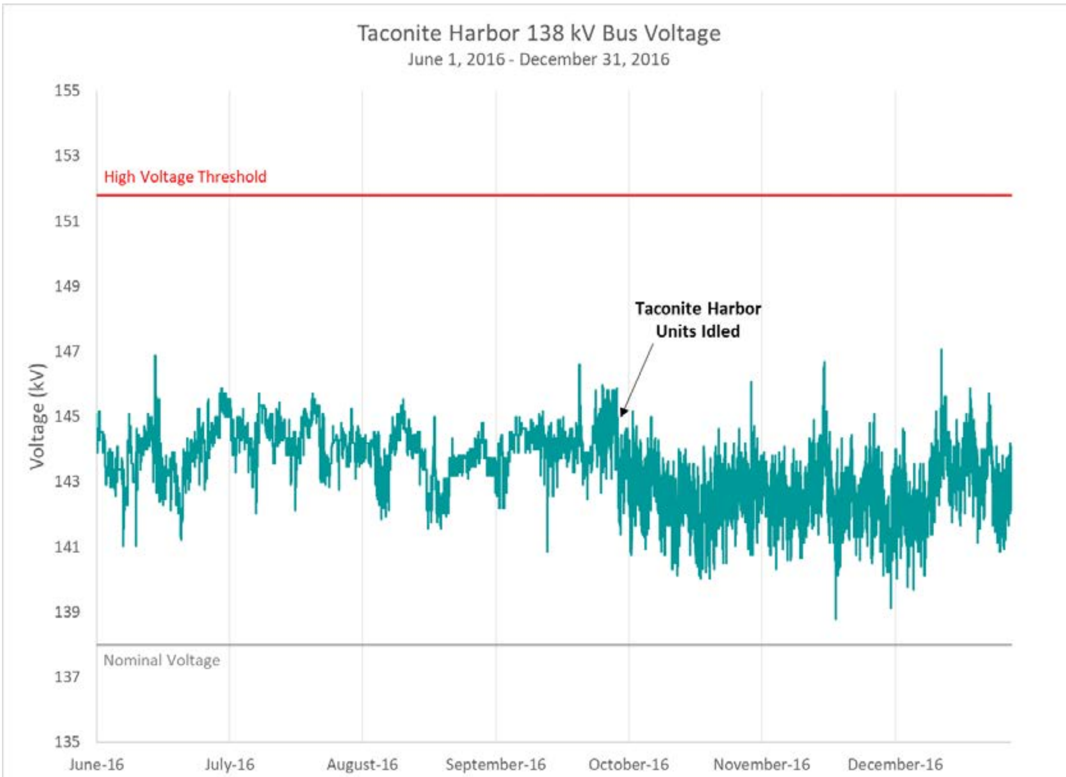
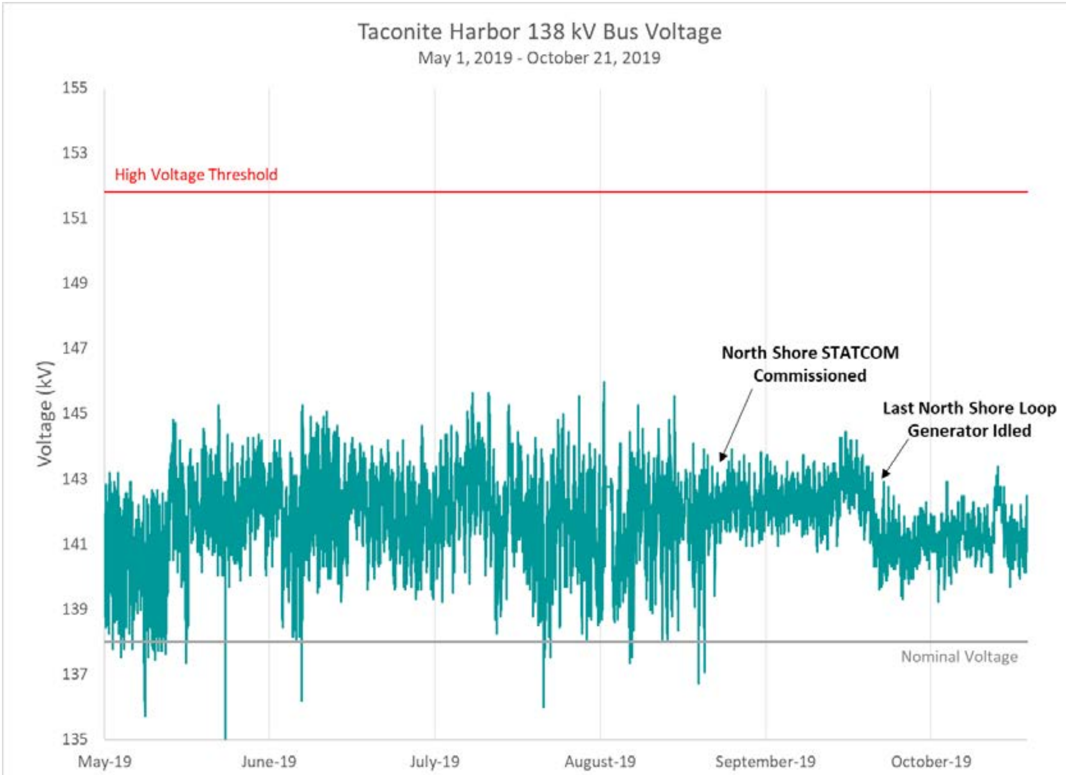


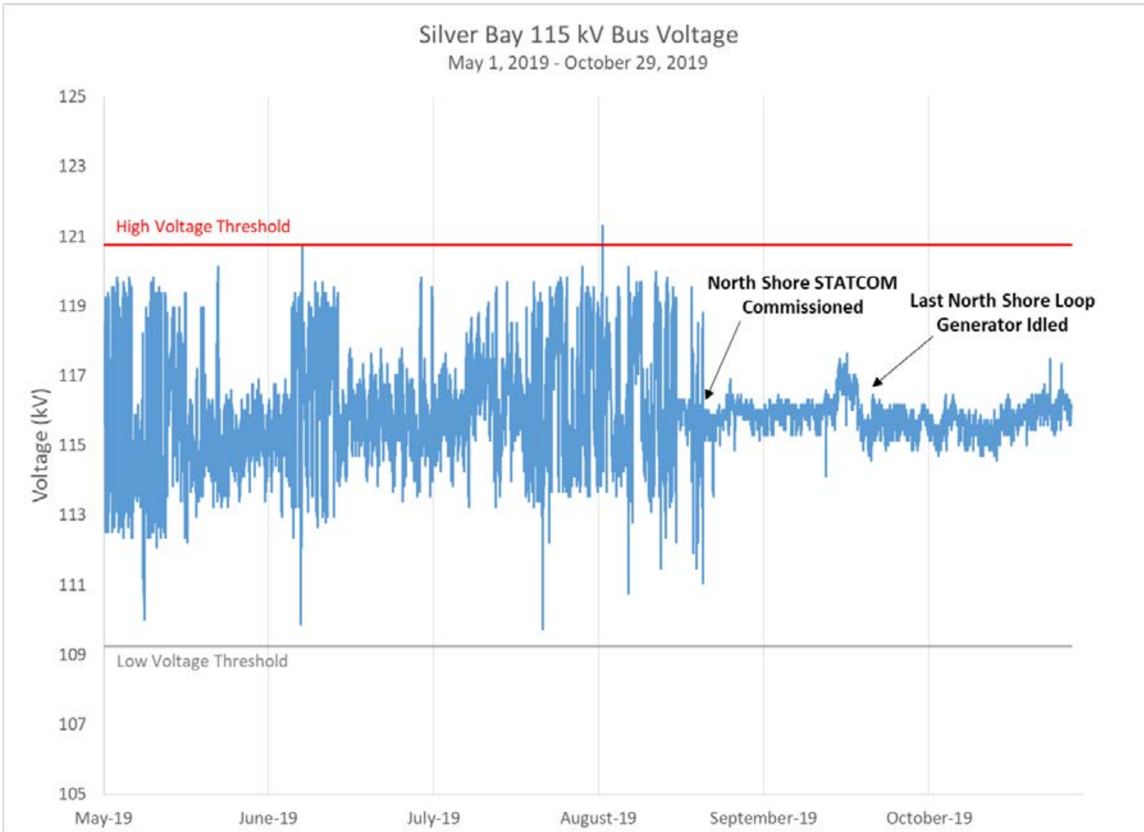
Figure 3: Taconite Harbor 138 kV Bus Voltage, May – October 2019



The North Shore Static Synchronous Compensator ("STATCOM") Project was designed to replace dynamic voltage support, including voltage regulation capability, for the North Shore Loop following the conversion, idling or retirement of all local baseload generators. Figure 3 shows the voltage at the same Taconite Harbor bus in the middle of 2019. As noted on the figure, the North Shore STATCOM was energized and commissioned in late August 2019. Though it is located 30 miles away from Taconite Harbor, the impact of the voltage regulating capability provided by the North Shore STATCOM is obvious. Even after the retirement of the last North Shore Loop generator – resulting in a step change in power flow through Taconite Harbor on the transmission system – the North Shore STATCOM is capable of supporting and regulating a robust bus voltage at Taconite Harbor.

The restorative impact of the North Shore STATCOM on North Shore Loop voltage regulation is most obvious in Figure 4, which shows the changing operation of the 115 kV bus voltage at the Silver Bay Substation from widely varying and unpredictable to tightly regulated and predictable following implementation of the STATCOM less than a mile away at the North Shore Switching Station.

Figure 4: North Shore 115 kV Bus Voltage, May – October 2019

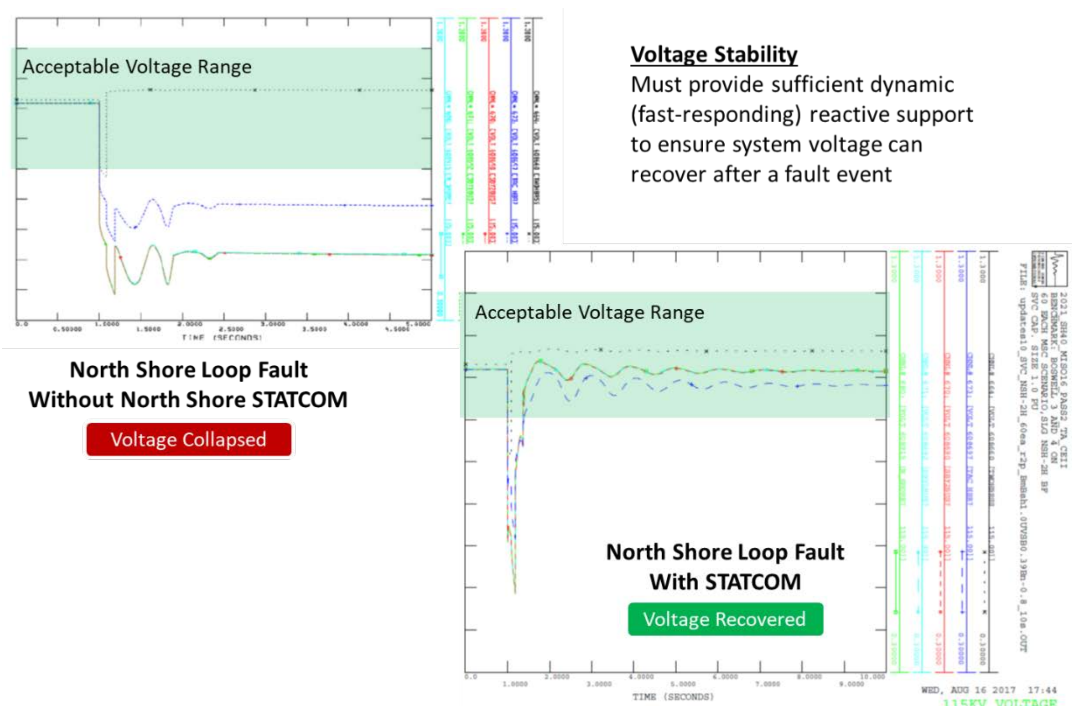


Without the more finely-tuned voltage regulation capability of the North Shore Loop generators or the STATCOM, the only voltage support resources available in the North Shore were mechanically switched capacitor banks ("MSCs"). Existing MSCs at the Colbyville and Big Rock Substations, as well as new MSCs at the North Shore Switching Station, are only capable of switching in large fixed chunks of reactive support. In a weak system, such as the North Shore Loop has become without the local baseload generators online, it becomes difficult to switch large fixed amounts of reactive support due to the increased sensitivity of the system. For example, where low voltage may necessitate additional reactive support, switching in a capacitor bank of a fixed size into a weak system may prove to increase the voltage too far in some circumstances – resulting in high voltage – and not enough in other circumstances. Besides offering finely-tuned voltage regulating capability from its own reactive power range (+/-75 MVAR), the North Shore STATCOM was designed to control four existing North Shore Switching Station MSCs in order to extend the capacitive end of its reactive capability by another 100 MVAR for voltage regulation and dynamic voltage support. Thus the North Shore STATCOM Project restored 175 MVAR of dynamic support and voltage regulating capability to the North Shore Loop, which represents slightly more than a one-for-one replacement of the total nameplate reactive support capability of the idled/retired Taconite Harbor and Silver Bay generators (166 MVAR).

The primary driver for the North Shore STATCOM, however, was not voltage regulation but voltage stability. Without the fast-responding voltage support of the generators, power flow studies determined that the transmission system was not capable of supporting all existing

North Shore Loop load under certain contingency conditions. Without replacing the support previously provided by the generators, there would be a risk of voltage collapse anytime the 140-mile transmission path between Colbyville and Laskin was severed. Voltage stability simply refers to the ability of the system to recover from an event and rapidly restore voltage to within the acceptable range. A voltage collapse is what occurs when the voltage in some part of the system cannot recover following an event – resulting in extremely low voltages and possibly localized blackouts. Figure 5 below shows a comparison of the same transmission system contingency with and without the North Shore STATCOM. Without dynamic reactive support from the STATCOM or the retired baseload generators, the contingency leads to voltage collapse on the North Shore Loop. With the STATCOM the transmission system voltage following the same event rapidly recovers to within the acceptable range.

Figure 5: North Shore Loop Voltage Stability Comparison



Finally, in terms of voltage support, studies identified several low voltage violations throughout the North Shore Loop and the surrounding area following transition away from the local baseload generators. Some of these low voltage violations are in the North Shore Loop and related to the voltage regulation and voltage collapse concerns discussed above. Those violations were mitigated by the addition of the MSCs and STATCOM at the North Shore Switching Station. Other voltage violations were identified in an area of the system adjacent to the North Shore Loop that is far away from the remote sources of power and voltage support that replace the local baseload generators and along heavily-loaded transmission paths between those remote sources and the loads in the North Shore Loop and on the eastern end of the Iron Range. To resolve these issues, MSCs were added at three additional locations:

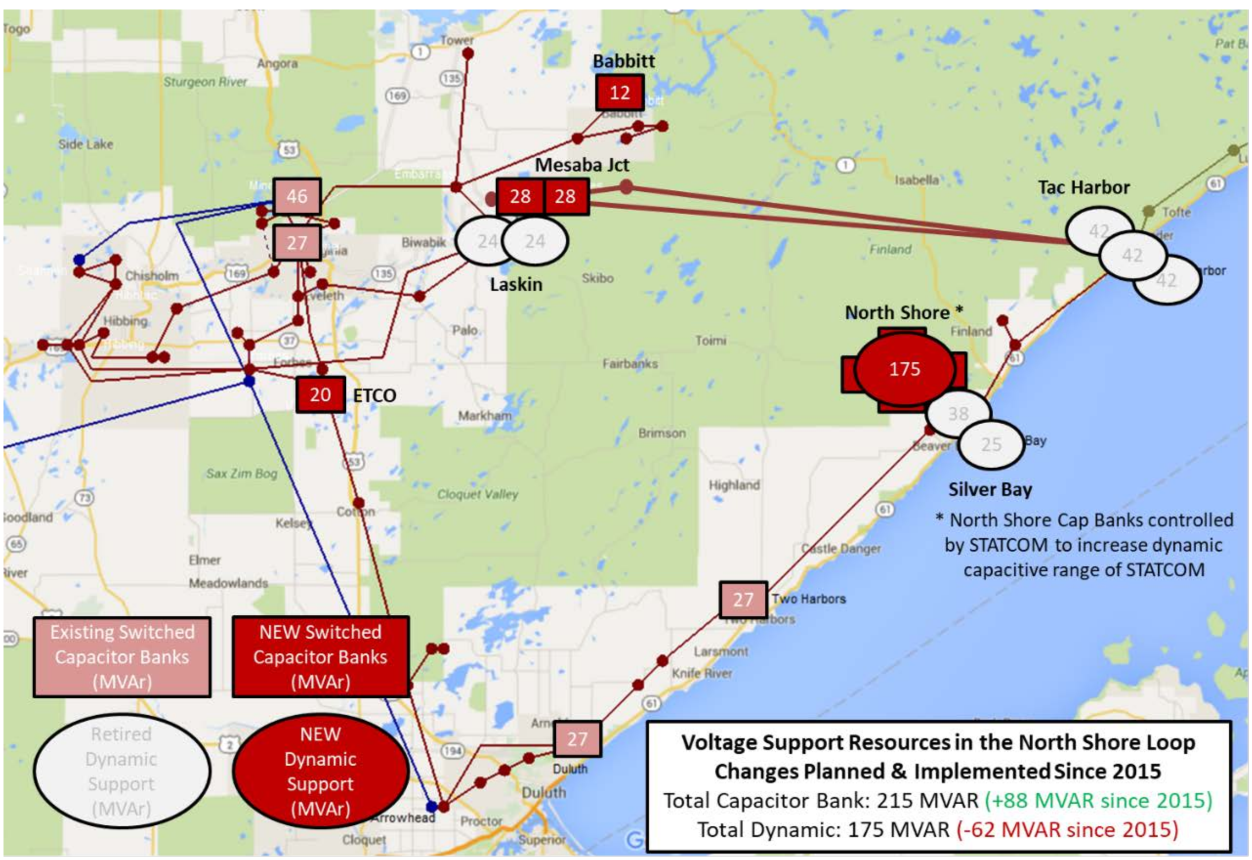
- **Babbitt Substation** (12 MVAR): On a radial (single source) transmission system approximately 40 miles from the nearest 230/115 kV source;

- **ETCO Substation** (20 MVAR): At a substation near a large industrial site along a heavily loaded 115 kV outlet 6 miles from the Forbes 230/115 kV source; and
- **Mesaba Junction Switching Station** (2x28 MVAR): 5.5 miles away from the Laskin Substation at the beginning of a 60-mile transmission path into the North Shore Loop that can become heavily loaded under certain contingency conditions.

Planned and completed reactive resource additions in the North Shore Loop following conversion, idling, or retirement of local baseload generation resources are shown in Figure 6 below. As noted on the figure, the cumulative reactive resource additions in and adjacent to the North Shore Loop are slightly more than a one-for-one replacement of the reactive support that was removed with the generators.

In summary, several transmission projects were necessary throughout and adjacent to the North Shore Loop in order to replace the voltage support historically provided by baseload generators. These transmission projects involved both dynamic voltage support, capable of rapid response times and finely-tuned voltage regulation, as well as mechanically switched capacitor banks to provide fixed amounts of voltage support at particular locations of concern. Total reactive support additions in the area slightly exceeded the total nameplate reactive support of the generators that were retired.

Figure 6: Voltage Support Resources in the North Shore Loop



Power Delivery Capability

Local baseload generators provide a dependable, available, and controllable source of power to the local transmission system. When baseload power is no longer provided locally, the replacement power must come from remote sources. In some cases, like the North Shore Loop, this can cause power flows on the transmission system well in excess of what the system was originally designed to accommodate. The North Shore Loop was historically an area with sufficient to excessive amounts of local generation going back to the mid-1900s when the local baseload generators were built. As such, the transmission system was not designed to accommodate significant flows of power into the North Shore Loop from remote sources. Without the local baseload generators online, the North Shore Loop now imports 100 percent of its power over the transmission system from remote sources. In Minnesota Power's transmission system, those remote sources are the nearest connections between Minnesota Power's 230 kV backbone transmission system and the local 115 kV network. This changing use of the transmission system has led to issues affecting both the remote 230/115 kV sources and the transmission paths that connect those sources to the North Shore Loop. At the remote 230/115 kV sources, issues include transformer overloads and increased severity associated with contingencies that weaken or sever the 230/115 kV connection. Along the 115 kV transmission paths connecting the remote sources to load, issues include transmission line overloads and increased severity associated with outages that weaken or sever the connection between the remote sources and the expanded area they must now supply.

Figure 7 and Figure 8 illustrate the shifting of the predominant source of power delivery in the North Shore Loop from local baseload generators to remote 230/115 kV sources. As shown in Figure 7, prior to the conversion, idling, and retirement of local baseload generators, there was approximately 205 MW more power generation capability in the North Shore Loop than the local peak load. This made the North Shore Loop a net exporter of power under most circumstances. In fact, due to the amount of excess generation compared to load in the North Shore Loop, special protection systems were maintained to runback or trip Taconite Harbor generation to avoid transmission line overloads and instability under certain contingency conditions. As the decarbonization of the North Shore Loop progressed, more and more of the power formerly supplied locally had to be delivered from the remote 230/115 kV sources at the Minntac, Forbes, and Arrowhead Substations. With all the North Shore Loop generators now offline, the area has become a constant importer of power with a local peak load up to 250 MW, as shown in Figure 8. This represents a 455 MW swing, from a net exporter of 205 MW to a net importer of 250 MW.

Figure 7: North Shore Loop Power Delivered from Local Generators

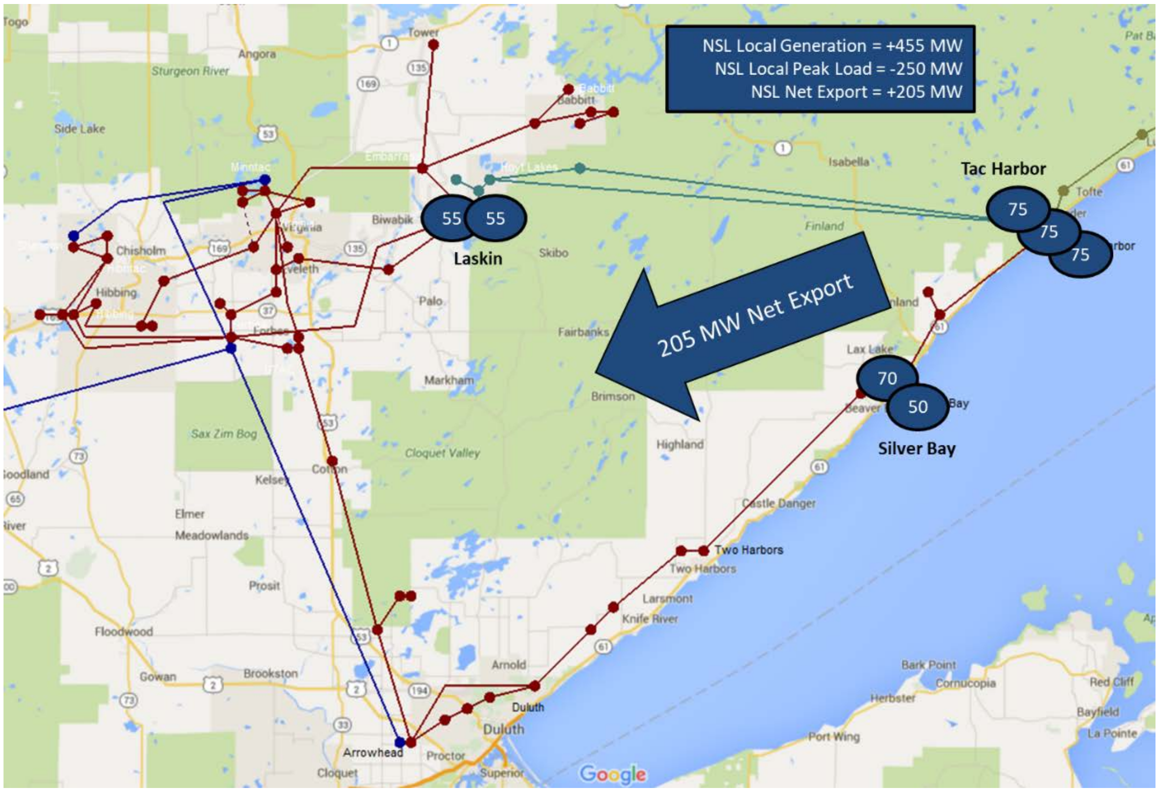
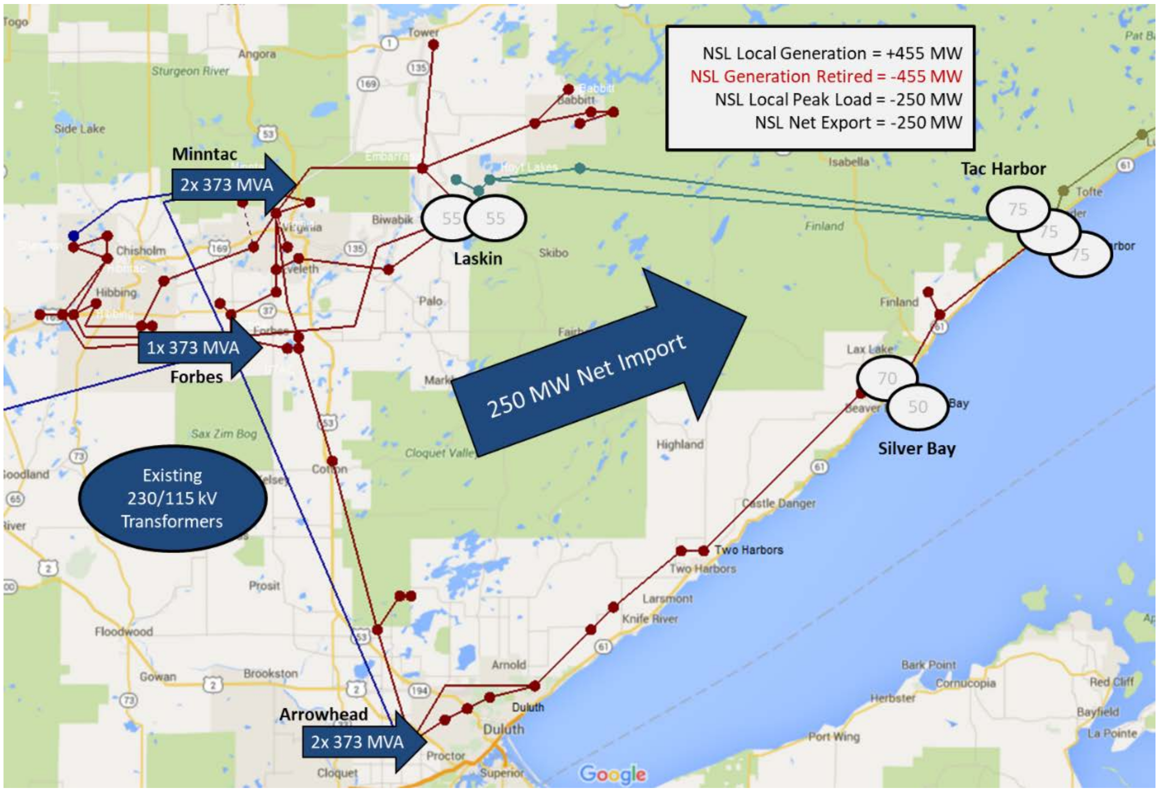


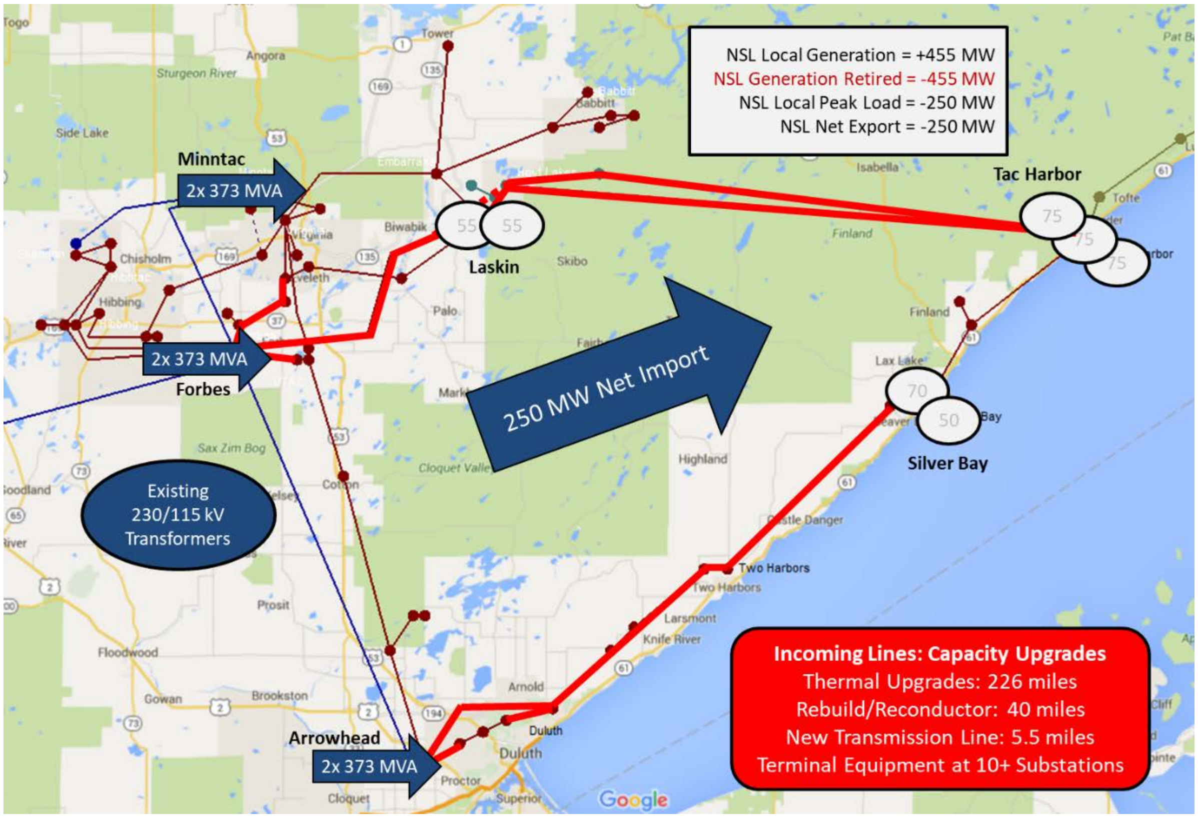
Figure 8: North Shore Loop Power Delivered from Remote 230/115 kV Sources



The impact of this transition on the 230/115 kV sources has been significant. Some of the earliest transmission improvements implemented in relation to the decarbonization of the North Shore Loop were reinforcements of the Forbes and Minntac 230/115 kV sources. At both substations, certain contingency events resulting in loss of the 230/115 kV connection at the substation were causing widespread and severe low voltages and transmission line overloads. To address the issues at the Forbes Substation, a second 230/115 kV transformer was added to ensure a constant connection between the 230 kV and 115 kV systems under the majority of contingency conditions. A breaker failure relay was also added to limit the impact of a particular contingency that could otherwise have resulted in loss of the entire 230 kV bus. A subsequent 115 kV bus reconfiguration project is planned to mitigate the last remaining potential contingency that could sever the Forbes 230/115 kV connection. At the Minntac Substation, the 230 kV bus was reconfigured and three additional 230 kV breakers were added to establish a more reliable bus configuration, ensuring that no single breaker failure would result in the loss of more than one transmission line and one transformer. In all of these cases, potential contingency conditions that existed and did not require mitigation for many years while the local baseload generators were online became unacceptably severe due to increasing reliance on the 230/115 kV sources.

In addition to driving upgrades at the 230/115 kV sources themselves, the changing use of the transmission system has driven the need for increased capacity on many of the transmission lines connecting the Minntac, Forbes, and Arrowhead sources to the North Shore Loop. Figure 9 illustrates the capacity upgrades that have been completed on the incoming lines connecting the North Shore Loop to the remote 230/115 kV sources.

Figure 9: Transmission Line Capacity Upgrades for Delivery of Power to the North Shore Loop



Capacity upgrades become necessary when the limiting element of a transmission line does not have sufficient capacity to deliver the power that is expected to flow on it under the worst single contingency condition. The scope of capacity upgrades ranges from replacement of limiting terminal equipment at a substation, to targeted structure replacements on a transmission line aimed at increasing the thermal rating of the line, to rebuilding or reconductoring the line with a higher-capacity conductor, to building a new transmission line. As noted in Figure 9, planned and implemented capacity upgrades on incoming North Shore Loop transmission lines have consisted of terminal equipment replacements at more than 10 different substations, thermal upgrades on approximately 226 miles of transmission lines, rebuilding or reconductoring of approximately 40 miles of transmission lines, and the construction of 5.5 miles of new 115 kV transmission line. Together, these capacity upgrades were necessary to provide sufficient power delivery capability to serve all North Shore Loop under all reasonable conditions with the same level of reliability historically achieved when the power was being delivered by the local baseload generators.

In summary, the power once generated locally by North Shore Loop baseload units must now be delivered over the transmission system from remote 230/115 kV sources. As a result, several transmission projects were needed to strengthen and reinforce the 230/115 kV sources as they became more heavily used. Capacity upgrades were also required on many miles of transmission lines and at many substations in order to facilitate the reliable delivery of power from those remote 230/115 kV sources into the North Shore Loop over a transmission system that was not originally designed to facilitate such power flows.

Redundancy

Local baseload generators provide a redundant source of power delivery and voltage support to the local transmission system. In many cases, the redundancy provided by the generators can offset the need for additional transmission connections. When a local baseload generating facility consists of multiple generating units, even more redundancy is built in to both the generating facility and the local power system. The Taconite Harbor Energy Center, for example, consisted of three 75 MW generating units. At any given time, the redundancy built into the generating facility meant that it was highly likely that at least two of the three units would be running and it was practically guaranteed that at least one unit would be running at all times, barring some abnormal conditions. In that sense, Taconite Harbor provided a dependable source capable of delivering 75 MW to 150 MW of power, along with voltage support, to the North Shore Loop with availability comparable to that of the transmission system. In the event of a planned or unanticipated transmission line outage, the generation facility could continue to provide power to the area, and its output and voltage schedule could be adjusted up or down to mitigate transmission line loading or voltage issues.

In an area of the system where transmission sources are relatively sparse, like the North Shore Loop, local baseload generators can even be designed to operate while isolated from the rest of the transmission system (“islanded”) in order to restore electric service to the local area following multiple-contingency events resulting in loss of all transmission sources. Without these local baseload generators in the North Shore Loop, electric service redundancy for the area has been lost. The resulting redundancy-related issues include post-contingent transmission line overloads following multiple-contingency events, loss of operational flexibility to respond to outages on the system, diminished ability to take maintenance outages, and increased exposure to events that could result in the loss of all sources of power to the area.

While all of the voltage support and power delivery capability projects discussed in the previous sections are related in some ways to the loss of redundancy from local baseload generators in the North Shore Loop, two projects in particular illustrate the types of transmission improvements that are necessary to restore redundancy. The Mesaba Junction 115 kV Project provides redundancy related to single points of failure on the Hoyt Lakes end of the North Shore Loop. The Duluth 115 kV Loop Project provides reduncancy related to multiple-contingency events, establishing consistent redundancy on the Duluth end of the North Shore Loop.

Mesaba Junction 115 kV Project

The Mesaba Junction 115 kV Project involves the development of a new switching station interconnected to existing transmission lines in the Hoyt Lakes area. Approximately 5.4 miles of new 115 kV line will be constructed along the existing Laskin – Hoyt Lakes transmission line corridor to extend the Forbes – Laskin 115 kV “38 Line” into Mesaba Junction. The existing 38 Line connection to the Laskin Substation will then be eliminated. In addition to the transmission line connections, the new switching station will include two switched capacitor banks to provide voltage support. To facilitate interconnection of the Mesaba Junction 115 kV Project, eliminate single points of failure, and modernize the area transmission system, existing 138 kV transmission facilities between Laskin, Hoyt Lakes, and Taconite Harbor will be converted to 115 kV operation in coordination with the Mesaba Junction 115 kV Project. The Mesaba Junction 115 kV Project and the Laskin – Taconite Harbor Voltage Conversion Project are shown in Figure 10 below.

As shown in Figure 11, single points of failure on the Hoyt Lakes end of the North Shore

Loop have the potential to leave the entire North Shore Loop served via single source from the Colbyville Substation, located 140 transmission line-miles away from Hoyt Lakes. In addition to voltage support and power flow issues, this configuration also leaves the area vulnerable during a prior outage of the Laskin – Hoyt Lakes transmission line to a second contingency potentially severing the connection to Colbyville and leaving the North Shore Loop without any adequate sources of power. The Mesaba Junction 115 kV Project and the Laskin – Taconite Harbor Voltage Conversion were designed to address these redundancy issues, in addition to voltage support, power delivery capability, and age and condition concerns.

Specifically, the Mesaba Junction 115 kV Project supports redundancy by providing a third transmission source into the area, establishing a more robust substation configuration, and enabling a standardized network voltage. The Mesaba Junction 115 kV Project establishes a new 115 kV line parallel to the existing Laskin – Hoyt Lakes transmission line and a new switching station that replaces the simple straight bus configuration of the existing Hoyt Lakes Substation with a more reliable ring bus configuration. The new transmission line provides a redundant connection on the Hoyt Lakes end of the North Shore Loop, alleviating single-contingency concerns about losing the connection to Laskin and prior outage concerns about losing all sources to the North Shore Loop. The new switching station relocates the critical bulk electric system path out of an aging customer-owned substation and into a modern, utility-controlled switching station in a more reliable configuration designed, owned, operated, and maintained by Minnesota Power. Finally, as mentioned above, the Mesaba Junction 115 kV Project will be coordinated with the Laskin – Tac Harbor Voltage Conversion Project, greatly enhancing the constructability of both projects and enabling Minnesota Power to realize all the benefits of a standardized network voltage for the area, including eliminating single points of failure by removing the 138/115 kV transformers.

Figure 10: Mesaba Junction 115 kV Project

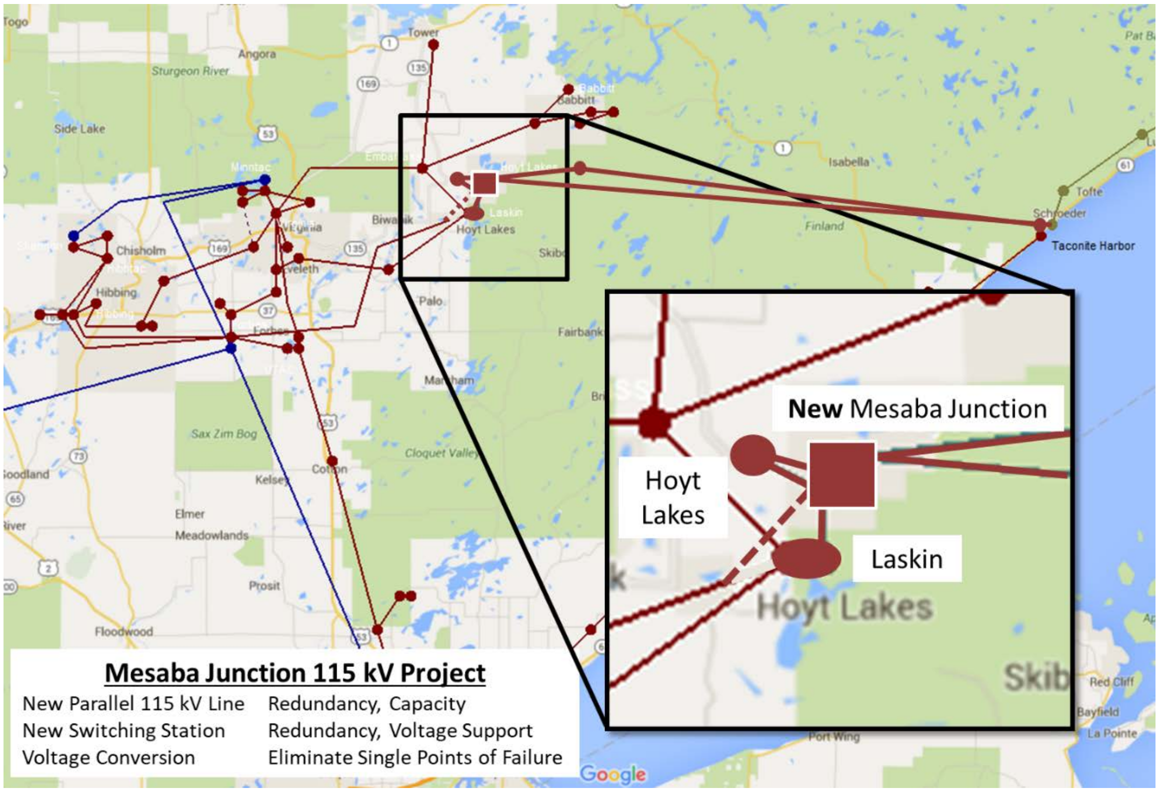
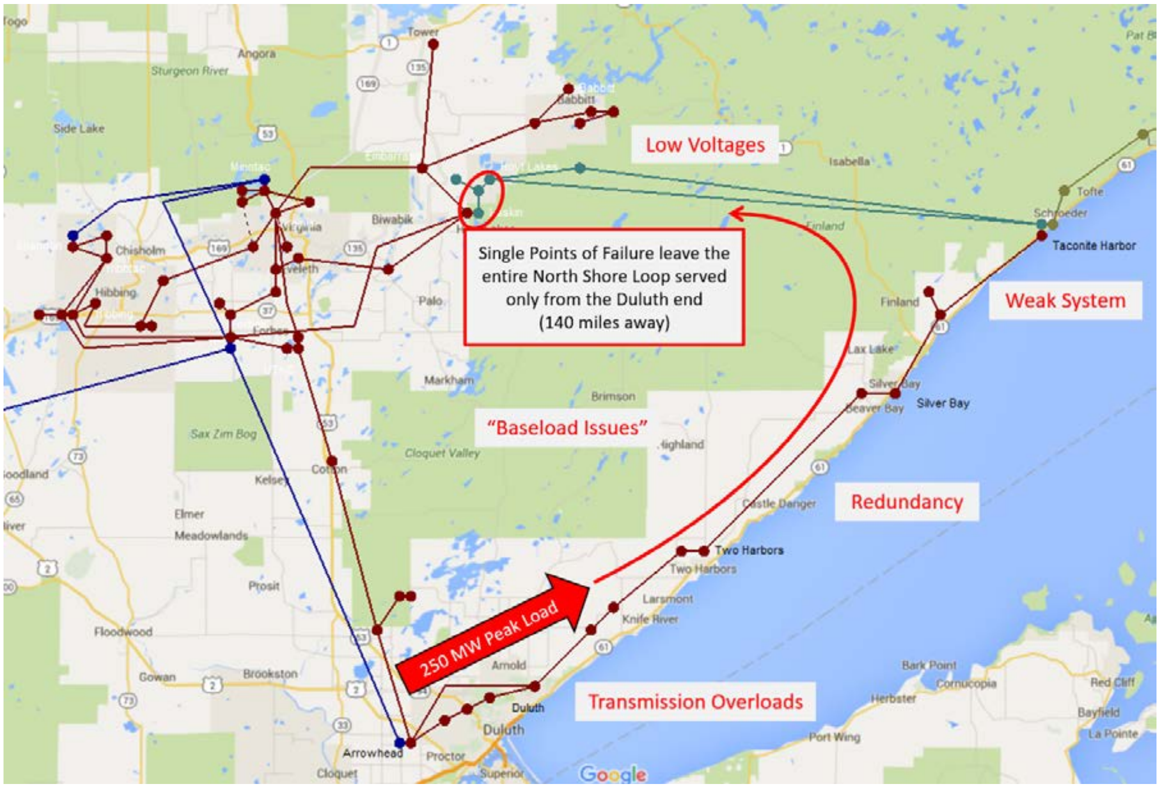


Figure 11: Hoyt Lakes Area Redundancy Concerns

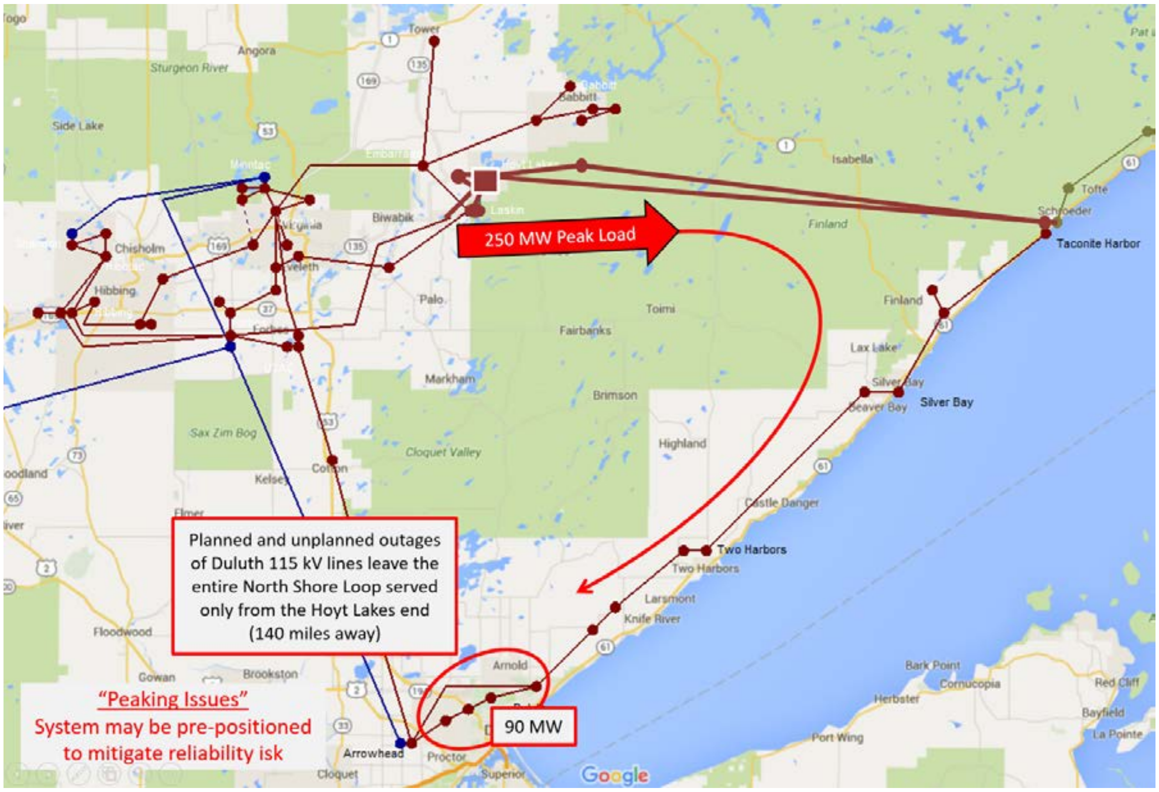


Duluth Loop Reliability Project

The Duluth Loop Reliability Project involves the development of a new 115 kV connection between the existing Hilltop and Ridgeview Substations along with short extension of the Hilltop 230 kV "98 Line" Tap to the Arrowhead Substation. While preferred routes have not yet been identified as of the date of this document, the project is estimated to include approximately 15 miles of new transmission construction, mostly collocated along existing transmission corridors in the Duluth area. Additionally, modifications will take place at the Ridgeview, Hilltop, and Arrowhead substations to accommodate project. It is expected that a certificate of need will be filed for this project mid-year 2021.

The concerns driving the need for the Duluth Loop Reliability Project stem from a risk of voltage collapse, thermal overloads, and low voltage issues caused by certain contingency events during a prior outage of one of the 115 kV lines between the Arrowhead, Haines Road, Swan Lake Road, Ridgeview, and Colbyville Substations in the eastern part of Duluth. Similar to the issues discussed above at the Hoyt Lakes end of the North Shore Loop, the loss of a second transmission line during a prior outage in the Duluth Loop area would leave this part of Duluth on the end of a single 140-mile transmission line originating in the Hoyt Lakes Area. This scenario is shown in Figure 12 below.

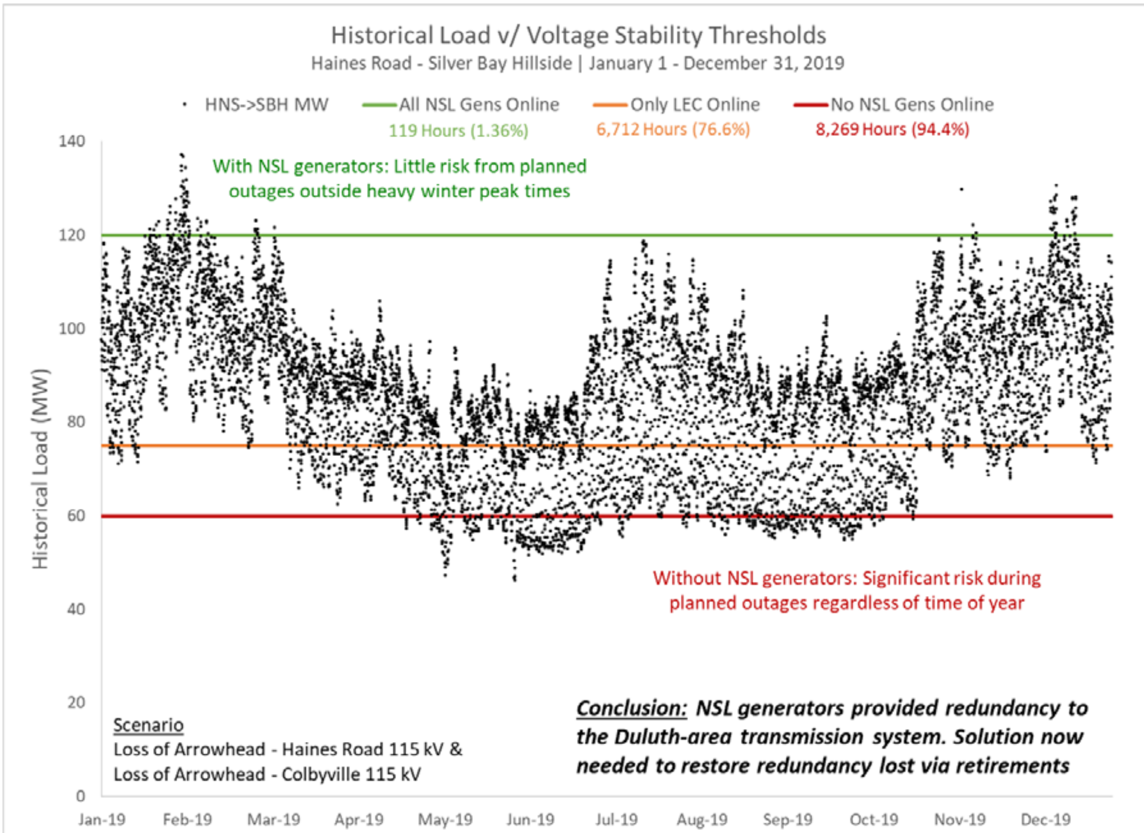
Figure 12: Duluth Loop Area Redundancy Concerns



Without the local baseload generators at Laskin, Taconite Harbor, and Silver Bay, the transmission system is no longer able to support the large amount of Duluth area load over the long distance of the transmission system between Hoyt Lakes and Duluth. The Duluth Loop Reliability Project will restore redundancy and load-serving capability to this area, mitigating the risk of voltage collapse and low voltage issues.

To illustrate the impact of fleet transition on the Duluth Loop, Figure 13 below shows historical coincident loading in the North Shore Loop between the Arrowhead substation and the North Shore Switching Station. This area includes the Duluth Loop substations plus Minnesota Power and Great River Energy load served from the French River, Clover Valley, Two Harbors, Big Rock, Waldo, and Silver Bay Hillside substations. When the transmission lines connecting this area to the Arrowhead Substation are lost, all load towards Duluth is served through the North Shore Switching Station. While the North Shore STATCOM provides sufficient voltage support for the Silver Bay area, the reactive power produced there cannot fully support the Duluth Loop area at the end of the radial system. The result, if load in the area is high enough, is a post-contingent voltage collapse. Figure 13 shows one year of historical load in the area versus the voltage stability threshold for different combinations of North Shore Loop generators online.

Figure 13: Duluth – Silver Bay Historical Load versus Voltage Stability Threshold



With all North Shore Loop generators online, the voltage stability threshold (**green** line on the plot) is generally only present during the heaviest periods of winter peak load. Since the voltage stability concern is associated with a prior outage situation, the issue could historically be handled reasonably well by scheduling planned outages in the spring or fall, when demand is much lower. However, as fewer local baseload generators are online in the North Shore Loop transmission system, the voltage stability threshold degrades significantly. With all North Shore Loop generators except Laskin offline (**orange** line), over 75 percent of hours are above the threshold. With all North Shore Loop generators offline (**red** line), there are less than 500 hours in the entire year when load does not exceed the stability threshold. There are only two days in this particular historical data sample period for which an 8-hour maintenance outage could have been scheduled without exceeding the stability threshold. These two days occurred several weeks apart in May and would have been very difficult to predict in advance so that work could have been coordinated successfully. The demonstrably degraded load-serving capability makes operating around this limitation during prior outages infeasible as a long-term solution. The Duluth Loop Reliability Project is designed to replace the redundancy previously provided by the local baseload generators such that there is sufficient load-serving capability to support all loads in the area and sufficient flexibility to operate and maintain the system reliably.

The issues described above show the extent to which the North Shore Loop baseload generators historically provided critical redundancy to the transmission system. Without these local baseload generators online, transmission system upgrades such as the Mesaba Junction

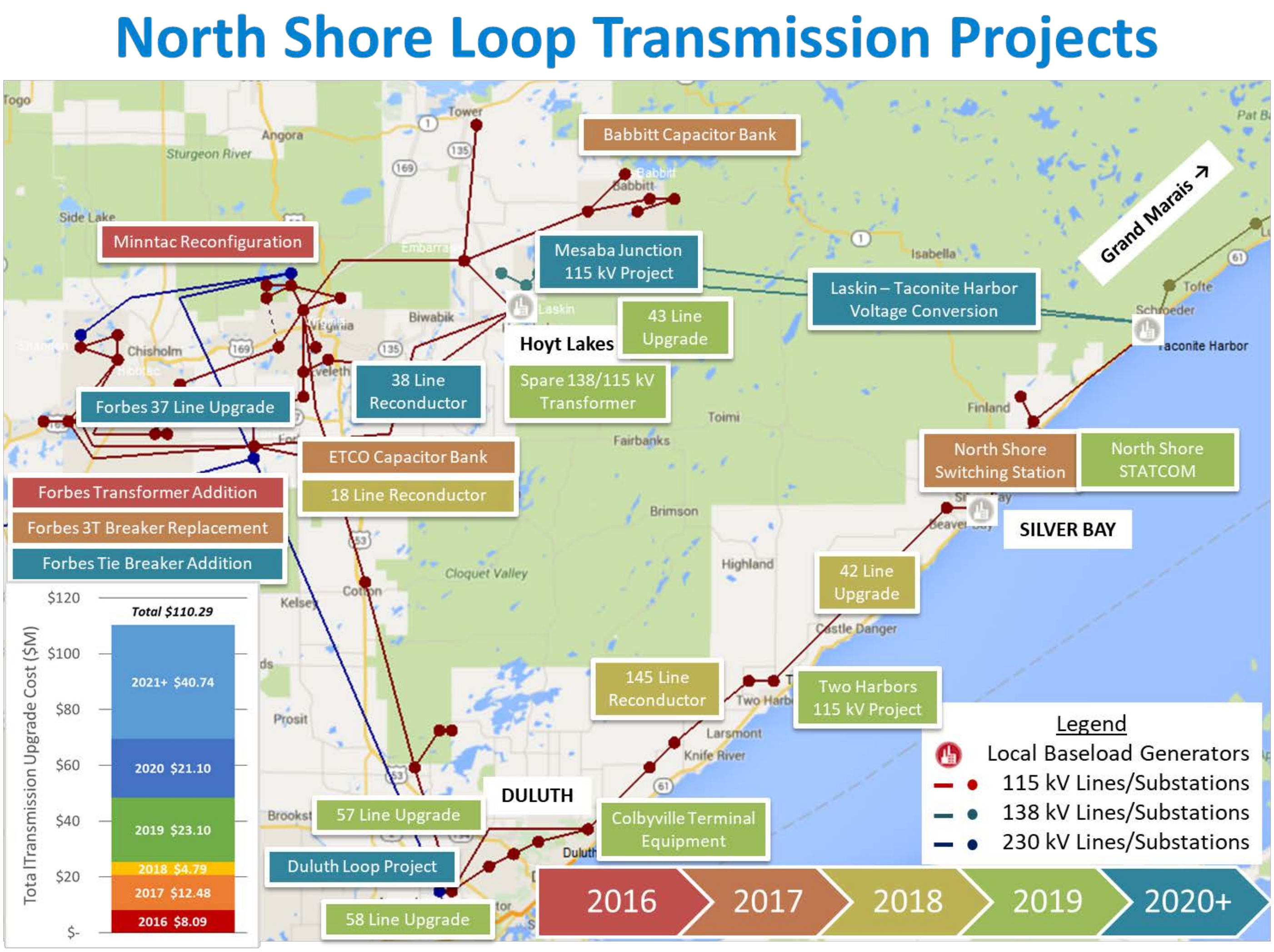
115 kV Project and the Duluth Loop Reliability Project are now required to replace the redundancy and power delivery capability they once provided. These upgrades are necessary to ensure that the system has sufficient backup capability for contingencies and planned outages, provide operational flexibility, and reduce exposure to events potentially causing extended power outages in the area when the few remaining sources of local power delivery are unexpectedly lost.

North Shore Loop Summary

The transmission system is designed to be highly reliable and redundant, yet affordable. Where local baseload generators have provided reliability services to the local transmission system for many years, the transmission system tends to be designed to rely on the local baseload generators being online. As long as the baseload generators were around to provide these reliability services, the cost of transmission upgrades that would decrease reliance on the generators was difficult to justify. With the removal of the local baseload generators, the transmission system in the surrounding area is practically guaranteed to require some amount of upgrading in order to offset the loss of reliability services formerly provided by the generators. The more dependent the transmission system was on the local baseload generators, the more significant the upgrades are likely to be.

In the particular case of the North Shore Loop, Minnesota Power has found that the transmission system was highly dependent on the local baseload generators. Many transmission projects were necessary in the North Shore Loop to replace the voltage support formerly provided by the generators, strengthen and reinforce remote sources of power delivery and transmission paths as they became more heavily used to deliver replacement power formerly generated locally, and restore redundancy formerly provided by the local baseload units. Figure 14 below provides a summary of all the transmission projects related to the decarbonization of the North Shore Loop. As noted on the figure, the total estimated cost of these projects through their completion in the mid-2020s is approximately $110 million.

Figure 14: Summary of North Shore Loop Transmission Projects Related to Fleet Transformation

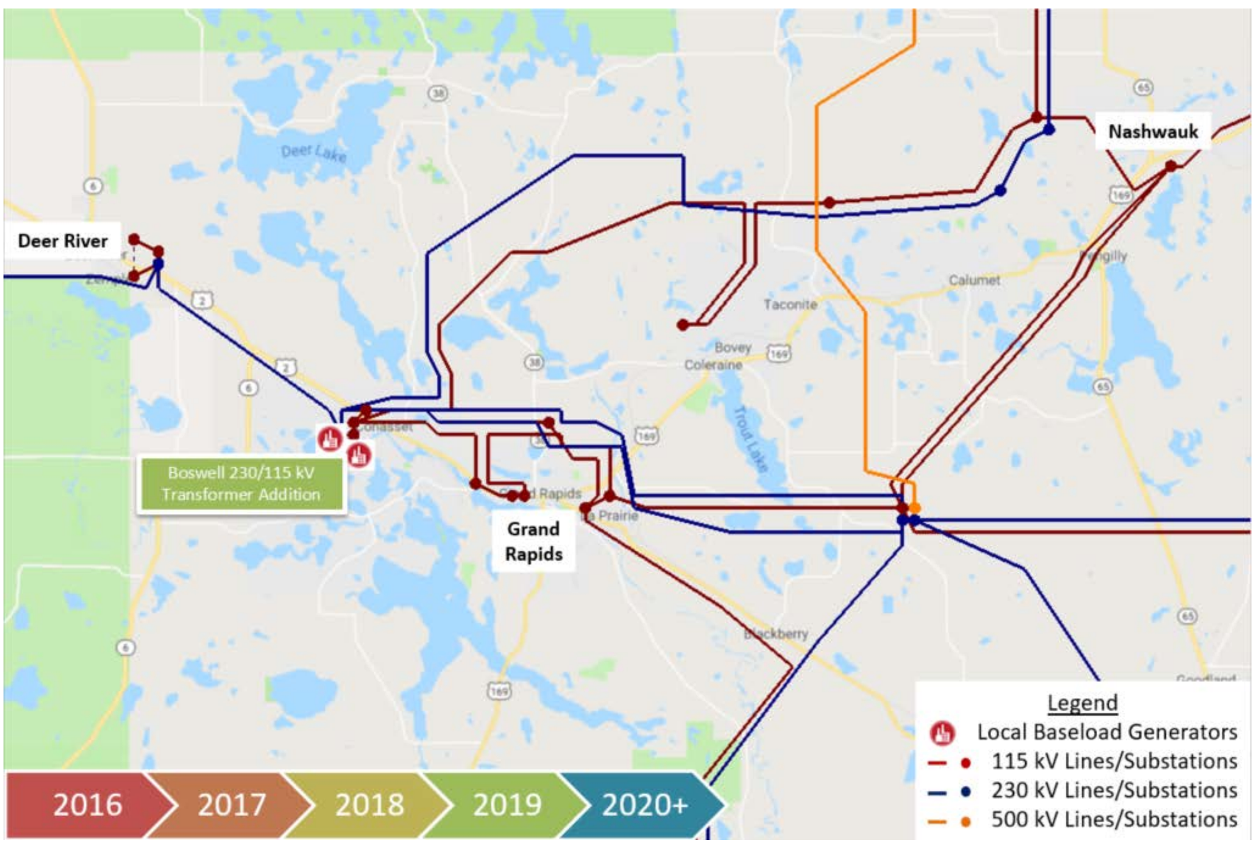


The Grand Rapids Area: Boswell Units 1 & 2

Background

The Grand Rapids area is served by a 115 kV system including the Boswell, Blandin, Lind-Greenway, Grand Rapids, and Tioga substations. Three 115 kV transmission lines connect the Grand Rapids area transmission system to 230/115 kV sources at the Blackberry and Riverton substations. While four coal-fired generators were historically located at the Boswell Energy Center, only BEC Units 1 and 2 were interconnected directly to the Grand Rapids area 115 kV system. BEC Units 3 and 4 interconnect directly to the 230 kV system and, prior to the Boswell Transformer Project discussed below, the nearest 230/115 kV transformer that tied back to the Grand Rapids area 115 kV system was located at the Blackberry Substation. There was no local electrical connection between the 230 kV and 115 kV systems in the Grand Rapids area, in part because the 115 kV system was supported by the operation of BEC Units 1 and 2. The transmission system in the Grand Rapids area is shown in Figure 15 below, including the local generators and one transmission upgrade related to the retirement of BEC Units 1 and 2.

Figure 15: Grand Rapids Area Transmission System



Similar to the North Shore Loop units, the presence of BEC Units 1 and 2 on the local 115 kV system contributed to the reliability of the Grand Rapids area transmission system for several decades by providing redundancy, voltage support, and local power delivery capability, among other things. Without the support provided by BEC Units 1 and 2, contingencies impacting one or more transmission facilities in the Grand Rapids area may lead to transmission line overloads, post-contingent high or low voltage conditions, increased risk of voltage collapse, loss of operational flexibility to respond to outages on the system, diminished ability to take maintenance outages, and increased exposure to events that could result in the loss of all sources of power to the area. In order to mitigate these concerns, Minnesota Power identified that a 230/115 kV source needed to be established in the Grand Rapids area by expanding the Boswell 230 kV Substation and connecting it to the existing 115 kV system ("Boswell Transformer Project").

Transmission System Impacts

The Boswell Transformer Project was needed to ensure the system could continue to be operated at the same or better level of reliability after the retirement of BEC Units 1 and 2. Therefore, Minnesota Power planned the development and construction of the Boswell Transformer Project to be completed in late 2018 prior to the retirement of BEC Units 1 and 2. However, a manufacturing issue caused a significant delay in the completion of the project to the point where it was not possible to put the new transformer in service by the end of 2018. As a result, there was an approximately eight-month period of time in 2019 when BEC Units 1 and 2 were retired, but the Boswell Transformer Project had not yet been placed in service.

When the manufacturing delay was identified, Minnesota Power evaluated the reliability impacts and risks of the delay. It was expected that no negative reliability impacts would be experienced as long as the 115 kV transmission paths and a local capacitor bank were available. As a result, planned outages of these facilities were restricted until the Boswell transformer could be placed in service. Even with this planning in place, two experiences during this period of time illustrate the reliability risks and uncertainties inherent with operating the system in an entirely new paradigm without BEC Units 1 and 2 and prior to implementing the necessary transmission reliability solution:

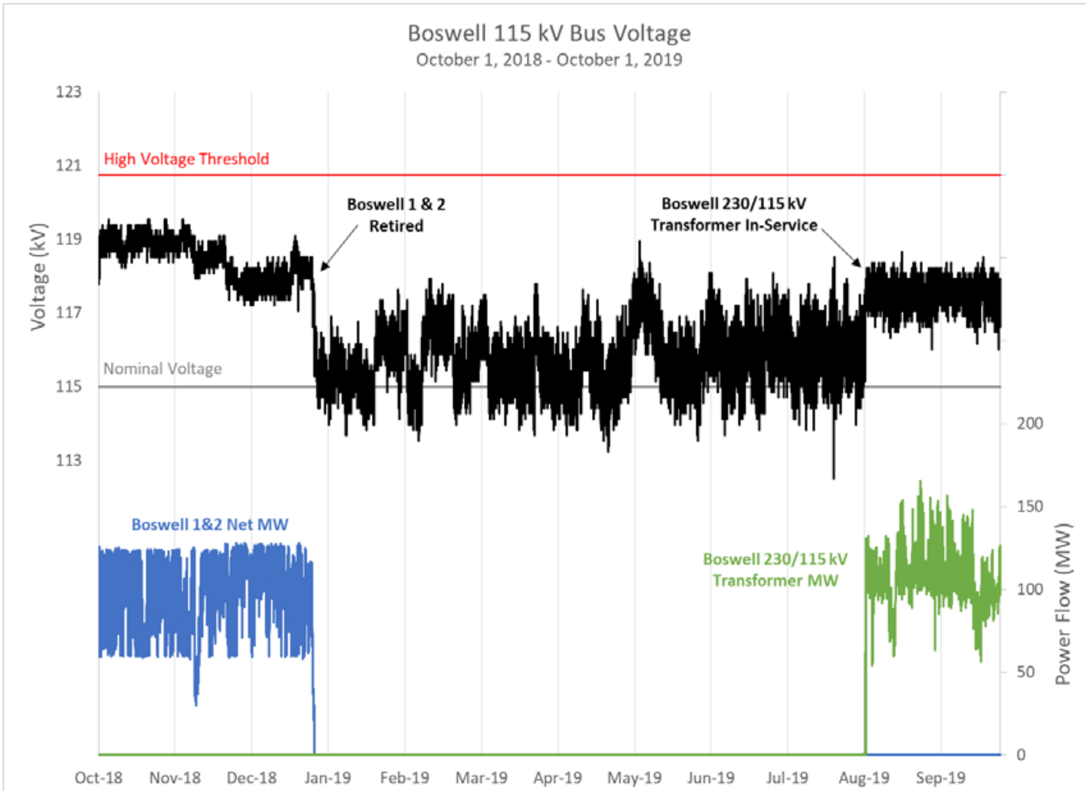
- During the polar vortex in late January 2019, a circuit breaker on one of the 115 kV transmission paths into the Grand Rapids area was locked out due to severe cold temperatures. This caused a forced outage of one of the transmission sources to the Grand Rapids area. During this forced outage, MISO's real-time contingency analysis tool identified that a subsequent outage on a second 115 kV path into the Grand Rapids area would lead to low voltage. While the next contingency never happened, Minnesota Power's system operators found that there were limited options in the local area for mitigating the low voltage without BEC Units 1 and 2. This is precisely the condition that the Boswell Transformer Project was intended to mitigate by providing an additional source to the Grand Rapids area.

- Toward the end of June and into early July 2019, a large power customer in the Grand Rapids area notified Minnesota Power that system events had caused a machine on the plant distribution system to trip offline on three occasions. The timing of the machine tripping was correlated with faults elsewhere in the Grand Rapids area on an entirely separate distribution system, where the only connection between the two is the 115 kV transmission system. After each of the first two events Minnesota Power adjusted the settings of a digital fault recorder in the area so that even a modest instantaneous voltage drop would record future fault events. Finally, the third event was successfully captured in a detailed record and analyzed. The voltage levels recorded did not violate operating or planning criteria voltage levels. Using details of the recorded fault, studies were then performed that demonstrated lower voltage during a fault with BEC Units 1 and 2 offline than experienced with them online. The study also confirmed that the planned 230/115 kV transformer mitigated and actually lessened the voltage impacts when compared to BEC Units 1 and 2 online. In all measured and studied conditions

> fault recovery was within Minnesota Power's planning criteria. The fact that there was a significant enough impact on the large power customer during these events to cause a machine to trip without any voltage deviations outside Minnesota Power's planning criteria illustrates some of the inherent risk with transitioning away from the support previously provided by the local baseload generators. It is a paradigm shift for an area that has been designed and built over many decades to rely on the voltage support and system strength provided by the local generators. This paradigm shift potentially has as much or more impact on customer-owned distribution systems as it has on Minnesota Power's transmission and distribution systems.

The Boswell Transformer Project was completed and placed in service about a month and a half after the last of the fault events noted above. Similar to what was noted previously in discussion of the North Shore Loop, voltage in the Grand Rapids area was noticeably more variable and generally lower during the period of time after retirement of the BEC units and before energization of the Boswell Transformer Project. Figure 16 below illustrates the differences in system voltage during these time periods. The experience in the Grand Rapids area indicates that the loss of voltage support and system strength from additional changes in operation of the remaining BEC units may have unintended consequences for Minnesota Power's customers if mitigating solutions are not placed into service prior to implementing the changes. Also of note from Figure 16 is the fact that power flow through the new Boswell 230/115 kV transformer is roughly equivalent to the power formerly produced locally by BEC Units 1 and 2. All of these findings generally work together to confirm Minnesota Power's conclusion that the essential reliability services provided by local generators must be replaced before they are retired.

Figure 16: Boswell Substation 115 kV Bus Voltage, October 1, 2018 – October 1, 2019



Part 7: Transmission System Analysis of Boswell Unit 3 & 4 Closures

The Boswell Energy Center ("BEC") is the only remaining baseload generating station in the Minnesota Power system, as well as in all of Northern Minnesota. This generating station provides essential reliability services – electrical support needed to ensure continuous reliable operation of the power system – and energy supply to a unique geographic area. The energy and reliability needs of both large industrial loads and sprawling rural areas must be served while also balancing regional power transfer needs, particularly as regional renewable energy production varies on minute-by-minute basis. If BEC were to shut down or transition to economic operation, the entire northern half of Minnesota and a large part of eastern North Dakota would be left with no operating baseload generators. With little support from the remaining small dispatchable generators, the majority of energy requirements and essential reliability services required to serve this area would need to be provided from remote resources. Operating in this manner in Northern Minnesota permanently or for extended periods of time would be a major change for the local area and the region, and would result in both local and regional reliability concerns. Minnesota Power has been working diligently to understand these reliability concerns, and a thoughtful transition plan will be crucial to ensuring continued safe and reliable operations in this region. This transition plan must include the development of new operational tools and criteria, coordination with MISO and other affected entities, and preparation of the transmission system to ensure regional and local reliability is not compromised by changing operations at BEC.

This section summarizes Minnesota Power's analysis of and conclusions regarding the transmission system impacts from changing operations at BEC by either shutting down one or both units or transitioning to economic operation. We have identified six pillars that are key to understanding the significance of BEC to the region and the transmission system impacts from changing operations at BEC. These pillars to understanding are informed by our recent experience from transition of our small coal fleet, as described previously in Part 6, and supported by several different areas of analysis. After summarizing the six pillars, the rest of this section will focus on providing an overview of these areas of analysis that have contributed to developing these conclusions.

Pillar #1: Northern Minnesota is Unique

A mixture of heavy industrial and rural residential load requirements, the configuration of the existing transmission system, and a dwindling number of dispatchable local generation resources produce unique challenges for transitioning away from existing baseload generation in Northern Minnesota. Removing BEC, the last remaining baseload generating station in Northern Minnesota, requires resolving issues from multiple operating scenarios that are unique to our geographic area and position in the regional power system. If the BEC units are shut down or transition to non-baseload operation, alternative solutions must be identified that can simultaneously meet the needs and expectations of large industrial sites, serve rural demand, and respond to significant variations in regional transfers across a large geographic footprint.

Pillar #2: Baseload Generator Retirements Require Holistic Replacements

Baseload generators provide more than just energy production. They also provide essential reliability services to local energy consumers and the regional power system that must be replaced when the generators are retired or transitioned to non-baseload operation. The North American Electric Reliability Corporation ("NERC") defines Essential Reliability Services as including frequency response, ramping, and voltage support.[2] For the purpose of this discussion, we will also use the term "essential reliability services" in an expanded sense to incorporate additional reliability concepts such as local power delivery, regional power delivery, and redundancy. Based on our experience with other baseload generator retirements (see Part 6) and the analysis discussed in this section, these additional reliability concepts are just as important to understanding and planning to address the holistic transmission system impacts of baseload generator retirements. BEC is the last remaining baseload generating station providing essential reliability services for Northern Minnesota. The local and regional transmission system has been designed over many decades to make optimal use of the essential reliability services provided by these generators. If the BEC units are shut down or transition to non-baseload operation, solutions must be identified that can replace the essential reliability services formerly provided by the local baseload generators on a continuous basis. Since there is a continuous, long-term, and in many cases round-the-clock need for essential reliability services to support the transmission system, storage and intermittent generation resources are at best only partial solutions and in many cases impractical for achieving holistic replacement of essential reliability services provided by the BEC units. Based on our assessments, we will focus our discussion of impacts from shutting down the BEC units on three main aspects of essential reliability services provided by these units: Voltage Support and System Strength, Local Power Delivery, and Regional Power Delivery.

Pillar #3: Baseload Generators Supply Voltage Support and System Strength

Voltage support and system strength provided by local baseload generators must be replaced to ensure continued reliable operations, power quality, and system protection. BEC, as the last remaining baseload generating station in Northern Minnesota, provides voltage support and system strength that support consistent & predictable system operations, large industrial processes, power quality, and properly functioning utility protection systems, among other things. If the BEC units are shut down or transition to non-baseload operations, alternative solutions must be identified that effectively and locally replace the voltage regulation, dynamic voltage support, and short circuit capability formerly provided by the local baseload generators on a continuous basis because these services can't be imported from remote sources.

Pillar #4: Dispatchable Generators Deliver Power to the Local Area

Power formerly provided locally by dispatchable baseload generators must be delivered into the local system from new sources. Often this means that power will flow into the local area from remote sources on transmission paths with limited capacity to facilitate increased power flow. Alternatively, replacement power may be supplied to the local area from new local dispatchable generation resources. BEC, as one of the last remaining dispatchable generating stations in Northern Minnesota, provides a dependable, available, and controllable source of energy that may be delivered locally to nearby energy consumers. If the BEC units are shut down or transition to non-baseload operation, solutions must be identified that strengthen delivery paths for energy from remote sources to be delivered to the local transmission system and/or maintain a presence of local dispatchable generation to be delivered to energy consumers in Northern Minnesota.

[2] *Essential Reliability Services, Whitepaper on Sufficiency Guidelines*, North American Electric Reliability Corporation (Dec. 2016), https://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSWG_Sufficiency_Guideline_Report.pdf. Helpful background and simplified explanations of these three concepts are also publicly available from the Midwest Reliability Organization (https://www.mro.net/clarity/the-changing-resource-mix/essential-reliability-services) and the United States Department of Energy (https://www.energy.gov/eere/articles/keeping-lights-essential-reliability-services).

Pillar #5: Dispatchable Generators Offset the Need for Regional Power Transfers

Power formerly provided locally by dispatchable generators must be delivered on the regional transmission network, which may have limited capacity to facilitate the delivery of the replacement power from remote resources. Alternatively, replacement power may be supplied from new local dispatchable generation. BEC, as one of the last remaining dispatchable generating stations in Northern Minnesota, provides a dependable, available, and controllable source of energy for the region, in addition to local energy consumers in Northern Minnesota. This is a benefit to all consumers of electricity in Northern Minnesota and the surrounding area, including those served by Minnesota Power, Great River Energy, Otter Tail Power, Minnkota Power, Xcel Energy, Missouri River Energy Services and others. When this dispatchable energy is no longer provided in Northern Minnesota, the replacement power to serve Northern Minnesota customers must be delivered from remote resources by the regional transmission network. The regional transmission network has not been designed to deliver this magnitude of replacement power to Northern Minnesota while continuing to facilitate existing regional transfers of energy. If the BEC units are shut down or transition to non-baseload operation, solutions must be identified that strengthen the regional transmission network to ensure continued stable and reliable operation in light of new and increased use and/or maintain a presence of local dispatchable generation in Northern Minnesota.

Pillar #6: Solution Development is a Multi-Year Process

Integrated resource, transmission, and distribution planning provides a holistic view of the potential impacts and costs associated with a baseload retirement study. However, the detailed transmission, distribution and resource planning studies necessary to identify and understand the impacts prompted by resource actions and develop a well-defined set of solutions are complex, resource-intensive, and time-consuming. While it is possible to anticipate general impacts and potential solutions at an early stage – such as in this IRP – there is inherent risk and uncertainty, and unforeseen circumstances or new developments are likely to arise in the process of evaluation and solution development. Once a decision is made and it becomes necessary to move forward with mitigating solutions, subsequent large transmission project implementation timelines and/or large resource additions may take ten years or more depending on the scope and scale of the solutions. If the BEC units are shut down or transition to non-baseload operation, impacts and solutions must be thoroughly vetted and coordinated with other affected entities through a multi-year process of detailed analysis and project development. Baseload retirement study decisions about resource actions should recognize and allow for a sufficient amount of time for the real-world implementation of these solutions.

The remainder of this section summarizes several studies assessing the impacts of BEC unit retirements. The discussion of these studies will begin with regional impacts evaluated through the MISO generator retirement study process and then transition to Minnesota Power's complementary assessments of the regional and local impacts from Boswell Energy Center retirement scenarios. These studies have helped inform the transmission network upgrade cost assumptions used for purpose of modeling different BEC operating scenarios in the IRP. The development of transmission network upgrade cost assumptions for generator retirements is discussed subsequently in Part 8.

MISO Generator Retirement Study

Regional impacts of generating unit closures on the transmission system consider transmission lines 100 kV and above owned and operated by the generation owner and neighboring utilities. Because Minnesota Power is a member of MISO, the regional transmission planner and operator for much of the Midwest, any generating unit closure on the Minnesota

Power system is required to utilize the MISO Attachment Y (unit retirement) process. Section 38.2.7 of the MISO Tariff describes the process for generator retirements:

1. First, the MISO market participant owning the generation resource involved must submit an Attachment Y to MISO stating when the generation resource is to be retired. This must be done at least 26 weeks before the targeted retirement date.
2. Second, MISO will perform reliability analyses to determine if the unit may be retired without causing reliability issues on the transmission system. NERC Transmission Planning ("TPL") standards and other applicable reliability criteria are applied.
3. Third, if the unit closure does not impact reliability, the unit is allowed to shut down as scheduled. If the unit closure results in reliability criteria violations on the transmission system, the unit is placed on a System Support Resource ("SSR") agreement per Attachment Y-1 of the MISO Tariff. The unit will then remain operational under the SSR agreement until the transmission upgrades necessary to provide adequate transmission system reliability are constructed.

The Attachment Y process ultimately results in a binding agreement between the generation owner and MISO to either close the unit or keep it online as a SSR for the reliability of the regional transmission system. MISO also offers a parallel investigative option, called the Attachment Y-2 process, by which a utility can request an information-only study of the regional reliability impacts of a particular generating unit closure without entering into a binding agreement to close the unit or keep it online.

In August 2018, Minnesota Power submitted an Attachment Y-2 Study request to MISO for a transmission system reliability assessment of various BEC retirement combinations. Mirroring the standard MISO generator retirement study (Attachment Y) process, the Attachment Y-2 Study was an information-only study of various scenarios to identify reliability issues due to the potential retirement of the BEC units. Based on the results of the Attachment Y-2 Study, MISO concluded that robust mitigating solutions would likely need to be built before the retirement of the BEC units could be allowed. The Executive Summary from the MISO Attachment Y-2 Study Report is attached in Part 9 of this Appendix.

One area of concern discussed in the MISO Attachment Y-2 Study is significant overloads of the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]**. This is not an unexpected finding as the Northern Minnesota power system becomes increasing dependent on the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** to deliver replacement power to the local area following retirement of the BEC units. While the MISO Attachment Y-2 Study process allows for these impacts to be mitigated by redispatch and load shedding, they are noted as driving a significant portion of the overall need for these actions in the Y-2 Study results, making them potentially worth addressing with a longer-term solution.

Another significant area of concern discussed in the MISO Attachment Y-2 Study, which is significant to regional reliability, is regional voltage stability and related transmission line overloads following tripping of the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** Line or other parallel or related north-south transmission facilities in the winter peak case with heavy north flows. Due to this regional stability concern, MISO concluded that one or both of the BEC units could potentially be designated as a SSR if mitigation is not in place. Since the MISO Attachment Y-2 Study is not intended to assess transmission solutions for the identified reliability issues, Minnesota Power subsequently conducted its own investigation of the underlying voltage stability issues.

Northern Minnesota Voltage Stability Study

Minnesota Power conducted the Northern Minnesota Voltage Stability Study in order to build on and further understand the results from the MISO Attachment Y-2 Study and previous Minnesota Power studies. The purpose of the Northern Minnesota Voltage Stability Study was to investigate the previously-identified voltage stability issue, begin to understand how to define a voltage stability interface and thresholds to accurately characterize the issue, examine the impacts of various regional drivers on the voltage stability issue and related facility overloads, and investigate potential operating limits for the combinations of BEC Unit 3 and 4 operating scenarios that were evaluated in the MISO Attachment Y-2 Study.

The Northern Minnesota Voltage Stability Study considered four power flow cases from the MISO Attachment Y-2 Study, listed below. All four cases represented a 2030 winter peak scenario with heavy Manitoba import (north flow).

- Base Case: Boswell 3 & 4 Online
- Boswell Unit 3 Offline
- Boswell Unit 4 Offline
- Both Boswell Units Offline

The starting power flow cases were unaltered from the MISO Attachment Y-2 Study. To understand the drivers behind the voltage stability issue noted in the MISO Attachment Y-2 Study, three different quantities were varied in each study case. The three quantities were total Boswell Generation, Northern Minnesota Load, and Manitoba Hydro Import. These study variables were increased or decreased in the power flow cases to find the voltage stability limit, defined as the last point at which the case is stable following the limiting contingency (in this case, tripping of the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** Line).

In order to understand and evaluate a voltage stability issue, the issue must be expressed in terms of an interface. In this case, a new Northern Minnesota Voltage Stability ("NOMN") Interface is needed to directly characterize the issue. The study considered several potential NOMN Interface definitions, ultimately finding that the definition shown in Table 4 represents the issue most accurately and directly by encompassing the transmission line associated with the initiating contingency and the parallel tie lines that become overloaded when it trips, leading to the voltage collapse. The NOMN Interface tie lines are also shown in Figure 17 below. **[Trade Secret Data Begins**

Table 4: Northern Minnesota Voltage Stability Interface

Northern Minnesota (NOMN) Interface Definition		
Facility	kV	Map Key
[redacted]		

Figure 17: Northern Minnesota Voltage Stability Interface Tie Lines

[redacted]

Trade Secret Data Ends]

The NOMN Interface stability limit was identified for twelve different study cases (four power flow cases, with three study variables assessed for each). Since it would not be secure to operate the system all the way to the stability limit, planning criteria require that a stability margin be maintained between the stability limit and an operating limit. The operating limit is defined as the lesser of the following: (a) 90 percent of the stability limit; or (b) the last interface transfer level at which low post-contingent voltage violations do not occur. The average NOMN Interface stability limit from the twelve study cases is 2411 MW, and the average operating limit is 2170 MW, with remarkably little variation across the study cases. To lend context to these numbers, Table 5 shows the flow on the NOMN Interface in each of the MISO Attachment Y-2 Study cases assessed in the NOMN Voltage Stability Study. Only the Base Case with both BEC units online is stable and close to being within the operating limit.

Table 5: NOMN Flow in Attachment Y-2 Study Cases

MISO Y-2 Study Case	NOMN
Base Case	2200 MW
Boswell Unit 3 Offline	2422 MW
Boswell Unit 4 Offline	2597 MW
Both Boswell Units Offline	2891 MW

Evaluation of the individual BEC unit retirement scenarios listed in Table 5 indicates that either Northern Minnesota Load or Manitoba Hydro Import would need to be reduced anywhere from **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** to bring NOMN Interface flow within the operating limit, depending on how much BEC generation is still online. With no reductions to the modeled load and transfer levels, a minimum of **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** of BEC generation is necessary to maintain NOMN within the operating limit. Based on this analysis, Minnesota Power concluded that active monitoring and operational management of the NOMN Interface may be sufficient to prevent regional voltage stability problems and related concerns with BEC Unit 3 offline. This conclusion is based on two observations. First, the BEC Unit 3 offline case requires a smaller amount of load reduction from the studied load level than the other study cases, indicating that the system is likely to spend less time operating above the threshold. Second, even when the system is operating above the critical load threshold with BEC Unit 3 offline, the smaller amount of Manitoba Hydro Import reduction needed to bring NOMN Interface loading within the operating limit would be more practicable in operations than the very large reductions needed for the other cases. A long-term permanent transmission or dispatchable generation solution for Northern Minnesota is recommended to maintain reliability and a reasonable amount of operational flexibility with BEC Unit 4 or Both BEC Units offline.

Another purpose of the Northern Minnesota Voltage Stability Study was to evaluate the relative impact of various regional drivers on the voltage stability issue and related facility overloads. As noted above, the three variables that were assessed for this study were Boswell Generation, Northern Minnesota Load, and Manitoba Hydro Import. For each of these variables, a distribution factor was calculated to describe the impact of the variable on NOMN Interface loading, as well as other potentially overloaded facilities. A distribution factor describes the percentage of the total change in power – from a change in load, generation, or interface transfer level – that will flow on an affected facility. Distribution factors from the three study variables on the NOMN Interface and three potentially overloaded facilities are summarized in Table 6 below.

Table 6: Summary of Distribution Factor Analysis

Constraint	Gen	Load	Transfer
NOMN Interface	74.89%	70.73%	74.04%
Benton County – Mud Lake 230 kV	17.50%	14.05%	15.46%*
Forbes 500/230 kV Transformer #8	37.72%	31.31%	32.84%
Forbes 230/115 kV Transformer #2	10.75%	13.95%	*1.20%*

Distribution factor analysis shows that Boswell Generation, Northern Minnesota Load, and Manitoba Hydro transfers have a strong and nearly identical impact on NOMN interface loading. This means that each of these variables is a roughly equal contributor to the Northern Minnesota Voltage Stability issue, with approximately a 70-75 MW change in NOMN Interface loading for every 100 MW change in any of the three variables. Similarly, though with notably less significant impact, the Benton County – Mud Lake 230 kV Line and Forbes 500/230 kV Transformer #8 are impacted in nearly equal amounts by the three study variables. The last constraint in the table, Forbes 230/115 kV Transformer #2, is only substantively impacted by Boswell Generation and Northern Minnesota Load.

Beyond Boswell Study

The Beyond Boswell Study was performed by Siemens PTI and Minnesota Power in 2016-17. The study investigated the technical transmission issues surrounding the possible retirement of BEC Units 3 and 4, in order to identify the load-serving and reliability impacts of retiring all Minnesota Power coal-fired generation. The study included steady state analysis, voltage stability analysis, and transient stability analysis performed on a range of historically challenging peak and off-peak system conditions. System impacts were monitored throughout a study area including Minnesota and parts of the Dakotas, Wisconsin, and Manitoba. Single and multiple-element contingencies, as defined in the NERC TPL standard were simulated throughout the study area, and results were evaluated against existing transmission owner performance criteria to identify where criteria violations develop in a post-BEC retirement case. The findings of this study are summarized below.

Steady state analysis in the Beyond Boswell Study identified non-convergence and facility overloads as concerns. Non-convergence in a power flow case refers to a scenario where the power flow software was not able to resolve the study case. This is often indicative of stability-related issues that must be assessed in greater detail in a voltage or transient stability study. In the Beyond Boswell Study, non-convergence resulted from loss of the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** Line in the Winter Peak case. Stability concerns related to these events were further evaluated in the voltage stability portion of the study. Steady state analysis also identified facility overloads, the most significant of which are listed in Table 7.

[Trade Secret Data Begins [redacted]

Study case	Facility	Contingency Event
[redacted]		

Trade Secret Data Ends]

The majority of overloads in the Winter Peak case are either directly caused by loss of the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** Line or involve related 345 kV, 230 kV or 115 kV lines on or in parallel to the NOMN interface discussed previously. There are also several 230/115 kV transformer overloads in the Winter Peak case. The only significant overload identified in the Summer Peak and Shoulder cases is one of the 230 kV outlets from the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]**.

Voltage stability analysis in the Beyond Boswell Study was performed to determine if the system is subject to uncontrolled decline in voltage following any contingency events, and what limitations may be necessary to prevent such circumstances. Voltage stability analysis focused on the non-converged contingencies identified in the steady state assessment of the Winter Peak case, which involved loss of the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** Line. Standard voltage stability criteria require a minimum of 10 percent margin from the point at which the voltage collapse occurs (that is, the point at which the system becomes unstable). Two scenarios were evaluated for the Beyond Boswell Study. First, load and regional transfers were held constant while the total amount of BEC generation was varied. This assessment identified that the minimum amount of BEC generation required to prevent voltage collapse in the Beyond Boswell Study Winter Peak case is **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]**. The second scenario involved holding load constant, BEC generation offline, and varying the most impactful regional transfer. For the Winter Peak case, the most impactful regional transfer is the power being imported by Manitoba from the United States on the Manitoba Hydro Export ("MHEX") interface. In the Winter Peak case, the base MHEX level is **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** import, which is consistent with the MISO-approved TSR amount for the interface. With BEC offline in the Beyond Boswell Study Winter Peak case, the total MHEX import needed to be reduced to **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** to bring the case within the voltage stability planning criteria. These results indicate that there is not a significant amount of margin in the Winter Peak case to accommodate reduced output from BEC before significant regional voltage stability concerns arise.

Transient stability analysis in the Beyond Boswell Study was performed to assess the system's response in the first few seconds after various regional contingency events. Transient stability analysis may be utilized to evaluate frequency and voltage response, synchronous machine response, and – in some cases – potential relay operations. Typical transient stability criteria require no unexpected generator or synchronous machine tripping, controlled frequency and voltage responses with acceptable limits, and positive damping of machine angle oscillations. Relay margins for certain types of protective functions may also be evaluated to ensure they are within limits. The Beyond Boswell Study transient stability analysis confirmed and further clarified the voltage collapse identified in the Winter Peak case following loss of the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** Line. Transient stability limits associated with this contingency event were found to be less limiting than the voltage stability limits discussed above. In addition, generally slower voltage response was noted throughout the Minnesota Power system with the BEC units offline, even though the response was still technically within Minnesota Power's planning criteria. The study also identified that the regional system relies heavily on the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** for voltage support during and after significant fault events. This dynamic reactive support facility, which was included in the Beyond Boswell Study models, was retired by Xcel Energy in Fall 2020. These results add clarity to the Northern Minnesota interface issues that have been highlighted in every BEC retirement study so far and also show the importance of dynamic voltage support for Northern Minnesota and the region. With the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** recently retired, the retirement of the BEC units is expected to drive a need for additional dynamic voltage support to support reliable, predictable system dynamic response to contingency events.

In summary, the Beyond Boswell Study provided a more in-depth look at the steady state, voltage stability, and transient stability impacts from BEC unit retirements. While this study is a preceded the MISO Attachment Y-2 Study and the Northern Minnesota Voltage Stability Study, it laid important groundwork for understanding the Northern Minnesota voltage stability issue, and provided additional understanding of potential facility overloads and transient stability impacts from BEC unit retirements.

Short Circuit Analysis

The CapX2050 Report, introduced earlier in Part 5, discusses system strength as the ability of the system to quickly and reliably respond to and mitigate disturbances. A fundamental component of a strong system is fault current – the amount of current flowing from generators to a short circuit on the transmission system. The CapX2050 Report explains that transmission system protection and control systems require a minimum amount of fault current in order to reliably identify and respond to disturbances. In a weak system with fewer generators online to contribute fault current, protection and control system mis-operations become increasingly likely because differentiating between normal and abnormal system conditions becomes increasingly complex. Voltage regulation is another important indicator of system strength that is discussed in the CapX2050 Report. Voltage regulation refers to the control local generators provide for maintaining predictable system voltages at necessary levels in the surrounding area. As demonstrated by Minnesota Power's real-world experiences from transitioning its fleet of small coal units, discussed previously in Part 6, idling or retiring local dispatchable generators will lead to less predictability and more variation in system voltages. Too little voltage control in a weak system may ultimately lead to voltage deviations outside acceptable limits that can damage electrical apparatus and end-user equipment or even cause system instability, as was the case in the North Shore Loop where a STATCOM was required to replace the dynamic voltage support previously provided by local baseload generators.

As noted previously, the BEC units are the only remaining baseload generators operating in Northern Minnesota. As the last remaining baseload generators, the BEC units provide voltage support and system strength on a continuous basis that support consistent and predictable system operations and properly functioning utility protection systems for the transmission system and the lower-voltage distribution systems that depend on it. In addition, Minnesota Power's significant concentration of large industrial customers depend on the predictable voltages and fault currents historically and presently provided by the BEC units to support their large industrial processes and power quality needs. It is typical for large industrial plant design, like utility distribution system design, to take into account as a design basis the fault current contributions and normal operating voltages of the utility transmission system. Without the BEC units online, the Northern Minnesota transmission system would operate for extended periods of time without any local generators online providing fault current and voltage regulation. This mode of operation would be unprecedented in the modern history of the Northern Minnesota transmission system and, if not adequately assessed and mitigated, would lead to a great deal of uncertainty and potential mis-operation in the transmission system and the lower-voltage industrial, municipal, and Minnesota Power distribution systems connected to it. Minnesota Power's real-world experiences in the Grand Rapids area after the retirement of BEC Units 1 & 2, previously discussed in Part 6, also support this conclusion.

Given the significance of system strength as a potential impact of BEC unit retirements, Minnesota Power is in the process of determining how best to evaluate this issue and ensure a minimum level of system strength is maintained for Northern Minnesota in the event the BEC units are retired or transitioned to long-term economic operation. Preliminary short circuit analysis has shown that the primary non-BEC sources of short circuit capability to Minnesota Power's transmission system are the extra-high voltage ("EHV") transmission sources at the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** Substation, the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** Substation, and the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** Substation. However, there is an inherent risk involved in depending entirely on these EHV Substations for access to external sources – over which Minnesota Power has no control or influence in the long-term planning of – for essential reliability services such as system strength and voltage support that directly impact the reliability and operations of Minnesota Power's customers and protection systems. Some amount of local short circuit capability and voltage support is needed to provide a continuous, predictable, and redundant source to Minnesota Power's system. Besides large local generators like the BEC units, synchronous condensers would appear to provide the best option for maintaining a local source of short circuit capability. A synchronous condenser is essentially a generator that is driven by the transmission system rather than by a steam turbine or some other form of mechanical energy. Synchronous condensers require no fuel for continuous operation and produce only reactive power. Synchronous condensers are capable of providing voltage regulation during normal system operations as well as dynamic voltage response and fault current during system disturbances.

In addition to new sources of short circuit capability, new operating criteria are also needed to ensure that critical sources – whether they are generators, synchronous condensers, or EHV Substations – are operated in a way that maintains a minimum level of system strength on a continuous basis. After completing preliminary screening of short circuit levels with and without BEC units online, Minnesota Power is gathering information and working with MISO to determine the best way to establish and maintain a minimum system strength requirement for the Minnesota Power system. Minnesota Power envisions the development of new system strength planning criteria requiring a minimum short circuit level at a handful of key nodes on the transmission system. The minimum short circuit level will take into account existing minimum short circuit levels with BEC units online, the design of transmission control and protection schemes, and allowable voltage deviations. Planning studies and system design will include credible prior outage scenarios to ensure the system can handle an outage (planned or unplanned) of at least any single source. Additional redundancy may be required for sources that require extended maintenance outages, such as generators or synchronous condensers. While there is presently no direct way to measure short circuit levels on Minnesota Power's system, an operating guide would be developed based on the planning studies to ensure that the required combinations of short circuit sources are online to maintain the minimum required short circuit level. This operating guide could be used to plan maintenance outages on the system or, in the event of unplanned outages, to bring short circuit sources such as generators or synchronous condensers online. As of the writing of this section, the studies and coordination discussions around minimum system strength requirements were still in development.

Synchronous Motor Starting Analysis

Minnesota Power has a number of large industrial customers whose processes place uniquely demanding requirements on the transmission system. Within many taconite processing facilities in northeastern Minnesota, large synchronous motors are used in various applications to process raw material into a finished product. These motors may take an extended amount of time to start up and eventually synchronize with the transmission system. During starting, the motors may draw an immense amount of reactive power, causing significant voltage drop on the transmission and the plant distribution system. The longer it takes to start a motor successfully, the more stress is placed on the transmission system, the plant distribution system, and the motor itself. The strength of the transmission system, typically measured by short circuit level, along with dynamic reactive power availability will aid in starting motors faster and reducing the voltage dip that is experienced during the starting sequence. It is not uncommon for synchronous motors to take 60-90 seconds to start up successfully. Beyond that duration, excess heat generated during the process may damage equipment and protective equipment may interrupt the sequence to prevent such damage.

Based on previous experiences evaluating synchronous motor starting following fleet transition in the North Shore Loop, Minnesota Power commissioned Siemens PTI to study potential impacts on motor starting capability for large power customers on the Iron Range if BEC Units 3 and 4 were to be retired. This study was meant to be indicative in nature only, not representative of any single customer or actual equipment. Much of the detailed industrial plant data needed to perform a specific motor starting study is not readily available to Minnesota Power, and the study was only intended to give a general idea of principles and impacts independent of the specifics of any given site. An existing large power 115 kV bus on the Minnesota Power transmission system was selected as a representative site for the analysis. From there, a slightly more detailed lower voltage system was added in, modeling the path from the 115 kV bus down to the synchronous motor terminal bus using parameters similar to actual known customer configurations. Siemens PTI performed a number of motor starting simulations by considering synchronous motor sizes from 3000 to 9000 horsepower (hp), varying lower voltage system impedances across a range of potential values, and toggling BEC unit availability. Key metrics considered in the study were the success and duration of motor starting attempts, defined as the time it takes from start until motor torque equals load torque (the point when motor is “synchronized”), as well as the voltage dip magnitude and duration observed at the point of common coupling with the transmission system – the 115 kV bus.

Key findings from the study are that steady-state voltages prior to motor starting are typically lower in the cases with BEC generation offline due to a loss of reactive power support. When motor starting simulations are performed with lower initial transmission system voltages, motor starting durations are extended and voltage dips during starting are more significant, both of which have a negative impact on motor starting. Additional sensitivity analysis was performed to generically replace the reactive power generated by the BEC units in the form of a fixed shunt capacitor bank at the representative 115 kV bus. Fixed shunt sizes were chosen in each scenario to perfectly match the 115 kV steady state voltage between the pre- and post-BEC retirement cases. Performing the motor starting simulations again with additional reactive support on the transmission system and BEC units offline, the differences in motor starting duration and voltage dip with and without the BEC units were negligible. This trend was observed across the entire range of synchronous motor sizes and lower voltage impedances. From this, Minnesota Power concludes that large synchronous motor starting is primarily dependent on pre-starting steady-state voltage, which must be adequately and predictably regulated with or without BEC units online. Another primary factor in successful motor starting is the impedance between the motor and the transmission system, which is dependent on the local plant distribution system configuration and generally out of Minnesota Power's control. Study results also indicate that, unlike the North Shore Loop, the transmission system on the Iron Range is capable of providing sufficient dynamic reactive support during motor starting with or without the BEC units online, as long as a robust pre-starting steady state voltage is maintained. This may allow for some of the voltage support presently provided by the BEC units to be replaced with fixed-size reactive resources like shunt capacitor banks. On the other hand, Minnesota Power's previous experiences in the Grand Rapids area and the North Shore Loop, as well as transient stability simulations from the Beyond Boswell Study and post-event analysis of the 2019 Grand Rapids-area fault events, show that adequate steady state and dynamic regulation of system voltages depends on a combination of both dynamically-responding reactive support and fixed-size reactive resources. The motor starting study results and the previous generator retirement experiences both indicate that the most effective leading indicator of whether or not large industrial customer motor starting and other processes will be negatively impacted by BEC unit retirements is Minnesota Power's ability to provide a healthy, predictable transmission system voltage similar to what is presently available with the BEC units online.

Part 8: Generator Retirement Network Upgrade Assumptions

Background

Much is known about the transmission impacts from BEC unit retirements at this time and much is still to be determined. As noted in the previous section, the development of specific solutions and detailed cost estimates for those solutions is a long and complicated process. This section provides an overview of the process Minnesota Power used to develop transmission upgrade cost assumptions for the purpose of modeling different BEC operating scenarios in the IRP. Due to the considerable amount of work left to understand and develop long-term solutions to the transmission issues discussed in Part 7, these cost assumptions should be considered preliminary. As discussed below, a range has been applied to the cost estimates to reflect the inherent uncertainties still in play at this early stage of solution development.

BEC Operating Scenarios

To provide a holistic understanding of the potential transmission upgrade costs associated with various changes in the operation of the BEC units, four potential operating modes were considered for each BEC unit:

Baseload Operation means that the unit is online with a high capacity factor similar to its historical baseload operations. It is assumed that full capability of the unit ("Pmax") is available to mitigate any transmission issues. If increasing the unit to Pmax is not sufficient to resolve the issue, then a transmission mitigation solution should be developed.

Economic Operation means that the unit may be dispatched offline, but is available to be turned online to resolve potential transmission issues. Under current operating practices, existing MISO processes would call on an offline unit to run if real-time contingency analysis indicated there was a transmission system constraint that would be resolved by running the unit. The actual unit startup time could be anywhere from 12-24 hours, so in most cases the units would need to be picked up well in advance of the anticipated conditions leading to transmission constraints. The identification of such constraints in real-time operations is entirely dependent on the actual elements, interfaces, and contingencies being assessed by MISO. For example, real-time contingency analysis currently only considers single element (NERC Category P1) contingency events. For the purpose of this assessment it was assumed that other single-initiating event contingencies, such as breaker failures or bus faults (NERC Category P2) or common tower failures (NERC Category P7) would also cause the unit to be picked up. MISO also does not presently define, monitor, or manage the Northern Minnesota (or "NOMN") stability interface discussed in Part 7. For the purpose of this assessment it was assumed that Minnesota Power could work with MISO to establish this new regional interface and develop appropriate criteria to manage it in real time operations where it would not result in significant curtailment of load or regional transfers. In order to avoid creating a situation where a unit intended for Economic Operation was effectively required to run like a Baseload unit, it was also assumed that the units would only be picked up to mitigate issues appearing in Summer Peak and Winter Peak cases. For any issues showing up only in an Off-Peak or Shoulder condition, or for any issues where turning on the unit and running it at Pmax would not resolve the constraint, a transmission mitigation solution was developed.

Shutdown means that the generator has been permanently shut down and is not available to run under any circumstances to mitigate transmission system constraints. For this planning exercise, replacement generation is assumed to be sited outside Minnesota Power's transmission system.

Several combinations of the four states listed above were considered for the BEC units in order to develop IRP cost estimates for mitigation of transmission system impacts. Table 8 below shows the unique scenarios developed for this exercise.

Table 8: Boswell Unit Scenarios Evaluated

Scenario	Boswell Unit 3	Boswell Unit 4
E1	Economic Operation	Baseload Operation
E2	Economic Operation	Economic Operation
S1	Shutdown	Baseload Operation
S2	Baseload Operation	Shutdown
S3	Shutdown	Shutdown

Conceptual Upgrades

Based on a review of the studies discussed in Part 7 and the operational experience discussed in Part 6, a list of expected transmission issues associated with changing operations at BEC was developed. The issues in the list were then categorized according to whether they were primarily related to voltage support & system strength, local power delivery, or regional power delivery as those categories are defined in Part 7. A conceptual solution was then developed for each of the identified issues. The following discussion will provide information on the issues and conceptual solutions in each category of impact.

Voltage Support & System Strength

As discussed in Part 7, the Northern Minnesota transmission system depends on the dynamic voltage support, voltage regulating capability, and short circuit capability of the BEC units. Presently, there are two large units at BEC providing voltage support and system strength. In the event one unit is lost, the other should remain on line. In the event that one unit is down for maintenance and the other unit trips, local sources of dynamic voltage support, voltage regulation, and short circuit capability in Northern Minnesota would be very limited. Therefore, the methodology employed by Minnesota Power for designing transmission solutions for voltage support and system strength is to provide short circuit capability similar to what has been provided by BEC Unit 3 (the smaller unit) at all times, considering both single-contingency events (unintended loss of a facility) and prior outage events (scheduled maintenance on one facility followed by unintended loss of another facility). What this effectively means is that three local sources of short circuit capability equivalent to BEC Unit 3 are necessary at any given time. Potential sources include synchronous condensers, new dispatchable generators, and the existing BEC generators. This approach conservatively does not rely at all on external sources of short circuit capability, such as the EHV Substations discussed in Part 7.

For the purpose of this exercise, the following upgrades were included to address concerns related to short circuit & voltage regulation:

- For the scenario involving economic operation of a single BEC unit (**E1**), one new synchronous condenser was included to ensure a continuous source of voltage support and system strength following unintended loss of the baseload BEC unit. For prior outage of either the baseload BEC unit or the synchronous condenser, it was assumed that the economic operation BEC unit could be brought online.[3]

- For the scenario involving economic operation of both BEC units (**E2**), two new synchronous condensers were included to ensure a consistent source of voltage support and system strength during times when both BEC units are offline and following unintended loss of one synchronous condenser. For prior outage of one synchronous condenser, it was assumed that one of the economic operation BEC units could be brought online.
- For scenarios involving shutdown of one BEC unit and baseload operation of the remaining BEC unit (**S1** & **S2**), two new synchronous condensers were included. The first synchronous condenser ensures a continuous source of voltage support and system strength following unintended loss of the baseload BEC unit. The second synchronous condenser ensures a continuous source of voltage support and system strength if the first synchronous condenser is unexpectedly lost during a prior outage of the baseload BEC unit, or vice versa.
- For the scenario involving shutdown of both BEC units (**S3**), three new synchronous condensers were included to ensure a continuous source of voltage support and system strength following unintended loss of one synchronous condenser and for prior outage of one synchronous condenser followed by loss of a second synchronous condenser.
- For scenarios involving the shutdown of one or both BEC units (**S1, S2, & S3**) an additional 300 MVAR of mechanically switched capacitor banks were included. These mechanically switched capacitor banks serve the purpose of preserving dynamic reactive range from the generators and synchronous condensers for system intact voltage regulation and post-contingency system response. The additional capacitors also offset the impact of the retirement of the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** which, as described in Part 7, the local system becomes increasingly dependent on with BEC units offline.

These voltage support and system strength issues and solutions are summarized alongside the other categories in Table 9 at the end of this section. For the purpose of this exercise, it was assumed that all synchronous condenser additions involve new construction. Potential conversion of one or both BEC units to synchronous condensers is also being investigated as an alternative to new synchronous condenser additions. It is anticipated that synchronous condenser conversion, if feasible, may prove to have a lower initial capital cost than the establishment of new synchronous condensers.

Local Power Delivery

As alluded to in Part 7, the Northern Minnesota transmission system becomes increasingly dependent on the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** substations for the delivery of power locally from remote resources when the BEC units are offline. For the purpose of this exercise, the following upgrades were included to address local power delivery concerns based on a review of the study results to date:

- For all scenarios, reconductoring of the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** line was included to mitigate overloads on these lines. Because these overloads were identified in the shoulder (off-peak) study cases, this solution was applied to all scenarios including economic operation or

[3] Minnesota Power is working with MISO on what transmission solutions and/or metric that will be required for economic dispatch at Boswell.

shutdown of at least one BEC unit. These two lines are relatively short in length, but become more critical as outlets for the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** Substation with one or more BEC units offline.

- For scenarios involving the shutdown of one or both BEC units (**S1, S2, & S3**) replacement of one of the existing **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** transformers with a larger transformer was included to mitigate overloads on this transformer. These overloads are present in peak cases for loss of a parallel transformer and mitigation is required in the listed scenarios because there is not a BEC unit available for Minnesota Power or MISO to bring online to resolve the issue.
- Also for scenarios involving the shutdown of one or both BEC units (**S1, S2, & S3**) a new **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** line was included to mitigate issues related to transformer loading and prior outages in the area. These issues are largely a result of increased dependence on the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** source and include overloads of the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** transformers, the existing **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** line, and underlying 115 kV transmission lines for prior outages involving the existing **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** line. With one or both BEC units retired and therefore unavailable to be brought online to help alleviate these issues, there are very limited options available for Minnesota Power or MISO to resolve the issues in operations and therefore a comprehensive transmission solution is necessary.

These local power delivery issues and solutions are summarized alongside the other categories in Table 9.

Regional Power Delivery

In practically every study, a regional voltage stability concern related to BEC unit retirements has been identified as an area of concern. For the purpose of this exercise, the following upgrades were included to address these regional power delivery concerns based on what is known about the issue at this time:

- For all scenarios, Minnesota Power and MISO must work together to define the NOMN voltage stability interface so that it may be monitored and managed in real-time operations. Developing this new interface in coordination with MISO is necessary to ensure that MISO has the proper operational tools to use within the existing real-time operating framework to anticipate and manage regional reliability concerns related to changing operations at BEC.
- For the scenario involving retirement of BEC Unit 3 only (**S1**), it was assumed that regional voltage stability concerns could be managed reliably in real-time operations by MISO using the NOMN interface to dispatch the system in a way that maintains sufficient stability margin. However, as loading on NOMN increases, study results also show underlying transmission capacity issues are likely to show up as well. While most of the transmission line overloads are likely to be mitigated as long as the NOMN interface is operated within its voltage stability limit, some may prove to be more limiting in real-time operations and therefore worth resolving. Anticipating these issues, two proxy upgrades of underlying 115 kV transmission lines were included in the listed scenarios.

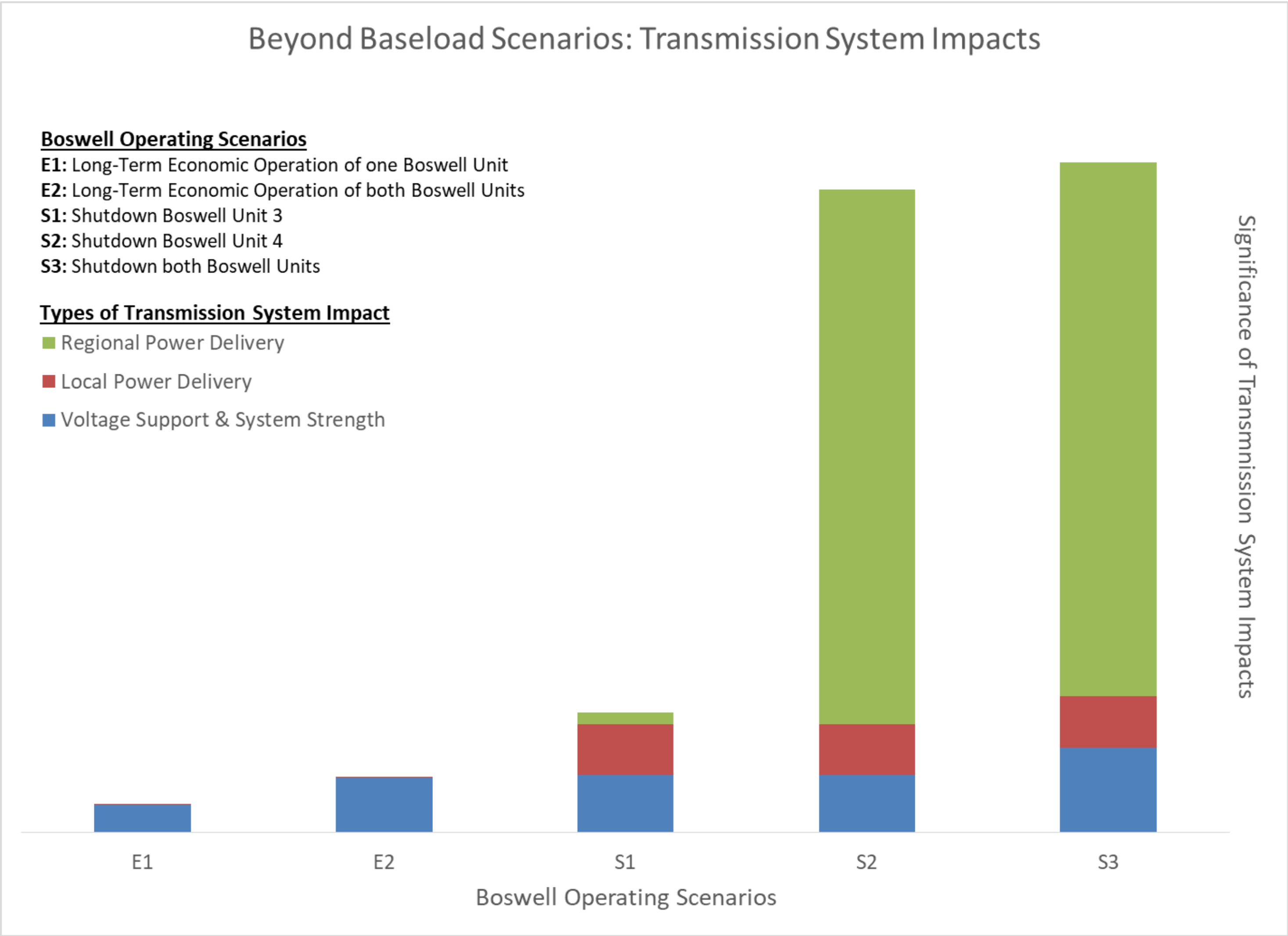
- For scenarios involving retirement of either BEC Unit 4 or both BEC units (**S2 & S3**), it was assumed that regional voltage stability concerns would become excessively challenging to manage in real-time operations, even with a defined, monitored, and managed NOMN interface. Therefore, a proxy regional transmission solution was included in these scenarios to mitigate voltage stability concerns and provide continuous, secure operation of the regional transmission system without the BEC units. The proxy solution involves the development of a new EHV transmission line electrically in parallel with the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** Line, the loss of which is the primary driver for voltage stability concerns. This solution mitigates voltage stability concerns by providing redundancy and additional transfer capability along the NOMN interface. The proxy EHV transmission solution was assumed to connect the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** Substation and the **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]** Substation, including substation expansions at both ends and a midline series compensation station. The midline series compensation station is included because the existing parallel EHV line is also series compensated. This is a proxy solution only, and a great deal of additional analysis is required to ensure the right long-term solution is identified and implemented for this issue.

These regional power delivery issues and solutions are summarized alongside the other categories in Table 9 on the following page. Figure 18 provides a summary view of the increasing significance of transmission impacts and solutions associated with changes in operation of the BEC units.

Table 9: Summary of IRP Generator Retirement Transmission Issues and Solutions

Category	Impact	Solution	E1	E2	S1	S2	S3
Voltage Support & System Strength	Need a continuous source of VSSS	Synchronous Condenser		X			X
Voltage Support & System Strength	Contingency loss of source of VSSS	Synchronous Condenser	X	X	X	X	X
Voltage Support & System Strength	Prior outage plus loss of source of VSSS	Synchronous Condenser			X	X	X
Voltage Support & System Strength	Steady state reactive power support	300 MVAR of additional capacitor banks			X	X	X
Local Power Delivery	Overload of [Trade Secret Data Begins [redacted] Trade Secret Data Ends] Outlets	Rebuild [Trade Secret Data Begins [redacted] Trade Secret Data Ends]	X	X	X	X	X
Local Power Delivery	Overload of [Trade Secret Data Begins [redacted] Trade Secret Data Ends] Transformer	Replace [Trade Secret Data Begins [redacted] Trade Secret Data Ends] Transformer			X	X	X
Local Power Delivery	Overload of [Trade Secret Data Begins [redacted] Trade Secret Data Ends] Transformer and related prior outage overloads in the area	Build new [Trade Secret Data Begins [redacted] Trade Secret Data Ends] Line			X	X	X
Regional Power Delivery	Northern Minnesota Voltage Stability & related issues	Define NOMN interface & manage in real-time	X	X	X	X	X
Regional Power Delivery	Underlying transmission overloads along NOMN interface	Upgrade existing [Trade Secret Data Begins [redacted] Trade Secret Data Ends] Lines			X		
Regional Power Delivery	Northern Minnesota Voltage Stability & related issues	New regional extra high voltage transmission line				X	X

Figure 18: Transmission System Impacts & Significance



Estimated Costs

In order to provide a range of estimated costs associated with each of the transmission solutions shown in Table 9 and total up the estimated generator retirement costs associated with each scenario, Minnesota Power utilized MISO's Transmission Cost Estimate Guide for MTEP19. The MISO cost estimation guide documents the per-unit costs assumptions used by MISO for assessing the business justification for transmission projects identified in MISO planning studies. Cost assumptions are provided for new and upgraded transmission lines, new and expanded substations, and reactive resources. Due to the preliminary and conceptual nature of the solutions applied to transmission impacts from BEC retirements, cost assumptions used by Minnesota Power were based on the MISO "exploratory" (Class 5) cost estimate. The basis of this estimate, including expected accuracy range, is shown in Table 10 below.

Table 10: MISO Exploratory Cost Estimate Assumptions[4]

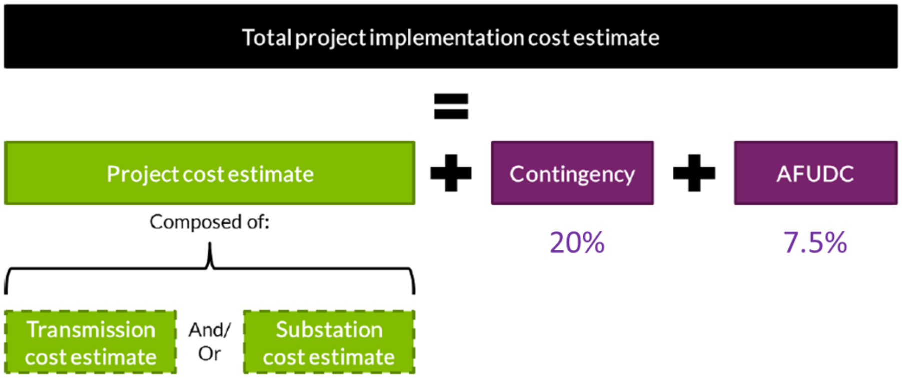
	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

The underlying assumptions behind MISO's cost estimates are discussed in detail in the Guide, and the estimates are intended to be inclusive of all aspects of a transmission project. MISO specifically states that the cost estimates include contingency and AFUDC, as shown in Figure 19 below. The specific contingency and AFUDC assumptions (20 percent and 7.5 percent, respectively) have been added to the figure for clarity.

[4] Source: MISO Transmission Cost Estimation Guide for MTEP20, Page 4, https://cdn.misoenergy.org/Transmission%20Cost%20Estimation%20Guide%20for%20MTEP%202020_Final337433.pdf

Figure 19: Contingency & AFUDC Assumptions[5]



For each of the transmission solutions described previously in this section, components of the solution were delineated including apparatus and line length assumptions. The per-unit cost estimating assumptions from the MISO Guide were then applied to these components and totaled up to represent an estimated cost for each solution. Finally, the solution costs were added together per the assessment summarized in Table 9 to provide an overall estimated transmission network upgrade cost for each BEC operating scenario. Total mid-level scenario costs estimates in 2019 dollars are shown in Table 11 below, broken down into the three categories of transmission impacts discussed above.

Table 11: IRP Generator Retirement Transmission Impact Cost Assumptions

Boswell Operating Scenarios	**Scenario Cost Estimate ($M)**				
Type of Transmission Impact	E1	E2	S1	S2	S3
Voltage Support & System Strength	$ 33	$ 66	$ 69	$ 69	$ 102
Local Power Delivery	$ 1	$ 1	$ 61	$ 61	$ 61
Regional Power Delivery	$ -	$ -	$ 14	$ 640	$ 640
TOTAL	**$ 34**	**$ 67**	**$ 144**	**$ 770**	**$ 803**

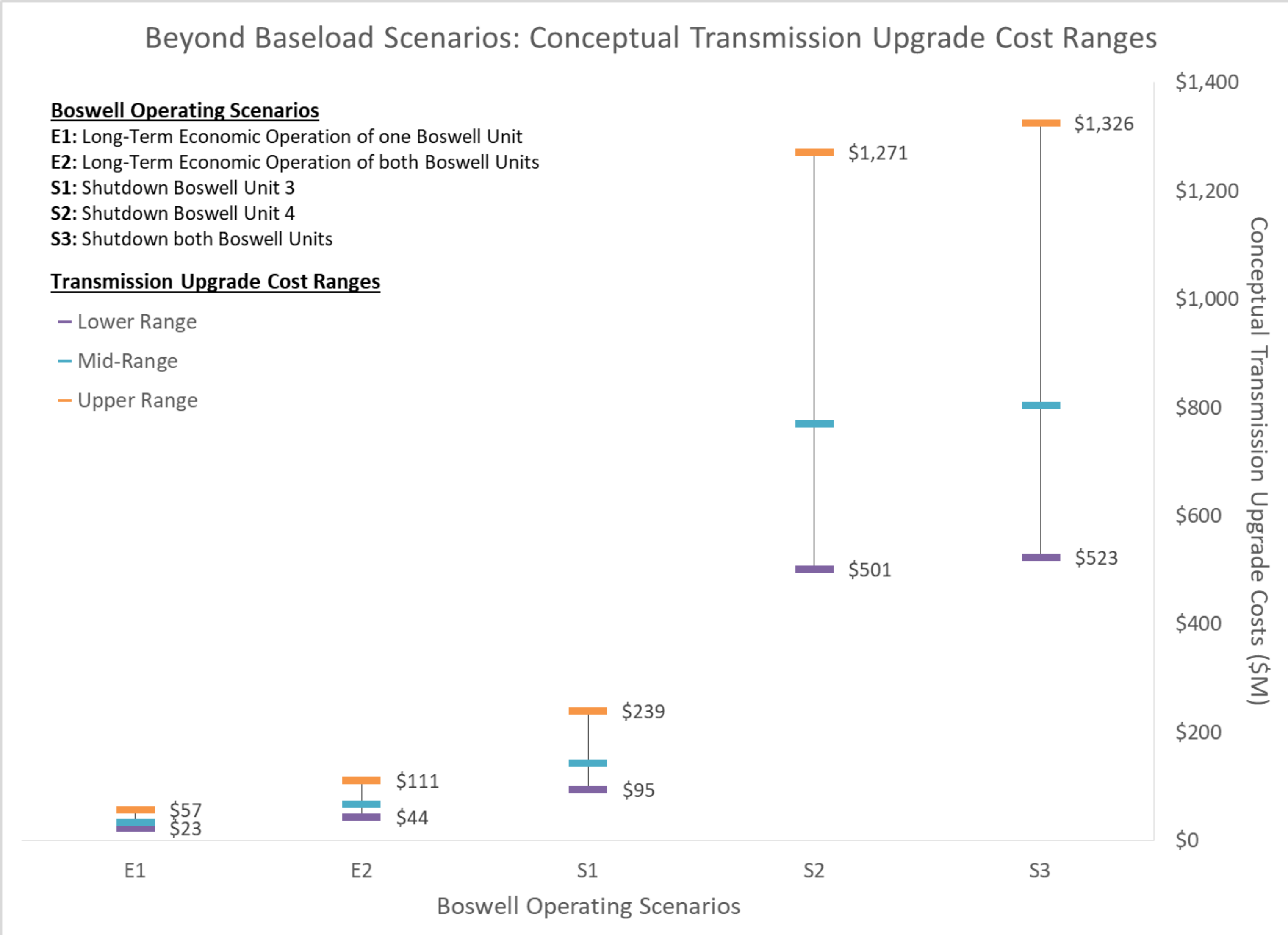
These mid-level estimated costs were escalated by 2.5 percent per year for use in the IRP modeling scenarios.[6]

While a single cost assumption is necessary to apply to IRP modeling scenarios, the estimated transmission solution costs should be viewed in context with an upper and lower bound applied to reflect uncertainties inherent at this early point in their development. Based on the MISO Guide, Minnesota Power applied an upper bound of +65 percent and a lower bound of -35%. The resulting cost ranges are shown in Figure 20 below.

[5] MISO Transmission Cost Estimate Guide for MTEP20, Page 5, https://cdn.misoenergy.org/Transmission%20Cost%20Estimation%20Guide%20for%20MTEP%202020_Final337433.pdf

[6] The 2.5 percent escalation is based on an independent cost trend report for transmission capital projects published by Handy Whiteman.

Figure 20: Generator Retirement Network Upgrade Cost Ranges



Part 9: MISO Attachment Y-2 Study (Redacted Version)

[Attachment]