Bayfield Peninsula System Assessment

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1.0 Executive Summary

This report represents the results of a reliability study for the electrical transmission network in the Bayfield Peninsula area of northern Wisconsin owned by Northern States Power Company-Wisconsin (NSPW or Company). This study reviewed the capability of the existing 34.5 kV transmission system to serve the current and future load on the Bayfield Peninsula. The existing 34.5 kV system is currently being operated as two radial lines that form a loop around the Bayfield Peninsula, with a normally-open switch located just east of the Cornucopia substation. One of the two radial lines starts at the Gingles substation in Ashland, WI and the other starts at the Iron River substation, located north of Iron River, WI. *See* Figure 2.1. Due to the current radial nature, local geography, the age, and long length and exposure of the 34.5 kV transmission system lines in the Bayfield Peninsula, the area is susceptible to frequent, and occasionally long outages. These outages occur because there are no other lines in the area from which the load can be restored or temporarily served.

This engineering study determined that the existing 34.5 kV system cannot adequately serve the current or future load during peak conditions, and improvements are necessary to address the situation. It is recommended that the Company rebuild a portion of the existing 34.5 kV line and build a new 34.5 kV single circuit line to bisect the existing loop. These components allow service with adequate voltage levels to all substations on the Bayfield Peninsula during N-1 conditions on the transmission system, now and in the future. An N-1 condition is when any one transmission element (for example a segment of 34.5 kV line) is not operational, putting the system into a contingency situation. The new 34.5 kV line will require (1) a new 115/34.5 kV substation on the Company's Bay Front – Iron River 115 kV transmission line and (2) a new 34.5 kV breaker station near the town of Bayfield on the existing 34.5 kV line. An emergency tie between the new and old 34.5 kV transmission lines on the east side of the Bayfield Peninsula is needed to serve the peninsula area load under contingency and maintenance situations. The recommended project will serve the projected load in the study area for the foreseeable future and provide flexibility for serving load beyond expected growth.

While there were numerous options studied, the preferred option, Option 4, includes the following facilities:

- New 34.5 kV line between Fish Creek Substation and Pikes Creek Substation, built to 69 kV standards
- New emergency 34.5 kV tie line between the new 34.5 kV circuit and existing Bayfield – Washburn 34.5 kV line
- New 115/34.5 kV substation on Iron River – Bay Front 115 kV line (Fish Creek Substation)
- New 34.5 kV breaker substation on the 34.5 kV line near Bayfield (Pikes Creek Substation)
- Add a 3 MVAR capacitor bank at Pikes Creek Substation (room for two banks)
- Rebuild existing Cornucopia – Bayfield Tap 34.5 kV line to 69 kV standards
    - This will occur after the new 34.5 kV circuit is installed
- Rebuild Iron River – Herbster 34.5 kV line to 69 kV standards
    - This will occur after the new 34.5 kV circuit is installed

Figure 1.1 shows a system one-line of the new system configuration after the construction of the preferred option.

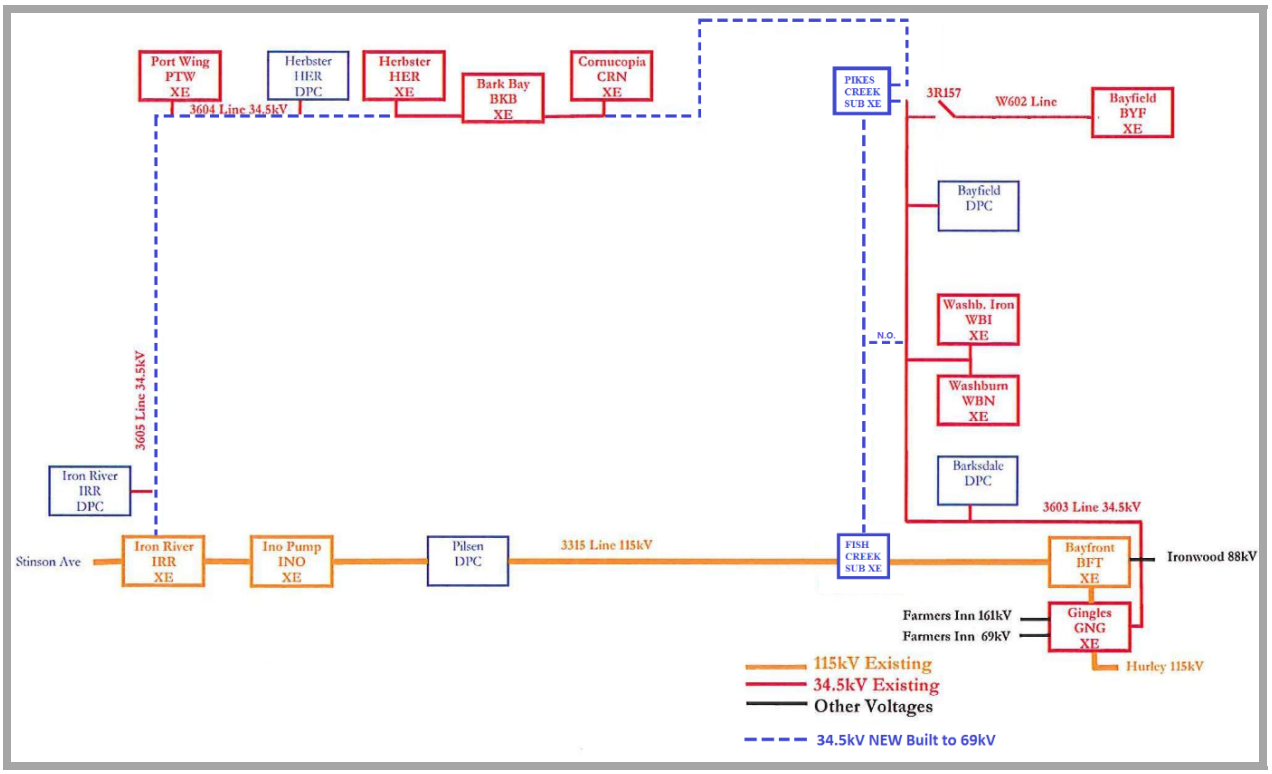


Figure 1.1 System One-line of Preferred Option

The preferred option offers the best overall results with respect to system performance (system intact, contingent loadings, and voltages), practicality (logistics of construction and operation) and price. Additionally, Option 4 is a modular approach that includes options for serving load if growth on the Bayfield Peninsula occurs faster than expected and would be installed when necessary. Potential future system modifications, which are not currently planned for implementation, could include[1]:

- Installing a second capacitor bank at the Pikes Creek Substation;
- Installing static VAR compensator (SVC) or static synchronous compensator (STATCOM) at Pikes Creek Substation;
- Converting the system from 34.5 kV to 69 kV operation by replacing transformers at the Cornucopia, DPC Herbster, Herbster, Port Wing, Oulu, and Iron River substations. These transformers are load serving and will likely need to be replaced in the future, at which time dual high side transformers could be installed, thus making the conversion to 69 kV straightforward if and when necessary. Additionally, the transformer at the new Fish Creek Substation would need to be replaced and a transformer added at the new Pikes Creek Substation.

The capacitive devices listed above are not suitable as standalone project options because the transmission system is weak and the capacitive devices alone do not provide enough voltage support or reliability benefit. If load grows faster than expected, these future capacitive devices, combined

[1] Future modifications outlined are conceptual and not planned. They are called out to show theoretical system improvements after the current study need(s) is addressed and if load growth is accelerated beyond what was used for the purpose of this study. If any of these system improvements are deemed necessary, the Company would seek any necessary regulatory or permitting approvals.

with the preferred option, would then be able to provide additional support to the area. If significant load growth occurs[2], which is not expected, the conversion from 34.5 kV to 69 kV is the best long term solution. If load growth in the area occurs slower than expected, the preferred plan will last through the foreseeable future load growth included in the planning models. Even with slow or no load growth, the preferred plan is still needed as the current system is radial and outages (unplanned or planned for maintenance outages) cause complete loss of power to customers.

2.0 Introduction

This report represents the results of a reliability study for the electrical transmission network in the Bayfield Peninsula area of northern Wisconsin. This study reviewed the capability of the existing 34.5 kV transmission system to serve the current and future load on the Bayfield Peninsula. The existing 34.5 kV system consists of two radial lines that form a loop around the peninsula from the Gingles substation in Ashland, WI to the Iron River Substation north of Iron River, WI. Figure 2.1 shows the current transmission system supporting the Bayfield Peninsula. Although the 34.5 kV lines in the Bayfield Peninsula were originally built to function as a closed loop, they are currently being operated as two radial lines with an open switch near Cornucopia (meaning that power does not flow around the entire loop; it stops flowing at the open switch) because of low voltage concerns if the switch were to be closed. Due to the radial nature of the lines in the peninsula resulting from the open switch, this area is more susceptible to more frequent and potentially longer outages than other areas of the Company's service territory. The outage history for the last seven years is included in Appendix B. In addition, maintenance on this line is very difficult because there is no alternate source of power to serve customers when line outages are required for maintenance repairs. The goal of this study is to analyze options for addressing these problems.

[2] No future commercial or industrial loads that would have impact on otherwise normal load projections were identified at the time of this study.

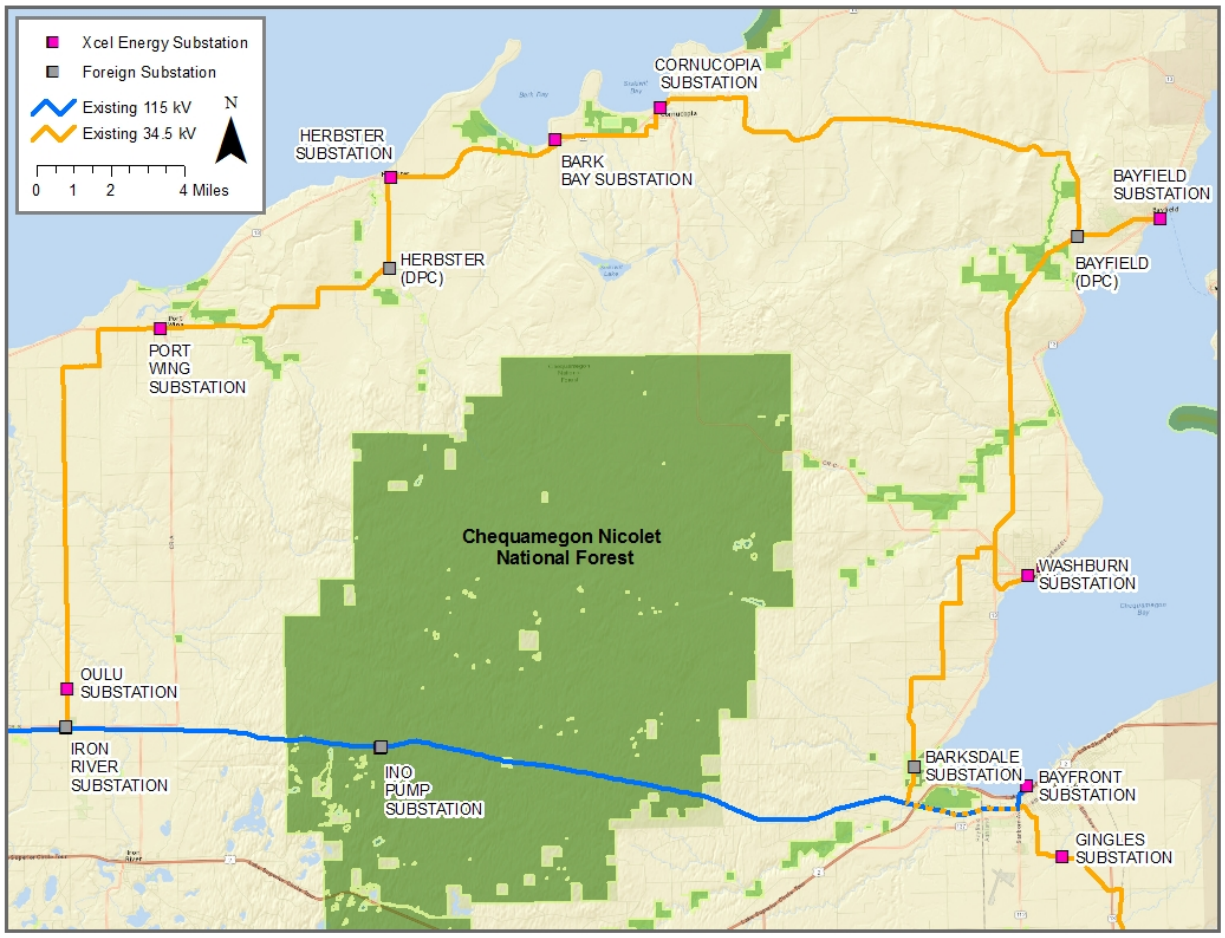


Figure 2.1 Map of the Bayfield Peninsula

2.1 Project History

The Bayfield Peninsula project, also known as the "Bayfield Loop Project," was in the planning phase until 2013 when it was presented to the public. During the summer of 2013, public meetings were held in Bayfield, WI and Ashland, WI to introduce the project need, review potential route options, and seek public comments. The initial proposal was for construction of a new 115 kV transmission line from a new Fish Creek Substation near the Northern Great Lakes Visitor Center to a new Pikes Creek Substation near Bayfield. After considering feedback from the public, further reviewing possible solutions, and refining cost estimates for each of the options, NSPW Planning staff identified an additional option that would utilize a new 34.5 kV line between the new Fish Creek Substation and Pikes Creek Substation.

2.2 Study Participants

NSPW Planning staff created all of the options considered in this study, performed power flow simulations, analyzed the results, and made recommendations based on those results. These results were presented and reviewed by NSPW Planning and Dairyland Power Cooperative (DPC) Planning staff, at which time comments, conclusions, and recommendations were developed to guide each successive stage of analysis.

3.0 Scope of Study

The purpose of this study is to examine the impact of multiple transmission addition options in the Bayfield Peninsula to address current system deficiencies. In addition, the age and condition of several sections of the existing 34.5 kV system in this area require a complete rebuild. Each transmission option was created to resolve the voltage concerns in the study area and allow additional load growth for the foreseeable future. The voltage problems in the area occur during peak conditions with the system intact. Steady state power flow cases were run to determine the impact of each transmission option on the transmission system under existing and modeled future load projection conditions. Due to the small size of the study area, local load serving nature of the loop, and lack of high voltage interconnections to the study area, dynamic simulations were not required in this analysis.

4.0 Need Overview

The Gingles to Bayfield[3] 34.5 kV line serves 17 MW on peak, with roughly half of that load at the end of a 25 mile long radial line. In this peak condition, the Bayfield Substation is currently unable to maintain acceptable voltage levels. Additionally, the entire Bayfield Peninsula does not have single point of failure reliability due to the radial nature of the lines serving the peninsula. This means that failure of a single pole anywhere on the 34.5kV transmission system results in customers being out of power. The lack of single point of failure reliability also means that maintenance is extremely difficult to perform, since the lines in the Bayfield Peninsula are unable to back each other up.

4.1 System Description

The defined study area for this analysis is the 34.5 kV transmission system located along the Bayfield Peninsula in northern Wisconsin. A 115 kV line between Duluth, MN and Ashland, WI provides two sources to the 34.5 kV system off of the same line. The entire Bayfield Peninsula is served by this 34.5 kV transmission system, with 17 MW of the peninsula's total 21 MW located on the eastern side of the peninsula at Xcel Energy's Bayfield, Washburn Iron, and Washburn substations and Bayfield Electric Cooperative's Bayfield (Salmo) and Barksdale substations. The existing system configuration is shown in Figure 4.1.

[3] The Bayfield Substation is the last substation on this stretch of 34.5 kV line before the open switch near Cornucopia.

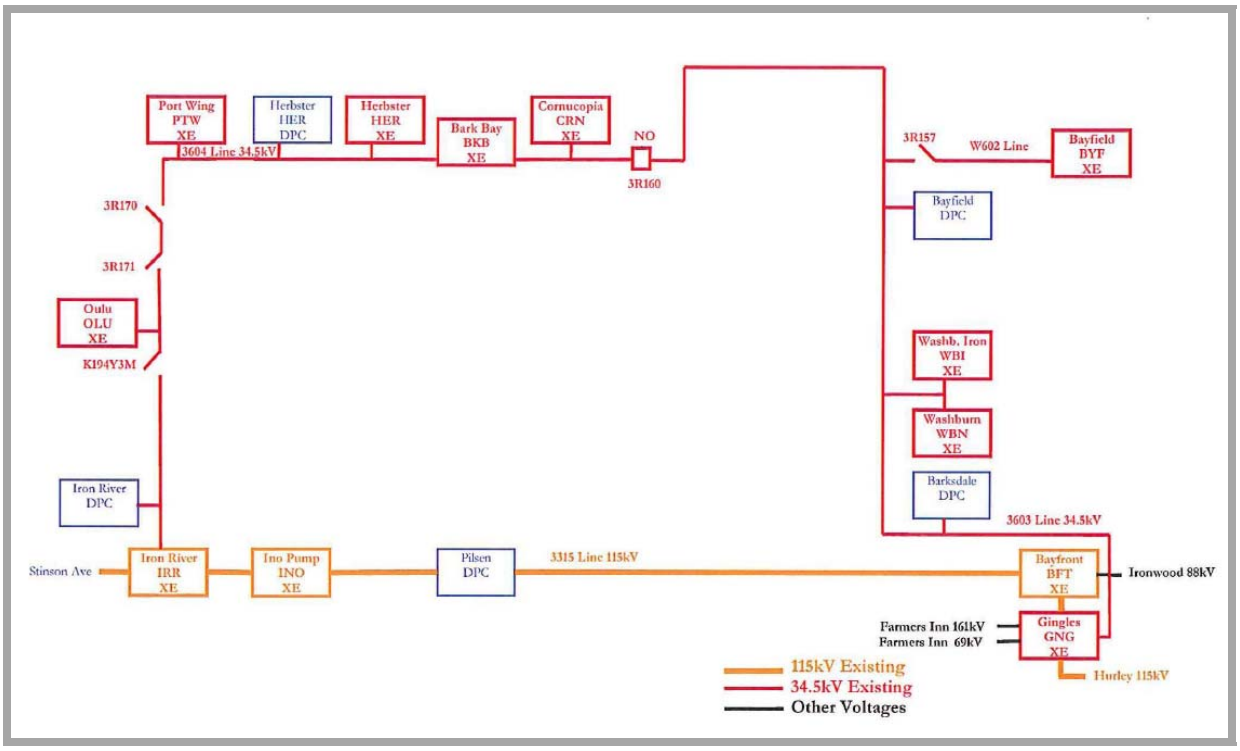


Figure 4.1 Existing System Configuration of the Bayfield Peninsula

While the 34.5 kV system in the Bayfield Peninsula was originally designed to be operated as a closed system, the system is currently being operated with a normally-open switch near Cornucopia which separates the looped system into two load serving radial lines. The normally-open switch can no longer be closed due to potential voltage collapse under single contingency (N-1) situations. A graphic depiction of the current system under peak load, with the switch open near Cornucopia, is shown in Figure 4.2. The voltage violation depicted in Figure 4.2 shows that the current system cannot handle peak loading conditions.

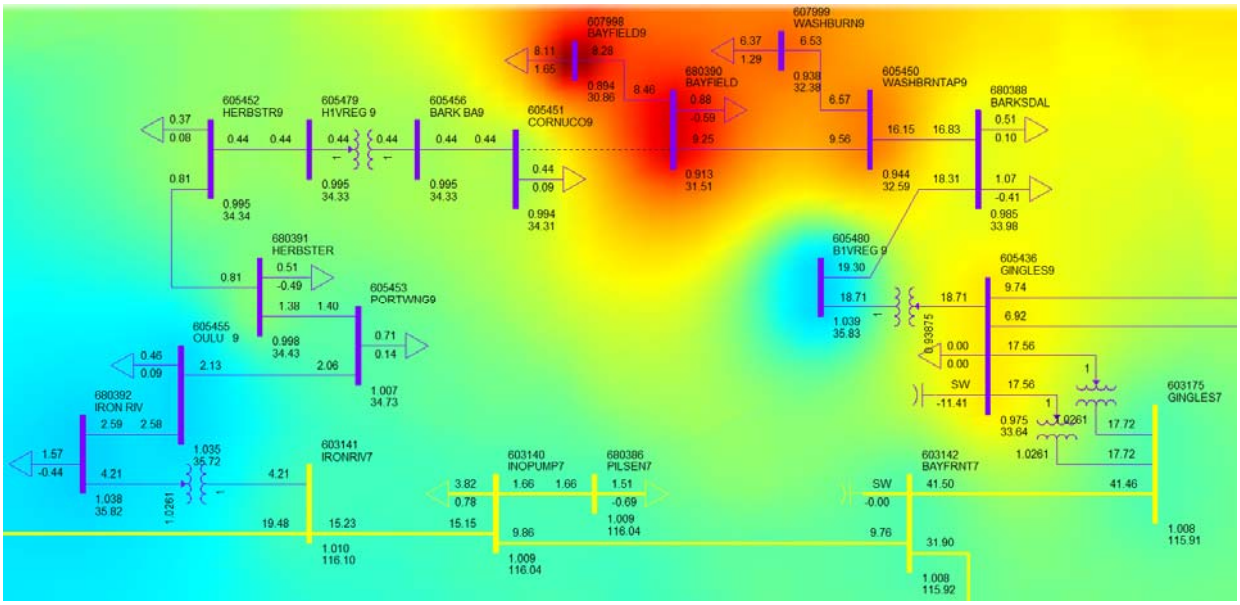


Figure 4.2 Contour Map of the Existing System Configuration under Peak Load

The modeling shows that under system peak for all loads on the Bayfield Peninsula, there will be voltage violations at NSPW Bayfield and DPC Bayfield substations per NSPW voltage criteria as described in Section 4.2.1. Note that red means low voltage, blue means high voltage, and dashed lines mean out-of-service.

For this analysis, the Bay Front Generation Station was the only local generation assumed on during system peak conditions. There is no wind or solar generation in this area and future renewable generation penetration was not studied in this analysis. There are currently no interconnection requests in this area. While Planning understands there has been a Request for Proposals for a Solar Garden in the northern part of NSPW's service territory, it cannot speculate on the potential for future requests or the locations thereof. The Company did, however, receive a recommendation from members of the public to investigate a project that combined solar and batteries. While the Company did not have the detail it would typically require if there had been an interconnection request, it did study this idea on a conceptual level and determined that it was not a feasible alternative. Generally speaking, renewable energy and storage are not a substitute for transmission facilities. This is because solar and wind are intermittent sources of power (i.e., we cannot know with certainty when power will be available from wind or solar generation due to variability in weather). While batteries are sometimes paired with intermittent sources in order to provide power when the intermittent sources cannot, batteries are a finite resource because they can only hold a set amount of power and cannot generate or receive power from other sources if the intermittent sources are not producing electricity.

The Bayfield Peninsula has historically had low voltages on the 34.5 kV system and is at the limitations of the current system. Load projections, based on historical averages for the study area and considering any customer load growth, provided by NSPW Distribution Capacity Planning and DPC, were used to determine the need for additional load serving support along the Bayfield Loop.

Due to the current radial nature, local geography, age, and long length (72 miles) of the 34.5 kV lines of the transmission system in the Bayfield Peninsula, this area is more susceptible to more frequent and potentially longer outages than other areas of the Company's service territory. These outages occur because there are no other lines in the area from which the load can be temporarily served. In addition, the age and condition of the poles and conductor on the 34.5 kV line sections from Iron River to Herbster and Cornucopia to Bayfield Tap require a complete rebuild. All options in this study include a way to address the age and condition concerns in the Bayfield Peninsula.

4.2 Planning Criteria

4.2.1 Steady State Voltage Criteria

When performing steady state analysis, the voltage criteria in Table 4.2 was applied to NSPW's buses under system intact (pre contingent) and post contingent conditions. This represents the voltage criteria for most of the NSPW owned facilities. Some exceptions to the voltage criteria exist on the NSPW system, but none of the exceptions are located in the area of this study.

Table 4.2

Facility	Maximum voltage (p.u.)	Minimum voltage (p.u.)	Maximum voltage (p.u.)	Minimum voltage (p.u.)
	Pre Contingent		Post Contingent	
Default for all buses > 100 kV	1.05	0.95	1.05	0.92
Default for all buses < 100 kV*	1.05	0.95	1.05	0.92
Default for all generator buses**	1.05	0.95	1.05	0.95

*For 34.5 kV and below non-generation buses, pre and post contingent voltage of 0.9PU would be acceptable.
**For all Category P0, P1, P2, P4, P5, and P7 contingencies. [1] After a Category P3 or P6 contingency, generator bus voltage would be allowed to drop to 0.92 PU.

4.2.2 Line Loading Criteria

The ratings for facilities (transmission lines, transformers and series compensators) owned by NSPW are specified in the NSPW Ratings Database. The winter and summer ratings of facilities account for the thermal limit of all equipment and relay loadability limits, as specified in North American Electric Reliability Corporation (NERC) FAC-008 and FAC-009 standards.

When planning NSPW's system, for system intact condition, the current flowing through a facility should not exceed the normal rating of that facility. When studying contingency conditions, the current flowing through a facility should not exceed the emergency rating of that facility. During transmission outages, it is assumed that the system operators would take remedial action when the current on a facility is lower than the emergency rating and greater than the normal rating. When such remedial action is not available, the normal rating of the facility should be used.

In addition to adhering to these planning criteria, NSPW meets all the guidelines outlined for the transmission planning standards as defined by NERC. NERC TPL-001-4 Table 1 is available in Appendix C.

5.0 Analysis of the Bayfield Peninsula 34.5 kV System

5.1 Models

5.1.1 Steady State Models

The power flow model employed was developed by the Minnesota Transmission Assessment and Compliance Team (MNTACT). The base study model for this analysis was the 2018 summer peak model used in the 2017 MNTACT Annual Assessment. The base model was then modified to utilize the most recent distribution load forecasts for all NSPW and DPC loads in the study area and provide a non-coincident peak for the study area. Table 5.1 shows the loads used in the study model.

Table 5.1 – Study Model Loads

Substation	Study Model 2018SUM MW
Barksdale (DPC)	1.0686
Barksdale (NSPW)	0.513
Bayfield (DPC)	0.8814
Bayfield (NSPW)	8.114
Cornucopia	0.436
Herbster (DPC)	0.5122
Herbster (NSPW)	0.371
Iron River (DPC)	1.5746
Oulu	0.463
Port Wing	0.707
Washburn	6.373

All differences have been verified by each distribution company in the area.

5.1.2 Dynamics Models

There were no power system dynamic stability runs completed as part of this study. The four options that were studied will have a negligible effect on the stability of the bulk transmission system due to the size of the study area, local load serving nature of the loop, and lack of high voltage interconnections to the study area.

5.2 Regional Level Transmission Impacts

There was no regional analysis completed in this study due to the lack of regional lines in the study area. Since the study area is primarily a local load serving system, the impacts of all options being studied on the regional transmission system are negligible, therefore a full regional analysis was not needed. The only line in the study area that has any regional benefit is the Stinson – Bay Front 115 kV line; however, this line has a phase shifter installed on it to limit the flow on the line out of Stinson to approximately 30 MVA, and thus has limited regional benefit. None of the options change this configuration.

5.3 Conditions Studied

5.3.1 Steady State Modeling Assumptions

The technical analysis was performed based on the 2018 summer peak model used in the 2017 MNTACT Annual Assessment. The base model was adjusted to represent the latest available forecast data at the time of this report for summer seasonal peak load conditions.

5.3.2 Performance Evaluation Methods

Due to the small study area, power system performance simulation, system intact and contingency analysis was performed manually with the aid of Power System Simulator for Engineering (PSS®E).

For the power system performance analysis, all NSPW and DPC buses, transmission lines, and transformers in the study area were monitored and included in the contingency analysis.

5.3.3 Steady State Contingencies modeled

For this study, Transmission Planning included all contingencies in the study area. Key area system deficiencies and contingencies are listed in Table 5.2. All of the contingencies listed below are N-1 contingencies that outage load, with no way to back up the outaged load.

Table 5.2 – Key System Deficiencies and Contingencies

Year	Contingency	Issue (Substations out of power)	Load Outaged
2018	Gingles - Barksdale 34.5 kV line	Bayfield, Bayfield (DPC), Washburn Iron, Washburn, and Barksdale loads outaged	17.0 MW
2018	Barksdale - Washburn Tap 34.5 kV line	Bayfield, Bayfield (DPC), Washburn Iron, and Washburn loads outaged	15.4 MW
2018	Washburn Tap - Bayfield Tap 34.5 kV line	Bayfield and Bayfield (DPC) loads outaged	9.0 MW
2018	Iron River 115/34.5 kV transformer	Cornucopia, Herbster, Herbster (DPC), Port Wing, Oulu, and Iron River (DPC) loads outaged	4.1 MW
2018	Iron River - Oulu 34.5 kV line	Cornucopia, Herbster, Herbster (DPC), Port Wing, and Oulu loads outaged	2.5 MW
2018	Oulu - Port Wing 34.5 kV line	Cornucopia, Herbster, Herbster (DPC), and Port Wing loads outaged	2.0 MW
2018	Port Wing - Herbster (DPC) 34.5 kV line	Cornucopia, Herbster, and Herbster (DPC) loads outaged	1.3 MW
2018	Herbster (DPC) - Herbster 34.5 kV line	Cornucopia and Herbster loads outaged	0.8 MW
2018	Herbster - Cornucopia 34.5 kV line	Cornucopia load outaged	0.4 MW

As shown in Table 5.2 with the loss of a line section between two substations (N-1 contingency), load is blacked out until the problem is fixed. Each of these contingencies has historically occurred and the towns north of the contingency were out of power.

5.4 Base Case Analysis

As described in Section 4.1, the Bayfield Peninsula is currently being operated as two radial load serving lines, without the ability to close the looped system. Due to the radial nature of the transmission system in the area, load will be dropped under any contingency until the problem is physically fixed. Key area system deficiencies and contingencies are listed in Table 5.2. Since the voltage and condition issues exist in the base case, and the lines are radial, the need in this area is independent of load growth and will not be eliminated with slow load growth.

Shown below in Figure 5.1 (and in Figure 4.1) is a contour map of the existing system as forecasted for 2018. Modeling the latest forecasted load values results in low voltages at Bayfield under normal system intact conditions. Note that red means low voltage, blue means high voltage, and dashed means out-of-service.

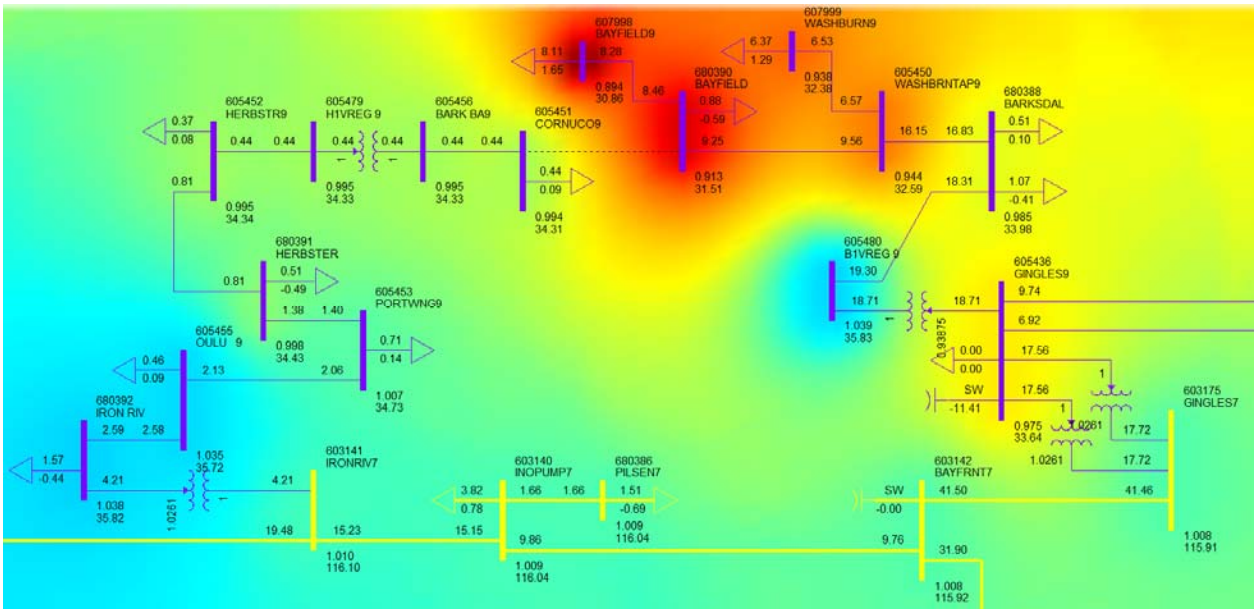


Figure 5.1 2018: System Intact - Summer Peak

Figure 5.2 shows the contour map for the largest loss of load condition: outage near Barksdale and attempting to close down the normally open switch to serve the entire load from the Iron River substation.

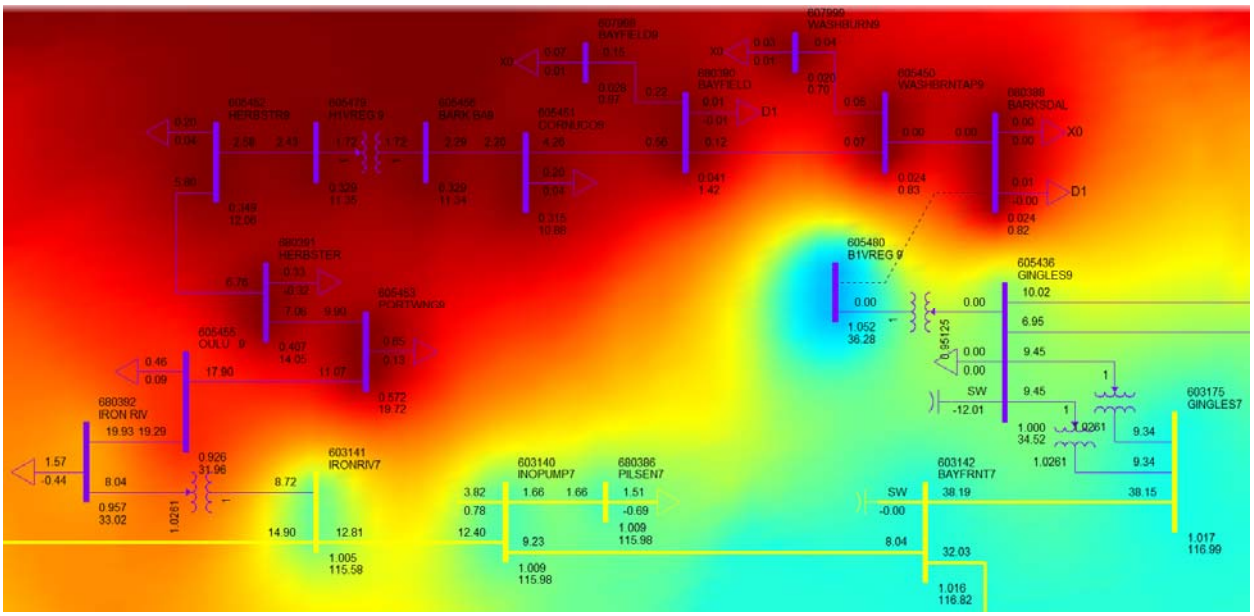


Figure 5.2 2018: Gingles – Barksdale 34.5 kV Outage, Attempting to Serve Load from Iron River at Peak Load. Result: Extreme Low Voltage/Voltage Collapse for the Entire Bayfield Peninsula

Figure 5.3 shows the contour map for the largest loss of load condition, outage near Barksdale, without closing down the normally open switch and instead not serving the entire load.

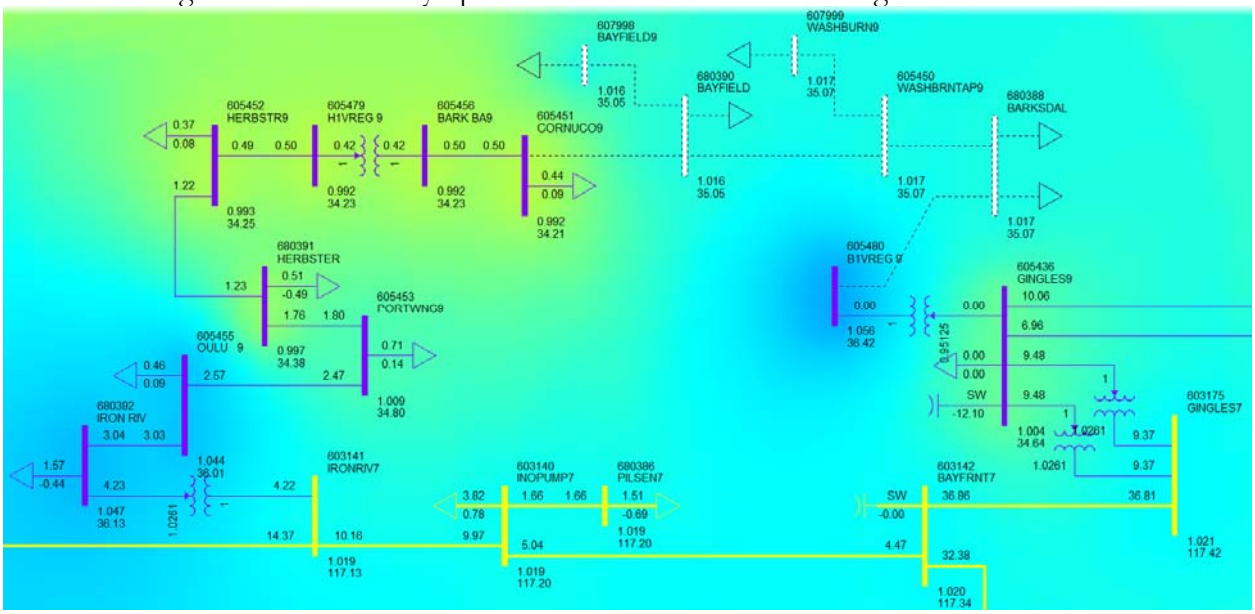


Figure 5.3 2018: Gingles – Barksdale 34.5 kV Outage, Without Attempting to Serve Load from Iron River. Result: Bayfield, Washburn, and Barksdale Loads are Out of Power

5.5 Options Evaluated

Since the Bayfield Peninsula 34.5 kV system is radial, any construction activities will need to be carefully coordinated with both Operations and Construction to ensure minimal impacts to customers along the peninsula. All options described below address the immediate and future load serving needs of the Bayfield Peninsula area.

5.5.1 Option 1: New 115 kV Line to Bayfield

This option would require a new substation to be built on the Bay Front – Ino Pump 115 kV line ("Fish Creek Substation") and on the Bayfield – Washburn 34.5 kV line ("Pikes Creek Substation"). To connect these two substations, a new 115 kV line from Fish Creek Substation to Pikes Creek Substation would be constructed. This 115 kV line would provide the Bayfield Peninsula with an additional strong power source and many years of room for load growth. This option would split the current system with two radial lines into two 34.5kV load serving loops, greatly reducing the exposure of load to power outages. This option also includes the age and condition rebuild of the existing Iron River – Herbster and Cornucopia – Bayfield Tap 34.5 kV lines. The new Pikes Creek Substation would be designed to handle future 34.5 kV capacitor banks, providing future flexibility to the area.

Estimated planning level cost for this option is $60 million.

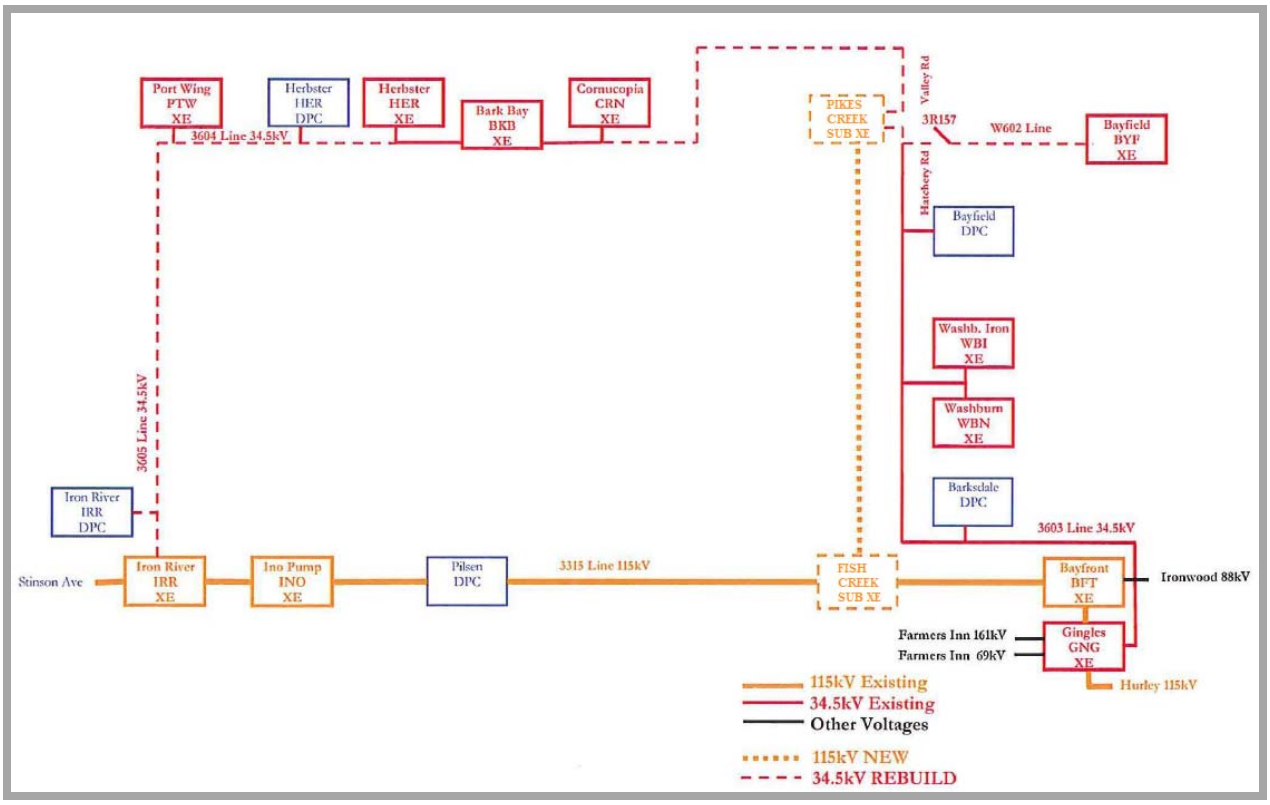


Figure 5.4 Configuration of Option 1

5.5.2 Option 2: Rebuild Entire 34.5 kV Loop to 115 kV

This option would rebuild the entire existing Bayfield Loop 34.5 kV line to a single circuit 115 kV line, including 19 miles of 24 kV distribution underbuild in the Herbster area. This option requires new 115 kV load serving substations at Iron River, Bayfield, Washburn, and Barksdale. The remaining existing substations along the Bayfield Peninsula would be served through the 24 kV distribution line built underneath the 115 kV line conductors. This option would create a 115 kV load serving loop with only a small portion of distribution remaining that serves the small substations from Port Wing to Cornucopia. This option is essentially future proof, in that the Bayfield Peninsula would be able to handle vast amounts of load and likely never run out of load

serving capabilities. However, given that the Bayfield Peninsula is not expected to see significant load growth, this option is too large for this area.

Estimated planning level cost for this option is $90 million.

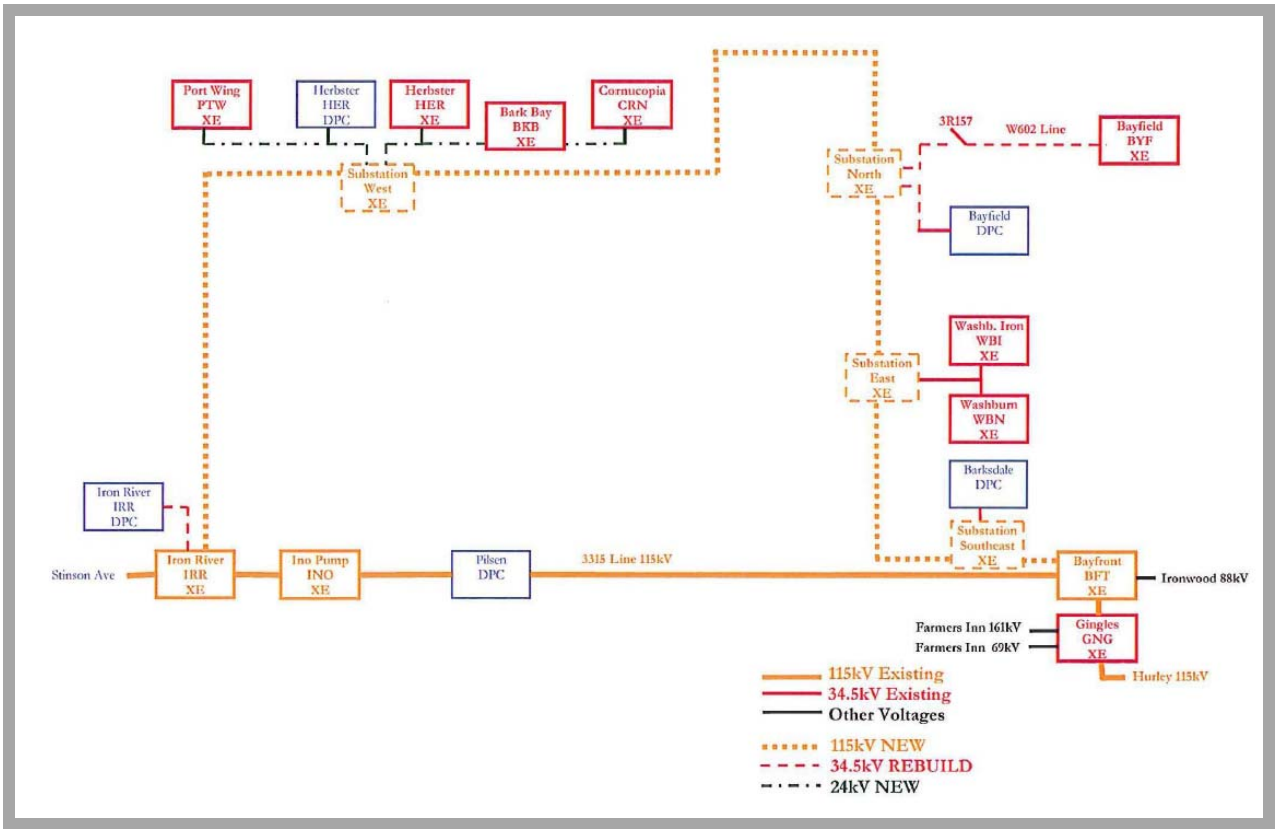


Figure 5.5 Configuration of Option 2

5.5.3 Option 3: Double Circuit 115/34.5 kV Entire Loop

This option would rebuild the entire existing 34.5 kV option to double circuit 115/34.5 kV, with new 115 kV substations near Herbster and Bayfield. The reason behind building the loop to double circuit is that the existing substations along the 34.5 kV loop will remain in their current state. This option would create a 115 kV looped system feeding a parallel 34.5 kV load serving loop at multiple injection points. Similar to the option in 5.5.2, this option is also essentially future proof. This option allows the Bayfield Peninsula to handle vast amounts of load and would likely never run out of load serving capabilities. However, given that the Bayfield Peninsula is not expected to see significant load growth, this option is too large for this area.

Estimated planning level cost for this option is $90 million.

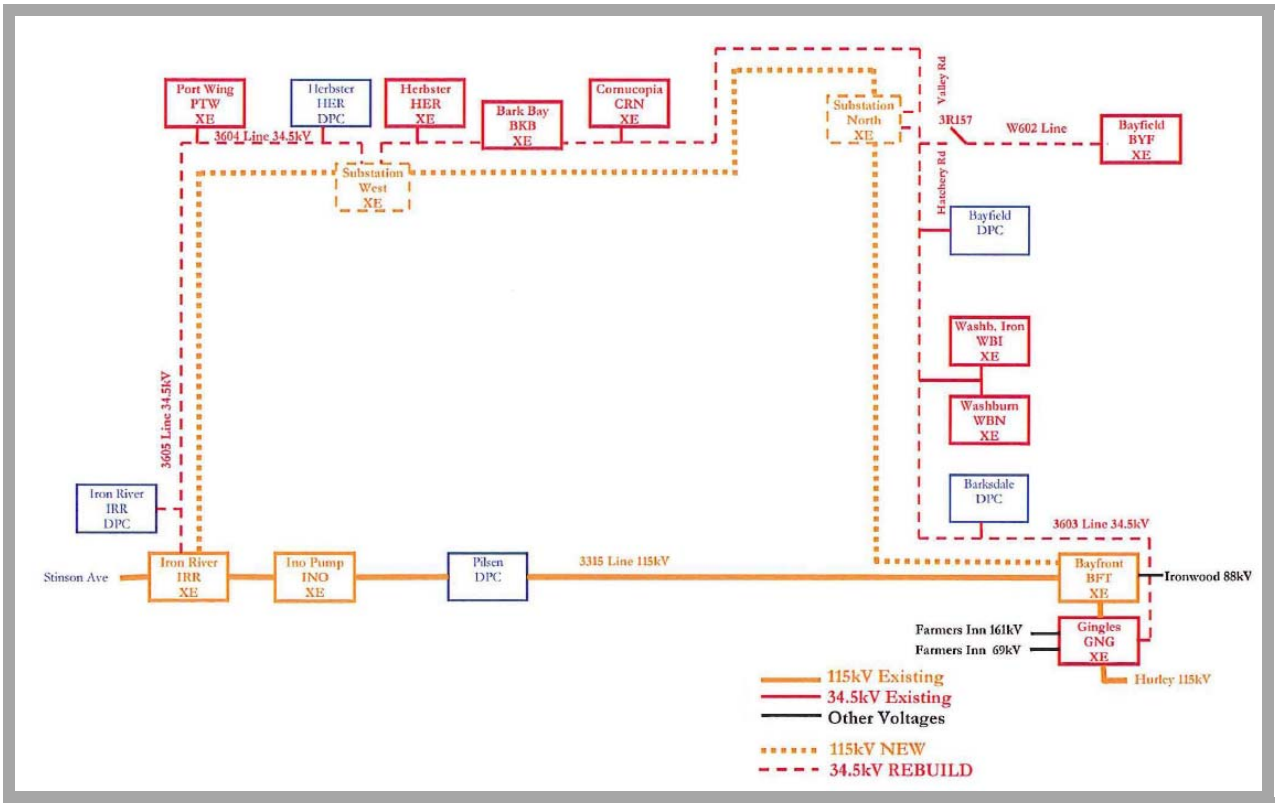


Figure 5.6 Configuration of Option 3

5.5.4 Option 4: New 34.5 kV Line to Bayfield Built to 69 kV Standards

This option would require a new substation to be built on the Bay Front – Ino Pump 115 kV line ("Fish Creek Substation") and on the Bayfield – Washburn 34.5 kV line ("Pikes Creek Substation"). To connect these two substations, a new 34.5 kV line from Fish Creek Substation to Pikes Creek Substation would be constructed. In addition, an emergency tie line would be constructed between the new 34.5 kV line and the existing 34.5 kV line to allow the system to handle N-1 contingency outages. The emergency tie would be operated normally open and only closed when a portion of either the existing or the new 34.5 kV line is outaged. This option also includes the rebuild of the existing 34.5 kV lines from Bayfield to Cornucopia and from Herbster to Iron River, following completion of the new 34.5 kV line.

The design for all new 34.5 kV would use horizontal post 69 kV insulators and shield wire, which provides greater reliability advantages over the existing 34.5 kV line's design. This shielded compact design allows the Company to accommodate longer spans (less footprint), needed lightning protection, and more robust structural load considerations to reliably traverse open expanses of territory. The proposed design for Option 4 also requires a narrower right-of-way width and smaller structures than would be necessary for a 115 kV line included in other options. Conventional "distribution" type geometry and line design used in 34.5 kV construction, such as the existing 34.5 kV system serving the Bayfield Peninsula, is suited for short spans in urban areas with smaller wire and multiple load serving taps. The conventional design is not well suited for this area.

With this option future load growth in the area could be accommodated using a modular approach by making the following modifications to the system[4]:

- Installing a second capacitor bank at the Pikes Creek Substation;
- Installing static VAR compensator (SVC) or static synchronous compensator (STATCOM) at Pikes Creek Substation;
- Converting the system from 34.5 kV to 69 kV operation by replacing transformers at the Cornucopia, DPC Herbster, Herbster, Port Wing, Oulu, and Iron River substations. These transformers are load serving and will likely need to be replaced in the future, at which time dual high side transformers could be installed, thus making the conversion to 69 kV simple when necessary. Additionally, the transformer at the new Fish Creek Substation would need to be replaced and a transformer added at the new Pikes Creek Substation.

This option provides an additional source of power to the area, and allows for a modular approach to serving potential future load growth.

Estimated planning level cost for this option is $40 million.

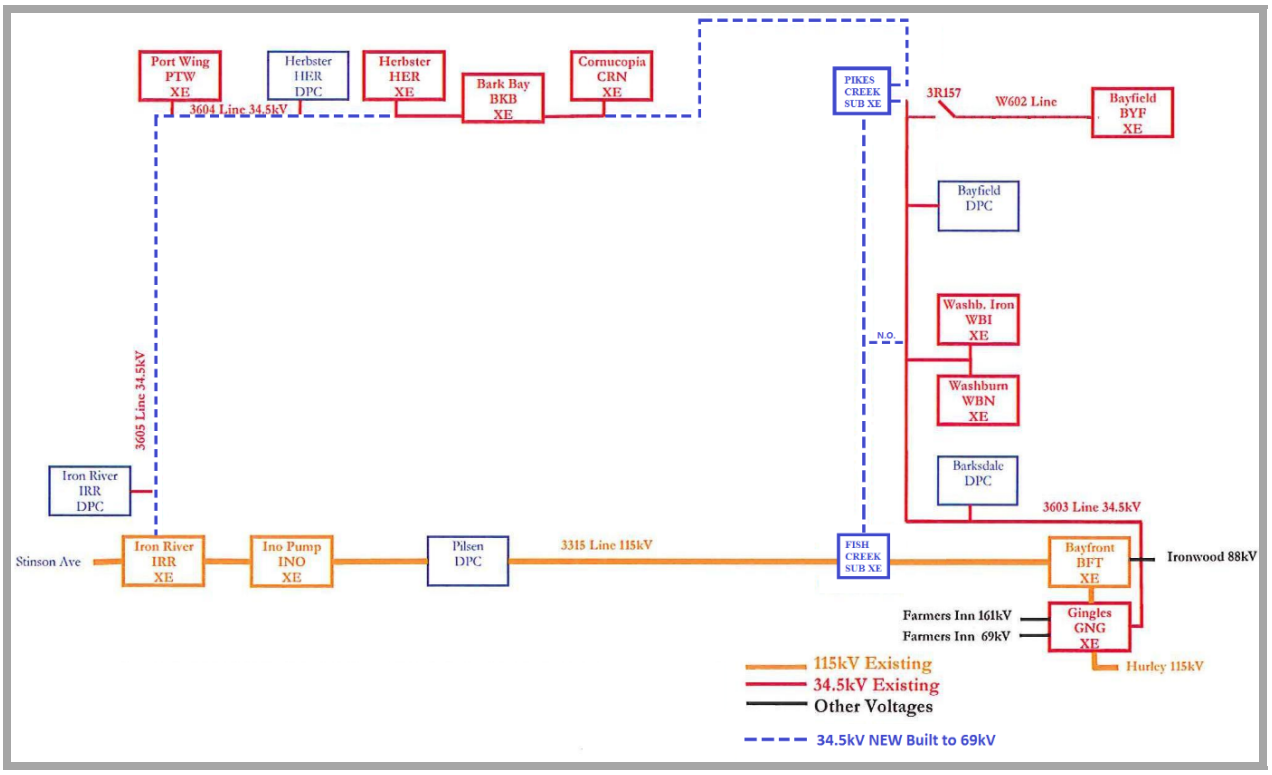


Figure 5.7 Configuration of Option 4

This option does not have a double circuit configuration as a standalone option like Option 2 and Option 3 above, due to the fact that double circuiting does not provide single point of failure reliability. This means that for the loss of a single double circuit tower, all customers between the

[4] Future modifications outlined are conceptual and not planned. They are called out to show theoretical system improvements after the current study needs are addressed and if load growth is accelerated beyond what was used for the purpose of this study.

outage and Cornucopia substation will be out of power. This topic will be discussed further in Section 6.0.

6.0 Planning Considerations for Transmission Structure Configurations

As part of the normal planning process, double circuiting with existing transmission lines is analyzed. This type of analysis is completed to determine if the system can handle the loss of the double circuit, since a common structure would form a single point of failure for two lines. For the Bayfield Peninsula, double circuiting the new line with the existing 34.5 kV line on the east side of the Bayfield Peninsula as a route alignment for Options 1 and 4 does not provide N-1 reliability for up to 17 MW of load on peak. This is because an occurrence (e.g, a single pole failing) will to take out both circuits of the line because they are both located on the same poles. This double circuiting configuration is not recommended because the west side of the peninsula is not capable of supporting any of the load on the east side of the peninsula as shown in Figure 5.2. Even after the Iron River – Herbster and Cornucopia – Bayfield Tap 34.5 kV lines are rebuilt, the west side of the Bayfield Peninsula will not be able to serve any of the load on the east side.

From a Transmission Planning and Operations perspective, a new completely independent line or a new line paralleling the existing 34.5 kV line is preferred for Option 1 and Option 4. Three possible routing alignments for the four options are discussed below.

6.1 New Alignment with Separate Right-of-Way from Existing Lines in Options 1 and 4

From a planning standpoint, building on a new right-of-way is always preferred because it provides isolation between the existing and new lines. Once the line is built, there are no common corridors or double circuit conditions that take out both circuits. Outage concerns during construction and future maintenance activities are also completely mitigated when using a completely new right-of-way.

6.2 New Alignment Paralleling Existing Lines in Options 1 and 4

Paralleling the existing 34.5 kV line with a new line performs electrically similar to the new right-of-way option listed above. This option does not provide the same geographic separation of lines that the separate right-of-way option above does, therefore there is minimal risk of a weather event in the corridor taking out both lines. In this option, the issue of a single pole failure or planned maintenance resulting in outages on both lines which is identified in the double circuit option below is eliminated. This "single point of failure" issue was one of the need drivers for the project and this alignment would allow either of the lines to be taken out while still providing power through the remaining line.

6.3 New Line Double-Circuited with Existing Lines in Options 1 and 4

Double Circuiting the existing 34.5 kV line with a new line performs electrically similar to the two other options listed above. However, double circuiting the existing 34.5 kV line with a new line involves rebuilding the existing 34.5 kV line in conjunction with construction of the new line. In this option, both lines would be located on new taller poles capable of accommodating three phases on each side. If this alignment were constructed the both unplanned and planned outage of the double circuit (both lines) would be included in all future planning analyses as a single event. Planning would always analyze this configuration as a single event since a pole outage causes both circuits to

go out. If a pole needs to be replaced for maintenance, either both circuits must be taken out or "hot" work (i.e., having crews work on the structure while one of the circuits was energized) would need to be utilized. Additionally, there are no current age and condition concerns with the existing Gingles – Bayfield Tap 34.5 kV line and the existing transmission line it would not otherwise need to be rebuilt in any of the other two alignment scenarios other than double circuiting with a new line. Transmission System Planning's recommendation is to not double circuit a new line with an existing line in Option 1 and Option 4.

Figure 6.1 shows a contour map of the double circuit outage in Option 4; note that the system collapsed.

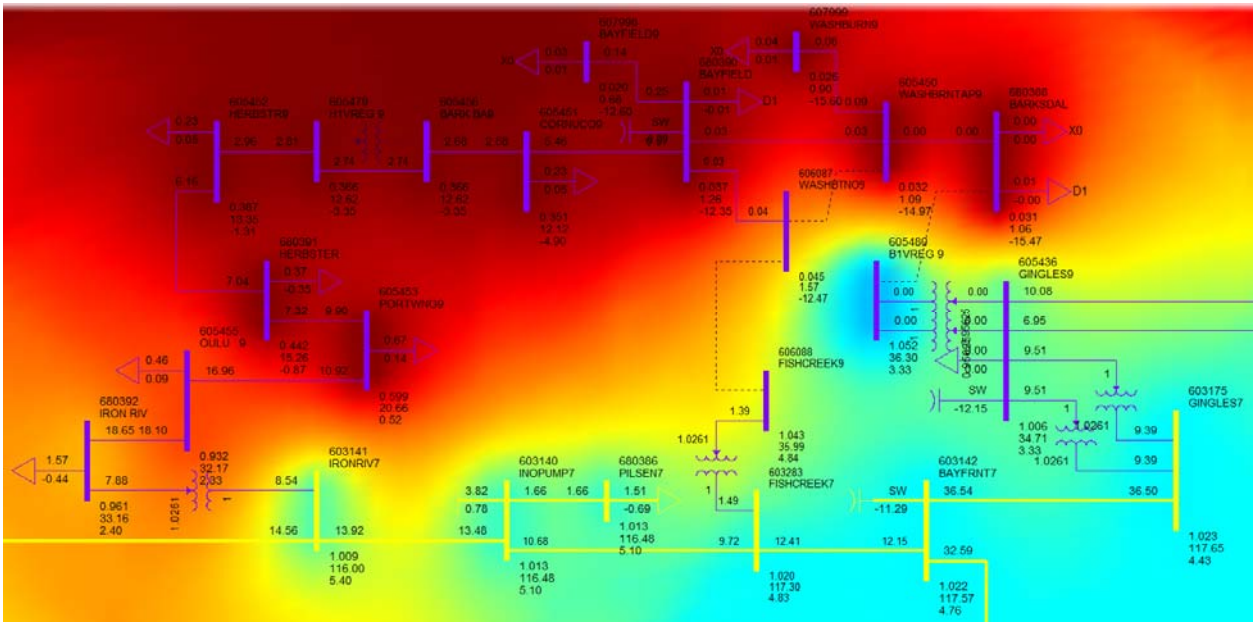


Figure 6.1 Contour Map Representing an Outage from a Double-Circuit Pole Failure

6.4 Double Circuiting With Existing Lines in Options 2 or 3

In the analysis of the alternatives, the use of double circuiting or utilizing distribution underbuild was driven by Transmission Planning for Option 2 (rebuild entire loop to 115 kV) and Option 3 (double-circuit entire loop to 115/34.5 kV). In the case of these two alternatives, double circuiting or distribution underbuild is actually preferred as integral to each option and does not impact system reliability. The reason why system reliability is not impacted when considering a double-circuiting in for Options 2 and Option 3 is because each new 115 kV line is built along the entire 72 miles of the Bayfield Peninsula and connected on both ends allowing adequate load serving capability from either direction.

7.0 Conclusion

The Gingles to Bayfield 34.5 kV line serves 17 MW on peak, with roughly half of that load at the end of a 25 mile long radial line. In this condition, the Bayfield Substation is currently unable to maintain acceptable voltage levels. Additionally, the entire Bayfield Peninsula does not have single point of failure reliability due to the radial nature of the lines serving the peninsula; this means that failure of a single pole results in customers being out of power. The lack of single point of failure reliability also means that maintenance is extremely difficult to perform, since the lines in the Bayfield Peninsula are unable to back each other up.

The Bayfield Peninsula Study reviewed the capability of the existing transmission system to serve the current and future load on the Bayfield Peninsula 34.5 kV loop. The resulting preferred option is Option 4. This option includes the constructing a new 34.5 kV single circuit line on the east side of the peninsula, building a new 115/34.5 kV "Fish Creek" substation along the Bay Front to Iron River 115 kV line, and building a new 34.5 kV "Pikes Creek" breaker substation near the middle of the existing system in the Bayfield Peninsula. An emergency tie between the new and existing lines on the east side of the Bayfield Loop is needed to serve load under N-1 contingency situations and will help minimize outage exposure to the peninsula. After the new Fish Creek to Pikes Creek 34.5 kV line is constructed, a portion of the existing 34.5 kV line on the west side of the peninsula will be rebuilt. All transmission lines included as part of this project will be constructed to 69 kV standards, which is the Company's standard design for 34.5 kV transmission facilities. Figure 7.1 shows a representative map of Option 4.

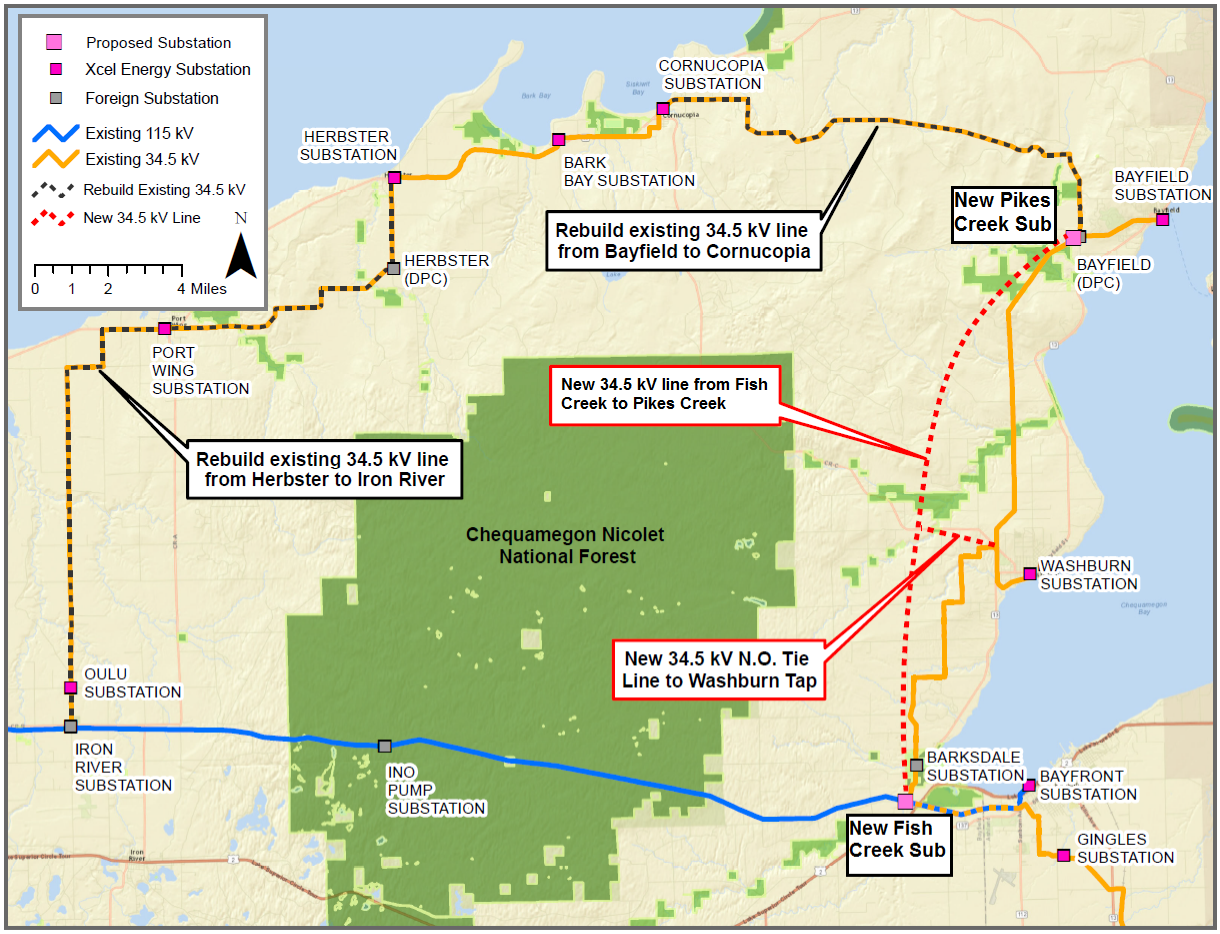


Figure 7.1 Map of Preferred Option 4

This recommended project will serve the projected load in the study area for the foreseeable future and provide flexibility for serving load growth beyond what is expected. Below in Figure 7.2 is the preferred option showing the same contingency as listed in the contour maps shown in Section 5 above. Note that all load is served under contingency.

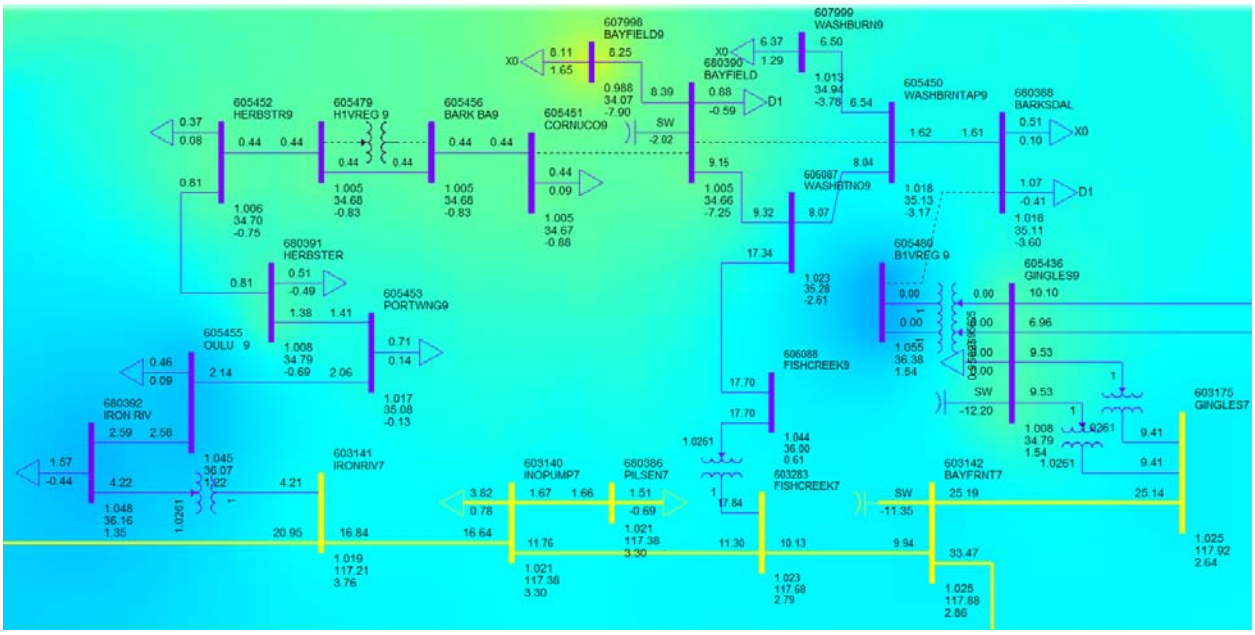
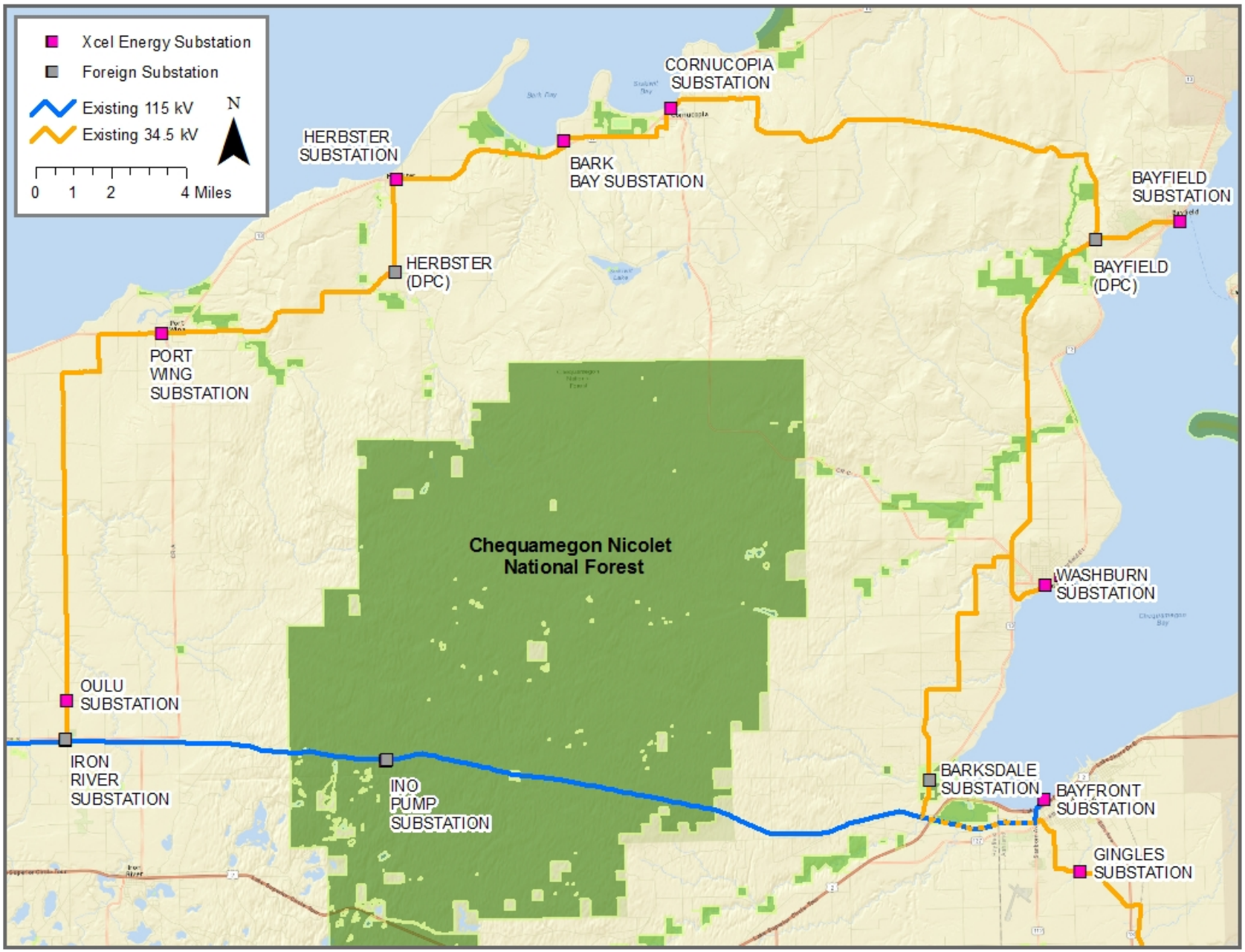


Figure 7.2 Preferred Option: 2018 Gingles – Barksdale 34.5 kV Outage, Serving All Load.

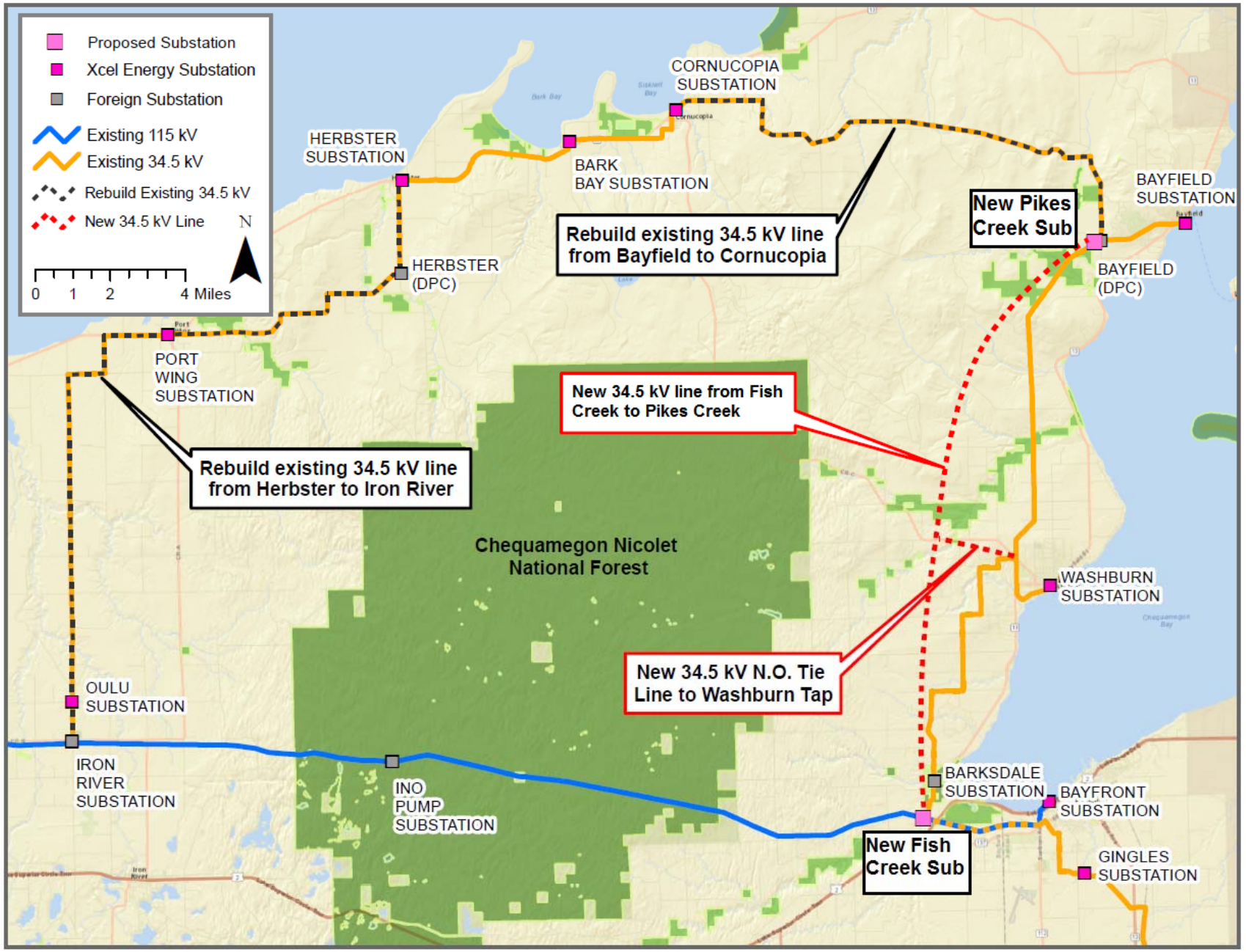
While all of the study options address the immediate and future load serving needs of the Bayfield Peninsula area, Option 4 is the preferred option because it accomplishes the project goals using smaller infrastructure than the three 115 kV options and does so at a lower cost.

Appendix A: Location Maps

The enclosed maps are for geographic orientation and planning purposes only.
Note that the new transmission line features are illustrative only and do not imply proposed routing.



Existing Transmission System in the Bayfield Loop



Preferred Option 4: Construct new 34.5 kV from New Fish Creek Substation to New Pikes Creek Substation, Rebuild Bayfield to Cornucopia and Herbster to Iron River

Appendix B: Bayfield Peninsula Outage History – Xcel Energy Substations

Substation	Outage Date	Outage Time	Outage Duration (minutes)	Outage Duration	CMOs (Customer Minutes Out)	Customers Out
Barksdale	10/15/2017	5:27 AM	5	5 min	685	137
Bayfield	10/15/2017	5:27 AM	5	5 min	13160	2,632
Washburn	10/15/2017	5:27 AM	5	5 min	7410	1482
Washburn Iron	10/15/2017	5:27 AM	5	5 min	5	1
Cornucopia	10/14/2017	9:46 PM	564	9 hr 24 min	73884	131
Herbster	10/14/2017	9:46 PM	564	9 hr 24 min	80652	143
Oulu	10/14/2017	9:46 PM	249	4 hr 9 min	23904	96
Port Wing	10/14/2017	9:46 PM	249	4 hr 9 min	89391	359
Cornucopia	10/10/2017	8:15 AM	Momentary	Momentary	Momentary	131
Herbster	10/10/2017	8:15 AM	Momentary	Momentary	Momentary	143
Oulu	10/10/2017	8:15 AM	Momentary	Momentary	Momentary	96
Port Wing	10/10/2017	8:15 AM	Momentary	Momentary	Momentary	359
Cornucopia	10/4/2017	10:12 AM	218	3 hr 38 min	28558	131
Cornucopia	10/4/2017	1:57 PM	93	1 hr 33 min	12183	131
Cornucopia	10/4/2017	10:10 AM	2	2 min	262	131
Herbster	10/4/2017	10:12 AM	218	3 hr 38 min	30738	141
Herbster	10/4/2017	1:57 PM	93	1 hr 33 min	13113	141
Herbster	10/4/2017	10:10 AM	2	2 min	282	141
Oulu	10/4/2017	10:12 AM	78	1 hr 18 min	7488	96
Oulu	10/4/2017	1:57 PM	39	39 min	3744	96
Oulu	10/4/2017	10:10 AM	2	2 min	192	96
Port Wing	10/4/2017	10:12 AM	78	1 hr 18 min	27534	353
Port Wing	10/4/2017	1:57 PM	39	39 min	14001	359
Port Wing	10/4/2017	10:10 AM	2	2 min	706	353
Barksdale	7/21/2016	4:26 AM	497	8 hr 17 min	5,964	12
Bayfield	7/21/2016	4:26 AM	497	8 hr 17 min	846,391	1,703

Substation	Outage Date	Outage Time	Outage Duration (minutes)	Outage Duration	CMOs (Customer Minutes Out)	Customers Out
Cornucopia	7/21/2016	4:02 AM	610	10 hr 10 min	79,910	131
Cornucopia	7/21/2016	8:33 PM	55	55 min	7,205	131
Herbster	7/21/2016	4:02 AM	658	10 hr 58 min	88,172	134
Herbster	7/21/2016	8:33 PM	61	1 hr 1 min	8,174	134
Oulu	7/21/2016	4:02 AM	707	11 hr 47 min	68,579	97
Port Wing	7/21/2016	4:02 AM	928	15 hr 28 min	155,904	168
Port Wing	7/21/2016	8:33 PM	61	1 hr 1 min	10,248	168
Washburn	7/21/2016	4:26 AM	497	8 hr 17 min	539,245	1,085
Washburn Iron	7/21/2016	4:26 AM	497	8 hr 17 min	497	1
Cornucopia	11/11/2015	10:07 AM	19	19 min	2,489	131
Herbster	11/11/2015	10:07 AM	19	19 min	2,812	148
Oulu	11/11/2015	10:07 AM	19	19 min	1,824	96
Port Wing	11/11/2015	10:07 AM	19	19 min	6,783	357
Barksdale	4/1/2015	3:10 PM	67	1 hr 7 min	9,179	137
Bayfield	4/1/2015	3:10 PM	143	2 hr 23 min	379,522	2,654
Washburn	4/1/2015	3:10 PM	143	2 hr 23 min	213,785	1,495
Washburn Iron	4/1/2015	3:10 PM	143	2 hr 23 min	143	1
Cornucopia	6/15/2014	3:03 PM	282	4 hr 42 min	37,788	134
Herbster	6/15/2014	3:03 PM	282	4 hr 42 min	42,300	150
Oulu	6/15/2014	3:03 PM	310	5 hr 10 min	29,760	96
Port Wing	6/15/2014	3:03 PM	282	4 hr 42 min	101,520	360
Cornucopia	4/18/2013	11:03 PM	472	7 hr 52 min	64,360	136
Herbster	4/18/2013	11:03 PM	472	7 hr 52 min	69,856	148
Oulu	4/18/2013	11:03 PM	472	7 hr 52 min	46,256	98
Port Wing	4/18/2013	11:03 PM	472	7 hr 52 min	168,504	357
Cornucopia	7/31/2012	3:43 AM	173	2 hr 53 min	22,490	130
Cornucopia	7/31/2012	7:12 AM	4	4 min	520	130
Herbster	7/31/2012	3:43 AM	173	2 hr 53 min	25,777	149
Herbster	7/31/2012	7:12 AM	4	4 min	596	149

Substation	Outage Date	Outage Time	Outage Duration (minutes)	Outage Duration	CMOs (Customer Minutes Out)	Customers Out
Oulu	7/31/2012	3:43 AM	173	2 hr 53 min	13,954	80
Oulu	7/31/2012	7:12 AM	4	4 min	392	98
Port Wing	7/31/2012	3:43 AM	173	2 hr 53 min	61,761	357
Port Wing	7/31/2012	7:12 AM	4	4 min	1,428	357
Cornucopia	12/1/2011	1:37 PM	48	48 min	6,240	130
Herbster	12/1/2011	1:37 PM	48	48 min	7,104	148
Oulu	12/1/2011	1:37 PM	48	48 min	4,608	96
Port Wing	12/1/2011	1:37 PM	48	48 min	17,088	356
Cornucopia	4/3/2011	6:35 AM	270	4 hr 30 min	35,640	132
Herbster	4/3/2011	6:35 AM	270	4 hr 30 min	39,690	147
Port Wing	4/3/2011	6:35 AM	270	4 hr 30 min	95,580	354
Bayfield	9/24/2010	11:36 AM	293	4 hr 53 min	754,475	2,575

Appendix C: NERC TPL-001-4 Table 1

Table 1 – Steady State & Stability Performance Planning Events						
Category	**Initial Condition**	**Event 1**	**Fault Type [2]**	**BES Level [3]**	**Interruption of Firm Transmission Service Allowed [4]**	**Non-Consequential Load Loss Allowed**
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes
P3 Multiple Contingency	Loss of generator unit followed by System adjustments9	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			

Table 1 – Steady State & Stability Performance Planning Events

Category	Initial Condition	Event 1	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes
P5 Multiple Contingency *(Fault plus relay failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes