414 Nicollet Mall
Minneapolis, MN 55401

June 21, 2017

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: RESPONSE TO NOTICE
GRID MODERNIZATION
DOCKET NO. E999/CI-15-556

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits this response to the Commission's April 26, 2017 NOTICE OF COMMENT PERIOD ON DISTRIBUTION SYSTEM PLANNING EFFORTS AND CONSIDERATIONS in the above-referenced Docket.

Pursuant to Minn. Stat. §216.17, subd. 3, we have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on all parties on the attached service list. Please contact me at bria.e.shea@xcelenergy.com or (612) 330-6064 if you have any questions regarding this filing.

Sincerely,

/s/

BRIA E. SHEA
DIRECTOR, REGULATORY AND STRATEGIC ANALYSIS

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Nancy Lange	Chair
Dan Lipschultz	Commissioner
Matthew Schuerger	Commissioner
Katie J. Sieben	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE COMMISSION INVESTIGATION INTO GRID MODERNIZATION: FOCUS ON DISTRIBUTION SYSTEM PLANNING

DOCKET NO. E999/CI-15-556

RESPONSE TO NOTICE

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits this response to the Minnesota Public Utilities Commission's NOTICE regarding utility distribution planning practices dated April 26, 2016 in the above-referenced docket.[1]

The Notice observes that changing customer and industry expectations, technological advancements, and growth in Distributed Energy Resources (DER) will provide new benefits and opportunities – but also new challenges for Minnesota. Distribution planning is anticipated to help the utilities be increasingly resilient and accommodating to these evaluations and to allow for more transparent evaluation of utility decisions.

To this end, the Commission's Notice seeks to do the following:

- Initiate a discussion regarding the current state of utilities' planning processes and results,
- Provide utilities and stakeholders an opportunity to identify potential improvements in planning processes, and
- Support a distribution system planning process and associated filing requirements.

This response is to Parts A and B of the Notice, which are intended to detail how Minnesota utilities currently plan their distribution systems and the status of each

[1] *See* NOTICE OF COMMENT PERIOD ON DISTRIBUTION SYSTEM PLANNING EFFORTS AND CONSIDERATIONS dated April 21, 2016 and corrected April 26, 2016.

utility's current plan, respectively. In addition to answering the questions included in the Notice, we provide a comprehensive discussion of our current planning practices.

The balance of our response is organized as follows:

INTRODUCTION

Utility distribution grids are evolving from a predominantly one-way system to an integrated network of centralized and decentralized energy resources connected and optimized through communication systems that share information across the grid. This advanced grid is expected to leverage automation and real-time monitoring to improve system efficiency and performance, prevent disruptions, and reduce the duration and impact of outages. Expanded sensors and controls will manage power flows and support new generation, load and storage technologies. Security protocols will protect against, detect, and remedy cyber and physical threats. These new system capabilities will expand the options available to customers who will increasingly expect a more customized, convenient, and clean energy experience that preserve the high reliability they have come to depend upon.

We have begun this transition, focusing first on the foundational elements needed to support fundamental communications and applications. Through this docket, the Commission is advancing the discussion and taking steps to help ensure Minnesota's distribution system is well-positioned to meet future system and customer needs, while maintaining reliability, safety and security. We support these efforts and the evolution of the grid, and look forward to continued active participation in this dialogue.

That said, the issue of distribution planning is timely. Distribution planning traditionally is the process of analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels and utilization rates of major system components such as substations and feeders. We see this changing as our planning processes evolve, however, to analyze future electricity *connections*, rather than just loads. The purpose of these assessments is to proactively plan for the future and identify existing and anticipated capacity deficiencies or constraints that will potentially result in overloads during *normal* (also called "system intact" or N-0 operation) and *single contingency* (N–1) operating conditions. Normal operation is the condition under which all electric infrastructure equipment is fully-functional. Single contingency operation is the condition under which a single element (feeder circuit or distribution substation transformer) is out of service.

Utility distribution systems are complex and dynamic, in that they involve thousands of pieces of equipment, must be resilient from outside forces over vast areas of geography, and must be able to respond to changes in customer loads and operational realities. Traditionally, distribution systems have been designed for the efficient distribution of power to provide customers with safe, reliable and adequate electric service – with geography playing a significant role in the design of the system. The Northern States Power Company – Minnesota Operating Company (NSPM) service area has diverse geography and therefore diverse planning criteria and considerations. The NSPM distribution system includes approximately 270 substations, 1,275 feeders, and 450 substation transformers, and approximately 27,000 circuit miles of line – 16,000 miles of which are overhead and 11,000 miles are underground – over three states (Minnesota, North Dakota, and South Dakota).

Corrective actions identified as part of the planning process may include a new feeder or substation, adding feeder tie connections, installing regulators, capacitors, or upsizing substation transformers. As our planning processes evolve and technologies mature, corrective actions may also include non-wire alternatives. For each project, we develop cost estimates and perform cost-benefit analyses to determine the best options based on several factors including operational requirements, technical feasibility and future year system need. Proposed projects are funded as part of an annual budgeting process, based on a risk ranking methodology that also funds other distribution investments and expenditures including asset health, grid modernization, and emergent issues such as storm response and mandated projects to relocate utility infrastructure in public rights-of-way when mandated to do so to accommodate public projects such as road widening or realignment.

The technology advancements and customer and utility adoption of DER that is underway will require utilities to think and act differently about the ways they plan and operate their systems. With the present limited levels of DER on the system, we believe our current planning processes that plan for the maximum annual peak sans DER appropriately ensure a stable system and cost-effective reliability for customers.

In some ways, we believe distribution planning will need to evolve toward a more granular process. The lowest level of planning today is at the feeder level. DER is more granular, and may have a significant impact on available capacity at certain times, and in others be limited in its impact. Planning practices will therefore need to evolve to better anticipate *net* load and multi-directional power flows, for example, which will require increased understanding of the capabilities and predictability of various types of DER. It will also require new or improved planning tools that are capable of integrating more granular details into system planning studies.

At the same time, we also believe planning practices will need to evolve toward a more broad and integrated process. While our current planning practices involve interfacing with transmission and resource planning, as DER grows and distribution planning practices mature, we expect the information shared as part of those interactions to increase in scope and specificity. Regardless of the specific changes that may occur, distribution planning will continue to ensure safe, reliable, adequate service – but is most certainly evolving to embrace a faster pace of change and to be more transparent and flexible in order to meet current and future customer and system needs.

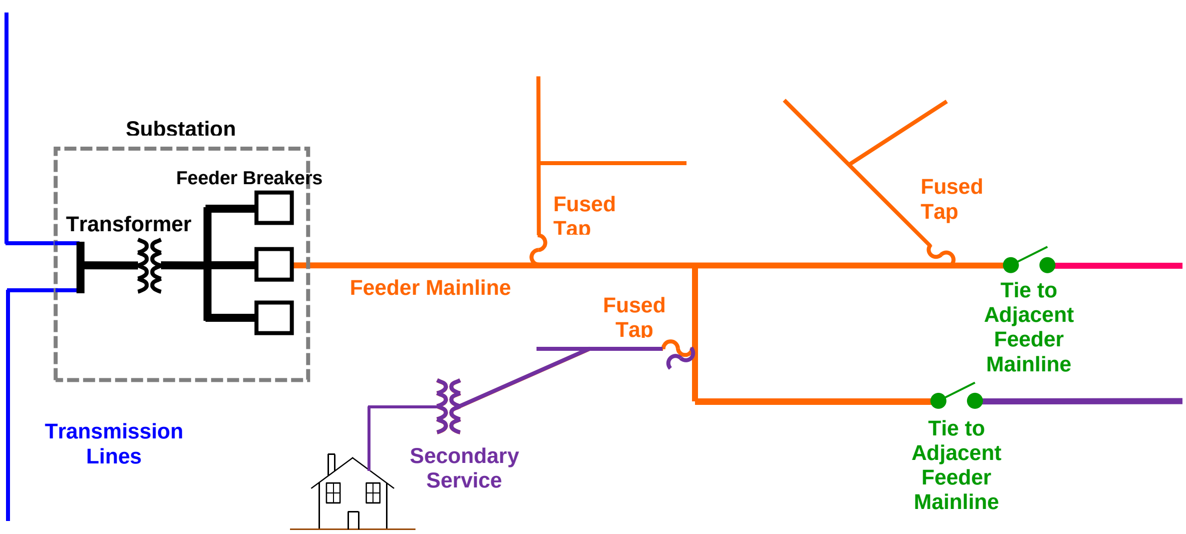
I. PRINCIPLES OF DISTRIBUTION PLANNING

We analyze our distribution system annually and conduct additional analyses during the year in response to new information, such as new customer loads, or changes in system conditions. In this section, we provide an overview of the distribution system and discuss the key planning criteria we apply in the planning process to ensure customer reliability. Section II discusses the specific steps in our planning process, which also includes discussion about the overall capital budgeting process for our Distribution business area.

A. Distribution System Overview

Distribution feeders for standard service to customers are designed as radial circuits. Therefore, the failure of any single critical element of the feeder causes a customer outage. This is an allowed outcome for a distribution system, within established standards for reliability, which typically measure the average duration (System Average Interruption Duration Index or SAIDI) and frequency (System Average Interruption Frequency Index or SAIFI) of interruptions. The distribution system is planned to generally facilitate single-contingency switching to restore outages within approximately one hour. Foundational components in distribution system design and planning are substations and feeders.

Figure 1: Distribution System: Basic Design
Schematic of Typical Radial Circuit Design



1. *Substations*

We plan and construct distribution substations with a physical footprint sized for the ultimate substation design, which is based on anticipated load, but can occasionally be limited by factors such as geography and available land. The maximum ultimate design capacity established in our planning criteria is three transformers at the same distribution voltage. There is one exception to this criterion. In downtown Minneapolis, we have one substation that houses four transformers to serve the significant load. This maximum size balances substation and feeder costs with customer service, customer load density, and reliability considerations.

Cost considerations include the transmission and distribution capital investment in the lines, load losses (which are generally proportional to line length), land cost, and space to accommodate growth. Customer service and reliability implications include line length and route, integration with the existing system, access, and security. Over time, transformers and feeders are incrementally added within the established footprint until the substation is built to ultimate design capacity. Higher levels DER will affect substation capacity, system protection, and voltage regulation.

Figure 2: Distribution Substation

2. Feeders

Feeders are sized to carry existing and planned customer load. Where possible, we design-in redundancy, which has a positive impact on reliability. Feeders have a "range," like a mobile phone service tower, where they can effectively serve. For 15kV, which is common in the Twin Cities metro area, the range is approximately three miles. In rural areas where system load is less geographically dense, the range is higher – approximately one mile per kV. Thus, if customer load density remains the same, then higher voltages can serve a proportionately greater distance.

Feeders typically serve approximately 1,500 customers, though this varies based on voltage, location, customer load density, and the utilization of the feeder. The industry benchmark for feeder capacity is approximately 600 amps, which provides an efficient balance of the costs of conductors, capacity, losses, and performance. This translates to a maximum load-serving capability of about 15 MVA on 13.8 kV feeders, and 37 MVA on 34.5 kV feeders.

B. Distribution System Design and Planning Criteria

We plan, measure, and forecast distribution system load with the goal of ensuring we can serve all customer electric load under normal and first contingency conditions. Our goal is always to keep electricity flowing to as many customers on the feeder as possible. Designing our system for adequate first contingency capacity allows for restoration of all customer load by reconfiguring the system by means of electrical switching, in the event of the outage of any single element. For example, we strive to load feeders to approximately 75 percent of maximum capacity, which provides reserve capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions.

Adequate substation transformer capacity, no normal condition feeder overloads, and adequate field tie capabilities for feeder first contingency restoration are key design and operation objectives for the distribution system. To achieve these objectives, we use distribution planning criteria to achieve uniform development of our distribution systems. Distribution Planning considers these criteria in conjunction with historical and projected peak load information in annual and ongoing assessment processes.

1. Planning to Meet the Peak Load

Our load forecast focuses on demand (kVA) not energy (kWh) to ensure we can serve loads during system peaks.[2] For planning purposes, we define "peak load" as the largest power demand at a given point during the course of one year. Measured peak loads fluctuate from year-to-year due to the impacts of duration and intensity of hot weather and customer air conditioning usage. In examining each distribution feeder and substation transformer for peak loading, we use specific knowledge of distribution equipment, local government plans, and customer loads to forecast future electrical loads. Planning Engineers consider many types of information for the best possible future load forecasts including: historical load growth, customer planned load additions, circuit and other distribution equipment additions, circuit reconfigurations, and local government-sponsored development or redevelopment.

[2] When three phase load data is available, we use the highest recorded phase measurement in our forecast.

2. *Basic Design Guidelines*

While the distribution guidelines vary depending on the specific distribution system attribute, there are several basic design guidelines that apply to all areas of our distribution system, as follows:

- Voltage at the customer meter is maintained within five percent of the customer's nominal service voltage, which for residential customers is typically 120 volts.
- Voltage imbalance goals on the feeder circuits are less than or equal to three percent. Feeder circuits deliver three-phase load from a distribution substation transformer to customers. Three-phase electrical motors and other equipment are designed to operate best when the voltage on all of the three phases is the same or balanced.
- The currents on each of the three phases of a feeder circuit are balanced to the greatest extent possible to minimize the total neutral current at the feeder breaker. When phase currents are balanced, more power can be delivered through the feeders.
- Under system intact, N-0 operating conditions, typical feeder circuits should be loaded to less than 75 percent of capacity.[3] We developed this standard to help ensure that service to customers can be maintained in an N-1 condition or contingency. If feeder circuits were loaded to their maximum capacity and there were an outage, the remaining system components would not be able to make up for the loss, because adding load to the remaining feeder circuits would cause them to overload.[4]

All distribution system equipment has capacity, or loading, limits that must factor into our planning processes. Exceeding these limits stresses the system, causes premature equipment failure, and results in customer outages. Our planning processes primarily focus at the substation and feeder levels, but also consider limitations and utilization of other system components such as cable, conductors, circuit breakers, transformers, and more.

[3] 34.5 kV follows a 50 percent loading rule.

[4] By targeting a 75 percent loading level, there is generally sufficient remaining capacity on the system to cover an outage of an adjacent feeder with minimal service interruptions. A feeder circuit capable of delivering 12 MVA, for example, should be normally loaded to 9 MVA and loaded up to 12 MVA under N-1 conditions.

3. Distribution Feeder Capacity and Spatial Considerations

Spatial and thermal limits restrict the number of feeder circuits that may be installed between a distribution substation transformer and customer load. Consequently, this limits substation size. Normal overhead construction is one feeder circuit on a pole line; high density overhead construction is two feeder circuits on a single pole line (double deck construction). When overhead feeder circuit routes are full, the next cost-effective installation is to bury the cable in an established utility easement. Thermal limits require certain minimum spacing between multiple feeder circuit main line cables. Thermal limits for primary distribution lines are defined in our Standards.

When we add new feeder circuits to a mature distribution system, we are not always able to maintain minimum spacing between feeder circuit mainline cables due to right-of-way limitations or a high concentration of feeder cables. Cable spacing limitations and/or feeder cable concentrations frequently occur where many feeder cables must be installed in the same corridor near distribution substations or when crossing natural or manmade barriers.

When feeder cables are concentrated, they are most often installed underground in groups (banks) of pipes encased in concrete that are commonly called "duct banks." When feeder circuits are concentrated in duct banks they experience mutual heating, therefore those cables encounter more severe thermal limits than multiple buried underground feeder circuits. Planning Engineers use software tools to determine maximum N-0 and N-1 feeder circuit cable capacities for circuits installed in duct banks. When underground feeders fill existing duct lines, and there is no more room in utility easement or street right-of-way routes for additional duct lines from a substation to the distribution load, feeder circuit routing options are exhausted. This would require constructing facilities from a different area to serve this load.

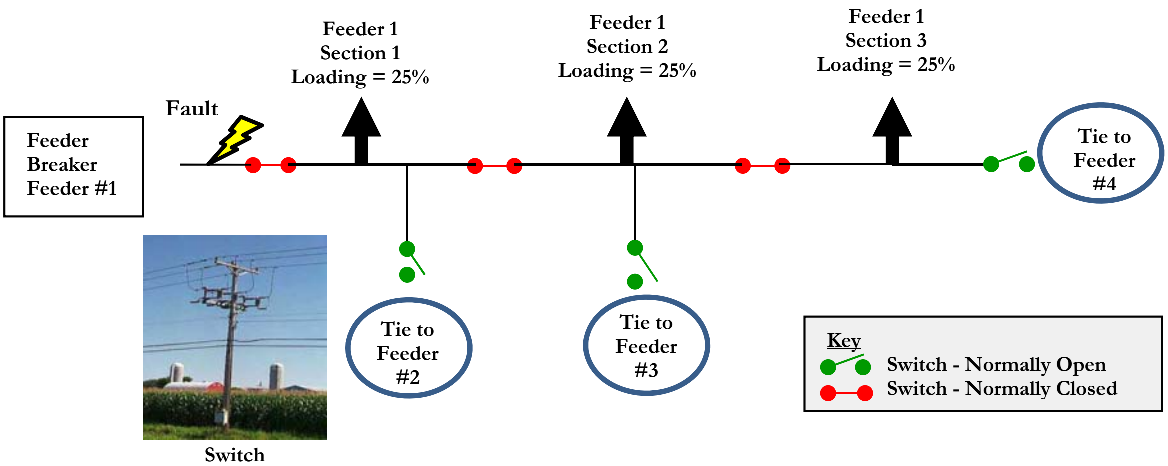
4. Feeder Circuit Utilization

As we have noted, our planning criteria aims to maintain feeder utilization rates at or below 75 percent to help ensure a robust distribution system capable of providing electrical service under first contingency N-1 conditions. Therefore, to assess the robustness of the system over time, Planning Engineers analyze the historical utilization rates and projected utilization rates based on forecast demand. They generally apply the 75 percent loading guideline when assessing the system across a larger area as part of an area study. The 75 percent guideline is appropriate for these larger area studies because it is often not practical to analyze the section and tie-transfer breakdowns for each individual feeder in each of the identified solution options similar to what is done in our annual planning process. Since the section and tie-transfer breakdowns are highly detailed and specific to the geography and topology of the individual feeders, it is easier to compare and articulate the differences between solution options with a 75 percent loading guideline.

Figure 3 below illustrates this concept with a mainline feeder. The feeder shows the three sections equally loaded to 25 percent of the total feeder capacity. The green and red symbols represent switches that can be operated to isolate or connect the sections of the feeder in the case of a fault. In that circumstance, the feeder breaker in the substation will operate to isolate the feeder where the fault is detected. Then, the normally closed section switches are opened to isolate the section of the feeder in which the fault is detected. Isolating the fault allows a portion of the customers served by that feeder to remain in service while we repair the fault and return the feeder to normal operation.

Figure 3: Typical Mainline Distribution Feeder with Three Sections Capable of System Intact N-0 and First Contingency N-1 Operations

Mainline Feeder No. 1



In this circumstance, Feeders 1 to 4 all have the same capacity – and are all loaded to 75 percent – so each of the feeder sections can be safely isolated and transferred to adjacent Feeders 2, 3, and 4 through the corresponding tie switches. This reconfiguration results in Feeders 2, 3, and 4 each being loaded to 100 percent (i.e., their original 75 percent, plus the transferred 25 percent from the adjacent Feeder #1 sections). This reconfiguration capability maintains electric service to customers while we repair the fault to the feeder and return the system to normal operation.

Area studies are typically initiated on a case-by-case basis, when Distribution Planning identifies a high number of individual risks or loading constraints within a localized area. These localized area studies vary in size, scope, and scale based on the issues identified, and can encompass a single substation, an entire city, or an entire geographic region. When the 75 percent guideline is applied in an area study, it provides an efficient means of approximating how much additional capacity is needed in that area. When the total feeder circuit utilization within the study area exceeds 75 percent (as calculated using Figure 4 below), it is generally no longer effective to perform more simple solutions – such as load transfers, or installing new feeder tie connections between existing feeders.

Figure 4: Total Feeder Circuit Utilization in Study Area

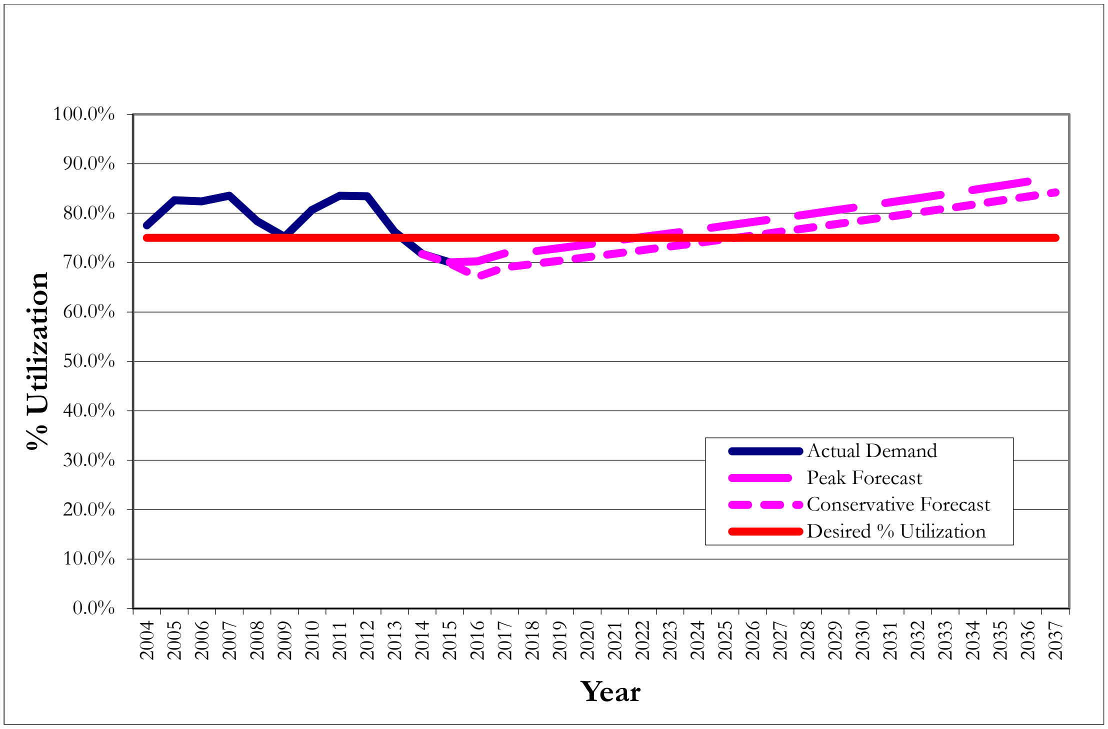
$$\text{Total Feeder Circuit Utilization} = \frac{\sum \text{Feeder Circuit Load in Area}}{\sum \text{Feeder Circuit Capacity in Area}}$$

These simple solutions merely patch a capacity-deficient portion of the system temporarily; rather than solve the issue, they often result in shifting the overloads or contingency risks from one feeder to another. However, when the total feeder circuit utilization is within a reasonable margin beneath 75 percent, there is generally enough capacity in the area for simple solutions to be viable for resolving any remaining risks.

While a generalized 75 percent utilization is ideal, it may not be feasible depending on system configurations. Feeder utilization in Minnesota is on average 66 percent; approximately 38 percent of the feeders are above 75 percent utilization. When we analyze feeders and transformers, we use the specific loading and configuration to determine the N-0 and N-1 overloads. Because of the wide variety of system configurations, the evaluation may show certain transformers or feeders may be loaded to higher utilization without causing an overload.

Figure 5 below shows an example of total feeder circuit utilization for feeders in a study area over the timeframe of the study period.

Figure 5: Total Feeder Circuit Utilization – Historical Peak Demand and Peak Demand Forecast



The feeder circuit load history is the actual non-coincident peak loading of all feeder circuits in the study area measured at the beginning of the feeder circuits in the substation. We compare the sum of the individual feeder circuit peak to the sum of the individual feeder circuit capacities to calculate feeder circuit utilization each year. We calculate average load growth for the time period by comparing total non-coincident feeder circuit loads from the beginning to the end of the comparison period. A peak load forecast starting from the historic peak level provides an upper forecast limit.

Isolated feeder overloads, which can be characterized by an individual feeder overload that occurs when average feeder utilization percentage is *less* than 75 percent, typically occur when there is new development or redevelopment that increases load demand within a small part of the distribution system. Widespread feeder overloads, which can be characterized by one or more individual feeder overloads that occur when average feeder utilization percentage is *more* than 75 percent, typically occur in distribution areas due to a combination of customer addition of spot loads and focused redevelopment by existing customers, developers or community initiatives.

Distribution systems that start out with adequate N-1 and N-0 capacity, can quickly progress beyond isolated overloads when a large part of the distribution system is redeveloped or focused redevelopment is targeted in an area or along a corridor.

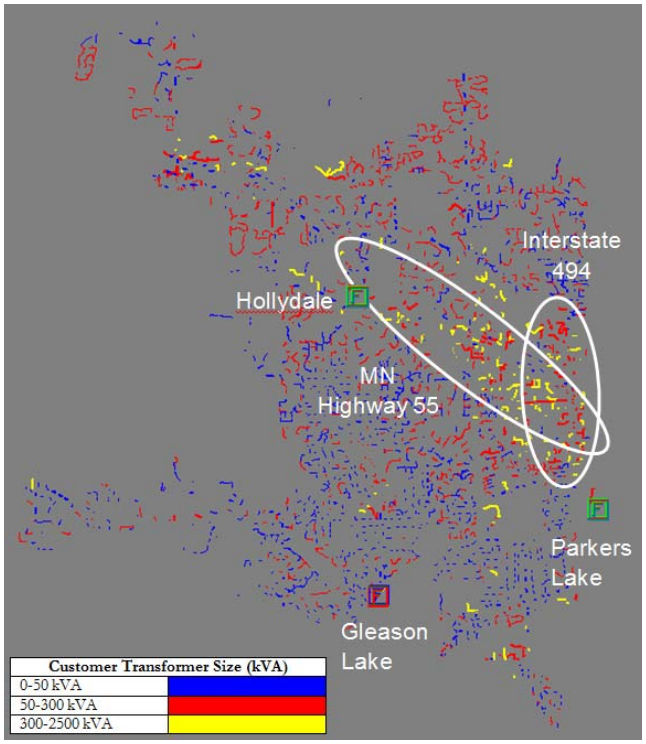
5. Feeder Load Density

In addition to feeder peak loads, Distribution Planning examines existing feeder load density by studying the distribution transformers serving the customers. Distribution transformers are the service transformers that step the voltage down from feeder voltages to the voltage(s) that the customer receives at their point of service. As customer load grows in developed areas, we change distribution transformers to higher capacity equipment when customer demand exceeds the capacity of the original transformer.

Distribution transformers are an excellent indicator of customer electrical loading and peak electrical demand, and are used to help validate the growth that is observed and forecasted in the annual peak demand and load forecast analysis.

Figure 6 below is an example of distribution transformer installation by size from a prior analysis we completed for western Plymouth. This view is helpful to understand present customer load density.

Figure 6: Distribution Transformer Installation by Size



Developed using Synergi Electric

After examining feeder circuit peak demands, we look at the loading levels for the transformers housed at the substations.

6. *Substation Transformer Capacity Limitations*

Transformers have nameplate ratings that identify their capacity limits. Our internal Transformer Loading Guide (TLG) provides the recommended limits for loading substation transformers adjusted for altitude, average ambient temperature, winding taps-in-use, etc. The TLG is based upon the American National Standards Institute/Institute of Electrical and Electronic Engineers (ANSI/IEEE) standard for transformer loading, ANSI/IEEE C57.92. The TLG consists of a set of hottest-spot and top-oil temperatures and a generalized interpretation of the loading level equivalents of those temperatures, which are the criteria used by Substation Field Engineers to determine normal and single-cycle transformer loading limits that planning engineers use for transformer loading analysis.

A transformer's *normal* loading limit is called the transformer "loadability," which represents the maximum loading that the transformer could safely handle for any length of time. A transformer's *single-cycle* loading limit represents the maximum loading that the transformer could safely handle in an emergency for at most one load cycle (24 hours), and is what we use for our substation transformer N-1 contingency analysis. When internal transformer temperatures exceed predetermined design maximum load limits, the transformer sustains irreparable damage, which is commonly referred to as equipment "loss-of-life." Loss-of-life refers to the shortening of the equipment design life that leads to premature transformer degradation and failure.

Transformer design life is determined by the longevity of all of the transformer components. At a basic level most substation transformers have a high voltage coil of conductor and a low voltage coil electrically insulated from each other and submerged in a tank of oil. Transformer loading generates heat; the more load transformed from one voltage to the other, the more heat; too much heat damages the insulation and connections inside the transformer. Hottest-spot temperatures refer to the places inside the transformer that have the greatest heat, and top-oil temperature limits refer to the maximum design limits of the material and components inside the transformer.

To ensure maximum life and the ability to reliably serve customers, our loading objective for transformers is 75 percent of normal rating or lower under system intact conditions. Substation transformer utilization rates below 75 percent are indicative of a robust distribution system that has multiple restoration options in the event of a substation transformer becoming unavailable because of an equipment failure or required maintenance and construction. The higher the transformer utilization rate, the higher the risk of a transformer outage that interrupts service to customers.

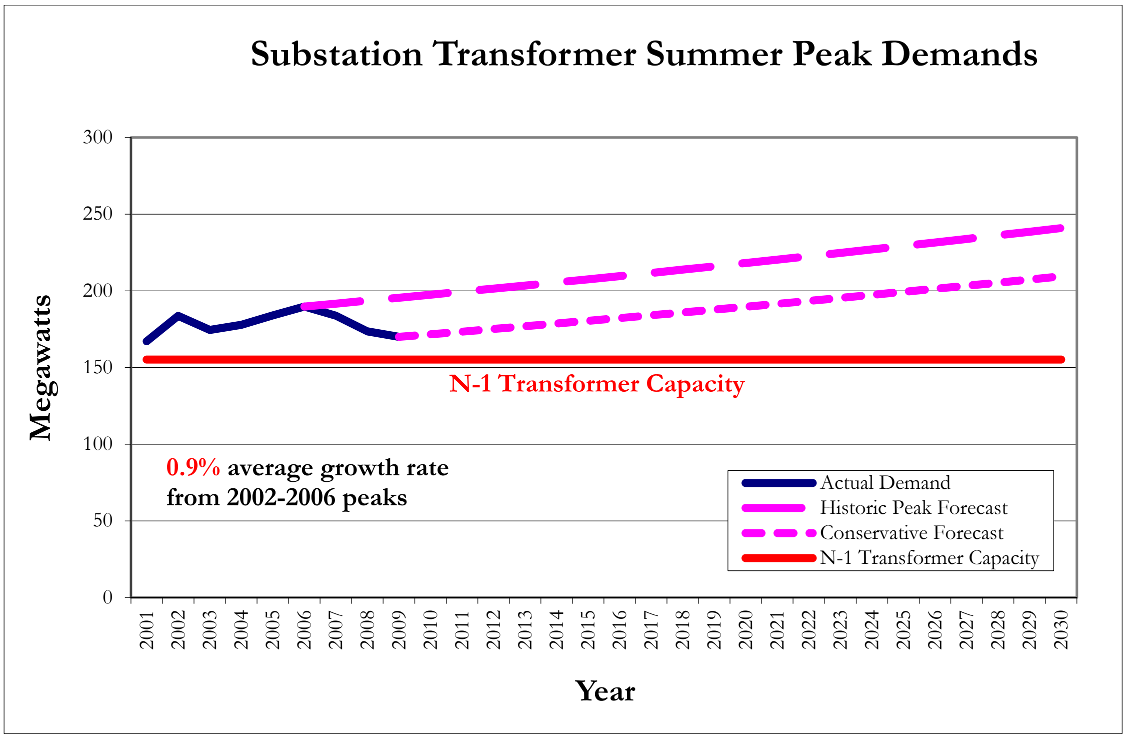
7. *Substation Transformer Utilization*

Each distribution substation has a demand meter that is read monthly for each substation transformer. These meters record the transformer's monthly peak. For those distribution substation transformers that have a Supervisory Control and Data Acquisition (SCADA) system connection, we are able to monitor the real-time load on the transformer. We currently have SCADA in about 165 of our distribution substations, which serve over 90 percent of our customers. Similar to distribution feeders, the transformer data feeds into a data warehouse, which can be combined with hourly historic and forecast peak load data in our Distribution Asset Analysis (DAA) system, so we can view the substation transformer's load history.

Each transformer's peak in a multi-transformer substation is non-coincident – meaning the transformers can each individually experience peak load at different times, and potentially on different days. This is a result of the fact that each transformer serves multiple feeder circuits that each serve different loads. Substation transformer peak load is proportional to, but usually less than, the sum of the feeder circuit peak loads served from that substation transformer. The detail of substation transformer loading is a larger granularity than feeder circuit loads with a corresponding greater impact on customer service due to the larger number of customers affected for any event on a transformer than on a feeder.

Figure 7 below is an example of load growth using historical and forecasted peak loads for a set of substation transformers

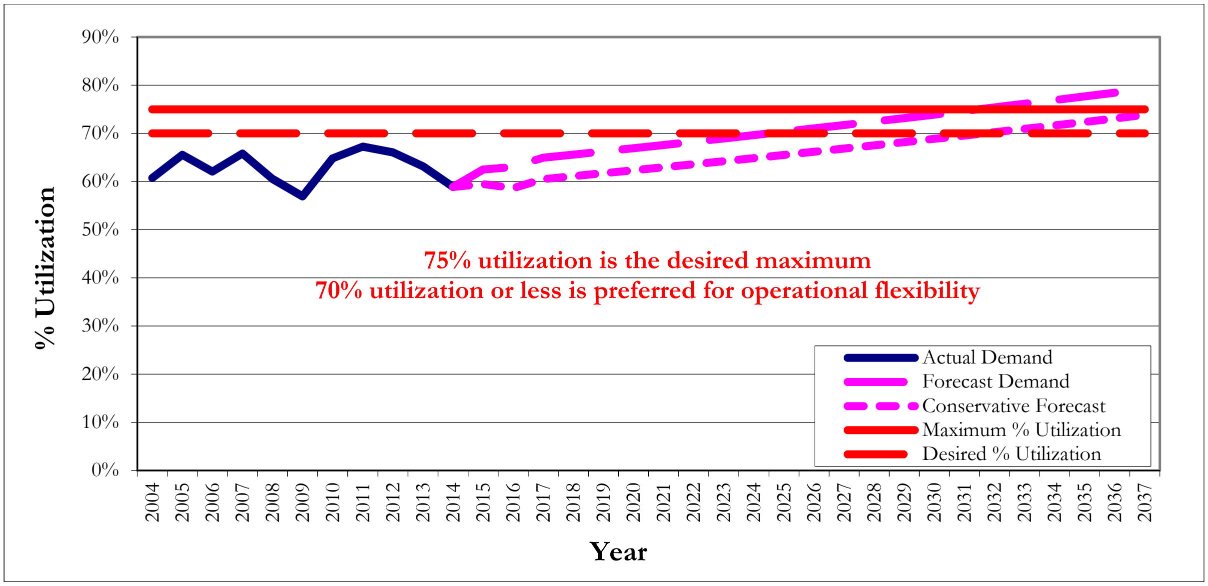
Figure 7: Greater Study Area – Historical and Forecasted Loads



The upper and lower dashed lines provide a bandwidth for growth, forecasted from the conservative peak and historic peak values, respectively.

As part of our analysis, we review the loading and utilization rates of distribution substations. We provide an example of our transformer utilization analysis in Figure 8 below, which illustrates the bandwidth of expected load growth that is forecasted to occur between the upper and lower dashed lines.

Figure 8: Total Transformer Utilization Percentage for Transformers – Focused Study Area



Even when using conservative peak load levels from the lower dashed line, in this circumstance forecasted load levels still exceed desirable loading levels for the substation transformers in the later years of the 20-year forecast in the study. The range of likely transformer utilization falls between the dashed lines of the conservative forecasted demand and the historic peak forecast load levels.

Using the planning criteria such as we have described above, Planning Engineers evaluate the distribution system, and are able to determine transformer and feeder loading and identify risks for normal and contingency operation of the system.

C. Distribution Planning Tools

Planning Engineers rely on a set of tools to perform the annual full system snapshot, ongoing distribution system assessments – including assessment of specific DER interconnections – and long-range area assessments. Currently, our hosting capacity analysis is done separately through Electric Power Research Institute's (EPRI) DRIVE tool.

Table 1 below summarizes the tools and how we use them in our planning process. We then discuss in more detail how we use each of the tools.

Table 1: Planning Tool Summary

Tool	Process	Description
DNV-GL Synergi Electric	Power flow	Contains a geospatially accurate model of the electric distribution Feeder system with known conductor and facility attributes such as ampacity, construction, impedance, and length to simulate the distribution system
ITRON Distribution Asset Analysis (DAA)	Medium to long-range load forecasting of major distribution system components, including feeders and transformers	System of record for historical peak feeder and substation transformer load information that we use to evaluate historical load growth and weather adjustments to match prior peaks and identified known load growth to establish a forecast for 1+ years out
Microsoft Excel Spreadsheets	Contingency planning	Analyze feeder and transformer contingency capacity by evaluating the available capacity on neighboring feeder ties and substation transformers for the forecasted years
CYMCAP	Determines normal and emergency ampacity for Feeder circuit cables	Determines the amount of amps that can flow through cables for various system configurations, soil types, and cable properties before they are thermally overloaded
Geographical Information System (GIS)	Provides the connectivity model source data to Synergi, as well as Feeder topology.	Contains location-specific information about system assets and components, allowing us to view, understand, question, interpret and visualize data in many ways that reveal relationships, patterns, and trends in the form of maps.
Distribution Supervisory Control and Data Acquisition (SCADA)	Peak load forecasting	Monitors and collects system performance information for feeders and substation transformers
WorkBook	Project Prioritization	An internal tool used to help rank projects based on levels of risk and estimated costs

We additionally outline our hosting capacity tool that is not currently part of the planning process.

Tool	Process	Description
Electric Power Research Institute (EPRI) Distribution Resource Integration and Value Estimation (DRIVE)	Hosting capacity	Using the actual Company feeder characteristics, DRIVE considers a range of DER sizes and locations in order to determine an indicative range of minimum and maximum hosting capacity by screening for voltage, thermal, and protection impacts.

Figure 9: Tool Summary by Distribution Planning Process

	Planning Process Component						
Tool	**Forecast**	**Risk Analysis**	**Mitigation Plans**	**Budget Create**	**Initiate Construction - EDP Memo**	**Long-Range Plans**	**Hosting Capacity**
Synergi Electric			X			X	X
DAA	X	X				X	
MS Excel		X		X		X	
CYMCAP		X					
GIS			X			X	X
SCADA	X						
WorkBook		X	X	X	X		
DRIVE							X

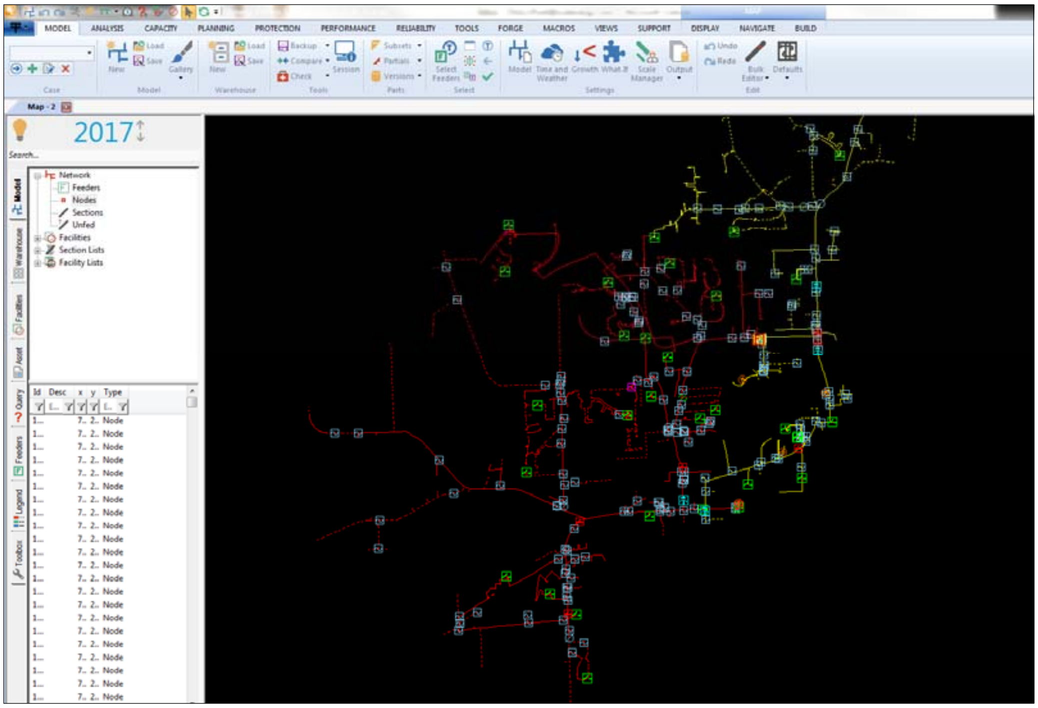
1. *DNV-GL Synergi Electric*

Synergi is the Company's distribution power flow tool, which we use to model the distribution system in order to identify capacity constraints, both thermal and voltage, that may be present or forecasted. It provides a geospatially accurate model of the electric distribution feeder system with known conductor, electrical equipment, and facility attributes such as material type, which contains ampacity and impedance values. We use it to model different scenarios that occur on the distribution system and to create feeder models that are an input to the DRIVE tool used for hosting capacity analysis; it can also be used to explore and analyze feeder circuit reconfigurations. As load is manually allocated to a feeder and we run a power flow process, exceptions such as voltage or thermal violations may occur. Areas of the feeder are then highlighted due to those exceptions to bring these issues to the engineer's attention.

Synergi can generate geographically correct pictures of tabular feeder circuit loading data, which is achieved through the implementation of a GIS extraction process. Through this process, each piece of equipment on a feeder, including conductor sections, service transformers, switches, fuses, capacitor banks, etc., is extracted from the GIS and tied to an individual record that contains information about its size, phasing, and location along the feeder. We provide a screenshot from Synergi as

Figure 10 below.

Figure 10: Synergi Electric Application Example



To calibrate the model, we import peak day customer usage data into the system, and allocate it to service transformers or primary customer service points. The Customer Management Module within this software takes monthly customer energy usage data and assigns demand values based on the customer class (i.e. residential, commercial, etc.), the assigned "load curves" for that class, and the desired time period. This is done feeder-wide, so that all customers are accounted for. When historical or forecasted peak load data is added from the DAA software package, Synergi is capable of providing power flow solutions for the given condition. At that point, we can also scale the loads up or down across the entire feeder depending upon the estimated demand and scenario need.

The "load curves" that are being utilized come from our load research department and represent different customer classes on a state by state basis. They are not used to analyze different loading scenarios throughout the day, but rather to attribute more accurate peak demands at locations across a given feeder.[5]

[5] For example, it ensures a potential residential customer receives more load at peak than a potential industrial customer with the same energy usage. This is because industrial customers typically have a flatter load profile curve. Accordingly, when industrial customers are compared to residential customers they have more consistent loading throughout the day and have less influence on the peak than the residential customer.

Ultimately, Synergi helps engineers plan the distribution system through modeling. It allows the ability to shift customers and load around, as well as add new infrastructure to simulate future additions to the system. It also can model distributed generation sources, such as solar or wind, so that those affects can be better accommodated.

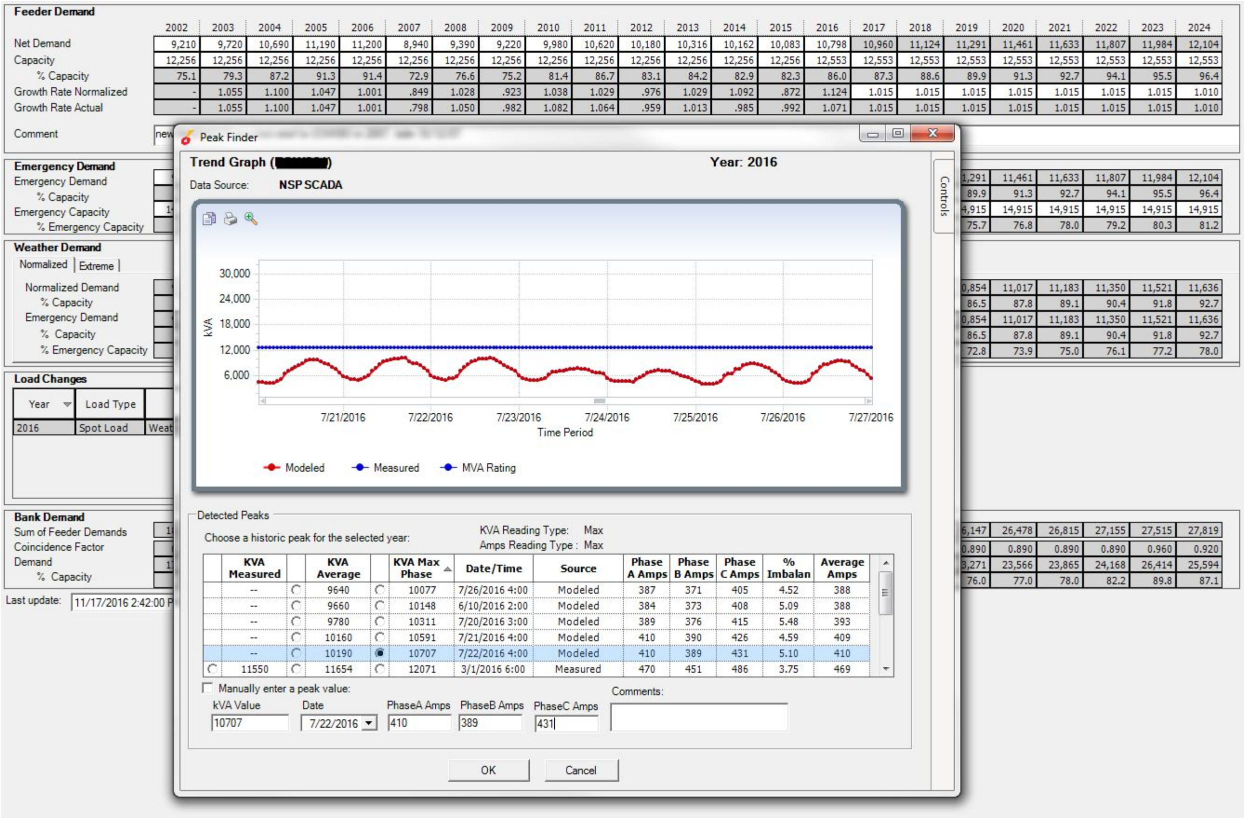
2. *ITRON Distribution Asset Analysis (DAA)*

We use DAA for medium to long-range load forecasting of distribution feeders and substation transformers. The DAA system is the historical peak system of record for those distribution elements. By having this collection of historical peaks we are better able to forecast future peaks by trending while taking into account other factors such as weather or known load growth. From this, we develop an annual load projection for future years.

Once our forecasted loads are updated every year we use DAA to create a peak substation load report for Transmission Planning and Transmission Real Time Planning. We also use these forecasts in our risk analysis evaluation, long range plans, and to populate models in Synergi for various purposes.

DAA is also a repository for feeder and substation transformer capacity limits that we use to identify areas of the system where there are capacity constraints. These limits are also passed on to Distribution Operations to ensure the correct notifications occur in the Control Center for any potential overloads.

Figure 11: Distribution Asset Analysis Application Example



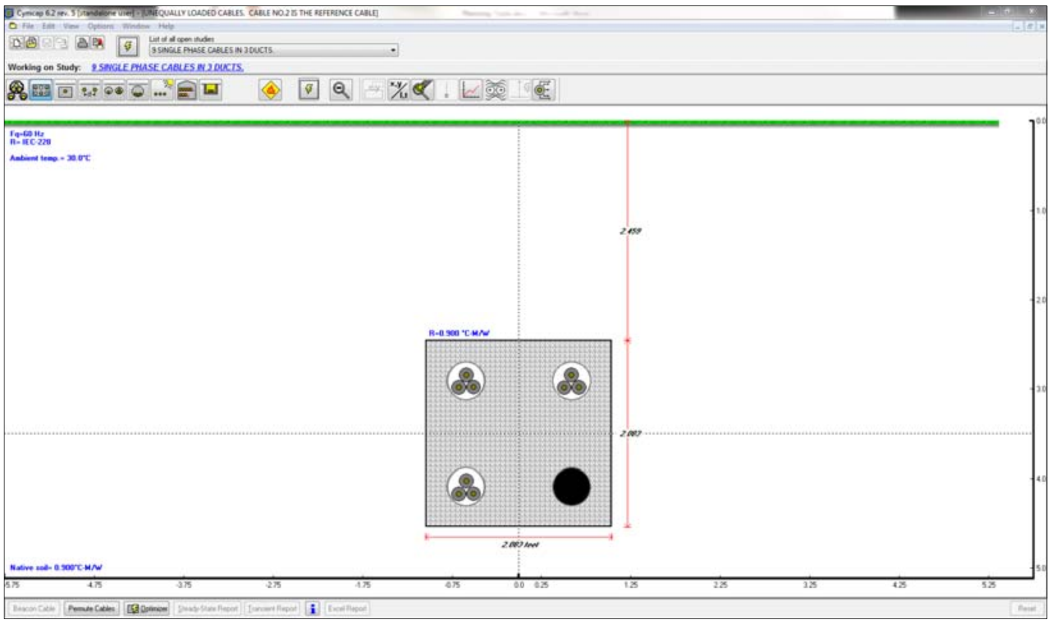
3. *Microsoft Excel Spreadsheets*

We use Microsoft Excel spreadsheets to perform feeder and substation transformer contingency planning. A key part of distribution planning is identifying risks, not only for normal operating situations, but also for situations where the system is in a contingency state; that is not whole. This helps in creating a system with flexibility. To do this we use a series of spreadsheets that include the tie points to other feeders and the capacity that is available at peak times through those tie points. While this is fairly simplistic tool, these spreadsheets provide valuable information about our system that we call "Load at Risk" that we use to justify projects that keep our system reliably robust.

4. *CYME CYMCAP*

Planning Engineers use CYMCAP for determining maximum normal and emergency feeder circuit cable capacities. This helps to determine the amount of amps that can flow through a given cable before it is thermally overloaded (ampacity). CYMCAP takes into account appropriate factors in determining these values, such as duct line configuration, soil conditions, and cable properties. Unlike overhead conductors that are exposed to the air and wind, underground cables have a tougher time dissipating heat. To ensure the cables are not overloaded, we model the true ampacity of them with the help of this program.

Figure 12: CYMCAP Application Example



5. General Electric Smallworld Geospacial Information System

Our GIS contains location-specific information about system assets and provides the connectivity model source data and feeder topology to Synergi, as well as other data to many other applications within Xcel Energy. The GIS allows us to view, understand, question, interpret and visualize data in many ways that reveal relationships, patterns, and trends in the form of maps.

GIS is also very helpful in capturing changes to the distribution system that may not always be visible to all. For example, we rely on GIS to show changes that would occur as the result of a new Community Solar Garden (CSG) installation. Any upgrades to the feeder that occurred as a result of that addition plus the details of the new CSG itself, would be added in to GIS. This would then be used to update our Synergi models for accurate modeling going forward.

6. Distribution Supervisory Control and Data Acquisition (SCADA)

Our SCADA system provides information to control center operators regarding the state of the system and alerts when system disturbances occur, including outages. For operational purposes, every few seconds it provides system status information, such as operating parameters for our generation and substation facilities. It monitors and collects system performance information for feeders and substations used to ensure the system is safely and efficiently operating within its capabilities. This performance information is also used by planning engineers to perform load and operating analyses to establish system improvement programs that ensure we adequately meet load additions and continue to provide our customers with strong reliability. As noted previously, we have SCADA in about 165 of our distribution substations, which serve over 90 percent of our customers – leaving approximately 105 substations without remote visibility or control. We have a long-term plan to install SCADA at each of our substations going forward.

For feeders where we have SCADA capabilities, we are able to monitor the real time average or three phase amps on the feeder for operational purposes. For planning purposes, the SCADA system collects enough information throughout the course of a year to determine daytime minimum load and peak demands for all feeders that have this functionality. However, it takes some manual effort beyond collecting the data to adequately decipher those values.[6] The data is maintained in a data warehouse and combined with the historic DAA hourly load data. When three phase load data is available, we use the highest recorded phase measurement to determine facility loading.

7. *Access Database WorkBook*

To help rank projects and perform cost-benefit analyses, we use an internally-developed Microsoft Access Database tool called WorkBook. This tool allows us to input our distribution system risks along with the proposed mitigations and their indicative costs that are intended to solve those risks. Algorithms in the tool result in a ranking score that helps to incorporate these projects in the budgeting process.

The primary risk inputs that planning engineers develop for entry into WorkBook include N-0 and N-1 risks for feeders and substation transformers. However, other inputs such as asset age and historic failures are also considered, which further aids prioritization of the projects as part of the budget process.

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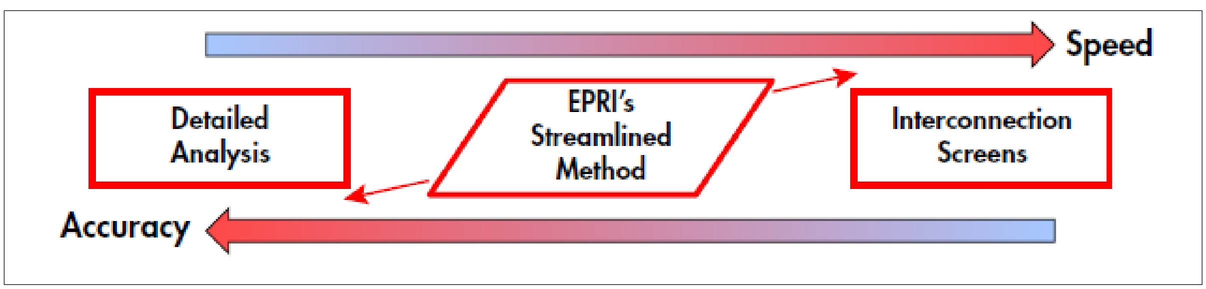
[6] This manual effort involves factoring out our minimum loads during non-daytime hours, adjusting for daytime minimum loads that occur under abnormal configurations, and eliminating other erroneous data possibly due to faults or other disturbances on the feeder.

D. Hosting Capacity Tool – Distribution Resource Integration and Value Estimation (DRIVE)

We summarize the DRIVE hosting capacity tool in this section. Please see our December 1, 2016 hosting capacity report and subsequent comments in Docket No. E002/M-15-962 for additional details.

On December 1, 2016 we submitted the results of our first hosting capacity study in Docket No. E002/M-15-962. We used the EPRI DRIVE tool for our analysis. EPRI defines hosting capacity as the amount of DER that can be accommodated on the existing system without adversely impacting power quality or reliability – and introduced the DRIVE tool as a means to automate and streamline hosting capacity analysis. The analysis is based on EPRI's streamlined hosting capacity method, which incorporates years of detailed hosting capacity analysis by EPRI in order to screen for voltage, thermal, and protection impacts from DER. Using the actual Company feeder characteristics, DRIVE considers a range of DER sizes and locations in order to determine the minimum and maximum range of hosting capacity. The electric system's hosting capacity is mainly impacted by DER location and system characteristics.

Figure 13: Balancing Speed and Accuracy in Analysis



As indicated by Figure 13 above, EPRI's method is intended to strike a balance between speed and accuracy. While it does not replace a detailed analysis, it provides more value than a traditional interconnection screening, such as the criteria found in the FERC Small Generator Interconnection Procedure. The result is a more complete and efficient way to understand a feeder's ability to integrate new DER.

For our hosting capacity analysis, we created over 1,000 feeder models in our Synergi Electric tool. The information for these models primarily came from our GIS, but was supplemented with data from our 2017 load forecast – as well as actual customer demand and energy data. Once the models were verified, load was allocated to the feeders based on demand data and customer energy usage – and analyzed using the DRIVE tool.

Generally, it is challenging to fully predict where future DER will be located – even with an interconnection queue. For instance, a large PV interconnection may be required to make some line upgrades to accommodate the proposed generation. The line upgrades and configuration changes for that interconnection are not reflected in our GIS until the design and construction phases are complete. This means that those system modifications do not enter GIS and subsequently the feeder models in a timeframe that is well-suited for forecasting accurate hosting capacity results.

E. Looking to the Future

Below we summarize a few projects that are helping to inform the evolution of our distribution planning processes:

1. National Renewable Energy Lab (NREL) Cooperative Research and Development Agreement

Xcel Energy Operating Company Public Service of Colorado is partnering with a research organization and a set of Colorado customers to examine different design and technology options to incorporate energy efficient and sustainable design. The site selected has a vision of sustainable development. One objective is to examine the level of DER (largely solar) that can be integrated in a practical manner. One aspect of the project will involve modeling the distribution system to assess the feasibility and costs of the design. Specifically, software modeling will examine voltage violations, tap changer operations, and capacitor switch banking operations. Once feasible design scenarios are established, a cost/benefit analysis will be performed to understand various tradeoffs between approaches used in the scenarios. (*Note: contract awaiting signature*)

2. EPRI Energy Storage Valuation Tool (ESVT)

ESVT is an EPRI developed financial simulation model that evaluates the cost-effectiveness of grid-tied energy storage systems (ESS) for different use and business cases. The model supports grid services from generation, transmission and distribution and also customer premise services. The tool simulates the energy storage operation for user-specified grid services through a hierarchical dispatch that prioritizes long-term commitment over shorter ones. The tool does not integrate with any of our other distribution planning tools but can be run separately on an identified potential battery system application.

3. *Participation in ARPA-E Network Optimized Distributed Energy Systems (NODES) project*

Xcel Energy is participating in ARPA-E's project with the vision to enable:

> …*renewables penetration at the 50% level or greater, by developing transformational grid management and control methods to create a virtual energy storage system based on the use of flexible lad and distributed energy resources.*

The University of Minnesota is the primary researcher on this project; NREL and others are on the project team. Along with MISO, Xcel Energy is a member of the advisory board. In addition to participating on the advisory board, we plan to provide location-specific distribution feeder data for use in NREL's simulation model. Currently, the project is at its initial phases.[7]

II. PLANNING PROCESS

In the fall of each year we initiate the planning process, beginning with the forecast of peak customer load and concluding with the design and construction of prioritized and funded capacity projects, as summarized in Figure 14 below.

As part of our annual distribution planning process, we thoroughly review existing and historical conditions, including:

- Feeder and substation reliability performance,
- Any condition assessments of equipment,
- Current load versus previous forecasts,
- Quantity and types of DER,
- Total system load forecasts, and
- Previous planning studies.

We begin our annual plans in the fourth quarter, using measured peak load data from the current year, as well as historic peak information to forecast the loads on our distribution system over a five-year time horizon. We then perform our risk analysis based on loads near the middle of the forecast period. Tangibly, in Q4 2017, we will use 2017 actuals and historical peak information along with any known system

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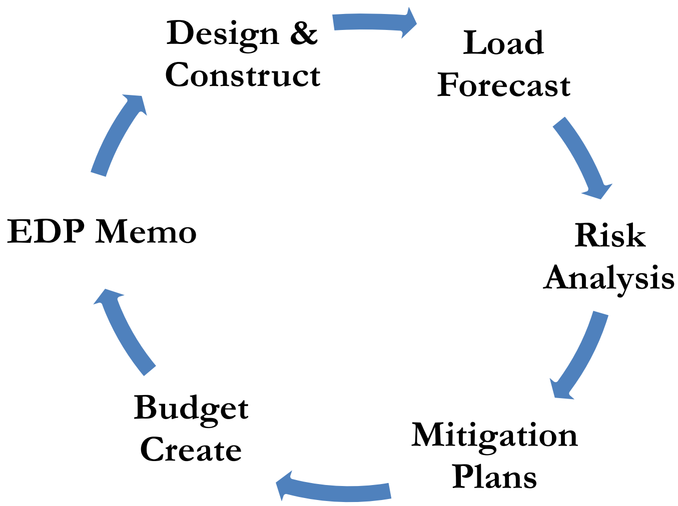
[7] *See* https://www.arpa-e.energy.gov/?q=arpa-e-programs/nodes

changes to forecast the 2018 to 2022 peaks, and perform our risk analysis based on the forecasted 2020 peak.

Figure 14: Annual Distribution Planning Process



A. Load Forecast

We begin our process by forecasting the load for both feeders and substations. In this step, we run a variety of scenarios that account for all the various drivers of load changes. This includes consideration of historical load growth, weather history, customer planned load additions, circuit reconfigurations, new sources of demand (penetration of central air-conditioning, electric vehicles), DER applications, and any planned development or redevelopment.

Then we generate a five-year forecast, aggregate the results, and compare this analysis with system projections. We then provide our distribution forecast to our transmission planning staff, who incorporate the load forecast into their planning efforts. In addition to this load forecast hand-off, we also communicate with transmission regularly throughout the year. Specifically, any time we become aware of larger loads or significant DER at any time of the year, we share that information with transmission. We also meet twice a year as a cross-functional group to further ensure we are each aware of plans and projects which may impact either system.

B. Risk Analysis

One of the main deliverables of distribution planning's annual analysis includes a detailed list of all feeders and substation transformers for which a normal overload (N-0) is a concern. A normal overload is defined as a situation in which the real time load of a system element (conductor, cable, transformer, etc.) exceeds its maximum load carrying capability. For example, a 105 percent N-0 for feeder FDR123 means that the peak load on FDR123 exceeds the limit of the feeder's limiting element by 5 percent.

Additionally, distribution planning delivers an N-1 Contingency Analysis, which is a list of all feeders and substation transformers for which the loss of that feeder or transformer results in an overload on an adjacent feeder or transformer. For example, a 1.5 MVA N-1 condition for feeder FDR123 means that for loss of FDR123, all but 1.5 MVA of FDR123's peak load can be safely transferred to adjacent feeders without causing an overload. The remaining 1.5 MVA that cannot be transferred is then referred to as "load at risk."

Our 2016 to 2020 annual planning process, initiated in Q4 2015, analyzed forecasted 2018 loads and identified the following total risks across NSPM:

- N-0 normal overloads on 67 feeder circuits
- N-0 normal overloads on 22 substation transformers
- N-1 contingency risks on 529 feeder circuits
- N-1 contingency risks on 133 substation transformers

This process of identifying N-0 overloads and N-1 risks for feeders and substation transformers is referred to as distribution planning's annual "risk analysis." We enter all of these risks into WorkBook. The total number of risks identified in the risk analysis generally exceeds the number of risks that can be mitigated with available funds. There is always a balance that we must strike in mitigating risks, planning for new customers, and addressing both the aging of our system – as well as preparing it for the future. We discuss this balance in Part II.D. below.

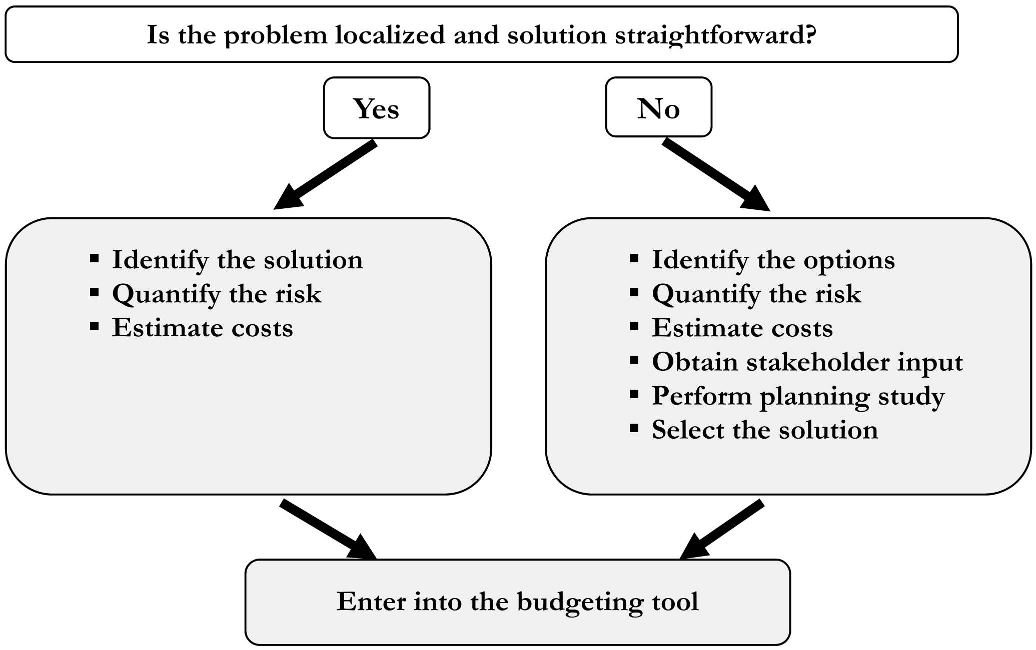
C. Mitigation Plans

After identifying system deficiencies, Planning Engineers identify potential solutions to provide necessary additional capacity to address the identified system deficiencies. We apply thresholds that risks must exceed before we develop a project to mitigate the risk. For N-0 conditions, the overload must exceed 106 percent; for N-1 conditions the load at risk must exceed 3 MVA before we develop a mitigation.

While many of the mitigation solutions are straightforward, others require a detailed analysis. At this point in the process the projects are high level and using indicative unit costs.

Figure 15 below depicts the steps we take to identify potential solutions.

Figure 15: Solution Identification Process



Distribution capacity planning methods address and solve a continuum of distribution equipment overload problems, including isolated feeder overloads, widespread feeder overloads, and substation transformer contingency overloads associated with widespread feeder overloads. Alternatives include reinforcing existing feeder circuits to address isolated feeder circuit overloads, adding or extending new feeder circuits and adding substation transformer capacity up to the ultimate substation design capacity to address more widespread overloads.

Planning Engineers first consider distribution level alternatives including adding feeders, extending feeders and expanding existing substations. If these typical strategies would not meet identified needs because they had already been exhausted or would not be sufficient to address the overloads, the engineers then evaluate alternatives that would bring new distribution sources into the area. DER has not historically been considered a viable alternative for resolving distribution capacity issues due to cost, reliability, capacity, longevity, dispatchability, space constraints and dependability. However, we see these constraints lessening as the technologies mature and operational experience increases.

If we conclude that distribution level additions and improvements would not meet the identified need, we consider the addition of new distribution sources (*i.e.*, substation transformers with associated feeder circuits) to meet the electricity demands. Ideally, new distribution sources should be located as close as possible to the "center-of-mass" for the electric load that they will serve. Installing substation transformers close to the load center-of-mass minimizes line losses, reduces system intact voltage problems, and reduces exposure of longer feeder circuits and outages associated with more feeder circuit exposure.

Once we identify a mitigation solution for the associated risk(s), we enter the mitigation description, indicative estimated costs, and the risks associated into WorkBook, which uses algorithms to develop a ranking score. The result of this entire step, including any necessary planning studies, is a slate of projects for consideration and review as part of the overall Distribution budgeting process. The outcome of last year's analysis for NSPM was 135 mitigation projects that would resolve a total of 481 risks (often one mitigation can solve multiple localized risks).

1. Long-Range Area Studies

If we determine a long-range plan is necessary, we conduct a location-specific study to evaluate various alternatives, which may include DER or Demand Side Management (DSM). Depending on the scope and scale of the focused study, this process can take weeks or even months, and generally involves the following:

- Identifying the study area (for instance, a single feeder, a substation, or maybe even an entire community or larger).
- Projecting future loads.
- Estimating the saturation of area (limits of development, zoning, etc. on load growth).
- Coordinating with transmission planning to advise them of our work and learn if they have area concerns or projects.
- Generating options.
- Studying and comparing the economics and reliability of the alternatives.

With respect to DSM, we are developing updated methodologies and distribution-avoided costs for energy efficiency.[8] Presently, for assessing distribution impacts, we

[8] *See* IN THE MATTER OF AVOIDED TRANSMISSION AND DISTRIBUTION COST STUDY FOR ELECTRIC 2017-2019 CONSERVATION IMPROVEMENT PROGRAM TRIENNIAL PLANS, Docket No. E999/CIP-16-541.

allocate energy efficiency impacts to each distribution substation and feeder load proportionally based on percentage of system load share. We perform a subsequent summer peak analysis to determine if projects could be deferred. We calculate a deferral value, expressed as $/kW, based on the Xcel Energy corporate cost of capital and using planning level costs for the deferral period. We note that we are also participating in the Minnesota Department of Commerce's Statewide Energy Efficiency Demand-Side and Supply-Side studies, which are examining the future potential for both customers and the Company to reduce peak and energy usage. The Supply-Side study is targeted at utility infrastructure efficiency on the generation, transmission and distribution systems.

These analyses, along with others such as focused long-term area studies, are important complements to our annual planning analysis. Examples of area studies we have completed include: South Minneapolis Electric Distribution Delivery System, provided as Attachment C, and Plymouth and Medina Electrical System Assessment, provided as Attachment D.

2. *Long Range Plan Selection Criteria*

If Distribution Planning determines a long range plan is needed, we use the following criteria to compare the potential solutions: System Performance, Operability, Future Growth, Cost, and Electrical Losses, which we describe in more detail below. All alternatives must have the ability to meet existing and forecast capacity requirements.

a. System performance

System performance is how the physical infrastructure addition of an alternative impacts energy delivery to distribution customers. Frequency of outages has been found to correlate to circuit length with longer feeders experiencing more outages than shorter feeders. Each unit of length of a feeder circuit generally has comparable exposure due to common outage causes, including underground circuit outages caused by public damage (*e.g.*, customer dig-ins to cable), equipment failure; and overhead circuit outages caused by acts of nature (*e.g.*, lightning). We use Synergi system models to examine loading levels and voltage impacts overall and on specific customers under normal and first contingency conditions. We evaluate performance based on the equipment and control systems required to maintain customer nominal voltage, and customer exposure to outages as differentiated by the length of the feeder circuit from the substation transformer to the customer.

b. Operability

Operability is how the alternative impacts the Company's distribution equipment, operating crews and construction crews operating the distribution system during normal and contingency operations. We evaluate operability based on system planning criteria that represent the robust capability of the distribution response as described by feeder circuit and substation transformer N-0 and N-1 percent utilization and ease of operation as impacted by integration with the installed distribution delivery system. Integration of non-standard equipment using new and untested technology in the first several generations of implementation are often complicated to operate, or have unanticipated difficulties that require additional engineering to solve problems, additional expenditures, additional equipment, new operating techniques and crew training. New technologies often require several generations of changes to reach simplicity of operation required to maintain present levels of customer service and reliability.

c. Future Growth

Future growth is how the alternative facilitates and enables future infrastructure additions required to serve future customer demand. Possibility for future growth is enhanced by an alternative that addresses future customer demand with the least cost amount of additional distribution infrastructure. For example, when considering a standard solution, an alternative that locates a substation nearest the load center and has room to add feeder circuits and substation transformers has better future growth possibilities than an alternative that requires adding another substation with an additional transmission line into the area.

d. Cost

For each alternative, we calculate the present value of all anticipated expenditures required for that alternative to serve the forecasted customer loads. The present value calculations are based on indicative estimates for the proposed alternatives,

e. Electrical Losses

Electrical losses are most often discussed in reference to the additional amount of generation required to compensate for the incremental line losses. Increased efficiency in the electrical delivery system reduces the amount of generation needed to serve load. Electrical losses also impact the amount of distribution system equipment by requiring incrementally increased amounts of electrical feeder circuits and substation transformers to make up for electrical energy lost by transporting electrical energy at distribution voltages when compared to using transmission line voltages.

3. Preferred Alternatives

From this evaluation, projects are assigned a risk score, similar to a cost-benefit ratio. This is useful for comparing the merits of disparate projects. From this risk score, we select and prioritize the actual solutions for which we intend to move forward.

Figure 16 below provides an example of an alternatives comparison that results from this process.

Figure 16: Alternatives Comparison Matrix

	ALTERNATIVES			
COMPARISON CRITERIA	**1** *2-13.8kV subs*	**2** *2 subs, 1 west*	**3** *1 sub-13.8 kV transmit*	**4** *4 subs-34.5 kV transmit*
1 - Distribution System Performance	4	3	0	2
2 - Operability	3	3	2	1
3 - Future Growth	4	3	2	1
4 - Cost	4	2	3	1
5 - Electrical Losses	4	3	1	2
Total	***19***	***14***	***8***	***7***

Note: Higher number ranking is a better alternative (i.e., 4 is a top individual criteria score, and a zero score indicates the alternative is not feasible due to not meeting minimum required standards.)

Based on the above analysis of alternatives capable of meeting area customer load requirements, Alternative 1 (A1) would be the preferred option, because it best satisfies the five distribution planning criteria. A1 locates a new distribution substation closest to the greatest amount of customer load, and has the shortest feeder circuits, resulting in the least amount of customer exposure to outages and the best system performance. It also uses the smallest addition of proven reliable elements to relieve existing overloads, resulting in the highest operability of the alternatives considered. A1 is the least expensive to construct and has the lowest electrical losses, making it the most cost-effective and efficient option of the four alternatives.

D. Select and Prioritize Solutions – Budget Create

Once we have all the projects identified, we weigh each investment using a risk/reward model to determine which solutions should be selected and prioritized. While we recognize that risk cannot be eliminated and funding is always a balance, our goal is to provide our customers with smart, cost-effective solutions. Accordingly, we evaluate operational risk dependent on:

- The probability of an event occurring (fault frequency, failure history of device, etc.) causing an outage, and
- The consequence of the event (amount of load unserved, number of customers, restoration time, etc.).

The final step in this process is prioritizing the proposed capacity projects into the distribution area's overall budget, which must also provide funding for asset health, new business, and meeting growing customer and policy expectations through support of new technologies and DER.

The overall budget process recognizes that customers want reliable and uninterrupted power. To address this priority, we regularly evaluate the overall health of our system and make investments where needed to reinforce our system. This includes an asset health analysis of the overall performance of key components of the distribution system such as poles and underground cables. As we replace these key components, we do so with an eye to the future to ensure that the investments we make not only support our customers' needs for reliable service today, but also lay the groundwork for the grid of tomorrow. We must also take steps to implement new systems and technologies that improve our operations and provide customers with more choices related to their energy use. An example of this is investments in our SCADA system, as well as the Advanced Distribution Management System (ADMS) we have underway. Together, these systems will provide our engineers and operational staffs significantly improved data from which to monitor and make decisions – all of which benefit our customers in both our planning and response to events occurring on the system.

Given these priorities, we must not only proactively maintain our system by making capital improvements when necessary to improve reliability and safety for our customers – we must also manage our budgets to be able to respond to outages caused by storms, mandatory work such as relocation of our facilities, and other conditions that cannot be foreseen with a high degree of accuracy. We factor-in all of these priorities as we weigh the risks associated with the various types of investments to develop our five-year budget commensurate with targeted funding levels.

As capital spending is determined and, throughout the year as new issues are identified, each operating area brings risks (problems) and mitigations (solutions) forward based on their knowledge of the assets and operations within their territory. The operating areas' focus is on building, operating, and maintaining physical assets while achieving quality improvements and cost efficiencies. All the risks and mitigations are submitted as project requests and entered into a software tool we developed and use to track and rank projects based on the inputs provided – including their annual costs and benefits.

Budgeting personnel focus on the health and age of our existing assets, standardization, and mitigation of risk, and provide coordination and consistency in evaluating individual project requests with the Distribution organization. Engineering and operations personnel then work with budgeting personnel around each risk to evaluate and score each mitigation individually before ranking the projects. The factors we use to prioritize investments are as follows:

- *Reliability* – Identification of overloaded facilities, potential for customer outages, annual hours at risk, and age of facilities,
- *Safety* – Identification of yearly incident rate before and after the risk is mitigated,
- *Environmental* – Evaluation of compliance with environmental regulations. To the extent this factor applies to the project being evaluated, it is prioritized, however this factor is not usually applicable,
- *Legal* – Evaluation of compliance before and after the risk is mitigated, and
- *Financial* – Identification of the gross cash flow, such as incremental revenue, realized salvage value, incremental recurring costs, etc. – and identification of avoided costs such as quality of service pay-outs and failure repairs.

An analysis of these factors results in a proposed project list that is ranked. We accomplish this by ranking the assessment of each project against each other. The highest priority is given to projects that Distribution must complete within a given budget year to ensure that we meet regulatory and environmental compliance obligations and to connect new customers. We note that we must also apply judgment in the prioritization process. An example of this is two competing new feeder projects – one in the metro area that only involves a short distance, and the other in a rural area that involves installing infrastructure for two miles. The cost of the rural example in this circumstance is higher, and the benefits of the two projects are the same – so the metro project would score higher. However, the rural project is also needed. Our process therefore contemplates some back-and-forth with the planning engineers to validate priorities.

After the capital expenditures budget is finalized, the approved project list becomes the basis for the release, or initiation, of projects during the calendar year. This process must be somewhat flexible to allow for needed additions and deletions within a given year. For example, should an emergency occur during the year, priorities may change and result in an adjustment to the list of projects. Projects that were previously approved may be delayed to accommodate the emergency. Through our budget deployment process we are therefore able to meet identified needs and requirements, adjust to changing circumstances and prudently ensure the long-term health of the distribution system.

Distribution Planning takes the approved capacity projects stemming from this process and communicates them with design and construction. The Planning team continues to participate in the ongoing capital budget processes as Distribution responds to changing circumstances and interfaces with design and construction to adjust priorities as needed. Please also see our discussion regarding the development and ongoing management of the Distribution area's Operating and Maintenance budgets in response to Notice Part A, QuestionA.2.g, provided as Attachment A.

E. Initiate Project Implementation – EDP Memo

Once the five-year budget is determined, the Planning Engineers write Electric Distribution Planning (EDP) memos for the first two years of approved capacity projects. An EDP memo is a high level step-by-step description of the project that will mitigate an identified risk. The memos describe the problem, the substation design/construction steps to take (if any), and any distribution line design/construction steps to take. The memos provide maps and text specifying where to place switches, capacitor banks, or where to cut into another feeder to transfer load to a new feeder. These memos initiate the design and construction portion of the project.

F. Design and Construct Projects

Finally, the selected projects are communicated to substation engineering and distribution engineers and designers who bring the projects to life – performing the detailed design and initiating their construction. We summarize the groups generally involved and their roles below:

- *Substation Engineering.* If a project requires a new feeder bay at an existing substation or a new substation entirely, this group performs the detailed engineering, design and construction.
- *Distribution Design and Construction.* This area performs the permitting, design, and construction of new feeder circuits or modifications of existing circuits.

Ideally, projects can be implemented precisely as envisioned by Distribution Planning, but often this is an iterative process.

CONCLUSION

Xcel Energy appreciates this opportunity to outline our distribution planning processes. We look forward to continued participation in efforts to ensure that Minnesota's distribution systems are well-positioned to meet future system and customer needs, while maintaining reliability, safety and security. We support these efforts and the evolution of the grid, and look forward to continued active participation in this dialogue.

Dated: June 21, 2017

Northern States Power Company

A. How do Minnesota utilities currently plan their distribution system?

In order to better ascertain the current state of utility distribution planning, the Commission requests the regulated utilities respond to the following questions. The Commission understands there are differences in planning, needs, and capabilities between the utilities; these questions are merely to understand the current planning process. It is entirely possible that the utility may not be able to answer a question for any number of reasons. The Commission seeks a baseline understanding of each utility, which will then inform any potential decisions about next actions on distribution system planning.

Please describe the following items with respect to current distribution system planning efforts:

1) The distribution planning resources utilized by utilities, including:

a. Types of modeling software used and for what specific purpose.

Planning Engineers rely on a set of tools to perform the annual full system snapshot and ongoing distribution system assessments. We summarize the tools and our application of them to the various components of our planning process below. See Parts I.C and I.D of the accompanying narrative for additional details.

Table 1: Planning Tool Summary

Tool	Process	Description
DNV-GL Synergi Electric	Power flow	Contains a geospatially accurate model of the electric distribution feeder system with known conductor and facility attributes such as ampacity, construction, impedance, and length to simulate the distribution system
ITRON Distribution Asset Analysis (DAA)	Medium to long-range load forecasting of major distribution system components, including feeders and transformers	System of record for historical peak feeder and substation transformer load information that we use to evaluate historical load growth and weather adjustments to match prior peaks and identified known load growth to establish a forecast for 1+ years out
Microsoft Excel Spreadsheets	Contingency planning	Analyze feeder and transformer contingency capacity by evaluating the available capacity on neighboring feeder ties and substation transformers for the forecasted years
CYMCAP	Determines normal and emergency ampacity for feeder circuit cables	Determines the amount of amps that can flow through cables for various system configurations, soil types, and cable properties before they are thermally overloaded
Geographical Information System (GIS)	Provides the connectivity model source data to Synergi, as well as feeder topology.	Contains location-specific information about system assets and components, allowing us to view, understand, question, interpret and visualize data in many ways that reveal relationships, patterns, and trends in the form of maps.
Distribution Supervisory Control and Data Acquisition (SCADA)	Peak load forecasting	Monitors and collects system performance information for feeders and substation transformers
WorkBook	Project prioritization	An internal tool used to help rank projects based on levels of risk and estimated costs

We additionally outline our hosting capacity tool that is not currently part of the planning process.

Tool	Process	Description
Electric Power Research Institute (EPRI) Distribution Resource Integration and Value Estimation (DRIVE)	Hosting capacity	Using the actual Company feeder characteristics, DRIVE considers a range of DER sizes and locations in order to determine an indicative range of minimum and maximum hosting capacity by screening for voltage, thermal, and protection impacts.

Figure 2: Tool Summary by Distribution Planning Process

Tool	Planning Process Component: Forecast	Risk Analysis	Mitigation Plans	Budget Create	Initiate Construction - EDP Memo	Long-Range Plans	Hosting Capacity
Synergi Electric			X			X	X
DAA	X	X				X	
MS Excel		X		X		X	
CYMCAP		X					
GIS			X			X	X
SCADA	X						
WorkBook		X	X	X	X		
DRIVE							X

b. Applicable engineering standards.

Table 2 below shows a list of some of the most common industry standard documents applied in distribution engineering. The list is not intended to be inclusive of all standards that may be applied to medium and low voltage systems, but rather is intended to provide insight into standards that are frequently used. Included are primarily documents from the Institute of Electrical and Electronics Engineers (IEEE) which are classified as Standards, Recommended Practice, and Guides. Standards carry more weight when compared to Recommended Practices. Guides often show a number of ways to achieve a technical objective and are the least prescriptive.

Table 2: Engineering Standards Summary

Condition	Standard
Safety	National Electric Safety Code (NESC)
	Xcel Energy Safety Manual
Voltage Limits	ANSI C84.1 – minimum and maximum voltage limits, voltage imbalance limits
	Xcel Energy Standard for Installation and Use – voltage limits and imbalance (same as ANSI C84.1)
Thermal limits	Xcel Energy Design Manuals (Distribution Standards Engineering)
	Substation Field Engineering (SFE) transformer loading database – based off of IEEE standards
	IEEE 738 – Overhead conductor ampacity rating IEC 287 and IEC 853 – Cable ampacity rating methodology in CYMCAP program
	IEEE C57.91 – transformer and regulator loading guide IEEE C57.92– power transformer loading guide
Distribution Interconnection	IEEE 1547 – Interconnection of Distributed Resources
Harmonics	IEEE 519 – total harmonic distortion and individual harmonic limits
Voltage Fluctuation	IEEE 1453 – rapid voltage change and flicker limits

Additionally, North American Electric Reliability Corporation (NERC) standard FAC-002-2 applies to studying the impact of interconnecting facilities to the Bulk Electric System, which comes into play with distribution substations. Specifically, Requirement R3 applies when we seek to interconnect new "end-user facilities" or materially modify existing interconnections to the transmission system. It states we shall coordinate and cooperate on studies with our Transmission Planner or Planning Coordinator as specified in Requirement R1. This includes many requirements such as reliability impact, adherence to planning criteria and interconnection requirements, conducting power flow studies, alternatives considered and coordinated recommendations.

Xcel Energy's Design standard books consist of Overhead, Underground, and Street Lighting Manuals. Each of these Manuals detail equipment and designs that have been previously reviewed against industry standards and best practices to ensure installation of facilities results in safe and reliable service. Documenting approved materials and equipment configurations allows for efficient design of construction projects. The Manuals simplify certain moderately-complex aspects of distribution engineering such that a Designer can often propose a design, without requiring engineering input for every project. Reference material on transformer sizing and conductor lengths, which already accounts for voltage and thermal limits, is also part of the Standards Manuals.

c. Personnel commitment: including utility personnel as well as contracted services and an overview of their roles and responsibilities.

We have five Distribution Planning Engineers in the Northern States Power Company – Minnesota (NSPM) operating company that are assigned geographically to align with our service center areas and to balance workload. [1]We supplement this full-time team with three part-time engineering interns. The Planning team is responsible to perform electric distribution planning, peak load forecasting, peak analysis, risk analysis, and project identification of capacity projects that will mitigate system overload risks. Xcel Energy's other operating companies also have Distribution Planning Engineers with the same core roles.

In support of these activities, the Planning Engineers also participate in the distribution budget create and analysis efforts – representing planning projects in relation to other distribution infrastructure needs, and initiating approved projects with design and construction. As needed, this team also engages in focused efforts and initiatives to advance the grid and our planning processes. For example, NSPM Planning Engineers are working on the Company's Advanced Grid Intelligence and Security (AGIS) efforts, the Advanced Distribution Management System (ADMS) and Grid Modernization efforts we have underway in Minnesota, and the hosting capacity analysis we recently developed and submitted to the Commission. We participate in Xcel Energy-wide initiatives, and also engage other engineering resources from across the Xcel Energy footprint to supplement the NSPM engineering resources as needed for certain focused initiatives.

Other functions involved in distribution planning are as follows:

- *Account Management*. Liaison with large customers and identifies new and changing large customer loads.
- *Area Engineering*. Area Engineers are assigned by geography to align with our service center territories, and once capacity projects are initiated by Planning project plans are moved to Area Engineering. Area Engineering is responsible to move the projects into design and then construction. Area Engineers also work with Planning when they identify large customer loads being added to the system. This team also examines system asset health, and coordinates with Planning on potential future needs.
- *Community Relations*. Liaison with local government staff and elected officials. Facilitates communication of larger capacity projects and coordination with

[1] Distribution Planning also has a full-time employee that is responsible for creating and managing the capital budget.

community infrastructure projects where we may have synergies. Aids with permitting as needed.

- *Construction*. Builds the designed projects, and offers constructability feedback in the project design phase.
- *Design*. Designers are assigned by geography to align with our service center territories, and are responsible to design approved projects at the direction of the Area Engineers, using Company Standards.
- *Economic Development*. Works with existing or prospective customers to drive large customer loads to areas that have capacity.
- *Environmental Services*. Assesses feeder routes and substation site locations for adherence to environmental requirements.
- *Operating Engineering*. Approves distribution system planned outages for capacity projects, and develops contingency plans should the project not go according to plan.
- *Regulatory*. Support regulatory filings and requests for information as needed.
- *Risk Analysis*. Provides tools and consultation for the project risk analysis and prioritization processes.
- *Siting and Land Rights*. Identifies land-related issues for capacity projects identified during the planning process, and facilitates permitting and purchase of needed land for approved projects.
- *Substation Engineering*. Designs distribution substation capacity projects and provides project scoping.
- *Substation Field Engineering*. Sizes mobile transformers for projects requiring temporary transformer resources, and looks to Planning for synergies with future capacity needs. This team also examines substation asset health, and coordinates with Planning on potential future needs.
- *System Performance*. Provides reliability data and recommendations for reliability improvements.
- *Transmission Planning*. Performs planning functions for the Transmission system and coordinates with Distribution Planning on joint, long-range plans and interconnections between the transmission and distribution systems. Distribution Planning provides substation peak load forecasts to Transmission Planning.

d. System visibility and data availability: At what circuit levels and over what time intervals is data collected? If possible, provide an

example of the range of data collected and available.

Generally, our SCADA collects hourly peak load information at the feeder and substation transformer levels over an entire year as the inputs to our planning process. Ideally, this includes three phase Amps, MW, MVAR, MVA, and Volts. However, not all of these data points are available for all locations. Our SCADA also collects enough information throughout the course of a year to determine daytime minimum load for all feeders equipped with this functionality.

For non-SCADA equipped substations, or substations lacking some of the data points mentioned above, on approximately a monthly basis, field personnel visit those substations to collect data including peak demands for feeders and transformers. Peak load values are recorded in the field and entered into a database that engineering accesses and uses for planning purposes. After the recordings are documented, field personnel reset the peak load register, so the following period's data can be accurately captured without influence from the previous period.

e. Percentage of substations and feeders are equipped with SCADA.

The NSPM distribution system includes a total of 1,274 feeders, 270 substations, and 449 substation transformers. We provide the breakdown by NSPM jurisdiction in Table 3 below:

Table 3: Distribution System Component by NSPM Jurisdiction

Component	MN	ND	SD	*Total*
Substations	240	13	17	*270*
Substation Transformers	397	24	28	*449*
Feeders	1,118	65	91	*1,274*

Approximately 60 percent of the total NSPM substations have SCADA – 45 percent of which have full SCADA and the remaining 15 percent provide only a limited set of data.[2] Approximately 85 percent of the NSPM feeders have SCADA. Combined, our SCADA-enabled substations and feeders serve approximately 90 percent of our customers (*Note*: most of our non-SCADA substations are in rural areas).

Given the importance of SCADA capabilities to reliability and load monitoring (for planning and in anticipation of increased DER), in 2016 we embarked on a long-term plan to install SCADA at more distribution substations – calling for installation of

[2] For example, while most substations monitor all three phase currents for each feeder some substations have SCADA data available only on a single phase or average of the three phases basis, which limits our ability to fully understand system status and loading for planning purposes.

SCADA at 3-4 substations each year.

f. Form of hosting capacity software or analysis, if any, used in the planning process and to conduct interconnection.

On December 1, 2016 we submitted the results of our first hosting capacity study in Docket No. E002/M-15-962. We used the Electric Power Research Institute (EPRI) Distribution Resource Integration and Value Estimation (DRIVE) tool for our analysis. The DRIVE tool is based on EPRI's streamlined hosting capacity method, which incorporates years of detailed hosting capacity analysis by EPRI in order to screen for voltage, thermal, and protection impacts from DER. This Distribution System Study presented the discreet hosting capacity of individual feeders, without analysis of the cumulative effects of DER additions to substations or the transmission system. The study was not a holistic system view, but rather a snapshot of the capabilities of individual feeders as they were positioned at that point in time.

While our development of our hosting capacity tool was a significant milestone toward a comprehensive analysis and process, a significant limitation of our initial analysis is that it did not factor-in the impacts from the approximately 778 MW of existing or proposed DG on our system. Accordingly, those feeders with existing or proposed DER have restrictions that we were unable to account for in this study, and likely reduce their hosting capacity in some manner. The 2017 upgrade to DRIVE will have the capability to include existing DER characteristics into the hosting capacity analysis. Our current power flow program and modeling capabilities are leveraged by the DRIVE tool analysis. Likewise, DRIVE will also have the ability to adjust DER characteristics in the evaluation of additional DERs being added to the system. We expect this functionality to continue to evolve and provide more accuracy.

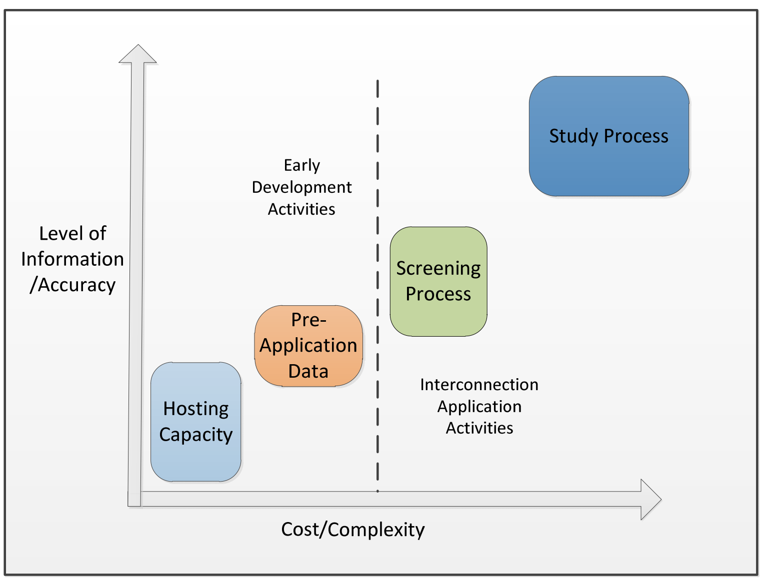
The determination of exactly where and how much DER can be added to our system is determined through the interconnection process; our hosting capacity study provides has the potential to streamline the interconnection process both in the short- and longer-term. Today, the hosting capacity results are available to the public and can assist developers in choosing sites that require only screening or a less involved study. Screening is less expensive than engineering studies and typically can be completed on a shorter timeline.

We view one of the first logical steps to automating parts of the interconnection process as achieving a level of accuracy for the hosting capacity tool that allows using the results in place of technical screens, including the initial and supplemental review found in the Small Generator Interconnection Procedure (SGIP). It is unclear at this time if an additional objective should be to fully automate the interconnection study process given that commercially available modeling software is at the nascent stages of development regarding fully automating the study of DER impacts. Furthermore, it is possible that choosing a hosting capacity tool with a narrow focus on automating studies actually limits capabilities of the tool for other planning use cases.

DRIVE alone will not create a streamlined interconnection process. The tool is only a part of the solution to streamlining the process, not the whole. We are closely watching the hosting capacity and automated interconnection developments in the industry in order to adopt the right tools at the speed of value.

Figure 2 below Shows how the different pieces of interconnection processing currently works. The lower cost and complexity options of hosting capacity and pre-application data provide information developers can use to target points on the distribution system for interconnection prior to submitting an application. The screening and study processes occur after an application has been submitted and entered into engineering review.

Figure 2: Interconnection Processes



We are still exploring how to best meet the range of interconnection needs. It is possible that an additional tool may be best suited if a future objective of the study were to become streamlining the detailed interconnection study analysis. A tiered approach would be in sync with many state interconnection processes that use different types of tools for screening and studies – with the level of accuracy associated with the methods in each process is tailored to meet the specific need for the level of review.

2) An overview of planning schedules and process, including:

a. Frequency in which the utility conducts distribution system planning.

We undertake a comprehensive planning analysis of our distribution system in the fourth quarter of every year. If significant system changes occur during the year, we assess the impact of those changes on the implicated feeder(s) and substation(s).

For the annual process, we use the current year actual and historical peak load information for each feeder and substation transformer to forecast the loads over a five-year period. We base our risk analysis on loads near the middle of the forecast period. For example, in Q4 2017, we will prepare a forecast of the 2018 peak using actual 2017 and historical information – and project that forecast over the 2018 to 2022 period. Our risk analysis will be based on the forecasted 2020 peak.

b. Frequency of planning updates or revisions: Are updates dependent on a set timing frequency (i.e. every 2, 5, or 10 years) or are there events that may trigger a more frequent planning cycle or revision? If so, please explain.

As noted in Part a. above, if there are significant changes during the year, we assess them as they occur. These changes may include new large customer loads or increases in existing large customer loads, power quality issues, or emergent issues such as changes mandates to relocate utility infrastructure in public rights-of-way or our response to severe weather. In these focused assessments, we use the same planning tools and the same forecast used in the most recent annual comprehensive planning cycle. The only difference from the annual process is that we are focusing our analyses on a *portion* of the system (i.e., feeder, substation, etc.). If the focused assessment identifies system risks, we apply our standard criteria to determine if we need to adjust our current plan.

c. Iterative updates and/or new plans: Are planning processes based on continuations of past plans, new planning cycles, or some combination? How long is each planning cycle's time horizon?

Our planning processes are iterative and build on past plans and historical actual customer load information. Our annual planning horizon is five years, with system risks assessed at the midpoint of the period. Using the 2017 annual planning cycle as an example, as part of that study, we will identify system risks for the forecasted 2020 system peak.

d. Planning elements or considerations included (or not included) in regular updates and revisions and a description of each: For example: circuit or substation data, power flow analysis, power quality analysis, fault analysis, load and demand forecasts, external policy and regulations, etc.

Our current annual distribution planning process assesses the capabilities of the system. At a high level, distribution planning assesses the loading, load flows and load duration curves of various system components in order to identify potential system overloads. This involves an annual examination of thermal limits and system performance of all distribution feeders, substation transformers, and substations. The annual planning process also assesses various contingencies, including contingencies of feeder circuits, and substation transformers.

We perform this annual assessment of the distribution system in order to establish performance and modeling requirements for the system to operate reliably under normal system configuration and probable contingencies. The assessment includes system intact and contingency analysis over the near-term (1-5 years) planning horizon; we initiate selected longer-range (10-20 years) area studies as needed. The purpose of these planning studies is to identify corrective projects or plans to mitigate performance outside the Company's reliability criteria.

Distribution planning has not traditionally considered external policies, like Integrated Resource Planning (IRP) does. Both are complex and incorporate assumptions and projections that form a common vision of what the future system may look like. Both also rely on a forecast and both produce an action plan – with a primary focus of identifying the least-cost approach to provide reliable service and meet growing demand.

IRPs are focused at the macro/generation and transmission system level, which fundamentally charts a long-term direction of how load can be served in a broad service area – and includes more detailed plans for the near-term. Near-term plans are often a continuation of previous IRPs, due to the long-term nature of resource additions and changes. Traditionally, IRPs have considered issues of size, type and timing. The past few years however have seen changes in integrated resource planning practices and methodologies due to the advance of renewable and distributed energy resources, slumping load growth, various environmental regulations and policy objectives, greater emphasis on energy efficiency and demand side strategies. This is evidenced in our most recent IRP where we introduced the concept of locational analysis as an important consideration to help inform technical and policy-based issues associated with the potential retirement of large generating units on the NSP System.

Distribution planning, on the other hand, is evolving from nearly a pure locational analysis of customer demand at various points on the system, to one more like an IRP in that it will identify a mix of resources that will minimize future system costs while ensuring safe and reliable operation of the system. Today however, distribution planning is more immediate, and analysis of DER is external to the core annual and ongoing system studies; its full planning horizon correlates to the five-year action plan period of an IRP. In short, the focus is similarly ensuring the system meets customer demand – but a distribution planning analysis is significantly more granular, involving analysis of thousands of points on the system.

Because the distribution grid holds many more complexities due to the increased granularity of the resources and the loads, an optimization analysis is much more complex than traditional IRP optimizations. Distribution planning starts with the customer and is bottom-up, whereas IRPs are top-down and modeled using supply costs and system load forecasts. An IRP optimization model is run to determine the least-cost mix of supply required to meet that load forecast. Similarly, distribution planning requires a load forecast, but it must be performed at the level of the customer, since DER can interact with load at this level – and voltage and grid assets depend on local load. In essence, distribution planning must create a plan for each feeder circuit and provide those plans "up" to transmission, which are ultimately included at a gross level into an integrated planning process.

e. **Integration of existing planning processes: Explain to what extent existing planning processes, including resource planning, transmission planning and other studies (i.e. interconnection) are used in the formulation of distribution plans.**

Today, the distribution, transmission, and resource planning groups have formal working sessions twice per year, and additionally work together as their respective planning processes impact or rely on one another. For example, distribution planning supplies transmission planning with substation load forecasts that are an input into the transmission planning process. The two groups also interact when distribution planning identifies the need for additional electrical supply to the distribution system – and similarly with interconnections, distribution is on point, and involves the appropriate planning resource as needed.

We are currently evaluating our existing planning processes and tools to determine how to better merge the distribution, transmission, and resource planning processes in the future.

f. Timing of associated distribution system budgeting processes: Is distribution system budgeting performed on an annual basis or on some other schedule?

The budget create process is annual, and corresponds to the distribution planning cycle, which results in an approved project list that is the input to the budgeting process. The annual budget process is necessarily somewhat flexible to allow for project additions and deletions within a given year. For example, should an emergent circumstance occur during the year, priorities may change and result in an adjustment to planned projects. Projects that were previously approved may be delayed to accommodate the emergent circumstance.

g. Process of developing capital budgets for distribution infrastructure.

In summary, once all areas identify their priority projects, we weigh each investment using a risk/reward model to determine which solutions should be selected and prioritized. While we recognize that risk cannot be eliminated and funding is always a balance, our goal is to provide our customers with smart, cost-effective solutions. Accordingly, we evaluate operational risk dependent on:

- The probability of an event occurring (fault frequency, failure history of device, etc.) causing an outage; and
- The consequence of the event (amount of load unserved, number of customers, restoration time, etc.)

The overall budget process recognizes that customers want reliable and uninterrupted power. We therefore must not only proactively maintain our system by making capital improvements when necessary to improve reliability and safety for our customers – we must also manage our budgets to be able to respond to outages caused by severe weather, mandatory work such as relocation of our facilities, and other conditions that cannot be foreseen with a high degree of accuracy. We factor-in all of these priorities as we weigh the risks associated with the various types of investments to develop our five-year budget commensurate with targeted funding levels.

The factors used to prioritize investments are as follows:

- *Reliability* – Identification of overloaded facilities, potential for customer outages, annual hours at risk, and age of facilities;
- *Safety* – Identification of yearly incident rate before and after the risk is mitigated;

- *Environmental* – Evaluation of compliance with environmental regulations. To the extent this factor applies to the project being evaluated, it is prioritized, however this factor is not usually applicable;
- *Legal* – Evaluation of compliance before and after the risk is mitigated; and
- *Financial* – Identification of the gross cash flow, such as incremental revenue, realized salvage value, incremental recurring costs, etc., and identification of avoided costs such as quality of service pay-outs and failure repairs.

The result of this process is a ranked list of proposed projects. We accomplish this by ranking the assessment of each project against each other. The highest priority is given to projects that Distribution must complete within a given budget year to ensure that we meet regulatory and environmental compliance obligations and to connect new customers.

After the capital expenditures budget is finalized, the approved project list becomes the basis for the release, or initiation, of projects during the calendar year. Distribution Planning communicates the approved capacity projects stemming from the budgeting process and initiates them with design and construction. The Planning team continues to participate in the ongoing budget processes as Distribution responds to changing circumstances during the year, and interfaces with design and construction to adjust priorities as needed. See Section II.D of the accompanying narrative for a more detailed description of our overall distribution budgeting process.

h. Process for developing operating budgets for distribution operating changes or projects.

Our O&M budgeting process takes into account our most recent historical spend in all the various areas of Distribution and applies known changes to labor rates and non-labor inflationary factors that would be applicable to the upcoming budget years. We also "normalize" our historical spend for any activities and/or maintenance projects embedded in our most recent history that we would not expect to be repeated in the upcoming budget years (e.g., excessive storm activities or one-time O&M projects). We then couple that normalized historical spend information with a review of the anticipated work volumes for the various O&M programs and activities we perform, factoring in any known and measurable changes expected to take effect in the upcoming budget year.

For example, for our major maintenance programs such as cable fault repairs and vegetation management, we review annual expected units/line-miles to be maintained and ensure required O&M dollars are adjusted accordingly. We also factor in any expected efficiency gains we believe would be captured by operational improvement efforts we continuously are working on within our processes and procedures, along with productivity improvements we would expect to achieve via the implementation or wider application of new technologies.

Given that no year transpires exactly as predicted or forecasted, we typically update our O&M expenditure forecasts during the year. As with our capital investments, one of our largest annual sensitivities for O&M expenditures is severe weather. The amount of O&M we spend on weather-related events, such as storm restoration and floods, can vary greatly from one year to the next. In addition, the Distribution business area will periodically respond to requests from the Company to adjust O&M costs within the financial year to account for changes in business conditions in other areas of the Company. When a greater need for expenditures in a particular area is identified, we try our best to re-prioritize and reallocate our budgeted O&M dollars while still operating within our overall O&M budget. However, there are times where circumstances dictate that, in order to maintain safe, reliable service at the levels our customers expect, we will need to spend more than our overall budget would allow to properly address certain items that come about during a given budget year.

We monitor our O&M expenditures on a monthly basis. In partnership with our Finance area, we report-out on our monthly and year-to-date actual expenditures versus budgets/forecasts. Part of this monthly reporting process includes deviation explanations for various categories of expenditures. This reporting is provided down to the individual manager business unit level and to the major Distribution business unit level directors. Monthly review meetings are then conducted at various levels to determine any pressure points and remediation plans that are needed to manage our overall O&M expenditures and ensure proper prioritization of those expenditures.

3) Demand and system loading forecast methodologies, including:

a. Granularity of load forecasting: To what extent is the collected system data reflected in load forecasts; e.g., does the utility employ an 8760-hour forecast at the substation level?

From the substations with SCADA we have hourly peak load data. Because the primary concern of distribution planning is having adequate capacity, we use the annual peak for forecasting. Where we don't have SCADA data available, we rely on manual substation and feeder meter reads. We describe our SCADA capabilities and data availability and uses in our response to Notice Part A, Question 1.d above, as well as Section I.B.7 of the accompanying narrative for further discussion of our data capabilities.

b. Use of company-wide peak forecasts versus aggregation of substation or other circuit-level peaks: Does the utility use a top-down forecasting approach versus a bottom-up approach, or some combination of these approaches?

As described in the accompanying narrative, we take a bottom-up approach – forecasting load for each feeder, which is then aggregated to the substation level and calibrated to historical measured substation data. The distribution planning substation-level data is an input to transmission planning processes.

c. Comparison of actual asset loading against past forecasts: Does the utility employ backcasting or ex post true-up to assess the accuracy of its forecasting process?

There are various factors that affect forecasting including weather and load variations due to customer changes. The annual peak can also be affected by Demand Side Management (DSM), DER, consecutive days of heat increasing air conditioning load, and the day of the week when the peak occurs. We therefore use historical actual load information to calibrate our forecasts.

This involves totalizing the feeder and substation loads by area and comparing the forecast to previous peaks and then analyzing the amount of load growth positive or negative. Calculation errors, over- or under-estimates, etc. are corrected and the original forecast adjusted accordingly.

d. Minimum load assessments and forecasts: Does the utility utilize minimum load to assess potential impacts of distributed generation on power flows? Are minimum loads measured during peak hours or during night hours?

Currently, our distribution planning processes do not use minimum load in the planning process. As we have discussed, the load input to the planning process is the annual peak.

Minimum load information is however used to analyze the impact of photovoltaics (PV) and other types of DER as part of the interconnection process. We summarize here how it is used, and note that our March 20, 2017 Supplemental Comments and our May 5, 2017 Reply Comments regarding our hosting capacity analysis in Docket No. E002/M-15-962 provides additional details.

In summary, our hosting capacity study involved a power flow analysis on over 1,000 feeder models created from our 2017 load forecast, as well as customer demand and energy data. We scaled-down the peak load (from our SCADA if available, and if not, from our manual monthly peak substation meter read process) for each feeder to 20 percent, to represent the daytime minimum loading.

Historically, we have used 20 percent of peak demand for calculating daytime minimum load in our interconnection study process for feeders that do not have SCADA enabled or other methods of determining the actual daytime minimum load. We initially decided on this value as a result of a National Renewable Energy Laboratory (NREL) paper.[3] Since that time we have compared it to nearly 150 feeders where we have SCADA data on our system and where interconnection requests have been submitted, and we have concluded that it is representative of our system, as the average for those feeders was 23 percent.

Further, a lot of the substations in our least populated areas (where we are seeing significant solar development) do not currently have SCADA and thus the ability to report daytime minimum loading. We are working with EPRI to make improvements to DRIVE going forward that could allow use of a minimum load value recorded from SCADA. As we also noted in the narrative accompanying our response, we also have a long-term plan underway to expand our SCADA capabilities to more substations.

e. Impact on load forecasts of the projected availability of DER: How is utility forecasting impacted by utility assessments on adoption and penetration of DER?

DER is a challenge to forecast accurately due to uncertainty associated with its adoption, as well as the variability we have seen with the more common types of DER – namely wind and solar. We have not to-date accounted for its potential impact in load forecasting in our annual distribution planning process. While DER may provide significant impact at certain times, it may be limited in its impact at other times. With the current limited levels of DER on the system, planning for the worst case scenario – or planning for the maximum annual peak sans DER – continues to be our preferred method for ensuring a stable system. However, as DER expands on our system and as our planning tools mature, we intend to incorporate it as appropriate.

4) Capital investments and operational projects

a. Assessment criteria and assessment process for feeder and substation reliability, condition of grid assets, and asset loading

[3] "Updating Interconnection Screens for PV System Integration." *See* http://www.nrel.gov/docs/fy12osti/54063.pdf

We recognize that customers want reliable and uninterrupted power. To address this priority, we regularly evaluate the overall health of our system and make investments where needed to reinforce our system. We discuss the criteria we apply to assessing system risks as part of our annual planning process – and the prioritization process for the overall distribution budget in Section II of the accompanying narrative. Here, we discuss how we assess and address asset health and reliability.

In addition to our annual distribution planning study of the NSPM distribution system, which assesses asset loading and results in actions that increase system capacity in the areas where that is needed, each year we also analyze the overall performance of key components of the distribution system to determine actions we must take to maintain our reliability levels. Projects in this category are related to replacing infrastructure that is experiencing high failure rates and, as a result, negatively impacting the reliability of service and increasing O&M expenditures needed to repair this equipment. When we identify poor performing assets, we identify and implement programs and develop and fund projects in an effort to improve asset performance, assure reliability, enable proactive management of the system as a whole, and effectively respond when outages occur. Infrastructure in this category generally includes underground cable, wood poles, overhead lines, substation equipment, transformers, and switchgear that have reached the end of their life.

Our annual reliability planning process begins with an analysis of the causes for historical outages examining outage cause codes for a multi-year time period, ranked in descending order by the number of Sustained Customer Interruptions. After considering the most common failures and their causes, as well as at-risk equipment, we develop work plans, or programs, to target our investments. These programs represent those proactive investments in our transmission and distribution systems that we believe are most likely to improve overall reliability, asset health, and meet various contingency planning requirements. These investments are made in addition to other capital investments that provide for adequate capacity to meet customer requirements and to accommodate load switching during outage response to minimize customer impacts.

The primary performance impacts of these programs include SAIFI (System Average Interruption Frequency Index), CAIDI (Customer Average Interruption Duration Index), CEMI (Customers Experiencing Multiple Interruptions), CELI (Customers Experiencing Lengthy Interruptions) and Customer Complaints. We note that programs typically require multiple years before their full impact is realized. At first, the programs may only halt Sustained Customer Interruption increases, but continuing investment eventually reverses adverse trends. Our current Reliability Management Program (RMP) investments are maintaining appropriate levels of overhead and underground system performance. Programs such as our Feeder Performance Improvement Program (FPIP) and Outage Exception Reporting Tool (OERT) have realized significant contributions in system performance, and are helping to eliminate or mitigate the failures that would be otherwise typical of aging equipment.

These programs become part of the annual RMP. A Reliability Core Team (RCT) consisting of field and planning functions monitors system performance and progress against the RMP on a monthly basis, taking actions as necessary to ensure the best possible system performance. The RCT will continue to monitor system performance on a monthly basis to determine if additional and/or shifts in actions should be initiated as the year unfolds. The actual amount of work completed under each program varies from year to year, and is based primarily on assessments of those areas requiring the greatest attention, as well as the results of our condition assessment (*i.e.,* the number of deficiencies requiring corrective action).

We also identify and implement improvements to existing work practices to improve customer reliability experience and our reliability performance. These are operational and/or procedural changes intended to either reduce the *duration* of outages should they occur – CAIDI – or the *frequency* of outages – SAIFI. We assess and prioritize the actions based on a balance of their ability to positively impact reliability (high, medium or low), as well our ability to incorporate into standard work practices – with most occurring concurrently. Many of these actions do not require additional funding to implement, and are achieved via ongoing employee training and/or incorporation into standard work procedures. We continuously monitor all actions, and update our plan as appropriate.

Some of the work practice improvements we have implemented over time have included an *internal version* of the Outage Map functionality that is on our website for customers. The internal version had increased functionality that displays more detailed/non-public data that allowed our outage dispatchers to simultaneously view the exact geographic location of all system outages, electric emergency calls, and first responders.

We have also developed CEMI tools over time. These allow us to better track the causes of outages from a customer experience perspective. In conjunction with a mapping tool, we can identify customers with multiple outages over a rolling 12 months, and visually present those outages across our service area. This customer-centric tool helps highlight customers that have had outages from different causes rather than a single root cause, as our traditional tools measured. This tool compliments other programs such as the OERT, which helps us identify specific equipment issues (for instance, the same device tripping multiple times in a defined time period). Since much of our analysis has focused on a system perspective, this new tool really rounds out our reliability planning by helping focus on the customers' experience.

Distribution's key strategic goals of reliability, safety, and customer focus drive our investments. We have aimed to increase our rate of replacement of aging infrastructure by introducing programs targeting substation asset health for components such as transformers and circuit breakers. From 2012 to 2014, a large percentage of Distribution's investments were in the area of Asset Health. Our distribution system is aging, as many of our facilities were placed in service between the 1950s and 1970s. Based on our asset health analysis, we have determined that to maintain the reliability of the distribution system we need to make increasing investments to replace key components of our system.

When assets are considered for replacement, we consider whether the functionality of a particular asset can be enhanced to promote grid modernization. For instance, we are replacing electro-mechanical relays with solid-state relays which are not only communication-enabled, but are also capable of providing fault data, which an ADMS can use to calculate probable fault location. This enables us to more quickly identify faults on our system and improve our response time. Secondly, regulators purchased for replacements will have controls which identify reverse-power flow and react accordingly. This will allow us to more easily incorporate DER onto our system.

b. alternative analysis protocols for identified needs:

i. Capital versus operating solutions: How does the utility determine whether an assessed need is best met through operational solutions?

Potential solutions for capacity risks on the system are dependent on not only the feeder we are analyzing, but also all adjacent feeders. We first consider operational solutions, such as phase balancing or transferring load to adjacent feeders. Sometimes operational solutions will work, but are generally only able to alleviate the issue short-term, and do not solve the issue longer-term. They are however an important tool in our 'toolbox,' as a short-term operational changes can allow us to delay a costly infrastructure investment that may benefit from advancement in technologies or other investments occurring on the system.

ii. Near-term versus long-term: Similar to the question above, with the additional factor that some less expensive capital projects may provide a shorter term solution than more comprehensive projects; how does the utility compare these alternatives?

Generally speaking, alternatives such as this are not considered in our annual distribution planning process. While Planning may brainstorm alternatives, the least-cost option that solves the risks and gets the loading and N-1 levels to our ideal criteria is typically selected. This mitigation is then entered into our risk assessment and project prioritization processes.

Planning Engineers first consider distribution level alternatives including operational changes, adding feeders, extending feeders and expanding existing substations. If these typical strategies would not meet the identified needs, because they had already been exhausted or would not be sufficient to address the overloads, we then evaluate alternatives that would bring new distribution sources into the area. If we conclude that distribution-level additions and improvements would not meet the identified need, Planning Engineers consider the addition of new distribution sources (*i.e.*, substation transformers with associated feeder circuits) to meet the electricity demands. All potential solutions must have the ability to meet existing and forecast capacity requirements.

iii. Non-monetized benefits: Apart from reliability and other traditional planning criteria, are other benefits (e.g., economic development, emission reduction) taken into account in considering alternative approaches to resolving system needs?

No, non-monetized benefits are not currently part of our risk ranking or prioritization processes.

iv. Non-wires alternative (NWA) versus traditional solutions: Does the utility consider the potential for DER or other non-wires solution to address an assessed need, to defer or eliminate the need for a traditional capital or operating solution?

While this is not part of our annual distribution planning process at this time, we have analyzed DER solutions for specific large capacity needs as part of a focused area study. We discuss these studies as part of the planning process in Section II.C of the accompanying narrative. In summary, if the identified issue and solution are not straightforward, we may perform a study focused on the surrounding area in order to identify potential solutions, which may include DER or NWA options. Examples of these focused area studies include: South Minneapolis Electric Distribution Delivery System (provided as Attachment C) and Plymouth and Medina Electrical System Assessment (provided as Attachment D). We also proposed a distribution demonstration project (Belle Plaine) to explore the benefits of energy storage and to defer a distribution capacity project.[4]

v. Assessing DER or NWA alternatives: What criteria or metrics are in assessing whether a DER or NWA can meet an identified need?

We consider the same factors as for traditional mitigation solutions, including: cost, reliability, capacity, dependability, longevity, dispatchability, space constraints, available land and routes, characteristics of the equipment/DER, characteristics of the feeder, and severity of the need.

vi. Scenario analysis: In developing solutions to an assessed need, does the utility consider multiple scenarios, including factors such as load forecasts and DER penetration? If so, what scenarios are standard?

As we have discussed, we currently only assess a peak load scenario for each feeder and substation transformer that includes rooftop DER, but not universal-scale (community) DER. With the current limited levels of DER on the system, planning for the worst case scenario – or planning for the maximum annual peak sans DER – continues to be our standard method for ensuring a stable system.

Unlike IRPs where a forecasted system peak is applied as a sensitivity at a macro level, distribution planning involves developing an individual forecasted peak for each major component on the system – which currently involves more than 1,700 individual forecasts, based on the present 1,274 feeders and 449 substation transformers. Increasing the numbers of scenarios and/or sensitivities would have an exponential impact on the volume and complexity of analysis. Distribution planning tools that would efficiently perform analysis of multiple scenarios, such as that which occurs at a system level in IRPs are not widely developed or available. We acknowledge that DER is expanding on our system. We are monitoring available planning tools as they are maturing, and will incorporate them into our process as appropriate.

c. Metrics for deciding among competing proposals: For any of the applicable categories described above, what specific metrics are used to conduct a comparison of alternative solutions? Are there examples of cost benefit studies or reports the utilities have

[4] *See* Grid Modernization Report, IN THE MATTER OF THE 2015 MINNESOTA BIENNIAL TRANSMISSION & DISTRIBUTION PROJECTS REPORT, DOCKET NOS. E999/M-15-439 and E002/M-15-962 (October 30, 2015).

conducted that can be provided with the responses?

See Section II.D of the accompanying narrative, which discusses the criteria applied to identified risks and the budget prioritization process. In summary, in considering viable alternatives for resolving distribution capacity issues we look at cost, reliability, capacity, dependability, longevity, dispatchability, space constraints, available land and routes. Distribution Planning generally only has alternative solutions associated with long range studies. We provide examples of past area studies that involved alternatives as Attachments C and D.

d. Historical distribution system spending: Please provide historical spending over the past five years for capital projects, operating changes or projects, information technology, communications and shared services.

Tables 4 and 5 below provide historical capital and O&M spend from 2011 – 2015. Both capital and O&M information has been grouped into the categories discussed in our recently concluded Minnesota electric rate case (Docket No. E002/GR-15-826).

Table 4: Electric Distribution Actual Capital Expenditures (excluding AFUDC) – NSPM State of Minnesota
($ Millions)

Budget Component	Year				
	2011	2012	2013	2014	2015
Fleet, Tools, and Equipment	$8.3	$13.9	$13.5	$7.1	$15.1
New Business	$34.3	$40.8	$41.9	$48.2	$44.1
Capacity	$18.7	$34.1	$42.5	$37.1	$20.7
Asset Health and Reliability	$65.2	$54.7	$78.8	$67.1	$75.5
Grand Total	**$126.5**	**$143.5**	**$176.7**	**$159.5**	**$155.4**

We note that Distribution's capital related to information technology and communications projects is included within Fleet, Tools, and Equipment category. However, our Business Systems area maintains additional capital that supports distribution information technology and communication investments.

Table 5: Electric Distribution Actual O&M Expenditures – NSPM State of Minnesota
($ Millions)

Budget Component	Year				
	2011	2012	2013	2014	2015
Internal Labor	$45.6	$45.3	$46.7	$48.1	$48.5
Contract Labor	$39.6	$38.2	$46.5	$44.3	$39.70
Fleet	$8.9	$8.7	$8.9	$8.4	$7.2
Materials	$7.4	$7.1	$8.2	$9.0	$8.2
Other	($0.4)	($1.3)	($0.4)	($2.6)	($2.8)
Grand Total	**$101.1**	**$98.0**	**$109.9**	**$107.2**	**$100.8**

Distribution's O&M budget includes labor costs associated with maintaining, inspecting, installing, and constructing distribution facilities such as poles, wires, transformers, and underground electric facilities. It also includes labor costs related to vegetation management and damage prevention. Finally, it includes the fleet (vehicles, trucks, trailers, etc.) and miscellaneous materials and minor tools necessary to build out, operate, and maintain our electric distribution system. Specifically, the O&M component of fleet are those expenditures necessary to maintain our existing fleet. This includes annual fuel costs plus the allocation of fleet support to O&M based on the proportion of the Distribution fleet utilized for O&M activities as compared to capital projects. Shared services costs are not reflected at a business area level. Rather Shared Services costs are direct-assigned or allocated to utility operations within NSPM (natural gas and electric), jurisdictions within NSPM (Minnesota, North Dakota, and South Dakota), and to the non-regulated business activities operated within NSPM.

5) Locational assessment of DER in long-term planning

a. Describe how the utility uses analytical criteria for assessing potential alternatives to capital and operating improvements during the planning process, if at all, including:

i. Locational DER assessments: Whether locational DER assessments are a part of the planning process or if a DER solution is only considered once a need has arisen.

As we have discussed, our annual planning process does not consider DER as a standard solution. We have however, performed specialized analyses that have considered DER alternatives.

ii. Time sensitivity of the system need: Does the system allow time to develop a potential DER solution? Are there short term traditional projects that can address imminent needs while a longer term DER solution is considered?

In short, yes, there is time to consider potential DER solutions within our annual planning cycle. However, we do not have robust tools to broadly consider DER in our analysis. As we have discussed, our annual planning process analyzes thousands of points on the distribution system and our tools are oriented to traditional solutions. Therefore, we currently only consider DER or NWA as part of a focused, or specialized area study.

In fact, using DER to potentially bridge the gap between an identified system issue may be more straightforward and save some time when compared to traditional alternatives, which can take between one and two years from the time of initiation to completion. For example, installing poles and stringing wire for a new feeder may be more time consuming than installing a battery at a single location.

However, traditional solutions generally have more latent capacity that can be utilized for years to come as new load is added to the system. From a cost perspective, this is presently more difficult to achieve with a DER solution. And while we believe DER will become more cost-effective as the technologies mature, they currently are not able to compete on a cost basis with traditional system solutions. As noted previously, we proposed a battery (Belle Plaine) as a distribution demonstration project to explore the benefits of energy storage and to defer a distribution capacity project. At an estimated cost of nearly twice the traditional solution at that location, the battery solution only reduces the overload to 100 percent utilization. In comparison, the traditional solution would bring the loading down closer to 50 percent, which also eliminates the need to come back in the near future to add more capacity.

b. Where DER or non-wires alternatives are on par with traditional projects, based on the analytic criteria described above, is there a mapping of those geographic areas in which DER could replace or defer specific capital or operating projects?

At this time, we have not identified any DER or NWA alternatives that are on par with traditional projects in terms of cost, capacity, and longevity. As noted above, the Belle Plaine battery proposal had costs that were roughly double that of the traditional solution, and yet it provided less than a quarter of the capacity benefit. Also, in this example, the performance of the battery asset will degrade over time, whereas a traditional solution such as a new transformer will retain its same capacity and may last 50-60 years with minimal maintenance. We however, believe it is important to get more experience with DER and NWA on our system, and continue to monitor the technologies as potential solutions for identified system issues.

We note that we have a provision in our Distributed Generation Interconnection and Power Purchase Tariff for customers operating certain qualifying distributed generating facilities to also receive a Distribution Facilities Credit (DFC) for installing DER in a location where a capital project can be deferred. The terms and conditions of the DFC are determined from a case-specific study of avoided distribution costs, which includes review of both avoided distribution lines and avoided distribution transformers. *See* our Minnesota Electric Rate Book – MPUC No. 2, Section No. 10, 2nd Revised Sheet No. 75 for more information.

6) Security

a. What controls and processes are used to secure consumer and system data, IT/communication systems, and physical infrastructure?

We have substantially increased our security focus and resiliency efforts over the last few years. This includes creating a new Enterprise Security Services business unit to focus on these issues and leverage synergies between physical and cyber security, as well as information protection and enterprise continuity. Results include implementing new technologies and new systems, expanding our enterprise event management processes, and enhancing our partnerships with other utility companies, federal agencies, Edison Electric Institute (EEI), American Gas Association (AGA), and third-party service providers that deliver security services to utility companies.

Our Enterprise Security Services group is charged with increasing our overall security posture, implementing preparations and plans to be able to quickly mitigate any adverse events, respond appropriately and effectively to large-scale events that would otherwise cause significant harm to Xcel Energy, and meet our ever-growing (in numbers and complexity) regulatory, legal, and best practice-based security needs. This group has implemented and operates multiple security systems and technologies to correlate all the data and bring visibility to what is happening on our infrastructure and at our facilities.

We take seriously our responsibility to maintain the security of the information and systems involved in the delivery of safe, reliable, clean energy at a reasonable cost to our customers. We are subject to extensive federal regulation of our physical and cyber security activities, and our program seeks to fully comply with the requirements and guidelines set forth by all relevant agencies or regulatory bodies. We build our program to ensure security, and then measure the outcome of our program attributes in terms of their compliance with various requirements.

A key tenet of our security program is limiting the extent to which sensitive information is accessed or shared. This is designed to help prevent key information about our security program from being accessible to those who wish to compromise its effectiveness. Therefore, we provide summary level information in our response to this Question. We would welcome however, the opportunity to discuss in greater detail the elements of our security programs and protocols to aid further understanding of the efforts and actions we take to ensure safe and reliable electric and natural gas service to our customers, while best ensuring the security of our programs.

Our cyber and physical security programs are overseen by our Chief Security Officer (CSO), who reports to our Chief Administrative Officer. The CSO has explicit security responsibilities, and leads a team that focuses on areas such as Risk & Compliance, Security Engineering, Security Operations, Identity & Access Management, Physical Security, and Enterprise Continuity. Our security program employs a robust combination of physical and logical policies, standards, controls, and processes to protect our facilities, our systems, and the information they contain.

Our cyber security program is generally based on the National Institute of Standards and Technology (NIST) SP 800-53, aligned with the NIST Cyber Security Framework, and follows the requirements and guidelines set forth by all relevant agencies or regulatory bodies such as NERC, Federal Energy Regulatory Commission (FERC), Transportation Security Administration (TSA), the Department of Homeland Security (DHS), and other NIST protocols.

The following policies are the foundation of our security program:

- Information Technology Security Requirements
- Information Technology Governance
- Physical Security
- Risk Management
- Information Management and Protection
- Xcel Energy Code of Conduct
- Appropriate Use of Company Assets

This is not a comprehensive list of all of Xcel Energy policies; however these are the policies that establish the framework of our security program and communicate expected behavior to employees and contractors.

We also have a body of Information Security and Technology Standards to support our policies, such as:

- Information Security and Technology Requirements
- Organization of Information Security
- Risk Management of Technology, Information, and Vendors
- Asset Management
- Access Management
- Authentication
- System Acquisition, Development, Maintenance, and Architecture
- Network Security
- Encryption
- Operations Management
- Physical and Environmental Security
- Business Resiliency

The Physical Security team develops and maintains physical security standards for Xcel Energy facilities to protect company personnel and assets. These include, but are not limited to: perimeter fencing, card access, video surveillance, key control and alarm monitoring. At high risk sites, we perform vulnerability risk assessments and create site-specific security plans.

Both physical and cyber security controls are deployed with a 'defense in depth' philosophy, increasing the difficulty for an intruder should an initial line of defense break down. The layers include preventive controls at the perimeter, detective controls and monitoring within the network or facility boundary, response protocols that leverage utility and law enforcement partnerships, and system restoration.

Planning for new or upgraded technology includes evaluation of security and continuity risk (based on the sensitivity of information within and the business processes supported by the technology), evaluation of vendor and technology security (including contractually-enforceable terms and the right to audit the vendor) and documentation of disaster recovery plans.

Our view is that security is not simply a matter of implementing a standardized base of security controls and processes that comply with all regulatory and legal requirements. Effective security also requires filling the security gaps that would exist if we focused solely on regulatory and legal compliance. Many large financial and retail companies have had their data hacked in recent years were compliant with regulatory and legal requirements. Therefore, while regulatory compliance with security requirements is the minimum standard, our objective is to be *secure* rather than just meeting our compliance requirements.

Our physical security team has a documented National Terrorism Advisory System (NTAS) policy and procedure to provide additional security measures in the event of a national, regional, state or local physical security event. These additional physical security measures will be deployed in the event the NTAS level is raised to ELEVATED or IMMINENT. We also provide a baseline for physical security measures to be in place through an additional level identified as NORMAL for day-to-day operations.

Substation assets, which include Control Centers, also follow prescribed physical security enhancement standards required for both current and new facilities. Finally, we have gone above and beyond regulatory compliance of assets identified as critical to the Bulk Electric System (BES) by identifying assets critical to Xcel Energy operations in each operating company, and adding additional physical security enhancements portfolio-wide for Transmission and Distribution assets.

b. What protocols and cooperative arrangements with NERC, NIST or other entities are used to identify threats and available defense measures?

We actively monitor multiple sources of information about threats, including DHS's US-CERT, ICS-CERT, NERC's Electricity Information Sharing and Analysis Center (E-ISAC), and are a founding member of EASE (Electricity Analytic Security Exchange) which leverages the platforms of the Financial Services Information and Analysis Center (FS-ISAC). Our threat analysts determine the applicability of this information to the Xcel Energy environment, and leverage technology and processes to mitigate the risk.

One example is the recent WannaCry ransomware threat. As soon as our Threat Intelligence group received information about the threat, we proactively issued an advisory to our cyber security operations team to scan for unpatched Windows devices, and engaged with the IT group to implement defensive controls. We are continuing to take defensive steps and to monitor for any indicators of compromise to ensure the company remains safe.

We leverage relationships with the Federal Bureau of Investigations (FBI), the National Guard, and local law enforcement via periodic communications as well as participation with them in various safety, security, and reliability drills throughout the year. Through formal and informal channels, Xcel Energy is able to tap the resources of these groups when preventing and responding to security incidents.

Through membership in the Electricity Subsector Coordinating Council (ESCC), we regularly engage with other industry and federal government executives to plan and discuss security research and development priorities, enhanced information sharing, cross-sector dependencies, coordination during incident response, and other topics. We are amongst over 100 participants in the Cyber Mutual Assistance program, where utilities can request or offer resources to assist in the event of a cyber incident.

In addition to regularly communicating with local, state and federal law enforcement, we also provide educational opportunities to them regarding the wide array of physical security enhancements at all of our facilities, including assets critical to the BES. This includes tabletop exercises, SWAT team walk-through and exercises at our facilities, intelligence gathering and sharing, educational programs at Federal, State and local law enforcement training centers, and attending classified briefings in the gas, electric, dams and financial sectors. We work with the TSA and their Visible Intermodal Response Team (VIPR) to conduct both covert and overt operations in and around our gas and electric assets on a monthly basis, including tabletop exercise participation for our physical infrastructure.

We have cooperative arrangements to attend classified and unclassified briefings with DHS, TSA, FBI, and Department of Energy (DOE), in order to receive just-in-time threat intelligence across our operating companies. Personnel on our security teams hold both Top Secret and Secret level clearances.

We provide an outline of our program as it relates to the effective information security program framework advocated by NIST, as follows:[5]

- *Periodic assessments of risk*. We employ a risk-based security model. Our Information Security Classifications standard classifies data types based on risk and also guides users through requirements related to access, handling and sharing based on the data classification. Additionally, to comply with the NERC Critical Infrastructure Protection (CIP) requirements, we perform a

[5] *See* http://csrc.nist.gov/groups/SMA/fisma/overview.html

periodic risk assessment to determine cyber systems that support the bulk electric system and ensure appropriate protections are in place. Using these and other risk assessment mechanisms, we focus security resources consistent with risk.

- *Policies and procedures based on risk assessments.* Security policies and standards consider level of risk when prescribing the appropriate protections to apply. The policies cover a number of topic areas. Violation of policies can be cause for employee discipline, including termination.

- *Subordinate plans.* A comprehensive set of standards, procedures, and technologies are used to secure the external network, applications and databases. Our physical security program uses physical controls such as identification badges, Closed Circuit Television and a myriad of alarm and monitoring systems.

- *Security awareness training.* All Xcel Energy computer users (including contractors) are required to take regular training on information security awareness. All personnel with physical access to Xcel Energy assets must take periodic physical security training. Other more-specific security training is required for employees in certain high-risk job functions. Additionally, a Security awareness program delivers periodic messages using multiple media, throughout the year.

- *Periodic testing and evaluation.* The Audit Services group within Xcel Energy includes evaluation of areas of the security policies and program in its annual audit plan. Regulatory agencies including NERC and DHS perform periodic audits of the Company for regulatory compliance. Individual business areas deploy continuous assessment programs to monitor the effectiveness of their security controls.

- *Process for remedial action.* Each of the Xcel Energy business areas, as well as Audit Services, has a process in place for outlining steps to remediate and prevent recurrence of identified deficiencies.

- *Procedures for security incidents.* Xcel Energy monitors both physical and electronic access to high-risk facilities and systems. 24x7 operations ensure prompt detection and response to suspected security incidents. We have a Computer Incident Response Team (CIRT) process that is periodically exercised and evaluated. We employ a 24/7/365 Security Operations Center and a separate Alarm Response Center to ensure company, Federal, State and local physical security requirements and incidents are responded to in a timely and appropriate manner.

- *Policies and procedures to ensure continuity of operations.* We employ technology and procedures to enable the recovery and reconstitution of key information systems, and perform periodic drills of these capabilities. Individual business areas plan and drill for continuation of operations in the absence of key facilities or information systems.

In addition to the built-in self-monitoring assessments, as an investor-owned utility that provides electric generation, transmission, and distribution, and natural gas storage, transmission and distribution, we are subject to and periodically audited by government agencies on cyber security requirements for different data types, including:

- Sarbanes-Oxley;
- Payment Card Institute Date Security Standard (PCI-DSS);
- Health & Human Services Health Insurance Portability and Accountability Act (HHS/HIPAA);
- State data privacy, security and data breach regulations;
- FERC/NERC Critical Infrastructure Protection;
- FERC Security Program for Hydropower Projects;
- DHS Chemical Facility Anti-Terrorism Standards (CFATS);
- DHS/Transportation Security Agency Gas Pipeline Security Requirements; and
- Nuclear Regulatory Commission (NRC) - Nuclear Energy Institute (NEI) 08-09.

As the number of physical and cyber threats, attacks, and regulatory requirements continue to increase in volume and complexity – and we add new security controls and processes to meet these ever-changing regulatory and data protection requirements – it is imperative that we have the ability to track the effectiveness of these controls against each individual requirement across each regulation and law. An organization like Xcel Energy can have thousands of changing requirements that need to be tracked against thousands of controls and processes. Therefore, in addition to investment in security protocols and tools to protect the integrity and confidentiality of our data and our systems, we are investing in systems to track our efforts and demonstrate compliance.

B. What is the status of each utility's current plan?

As compared to the section above, the section seeks information on each utility's current distribution system plan, as opposed to the process to develop the plans. Please describe information on any existing distribution system plan, including (where applicable):

1) The date initiated, completed, and the planning timeframe used: For each planning component, the number of years to which it is applicable should be specified.

We initiated our 2017 capital plan on September 1, 2015. The resulting budget process occurred in1st quarter 2016, and it was considered complete when we initiated approved projects with Design and Construction by August 31, 2016.

2) Scenarios: the range of any scenarios that were considered should be identified, e.g. high/low load forecast, high/low DER penetration.

As we have discussed, we currently use one scenario – the peak load forecast, which includes rooftop solar – but no universal scale (community) DER. We currently take this approach due to the current limited levels and availability of DER on the system, and because our current planning tools do not provide an efficient method to incorporate this data into our analysis. As DER expands on our system and as our planning tools mature, we intend to more fully integrate DER into our planning processes as appropriate.

3) System constraints and needs:

a. At a high level, what system constraints and needs are anticipated to develop or occur within the planning period? (Further detail is requested below)

Our 2016 to 2020 annual planning process that analyzed forecasted 2018 loads identified a total of 751 risks. We identified 135 mitigation projects that would resolve a total of 481 of the total risks. We note that not all risks are mitigated – and often one mitigation can solve multiple localized risks. See Section II of the accompanying narrative for more details on our planning process.

b. How have these constraints and needs been prioritized based on assessment criteria, time sensitivity, budget impact, or other criteria?

As we have discussed, we weigh each potential investment (or mitigation) using a risk/reward model to determine which solutions should be selected and prioritized. Our process recognizes that risk cannot be eliminated and funding is always a balance. Therefore, our goal is to provide our customers with smart, cost-effective solutions. Accordingly, we evaluate operational risk dependent on:

- The probability of an event occurring (fault frequency, failure history of device, etc.) causing an outage; and
- The consequence of the event (amount of load unserved, number of customers, restoration time, etc.)

See the discussion regarding Risk Analysis and Select and Prioritize Solutions in Sections II.B and II.D respectively, of the accompanying narrative for more details on how we prioritize mitigations.

4) The current and forecasted extent of DER deployment by type, size, and geographic dispersion.

We provide a summary the DER currently installed and forecast to be installed on our system in Minnesota as Table 1 below.

Table 1: DER Deployment – State of Minnesota

		Megawatts		Number of Projects	
DER Type	**Size (Category)**	**Installed**	**Forecast** (through 2020)	**Installed**[6]	**Forecast** (through 2020)
Solar Rooftop*	Less than 20 kW	13	42	1,705	5,616
Solar Rooftop*	Greater than 20 kW	15	86	298	1,664
Community Solar Gardens**	Non-Utility	80	450	22	126
Wind***	Non-Utility	16	N/A	65	N/A
Bio-Gas***	Non-Utility	1	N/A	< 15	N/A
BioMass***	Non-Utility	10	N/A	< 15	N/A
Diesel***	Non-Utility	202	N/A	165	N/A
Hydro***	Non-Utility	25	N/A	< 15	N/A
Natural Gas***	Non-Utility	26	N/A	26	N/A

Sources:
* 2016 SES Report, Docket No. E999/M-17-283 (June 1, 2017), supplemented via IR No. MPUC-1 filed in eDockets June 19, 2017.
** Community Solar Gardens Compliance Report, Docket No. E002/M-13-867 (June 15, 2017).
*** Annual Distributed Generation Interconnection Report, Docket No. E999/PR-17-10 (March 1, 2017).

[6] We maintain a 15/15 aggregation standard for customer energy usage data. Because the Minnesota DER Deployments in Table 1 are customer usage-related, we have applied this standard. Some types of DER have fewer than 15 customer installations. We have therefore noted these with "< 15" rather than providing the specific number in an effort to be transparent, and at the same time protect our customers' privacy and confidentiality.

5) Currently planned distribution capital projects and operating changes, including:

a. Capital and operating budgets over the applicable planning period, and to the extent possible, breakdowns of categories of expenses and budgets.

The below tables provide the budgeted capital expenditures and O&M expenses grouped into the categories highlighted and as originally submitted in association with our recently concluded Minnesota electric rate case (Docket No. E002/GR-15-826).

The budgeted capital spend is shown for 2016 – 2019, and is based on the budgets established in May 2015 (Actuals through April 2015).

Table 2: Electric Distribution Budgeted Capital Expenditures (excluding AFUDC) - NSPM State of Minnesota
($ Millions)

	Year			
Budget Component	**2016**	**2017**	**2018**	**2019**
Fleet, Tools, and Equipment	$15.0	$15.3	$18.7	$18.8
New Business	$59.9	$61.2	$63.3	$65.4
Capacity	$27.3	$19.2	$22.8	$18.6
Asset Health and Reliability	$72.8	$90.1	$101.7	$103.8
Grand Total	**$175.0**	**$185.8**	**$206.5**	**$206.6**

The 2016 O&M budget was established in July 2015 (Actuals through June 2015). Per Company Witness Mr. Charles R. Burdick's Direct Testimony in our recently-concluded electric rate case, O&M costs beyond 2016 have been escalated as follows:

- O&M expenses related specifically to labor should be escalated according to an IHS Global Insights, Inc. (IHS) labor escalator, specifically FERC 920, Administrative and General Salaries.
- O&M expenses should be escalated on a FERC Account basis, according to IHS cost factors.
- O&M expenses for which IHS does not provide an escalation factor for that specific FERC Account should have a reasonable composite factor applied for escalation. We developed a composite factor using IHS data on the 2016 Test Year amounts by FERC Account for
  - FERC Account 556, Load Dispatch

- Miscellaneous non-retail revenues and O&M credits that offset the revenue requirement should also be escalated using the composite factor, including:
    - FERC Account 450, Forfeited Discounts (revenue)
    - FERC Account 451, Miscellaneous Service (revenue)
    - FERC Account 454, Rent from Electric Property (revenue)
    - FERC Account 922, Administrative Transfer (credit)
    - FERC Account 929, Duplicate Charge (credit)

Table 3: 2016 Electric Distribution Actual O&M Expenditures – NSPM
($ Millions)

Budget Component	Amount
Internal Labor	$51.4
Contract Labor	$46.2
Fleet	$9.2
Materials	$8.4
Other	($3.1)
Grand Total	**$112.10**

b. Where individual budget categories contain a substantial increase or decrease from historical levels, please explain the rationale for the change.

We note that we provide actual historical capital expenditures and O&M expenses in our response to Notice Part A, Question 4.d.

<u>Budgeted Capital</u>

The increase of approximately $20 million from 2015 actual capital spend ($155.4 million) to the 2016 capital expenditure budget of $175.0 million is primarily driven by anticipated growth in new business and additional capacity work.[7] An increase of approximately $21 million from 2017 to 2018 is primarily driven by expected increases to our asset renewal program including cable replacement, pole replacement and substation end-of-life replacement programs.

<u>Budgeted O&M</u>

Historically, the O&M Labor increase from 2014 to 2015 was lower than typical due to a slight drop in OT Labor in 2015, along with impacts of capitalization policy changes.[8] The 2016 Budget is anticipated to be back to a normal historical 2.5 to 3.0

[7] *See* our response to Notice Part A, Question 4.d for actual historical capital expenditure levels.
[8] *See* our response to Notice Part A, Question 4.d for actual historical O&M expense levels.

percent growth rate for Labor, primarily due to an expected return to normal average OT Labor and higher volumes of work being budgeted.

The 10 percent reduction in Contract Labor from 2014 to 2015 was primarily driven by reductions in Vegetation Management/Ancillary Services due to 2015 management initiatives. The 2016 Budget anticipates a return to average annual Vegetation Management/Ancillary Services budgets, plus a larger than average increase in the area of Damage Prevention driven by an uptick in the number of forecasted electric locate requests in 2016.

c. Any analysis of alternatives, mitigation, or deferrals of capital or operating projects that were conducted.

See the discussion regarding Risk Mitigation and Budget Create in Sections II.B and II.D, respectively, of the accompanying narrative for more details on how we prioritize mitigations. Additionally, we note our proposal of the Belle Plaine battery demonstration project in our response to Notice Part A, Question 4.b.iv above, and provide examples of past area studies that involved alternatives as Attachments C and D.

d. Identification of any future capital or operating projects that could reasonably be considered for substitution, mitigation, or deferral using DER alternatives.

Distribution Planning historically has not considered DER as a viable alternative for resolving distribution capacity issues due to cost, reliability, capacity, longevity, dispatchability, space constraints and dependability. We however see many of the constraints surrounding DER lessening as the technologies mature and industry operational experience increases. As we have noted, this type of analysis is typically only done outside of the annual process as part of a specialized or focused area study.

e. Identification of any non-monetized benefits of planned projects.

As we noted in our response to Notice Part A, Question 4.b.iii above, Distribution Planning does not currently consider potential non-monetized benefits as part of its risk ranking or prioritization processes.

f. Identification of any projects that will enhance the company's future ability to integrate DER into system operations.

As discussed in our October 30, 2015 Grid Modernization Report filed in Docket No. E002/M-15-962, our planned ADMS is a collection of core functions and applications designed to monitor and control the entire electric distribution network efficiently and reliably. As it pertains to the ability to integrate DER, ADMS (leveraging GIS, SCADA, weather and OMS information) will provide improved awareness of DER influences on the grid and accurately model all elements in the network (including DER) for better forecasting and more insight for system planning.

We also expect that Advanced Metering Infrastructure (AMI) and Fault Location Isolation Service Restoration (FLISR) will also further enable DER on the system. AMI enables a more distributed grid by providing the ability to monitor and control DER through AMI. AMI, along with ADMS, facilitates grid management which helps the grid operator take corrective action when warranted which eases the integration of DER into the overall system. Similarly, FLISR will benefit DER as it provides automated switching and restoration to optimize outage response, which minimizes outage duration for all customers, including DERs.

In addition, our recently filed Hosting Capacity Report also enhances the integration of DER into the system by providing information to the public about the amount of DER a feeder can accommodate before operating criteria are violated. In this way, this helps developers or interested stakeholders narrow potential locations for planned DER. Similarly, we would also expect the interconnection process improvements (being addressed in Docket No. E999/CI-16-521) will help facilitate the implementation of DER.

g. Identification of any other projects, or investments, not specifically identified pursuant to (f) above, that support grid modernization as defined in the Staff Report on Grid Modernization (March 2016).

Distribution Planning will need additional tools that would interface with the advanced grid initiatives to allow our planning and forecasting to evolve as our system incorporates these new technologies and added functionality.

Appendix A.1

South Minneapolis Electric Distribution Delivery System Long-Term Study

SOUTH MINNEAPOLIS ELECTRIC DISTRIBUTION DELIVERY SYSTEM LONG-TERM STUDY

Scott Zima
Distribution Planning Department
Northern States Power Company
March 2009

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1.0 ABSTRACT

In recent years, the Distribution Planning Department ("Distribution Planning") of Northern States Power Company, a Minnesota corporation ("Xcel Energy"), observed an increasing frequency and length of overload conditions on the electric distribution delivery system in the south Minneapolis area during their review of distribution system load. In response, Distribution Planning conducted detailed analyses of the 39 feeder circuits in the geographic area of south Minneapolis that is experiencing the most significant overload conditions and determined that based on 2006 peak load levels, there is an existing deficit of 55 megawatts ("MW") and that by 2018 this deficit would increase to 74 MW. Distribution Planning further determined that common distribution system improvements, including adding new feeder circuits, extending existing feeder circuits and reconfiguring feeder circuits, have been exhausted and would no longer be able to provide the necessary system support.

Distribution Planning then conducted detailed analyses of a larger area of south Minneapolis, encompassing a total of 15 substation transformers and 110 feeder circuits, including the original 39 feeder circuits, to evaluate whether there was existing capacity that was available to address the identified capacity deficit. Distribution Planning determined that the distribution system in the greater south Minneapolis area was already at or beyond capacity and existing area substations could not be expanded any further to accommodate the electrical equipment required to provide the needed additional capacity. Distribution Planning concluded that a new distribution source would be needed to provide the additional required capacity.

Distribution Planning next looked at four "new source" alternatives that could provide the additional capacity needed in the Midtown area, which is the area with the most significant overload conditions in south Minneapolis. Distribution Planning found that the alternative that performed the best with respect to system performance, operability, future growth, cost, and electrical losses, consisted of a new Hiawatha Substation that would tap the existing Elliot Park – Southtown 115 kilovolt ("kV") transmission line between 26th and Lake streets near Hiawatha Avenue; a new Midtown Substation between 26th and Lake Streets and between Chicago Avenue and Interstate 35W that would also tap the existing Elliot Park – Southtown 115 kV transmission line; and two new looped 115 kV transmission lines connecting the two substations. The initial installation of this proposed configuration is estimated to cost $33.4 million and will provide an additional 120 MW of load serving support in the Midtown area. This additional capacity will meet the immediate distribution system needs and provide additional support for further demand growth in the Focused Study Area.

This document is a compilation of these various study efforts undertaken by Distribution Planning.

2.0 PRINCIPLES OF DISTRIBUTION PLANNING

2.1 DISTRIBUTION SYSTEM OVERVIEW

Distribution feeder circuits for standard service to customers are designed as radial circuits. Therefore, the failure of any single critical element of the feeder circuit causes a customer outage, which is an allowed outcome for a distribution system. Feeders are designed to facilitate restoration of mainline capacity and restoration of service to most customers with simple manual field switching with some exceptions. The distribution system is planned to generally facilitate single-contingency switching to restore outages within approximately one hour.

2.1.1 Distribution Substations

Xcel Energy plans and constructs distribution substations with a physical footprint sized for the ultimate substation design. The maximum ultimate design capacity established in Xcel Energy planning criteria is three transformers at the same distribution voltage.[1] This maximum size balances substation and feeder circuit costs with customer service considerations including limitations of feeder circuit routes emanating from substations, circuit exposure of long feeder circuits, ease of operation, cost of operation, customer outage restoration, and the electrical losses. Over time, transformers and feeder circuits are incrementally added within the established footprint until the substation is built to ultimate design capacity.

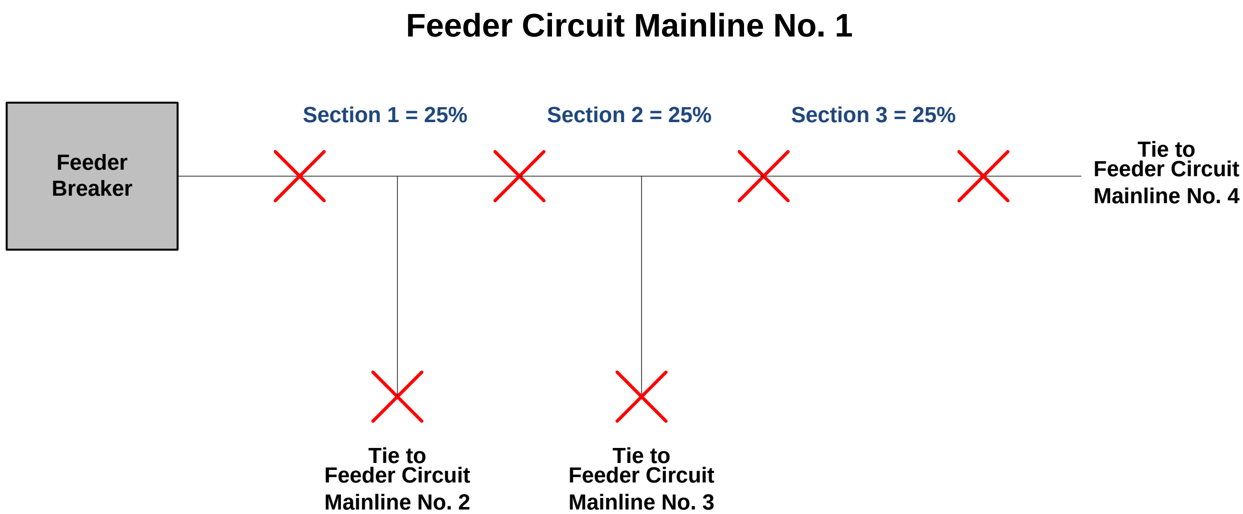
2.1.2 Distribution Feeder Circuits System Intact and First Contingency Planning

Normal operation (also called system intact or N-0 operation) is the condition under which all-electric infrastructure equipment is fully functional. First contingency operation (also called N-1 or contingency operation) is the condition under which a single element (feeder circuit or distribution substation transformer) is out of service. Each distribution main feeder is generally composed of three equal sections. A feeder circuit should be loaded to no more than 75% of capacity during N-0 conditions. For example, a 12 MVA feeder circuit is designed to be loaded to 9 MVA during normal operating conditions. To achieve this goal, a main feeder is generally designed so that each section is loaded to approximately 25% of the total capacity for the main feeder. This loading level provides reserve capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions.

Figure 2.1 depicts a main feeder circuit, including the breaker and the three sections. The Xs in the diagram represent switches that can be activated to isolate or connect sections of a feeder lines.

[1] There is one exception to this criteria. In downtown Minneapolis, the Fifth Street Substation houses four transformers to serve the significant load.

Figure 2.1: Typical Distribution Feeder Circuit Mainline with Three Sections Capable of System Intact N-0 and First Contingency N-1 Operations



2.2 Distribution System Design and Operation

Distribution system load is planned, measured, and forecasted with the goal to serve all customer electric load under system intact and first contingency conditions. A distribution delivery system that has adequate N-1 capacity is one in which all customer load can be restored through distribution system reconfiguration by means of electrical switching in the event of the outage of any single element.

Adequate N-1 substation transformer capacity, no feeder normal (N-0) overloads, and adequate field tie capability for feeder first contingency (N-1) distribution restoration are key design and operation objectives. To achieve these objectives, Xcel Energy uses distribution planning criteria to achieve uniform development of Xcel Energy's distribution systems. Distribution Planning considers these criteria when identifying deficiencies with existing distribution systems and identifying improvements to address the identified deficiencies.

2.2.1 Planning Criteria, Distribution Feeder Circuits

While the distribution guidelines vary depending on the specific distribution system, there are several basic design guidelines that apply to all areas of Xcel Energy's distribution system. They are as follows:

- Voltage at the customer meter will be maintained within 5% of nominal voltage, which is typically 120 volts.

- Voltage imbalance goals on the feeder circuits are less than or equal to 3%. Feeder circuits deliver three-phase load from a distribution substation transformer to customers. Three-phase electrical motors and other equipment are designed to operate best when the voltage on all of the three phases is the same or balanced.

- The currents on each of the three phases of a feeder circuit are balanced to the greatest extent possible to minimize the total neutral current at the feeder breaker. When phase currents are balanced, more power can be delivered through the feeders.

- Under system intact, N-0 operating conditions, typical feeder circuits should be loaded to less than 75% of capacity. Xcel Energy developed this standard to help ensure that service to customers can be maintained in an N-1 condition or contingency. If feeder circuits were loaded to their maximum capacity and there were an outage, the remaining system components would not be able to make up for the loss because adding load to the remaining feeder circuits would cause them to overload. By targeting a 75% loading level, there is generally sufficient remaining capacity on the system to cover an outage of an adjacent feeder with minimal service interruptions. A typical feeder circuit capable of delivering 12 MVA, for example, is normally loaded to 9 MVA and loaded up to 12 MVA under N-1 conditions.

2.2.2 Limitations to Installing Feeder Circuits

Spatial and thermal limits restrict the number of feeder circuits that may be installed between a distribution substation transformer and customer load. Consequently, this limits substation size. Normal overhead construction is one feeder circuit on a pole line; high density overhead construction is two feeder circuits on a single pole line (double deck construction). When overhead feeder circuit routes are full, the next cost effective installation is to bury the cable in an established utility easement. Thermal limits require certain minimum spacing between multiple feeder circuit main line cables. Thermal limits for primary distribution lines are defined in Electric Distribution Bulletins ("EDB"): UND6 and CAL2 for underground and the Construction & Design Manual C-26 for overhead.

When new feeder circuits are added to a mature distribution system, minimum spacing between feeder circuit main line cables sometimes cannot be achieved because of right-of-way limitations or a high concentration of feeder cables. Adding express feeders to serve distant high-load concentrations requires cable installation across distribution service areas where they do not serve any customer load. Cable spacing limitations and/or feeder cable concentrations frequently occur where many feeder cables must be installed in the same corridor near distribution substations or when crossing natural or manmade barriers.

When feeder cables are concentrated, they are most often installed underground in groups (banks) of pipes encased in concrete that are commonly called "duct banks". When feeder circuits are concentrated in duct banks, those cables encounter more severe thermal limits than multiple buried underground feeder circuits. Planning Engineers use CYMCAP software for determining maximum N-0 and N-1 feeder circuit cable capacities for circuits installed in duct banks.

When underground feeders fill existing duct lines to the rated thermal capacity, and there is no more room in utility easement or street right-of-way routes for additional duct lines from a substation to the distribution load, feeder circuit routing options are exhausted.

2.2.3 Planning Criteria, Distribution Substation Transformers

Transformers have nameplate ratings that identify capacity limits. Xcel Energy's Transformer Loading Guide provides the recommended limits for loading substation transformers adjusted for altitude, average ambient temperature, winding taps-in-use, etc. The Transformer Loading Guide is based upon the American National Standards Institute/Institute of Electrical and Electronic Engineers ("ANSI/IEEE") standard for transformer loading, ANSI/IEEE C57.92.

The Xcel Energy Transformer Loading Guide consists of a set of hottest-spot and top-oil temperatures and a generalized interpretation of the loading level equivalents of those temperatures. The top-oil and hottest-spot temperatures in the Xcel Energy Transformer Loading Guide are the criteria used by Substation Maintenance engineers to determine Normal and Single-Cycle transformer loading limits that Capacity Planning Engineers use for transformer loading analysis. When internal transformer temperatures exceed pre-determined design maximum load limits, the transformer sustains irreparable damage, which is commonly referred to as equipment "loss-of-life". Loss-of-life refers to the shortening of the equipment design life that leads to premature transformer degradation and failure.

Transformer design life is determined by the longevity of all of the transformer components. At a basic level most substation transformers have a high voltage coil of conductor and a low voltage coil electrically insulated from each other and submerged in a tank of oil. Transformer operation generates heat; the more load transformed from one voltage to the other, the more heat; too much heat damages the insulation and connections inside the transformer. Hottest-spot temperatures refer to the places inside the transformer that have the greatest heat, and top-oil temperature limits refer to the maximum design limits of the material and components inside the transformer.

To ensure maximum life and the ability to reliably serve customers, Xcel Energy's loading objective for transformers is 75% of normal rating or lower under system intact conditions. Substation transformer utilization rates below 75% are indicative of a robust distribution system that has multiple restoration options in the event of a substation transformer becoming unavailable because of an equipment failure or required maintenance and construction. The higher the transformer utilization, the higher the risk that service will be interrupted in the event of a transformer outage.

2.2.4 Ongoing Distribution System Reliability Assessment

Distribution Planning regularly evaluates loads to determine overloads. Mitigations (projects) are developed to address the overloads. In general, infrastructure additions that address overloaded distribution system elements is an ongoing process.

Distribution Planning annually compares feeder circuit historical and forecast peak load demands to distribution feeder circuit maximum loading limits to identify feeder circuits overloaded under system intact (N-0) conditions and feeder circuits overloaded under single contingency (N-1) conditions during peak loading.

Distribution Planning also annually compares substation transformer historical and forecasted peak load demands on substation transformers to capacity load limits under system intact (N-0) and single contingency (N-1) conditions. Distribution Planning provides distribution substation transformer loads to the Transmission Planning Department ("Transmission Planning"). Distribution and transmission planners routinely coordinate to identify distribution load impacts to the transmission system.

Distribution Planning then quantifies the amount of overload and the duration of peak loading for feeder circuit and substation transformer overloads under system intact (N-0) and single contingency (N-1 conditions), determines the approximate cost of mitigating the overloads, and identifies the most critical distribution system needs.

When Distribution Planning determines that a distribution system requires additional capacity from a new distribution source, it makes a formal request to Transmission Planning to interconnect to the transmission system. Transmission Planning takes the request and Distribution Planning and Transmission Planning coordinate to develop several options that will address the distribution system deficiencies. Transmission Planning performs analyses to determine the impact of the selected options on the transmission system.

3.0 SOUTH MINNEAPOLIS STUDY AREAS

Distribution Planning conducted this detailed distribution area planning study of the south Minneapolis area distribution delivery system because the area was experiencing more frequent feeder circuit overloads due to an increase in the demand for power. To better isolate the problem, Distribution Planning developed two study areas. They are generally described as follows:

Focused Study Area: First, Distribution Planning examined an area of south Minneapolis, clearly defined by geographic boundaries, that is served electrically by 39 specific distribution feeder circuits and is experiencing the most severe overload conditions. Distribution Planning analyzed the loading levels on these 39 distribution feeder circuits.

Greater Study Area: Second, Distribution Planning examined a larger area of south Minneapolis, defined not by geographic boundaries but by the location of five distribution substations, which house an aggregate total of 15 distribution substation transformers, and the 110 distribution feeder circuits emanating from those five substations. Distribution Planning analyzed the loading levels of these 15 distribution substation transformers.

More detailed descriptions of the study areas are provided below.

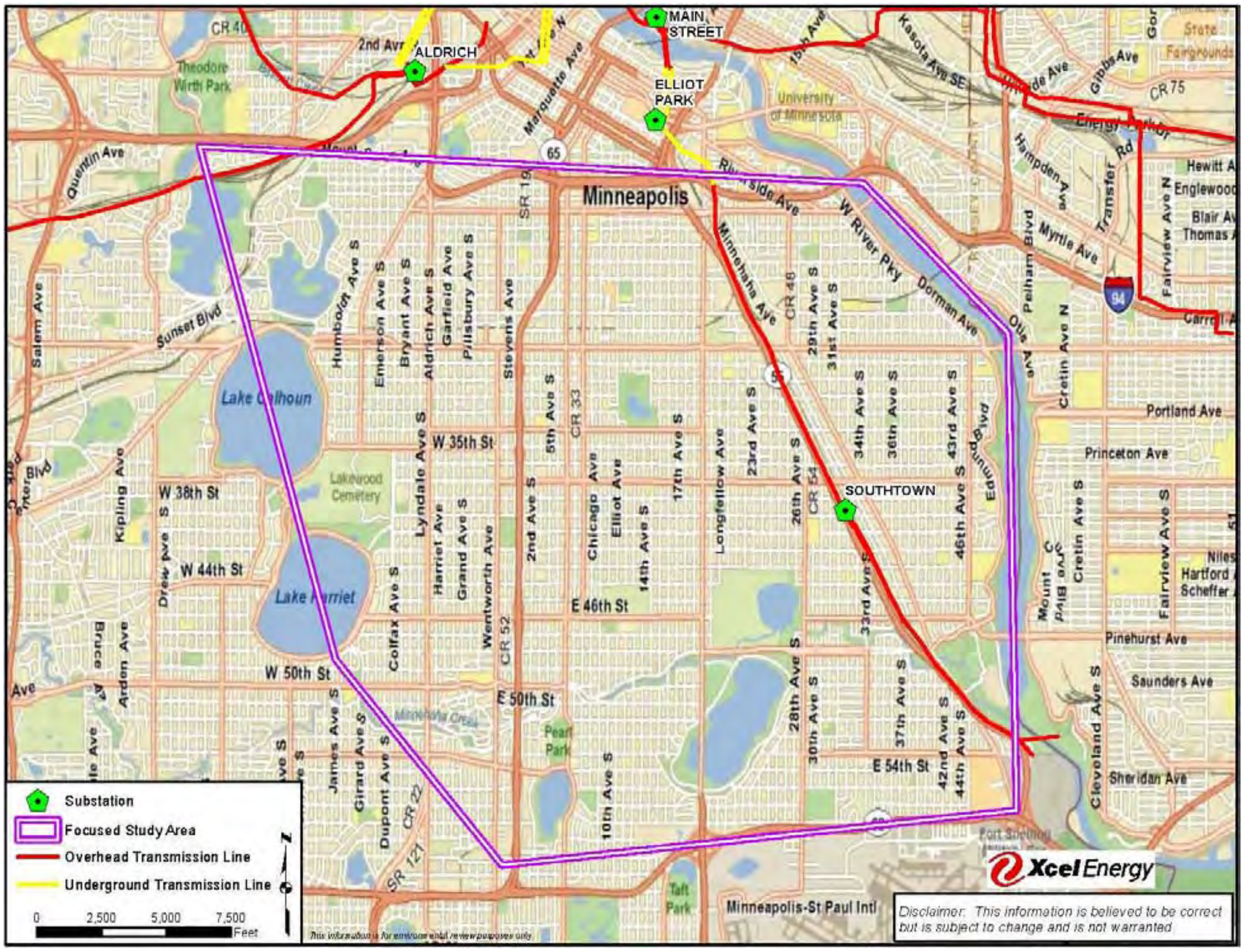
3.1 DESCRIPTION OF FOCUSED STUDY AREA

The Focused Study Area is an approximate 22-square mile area in south Minneapolis with the following geographic boundaries:

> North Boundary: Interstate 394 and Interstate 94 from Cedar Lake on the west to the Mississippi River on the east;
>
> East Boundary: Mississippi River from Interstate 94 on the north to the Crosstown Freeway (State Highway 62) on the south;
>
> South Boundary: State Highway 62 from the Mississippi River on the east to Interstate 35W on the west; and
>
> West Boundary: a line from the intersection of Interstate 35W and Crosstown Freeway to the south end of Lake Harriet at W. 47th Street to the north end of Cedar Lake near the junction of Interstate 394 and Theodore Wirth Parkway.

The Focused Study Area is illustrated in Figure 3.1.

Figure 3.1: Focused Study Area



The Focused Study Area distribution load is primarily fed from three 115 kV transmission lines: Elliot Park – Southtown, Southtown – Cedarvale and Southtown – Shepard, which make up part of the looped 115 kV transmission system that extends from downtown Minneapolis south to the cities of Eagan and St. Paul. Thirty-nine feeder circuits emanating from four substations serve the Focused Study Area. The four substations include Southtown, Aldrich, Elliot Park and Main Street substations. The 39 feeder circuits, all at a distribution voltage of 13.8 kV, provide power to the Focused Study Area.

The Southtown Substation is the only substation within the Focused Study Area. The Southtown Substation, which is located in the southeast quadrant of the Focused Study Area at the northeast corner of Hiawatha Avenue and East 38th Street, has 23 feeder circuits and currently serves the majority of the load in the Study Area. Aldrich, Elliot Park and Main Street substations, which are located outside of the perimeter of the Focused Study Area, serve the majority of the remaining Focused Study Area load. Wilson and St. Louis Park substations serve less than 1%, a statistically insignificant amount, of Focused Study Area load and, therefore, were not included in the analyses completed for the Focused Study Area. Figure 3.2 summarizes the amount of 2008 load that the four primary electric distribution substations and the associated 39 feeder circuits served in the Focused Study Area.

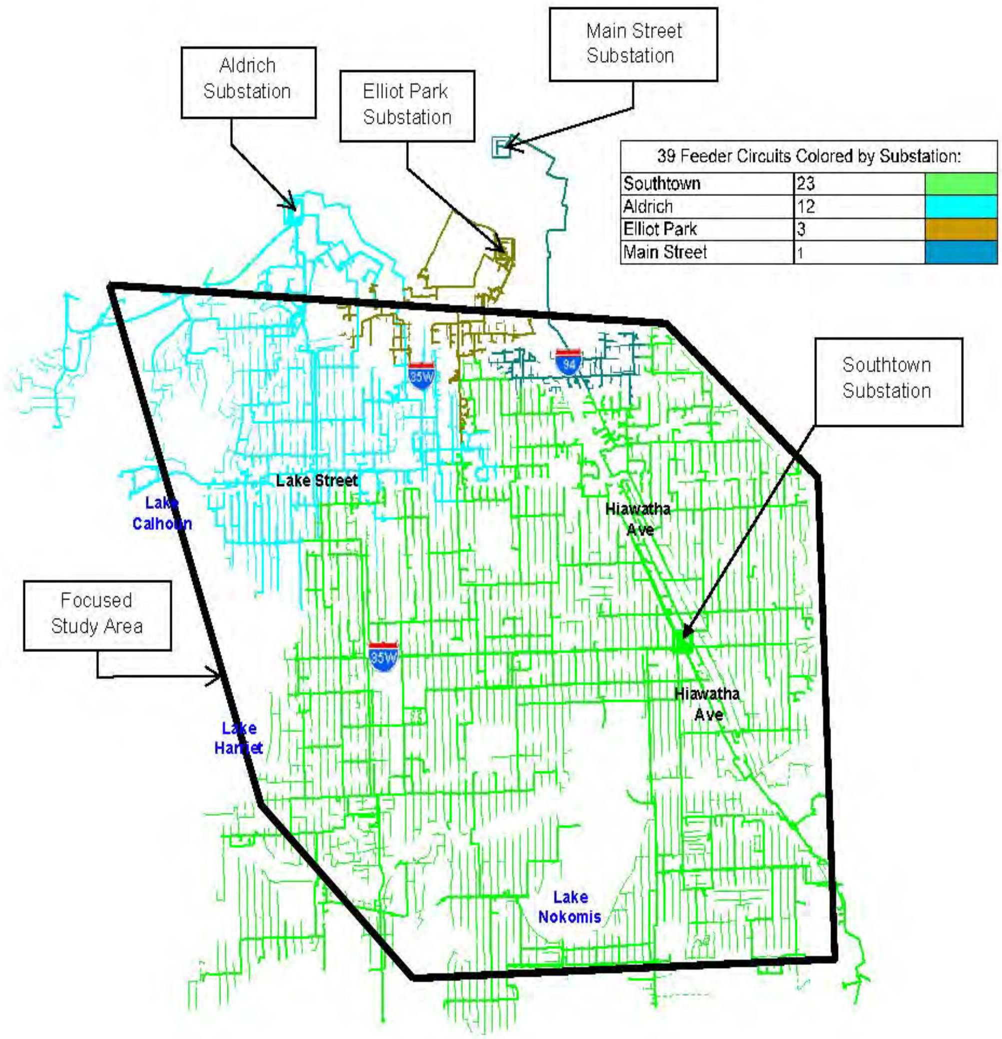
Figure 3.2: Electric Distribution Substations and Associated Feeder Circuits Serving 2008 Load in Focused Study Area

Substations	No. of Feeder Circuits	Amount of Load (kW) Served by Substation	Percentage of Load Served by Substation
Within Focused Study Area			
Southtown	23	184,418	60%
Bordering Focused Study Area			
Aldrich	12	90,430	29.3%
Elliot Park	3	22,954	7.3%
Main Street	1	8,935	2.8%
Total	**39**	306,737	99.4%*

*The remaining 0.6% of Focused Study Area load, which amounts to approximately 1,800 kW, is served by feeder circuits from the Wilson and St. Louis Park substations.

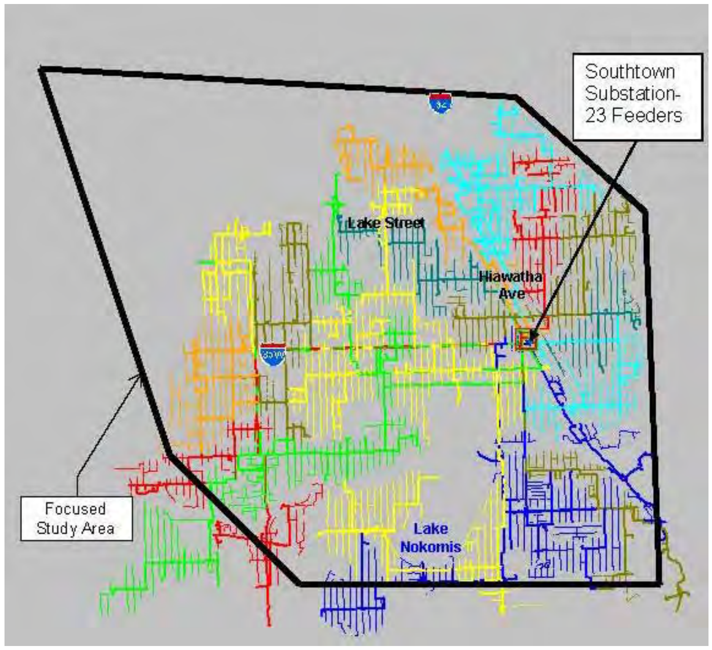
Each of these substations and its respective number of feeder circuits that serve the Focused Study Area load are depicted in Figures 3.3 through 3.7.

Figure 3.3: Primary Electric Distribution Substations and Associated Feeder Circuits Serving Focused Study Area Load



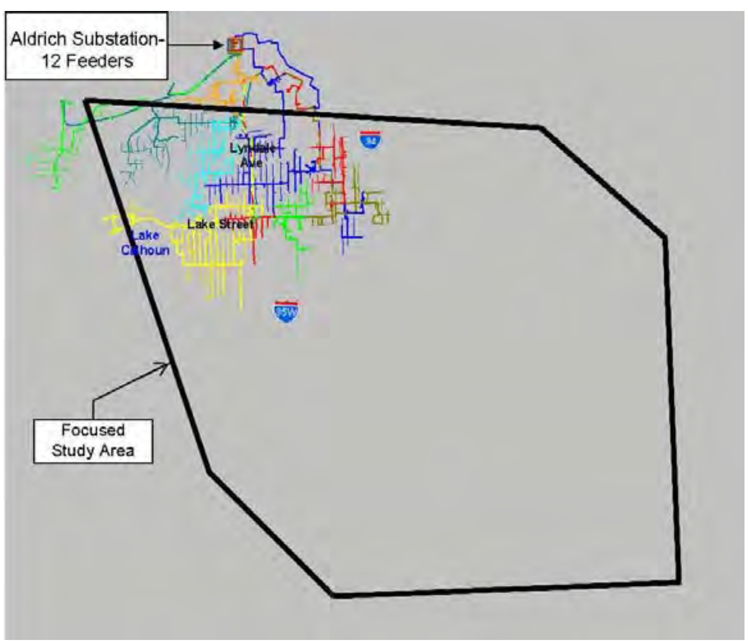
The above Figure 3.3 shows each of the distribution substations and their associated feeder circuits that serve Focused Study Area load. Green feeder circuits are served by the Southtown Substation. Turquoise feeder circuits are served by the Aldrich Substation. Dark yellow feeder circuits are served by the Elliot Park Substation, and dark teal feeder circuits are served by the Main Street Substation.

Figure 3.4: Southtown Substation and Associated 23 Feeder Circuits Serving Focused Study Area Load



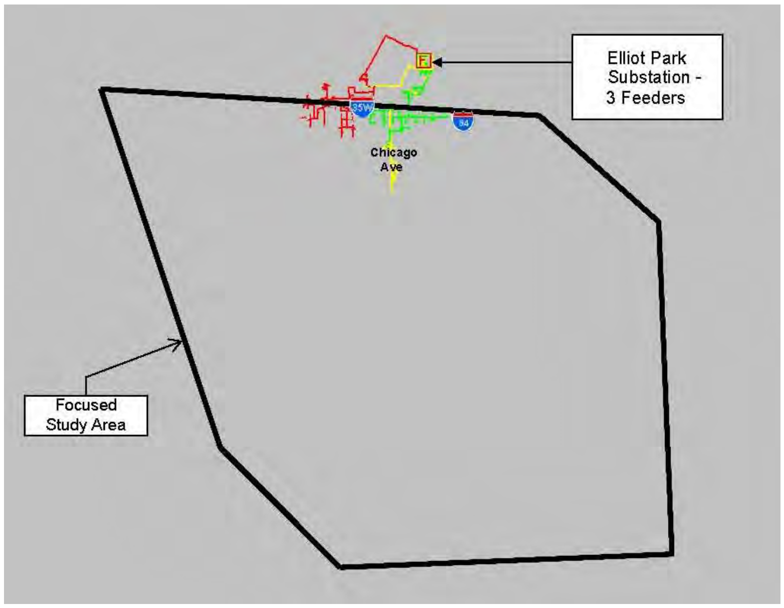
The above Figure 3.4 shows the Southtown Substation and the 23 feeder circuits, each highlighted in a different color, that emanate from that substation and serve Focused Study Area load.

Figure 3.5: Aldrich Substation and Associated 12 Feeder Circuits Serving Focused Study Area Load



The above Figure 3.5 shows the Aldrich Substation and the 12 feeder circuits, each highlighted in a different color, that emanate from that substation and serve Focused Study Area load.

Figure 3.6: Elliot Park Substation and Associated Three Feeder Circuits Serving Focused Study Area Load



The above Figure 3.6 shows the Elliot Park Substation and the three feeder circuits, each highlighted in a different color, that emanate from that substation and serve Focused Study Area load.

Figure 3.7: Main Street Substation and Associated One Feeder Circuit Serving Focused Study Area Load

The above Figure 3.7 shows the Main Street Substation and the one feeder circuit that emanates from that substation and serves Focused Study Area load.

3.2 BACKGROUND OF THE SOUTH MINNEAPOLIS FOCUSED STUDY AREA

During the 1940s and 1950s, four 13.8 kV/4.16 kV substations were installed within the Focused Study Area. These four substations (Nicollet, Garfield, Hiawatha and Oakland substations), which were sourced from the existing 115 kV/13.8 kV Southtown and Aldrich substations, mostly served resistance loads, such as lights, irons, and small motors, as well as some larger loads, including a former Honeywell manufacturing plant near Interstate 35W and 28th Street, which is currently the location of the Wells Fargo Home Mortgage complex. Over the years, south Minneapolis experienced load growth, some of which was the result of increased use of new household technologies and a large amount of which was the result of new development and increasing population in south Minneapolis.

By the 1980s, the growth in the area outstripped the ability of the 4.16 kV distribution sources to support the distribution system. Distribution engineers also determined that the 4.16 kV distribution delivery system was too costly and inefficient to continue serving the growing loads in south Minneapolis, and in the 1980s, the 4.16 kV distribution voltage began to be phased out. Between 1990 and 2007, the Nicollet, Garfield, Hiawatha and Oakland substations in the Focused Study Area were retired, and their associated distribution lines were generally upgraded to the higher distribution voltage of 13.8 kV.

Since the installation of the 13.8 kV/4.16 kV substations, customer electricity usage has grown in south Minneapolis. There has been a great deal of development in the Focused Study Area, especially concentrated along Lake Street and Hiawatha Avenue, but also including the Abbott Northwestern Hospital, Anderson Open Elementary School, various medical offices, a hotel, condominiums, commercial and industrial buildings, and shopping centers.

Average residential usage has also grown substantially. The average residential home now uses more than twice the amount of power than it did 50 years ago. Information from the Minnesota Department of Commerce in a report titled "Energy Policy and Conservation Report 2004" shows that weather normalized electric consumption among Minnesota residential customers increased from just over 4.0 annual megawatt hours in 1965 to just under 9.0 annual megawatt hours in 2000. This report is available on the Minnesota Department of Commerce website at the following location: http://www.state.mn.us/mn/externalDocs/Commerce/Quadrennial_Report__2004_071404102049_2004-QuadReport.pdf. Weather is a major factor in the amount of residential electric load and the increased availability and use of air conditioning in private residences is a major reason for this load growth. This increase in annual usage is also partly due to the number of consumer electronics that are available and commonly in use in homes.

Land use trends in the Midtown area between 1990 and 2000 are summarized in Figure 3.8.

Figure 3.8: Land Use Trends in Midtown Area Between 1990 and 2000

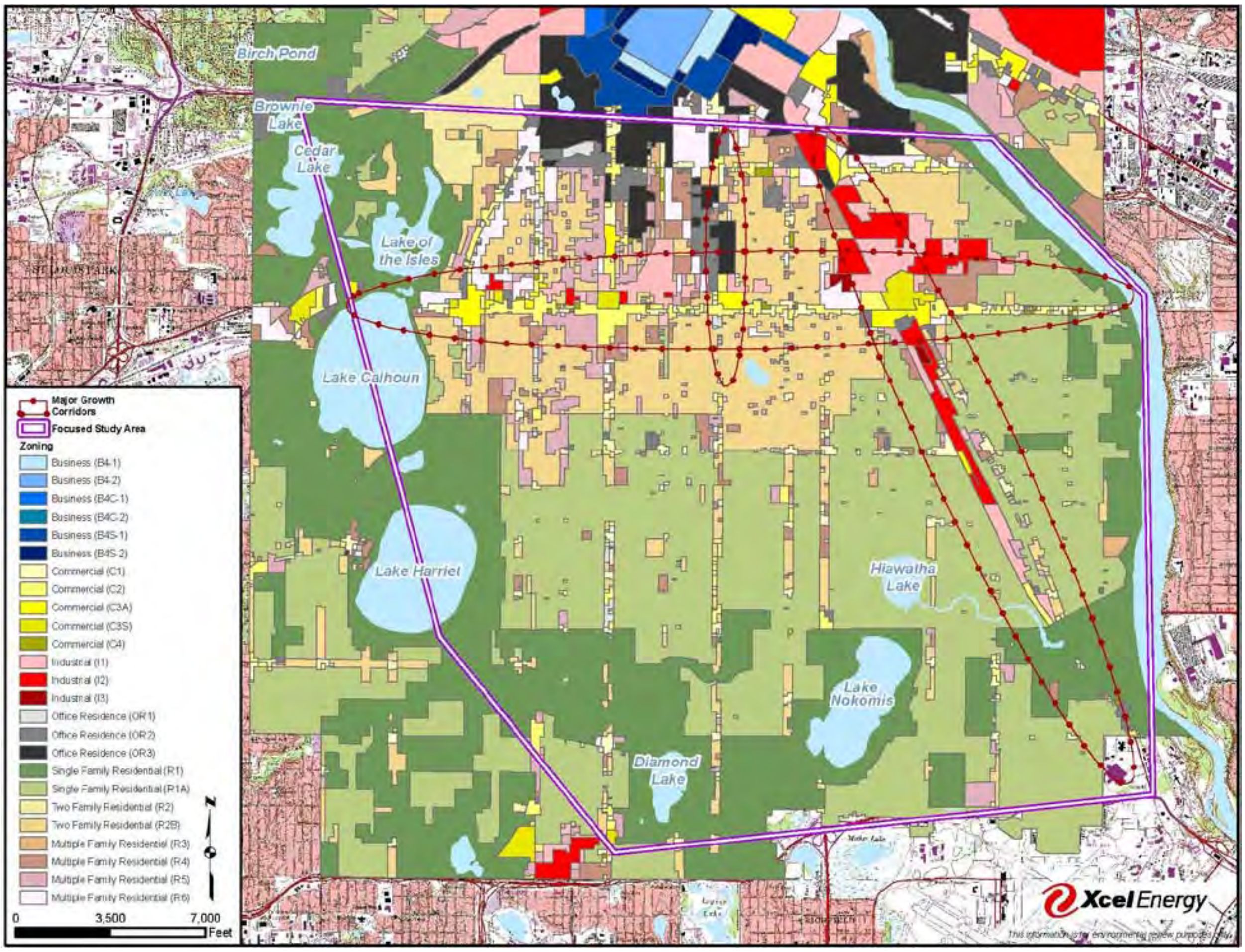
Land Use	1990		2000		Change	
	Acres	Percent	Acres	Percent	Acres	Percent
Retail/Office/General Commercial	182.7	23.2%	197.5	25.1%	14.8	8.1%
Institutional	50.2	6.4%	55.2	7.0%	5.0	9.9%
Commercial Total	**232.8**	**29.6%**	**252.7**	**32.2%**	**19.8**	**8.5%**
Industrial	146.6	18.7%	75.2	9.6%	-71.3	-48.7%
Industrial Total	**146.6**	**18.7%**	**75.2**	**9.6%**	**-71.3**	**-48.7%**
Single Family	131.5	16.7%	206.9	26.3%	75.4	57.3%
Multi-Family	210.3	26.8%	148.7	18.9%	-61.6	-29.3%
Vacant/Undeveloped	10.8	1.4%	17.2	2.2%	6.4	59.0%
Residential Total	**352.6**	**44.9%**	**372.7**	**47.4%**	**20.2**	**5.7%**
Park, Recreational, & Preserve	47.1	6.0%	72.0	9.2%	24.9	52.7%
Open Space Total	**47.1**	**6.0%**	**72.0**	**9.2%**	**24.9**	**52.7%**
Major Highway	3.0	0.4%	9.5	1.2%	6.5	216.3%
Water	3.6	0.5%	3.6	0.5%	0.0	0.1%
Other Total	**6.6**	**0.8%**	**13.1**	**1.7%**	**6.5**	**98.7%**
Grand Total	**785.7**	**100.0%**	**785.7**	**100.0%**	**0.0**	**0.0%**

*Source: Midtown Greenway Land Use Development Plan, The City of Minneapolis Community Planning and Economic Development Department, p. 21 (Feb. 23, 2007), available at http://www.ci.minneapolis.mn.us/cped/docs/Midtown_Greenway_full_plan_noapp.pdf.

The loads in south Minneapolis are expected to continue to grow. Planning reports issued by the City of Minneapolis planning department describe City plans to facilitate continued large-scale redevelopment in the south Minneapolis area over the next few years. Current and future redevelopment is concentrated along Lake Street and the Hiawatha Light Rail Transit ("LRT") corridors and in areas adjacent to those corridors (*e.g.*, Midtown Exchange, Abbott Northwestern Hospital, Minneapolis Children's Hospital and the Veterans Administration hospital). The Minneapolis Plan (Mar. 24, 2000; available at http://www.ci.minneapolis.mn.us/cped/mplsplan.asp) and the Midtown Greenway Land Use Development Plan (Feb. 23, 2007) designate planned land use along these two major growth corridors to include higher density housing, commercial, public/institutional, transportation/communications/utilities, light/medium industrial and other land use types. The Minneapolis planning reports also provides that the City intends to continue to promote business retention and expansion and residential growth within the City. The City plans to do this by developing and maintaining the City's infrastructure to help serve the needs of businesses and residents and to increase its supply of housing. These planned developments and improvements will increase load demand in the Focused Study Area.

Figure 3.9 delineates the existing major growth corridors in the Focused Study Area.

Figure 3.9: Existing Major Growth Corridors in Focused Study Area



Zoning Data Source: City of Minneapolis, Department of Community Planning and Economic Development, Planning Division. Revised March 5, 2009.

The 13.8 kV distribution delivery system in south Minneapolis has struggled to keep up with the increasing customer demand for electricity. And because the Southtown Substation is the only remaining distribution substation source in the Focused Study Area, the 13.8 kV feeders in that area are serving increasingly larger loads farther from the nearest substation source, resulting in higher electrical line losses and reduced customer reliability. In response to this load growth Xcel Energy has taken numerous steps to maintain reliable service in the Focused Study Area, including reinforcing existing feeder circuits, adding new feeder circuits, replacing equipment damaged by overloads, and rearranging feeder circuits to maintain service during overloads. See Appendix A for a summary of feeder circuit improvements completed in the Focused Study Area in recent years.

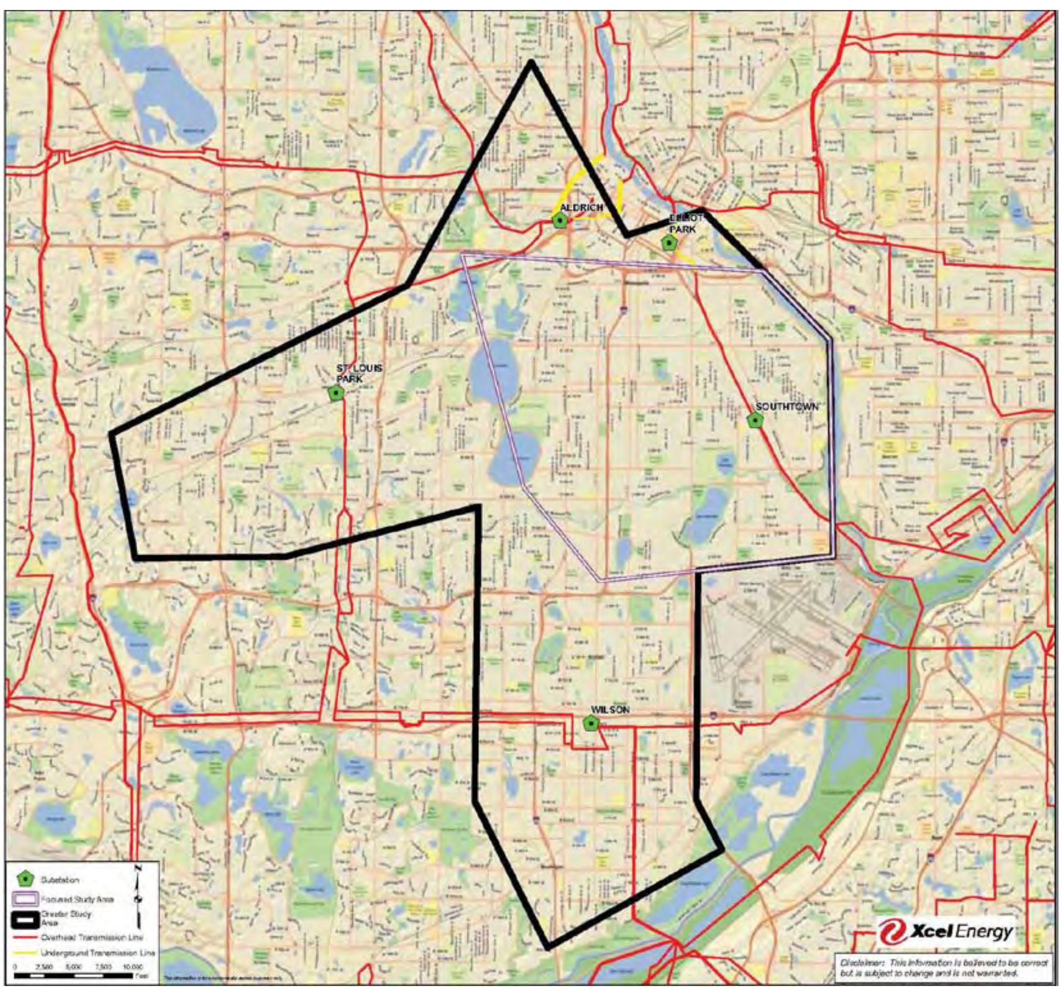
In 2005 and 2006, the south Minneapolis distribution delivery system experienced historical peak loads. It became apparent that the distribution delivery system in the area was becoming increasingly vulnerable to more and longer overloads. As a result, Distribution Planning Engineers in 2007 intensified their analysis of the south Minneapolis distribution delivery system, concentrating in particular on the Focused Study Area to develop a more robust, longer-term solution to address the continued growth in power demand.

3.3 DESCRIPTION OF THE GREATER STUDY AREA

Distribution Planning also examined the south Minneapolis electricity distribution delivery system within the Greater Study Area, in part, to assess the availability of existing capacity, if any, on distribution transformers near the Focused Study Area.

The Greater Study Area consists of the geographic area served by five substations, including Southtown, Aldrich, Elliot Park, St. Louis Park and Wilson substations, and their associated substation transformers and circuit feeders. The Greater Study Area, which covers an approximate 60 square-mile area, is illustrated in Figure 3.10.

Figure 3.10: Greater Study Area



The Greater Study Area distribution load is served by 110 feeder circuits, all at a distribution voltage of 13.8 kV. These feeder circuits are served from fifteen distribution substation transformers that are housed at a total of five substations (three transformers per substation). The five substations, in turn, are served from 115 kV transmission lines that loop the Greater Study Area.

Figure 3.11 summarizes the amount of 2008 load that the electric distribution substations served in the Greater Study Area.

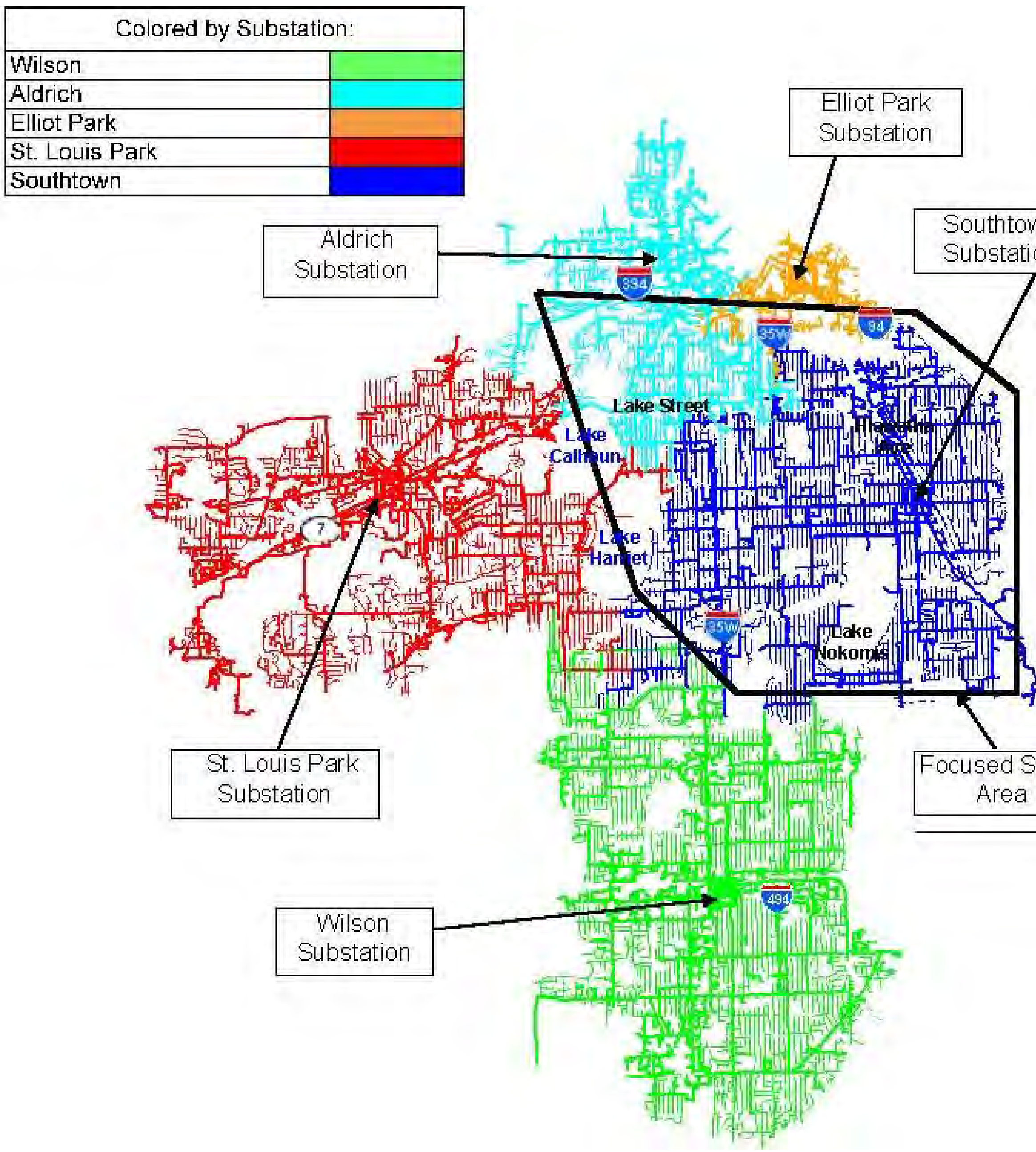
Figure 3.11: 2008 Non-Coincident Substation Transformer Load in Greater Study Area

Substations	No. of Feeder Circuits	Load (in kW) Served by Substation	% of Load Served by Substation
Southtown	23	169,070	22.4%
Aldrich	21	137,033	18.2%
Elliot Park	19	116,881	15.5%
St. Louis Park	21	142,149	18.9%
Wilson	26	188,348	25.0%
Total	**110**	753,181	100%

Main Street Substation was not considered in the Greater Study Area because the one feeder circuit from the Main Street Substation presently serving customer load in the Focused Study Area is not part of future plans to serve load in either the Focused or the Greater Study Areas. The one (1) Main Street Substation feeder circuit traverses several miles and crosses the Mississippi River to reach the study areas. All Main Street feeder circuits crossing the Mississippi River were damaged when the Interstate 35W bridge collapsed in 2007. As a result, 10,000 kW (or approximately 10 MW) of load that was normally served by the Main Street Substation was transferred to Elliot Park Substation and is accounted for in the above Figure 3.11. A total of 52,000 kW (or approximately 52 MW) of Greater Study Area load, however, is not accounted for in the above Figure 3.11. Between 2000 and 2008, an aggregate total of 52 MW of Greater Study Area load was transferred outside of the Greater Study Area to adjacent substations with available capacity because the Aldrich and St. Louis Park substations in the Greater Study Area were overloaded. In their analysis of substation transformer load growth in the Greater Study Area, which is summarized in Section 5.0 of this Study, Distribution Planning Engineers took into account load transferred out of the Greater Study Area to adjacent substations.

Each of the substations and its respective number of feeder circuits that serve Greater Study Area load are depicted in Figure 3.12.

Figure 3.12: Substations and Associated Feeder Circuits Serving Greater Study Area Load



4.0 ANALYSIS OF THE SOUTH MINNEAPOLIS ELECTRIC DISTRIBUTION DELIVERY SYSTEM IN THE FOCUSED STUDY AREA

4.1 FEEDER CIRCUITS

Distribution Planning assessed the electric distribution delivery system's ability to serve existing and future electricity loads in the Focused Study Area by evaluating the historical and forecasted load levels and utilization rates of the 39 feeder circuits that serve the Focused Study Area over a period of 20 years (*i.e.*, target year of 2028). The Planning Engineers then identified existing and anticipated capacity deficiencies resulting in overloads during N–0 (system-intact) and N–1 (single contingency) operating conditions.

In conducting this Study, Planning Engineers relied on the following resources:

- <u>SynerGEE Electric software package</u>. SynerGEE is a software tool that can be used to explore and analyze feeder circuit reconfigurations. When historical peak load data is added from the Distribution Asset Analysis ("DAA") software package, SynerGEE is capable of providing load flow and voltage regulation analysis. SynerGEE is a tool that can generate geographically correct pictures of tabular feeder circuit loading data. This functionality has been achieved through the implementation of a Geographical Information System ("GIS") extraction process. Through this process, each piece of equipment on a feeder, including conductor sections, service transformers, switches, fuses, capacitor banks, etc., is extracted from the GIS and tied to an individual record that contains information about its size, phasing, and location along the feeder. All 39 distribution feeders that are part of the Focused Study Area were extracted from the GIS software and imported into SynerGEE.

- <u>Xcel Energy Distribution Planning Load Forecast for N-0 feeder circuit and substation transformer analysis</u>. Planning Engineers used DAA to record historical non-coincident peak loads on distribution feeder circuits and distribution substation transformers. Distribution Planning Engineers annually examine each distribution feeder circuit and distribution substation transformer for peak loading. They use specific knowledge of distribution equipment, local government plans and customer loads to forecast future electrical load growth. Planning Engineers consider many types of information for the best possible future load forecasts including: historical load growth, customer planned load additions, circuit and other distribution equipment additions, circuit reconfigurations, and local government sponsored development or redevelopment.

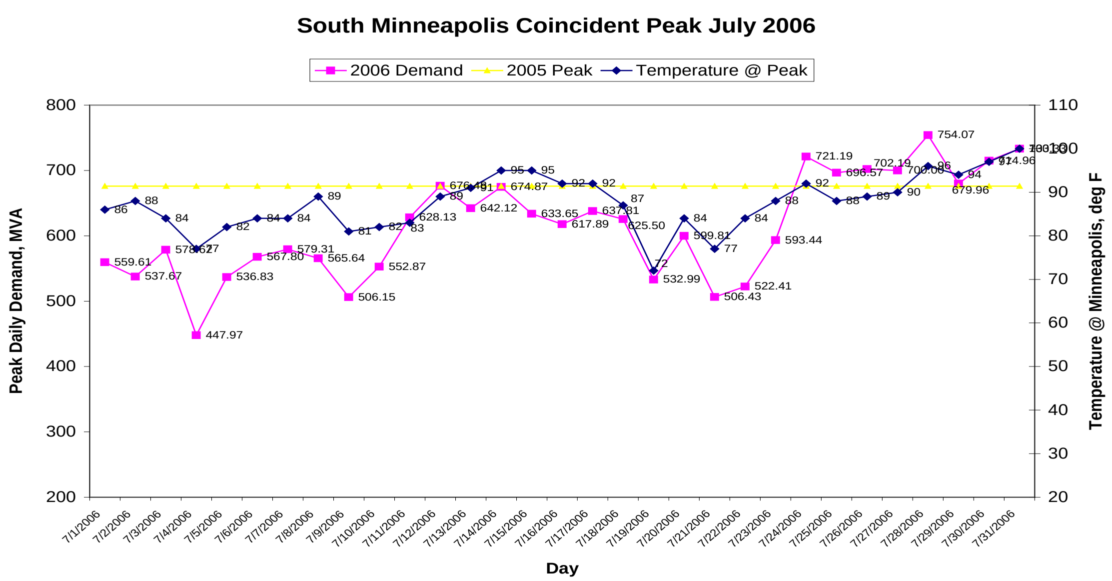
- <u>Xcel Energy Feeder Status Sheets for feeder circuit N-1 load allocation and N-1 analysis</u>. Planning Engineers used Feeder Status Sheet software ("FSS") to allocate measured peak loads to main line feeder sections. Engineers validate and record feeder main line additions and reconfigurations using this tool. They analyze the N-1, first contingency breakdown of each distribution feeder circuit for the forecasted years.

- Xcel Energy Substation One Line Drawings. Planning Engineers used Xcel Energy Computer Aided Design software ("CAD") to develop CAD drawings modified by substation engineers as needed to reflect present substation configurations.
- Xcel Energy Distribution Feeder Maps. Planning Engineers used Xcel Energy CAD software to develop CAD drawings to reflect present feeder circuit mainline and tap configuration.
- South Minneapolis Maps. Planning Engineers used Internet live search maps to make an ad hoc map of the area, GIS software and SynerGEE software tool to make geographic based pictures of the feeder circuit configuration and to illustrate feeder circuit loading levels.

4.1.1 Feeder Circuit Historical Load and Load Forecasts

Feeder circuit peak loading in the south Minneapolis area specifically and the Twin Cities metropolitan area are measured during the summer. Both feeder circuit and substation transformer load correlates to summer temperature based on customer air conditioning usage response to summer temperature. This is illustrated in Figure 4.1, which compares the Greater Study Area Substation transformer measured peak load and outside temperature during July 2006.

Figure 4.1: July 2006 Greater Study Area Substation Peak Load and Outside Temperatures



Coincident Peak July 2006 graphed with South Minneapolis Temperature

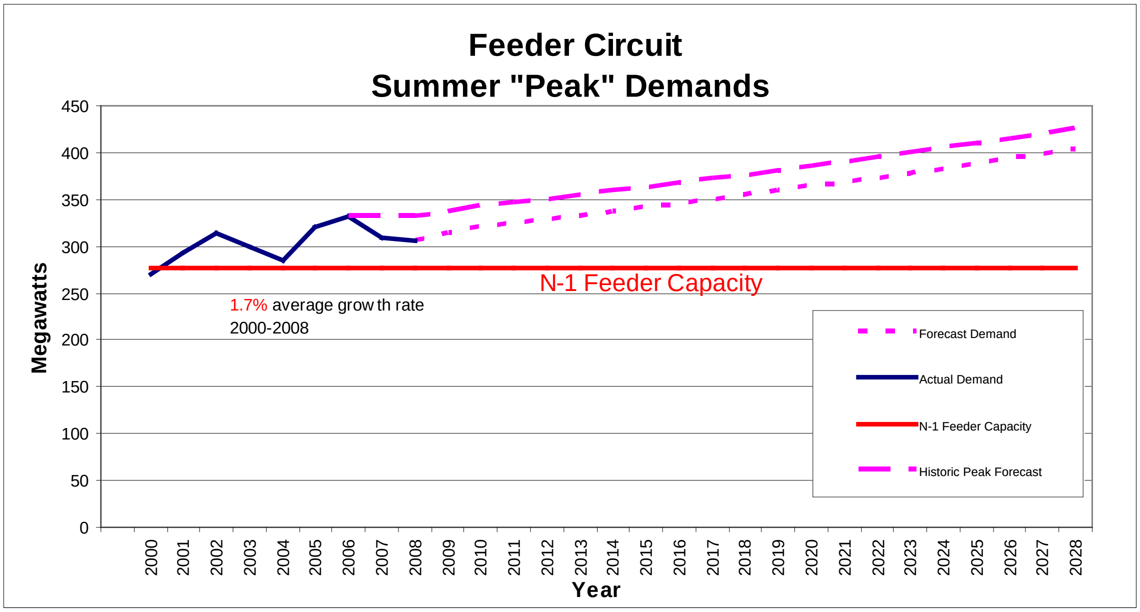
Each distribution feeder in the south Minneapolis area has three phase meters located in the substation which are read monthly and the data recorded in Passport, a record-keeping software. These meters record the monthly peak for the feeder. The 39 distribution feeders in the Focused Study Area also have a SCADA system that monitors the real time average or three phase amps on the feeder. This system feeds a SCADA data warehouse and the DAA warehouse where hourly data is stored so the feeder load history can be viewed by Electric Capacity Planning and Field Operations. When three phase load data is available, the highest recorded phase measurement is used in the distribution forecast. Each feeder circuit non-coincident peak history from 2000 through 2008 is used to forecast 2009 through 2028 peak loads.

Measured peak loads fluctuate from year to year due to the impacts of duration and intensity of hot weather and customer air conditioning usage. In the Focused Study Area, feeder circuit load fluctuates in a bandwidth of 15 MW to 22 MW from historic peaks occurring in 2002 and 2006 and successive cooler years. Even though the measured peak load decreases, the historic peak represents latent load levels that will recur in years that have higher temperatures than in 2008. The measured peak load for feeders increased an average of 1.7% per year in the eight years between 2000 and 2008, resulting in a peak load growth of approximately 37 MW. The historical and forecasted loads for the 39 feeder circuits serving the Focused Study Area from 2000 through 2028 are summarized in Appendix B.

Distribution Planning took a conservative outlook for forecasting feeder circuit load for this Study because of anticipated customer conservation and a soft economy. Distribution Planning used a lower than historical forecast growth rate of less than 1.3% to forecast load levels on the 39 feeders for the next 20 years, representing growth in demand of approximately 50 MW by 2018.

Figure 4.2 is a linear depiction of the load growth ("forecast demand") on the 39 feeder circuits in the Focused Study Area from 2000 through 2028, using the conservative peak loads forecast based on the cooler year peak loads from 2008. Figure 4.2 also shows the upper limit peak load forecast using 2006 historic peak loads ("historic peak forecast"), which is 22 MW above the conservative peak load forecast shown in the figure. Actual peak loads will likely fall between the conservative forecast and the historic 2006 peak levels.

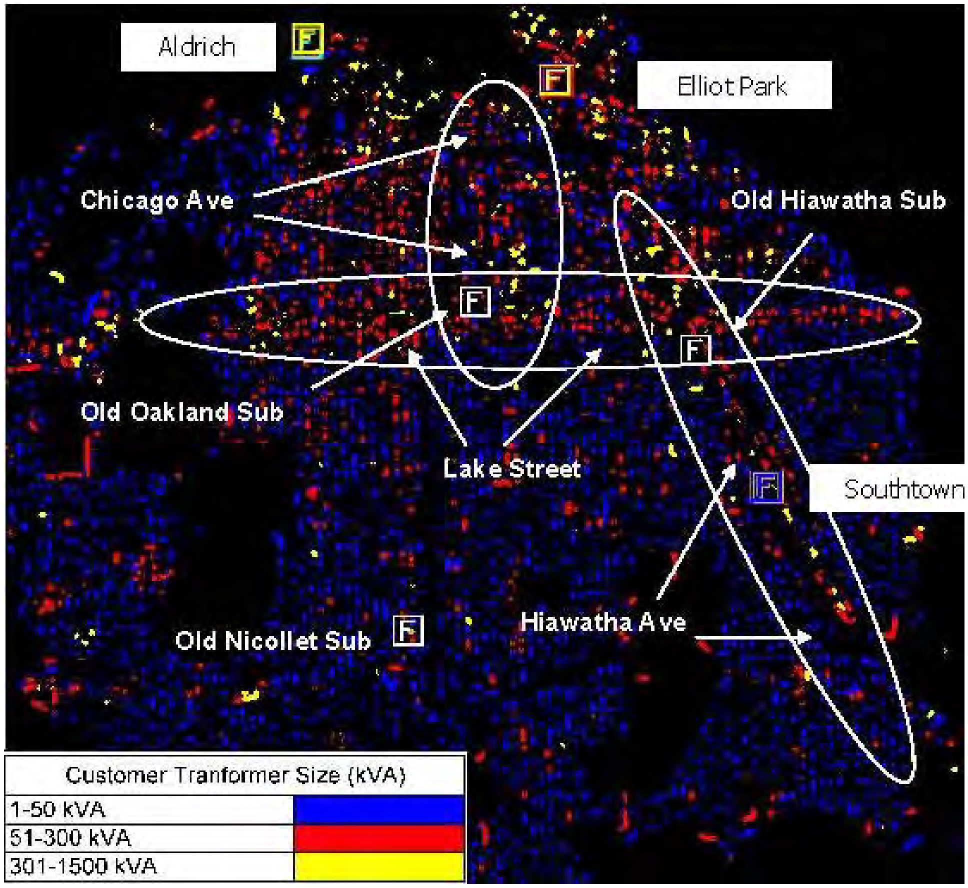
Figure 4.2: Historical and Forecasted Load Growth on 39 Feeder Circuits in Focused Study Area



Over time, demand on the distribution system generally trends upward, with some dips due to weather or economic downturns. The historic downturns have been followed by increases in demand that reach levels equal to or greater than the prior peak. For example, from the year 2002 to the year 2004, demand declined by approximately 30 MW. Then, from the year 2004 to the year 2006, demand increased again by approximately 46 MW, reaching a new peak of 331 MW. From year 2006 to 2008, there has been a similar decline in demand from the historical 2006 peak by approximately 22 MW. It can be reasonably expected that 2006 summer peak load levels will recur within the next several years once temperatures approach the same levels that occurred in the 2006 summer season as illustrated in the above Figure 4.2.

In addition to peak loads, Planning Engineers researched existing customer load density. As customer load grows in developed areas such as the Focused Study Area, distribution transformers are changed to higher capacity equipment when customer demand exceeds the capacity of the original transformer. Distribution transformers are an excellent indicator of customer electrical loading and peak electrical demand. Figure 4.3 is a graphic, developed using SynerGEE software, illustrating distribution transformer installation by size (which indicates present customer load density) in the Focused Study Area.

Figure 4.3: Distribution Transformer Sizes (Which Is Indicative of Customer Load Density) in Focused Study Area (2006)



The customer load serving transformers shown in Figure 4.3 are colored based on the size of the transformer. The largest commercial customers in south Minneapolis are shown in yellow. Customers in large multi-residence buildings (more than 100 units), large multi-use buildings (*e.g.*, Midtown Exchange), large retail stores (*e.g.*, K-Mart), or corporate data centers typically have one or more transformers depicted as yellow dots. Customers in small and mid-sized commercial buildings, including retail stores and restaurants are served by smaller transformers that are shown as red. Residential customers and other lowest usage customers are shown in blue. Red and yellow show high density load corridors along Lake Street, Hiawatha Avenue, Excelsior Boulevard, and Chicago Avenue.

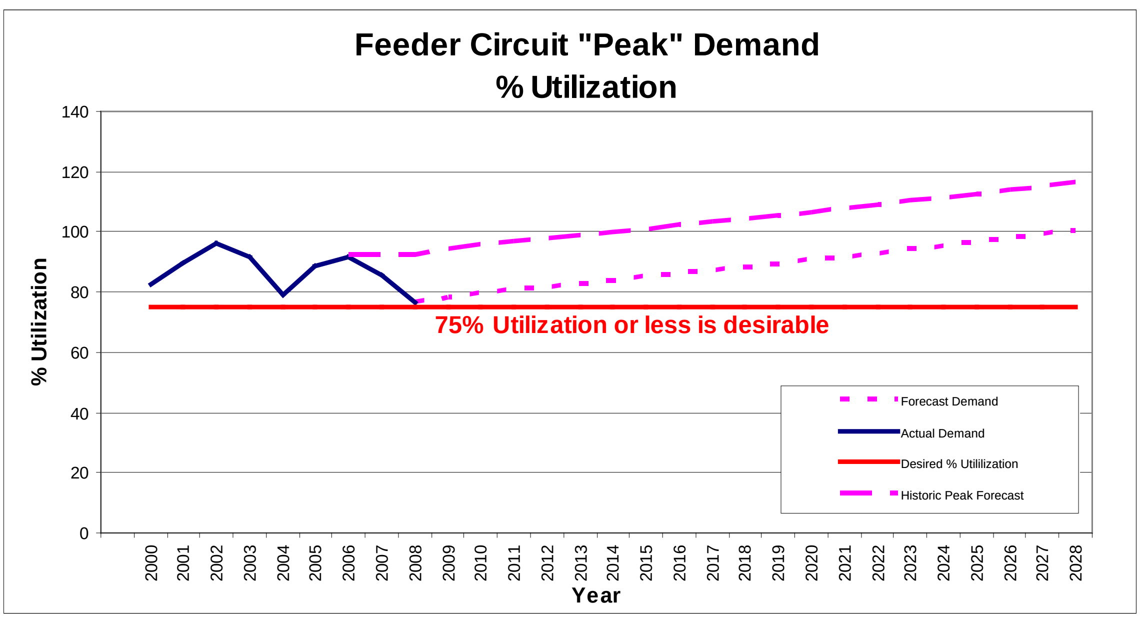
As shown in Figure 4.3 and discussed in Section 3.2 of this Study, the highest load density is concentrated along Lake Street, Hiawatha Avenue and Chicago and Park Avenue corridors. The load density in this area is due in part to various redevelopment projects that have been implemented in the area over the past years. The City of Minneapolis is several years into a redevelopment initiative demonstrated by the Sears Building redevelopment as Midtown Exchange with new high density residential, hotel and surrounding buildings. The State of Minnesota installation of light rail along Hiawatha Avenue is complemented by City of Minneapolis and contractor high density residential projects. Recent improvements along the Chicago Avenue corridor by Abbott Northwestern Hospital and Children's Hospitals and redevelopment north and south of these large hospitals have contributed to historical and continued electrical load growth in the area.

4.1.2 Feeder Circuit Overloads and Utilization Percentages

As discussed in Section 2.0, Distribution Planning aims to maintain utilization rates at or below 75% on distribution feeder circuits to help ensure a robust distribution system capable of providing electrical service under first contingency N-1 conditions. Therefore, to assess the robustness of the system in the Focused Study Area over time, Planning Engineers analyzed the historical utilization rates and projected utilization rates based on forecast demand. This analysis revealed utilization rates of feeder circuits above 75% in the Focused Study Area despite the addition of six (6) new feeder circuits between 2000 and 2008. Current average utilization rates remain above desired 75% levels. Forecast average utilization rates will exceed 90% by approximately 2015 unless system improvements are made.

Planning Engineers examined the historical loading and utilization of the 39 feeder circuits that serve Focused Study Area load. Figure 4.4 shows the conservative forecast linear growth ("forecast demand") of feeder circuit utilization for these 39 feeder circuits between 2000 and 2028 as well as the upper-limit peak load forecast ("historic peak forecast") based on 2006 peak load levels.

Figure 4.4: Focused Study Area - 39 Feeder Circuits, Utilization Percentage



The feeder circuit load history shown is actual average non-coincident peak loading of all 39 feeder circuits measured at the beginning of the feeder circuit in the substation. The sum of the individual feeder circuit peak loads is compared to the sum of the individual feeder circuit capacities to calculate feeder circuit utilization each year. Average load growth for the time period is calculated by comparing total non-coincident feeder circuit loads from the beginning to the end of the comparison period. Feeder utilization trended lower between 2000 and 2008 because of the addition of six new feeder circuits in the Focused Study Area.

A peak load forecast starting from the historic peak 2006 level provides an upper forecast limit of more than 16% above the conservative forecast utilization levels in Figure 4.4.

The feeder circuit load is forecasted for each feeder circuit. Feeder circuit load forecast evaluation, trending method, considers a combination of historical growth, customer reported load additions, local government and developer projects or plans, and any additional information that impacts the circuit load growth. The table entries were calculated using the 39 individual feeder circuit forecasts provided in Appendix B.

Figure 4.5 provides additional detail on the historical and anticipated utilization percentages and overloads for the 39 feeder circuits in the Focused Study Area for various years between 2000 and 2028.

Figure 4.5: Summary of Feeder Circuit Utilization and Overloads for Focused Study Area

Historical Feeder Circuit Utilization and Overloads And Forecast Using Trending Method									
	2000	**2004**	**2006**	**2008**	**2009**	**2013**	**2018**	**2023**	**2028**
# of Circuits	33	36	39	39	39	39	39	39	39
MW Capacity	<327	<362	<402	402	402	402	402	402	402
Feeder Actual	2000-2008 Average								
% Growth	1.7%								
% Utilization	>83%	>79%	>83%	76%					
Forecast					2009-2018 Average			2019-2028 Average	
% Growth					1.28%			1.25%	
% Utilization					78%	83%	88%	94%	100%
N-0 Overloads									
# Severe >115%	5	6	4	2	4	4	8	12	15
# of Circuits	10	10	12	6	7	13	16	18	22
MW > 100%	15.8	17.0	12.2	7.6	9.2	14.1	24.3	37.2	52.6
N-1 Conditions									
# Circuits > 75%	21	21	24	24	25	27	27	28	31
MW > 75%	47.3	51.0	54.7	38.7	46.4	58.3	73.9	94.1	113.8

The information in Figure 4.5, which was extracted from the detailed feeder circuit forecast data in Appendix B, shows that the Focused Study Area distribution system experienced steady peak growth in the decade leading up to 2008 loads that increasingly exceeded circuit capacities with increasing numbers of circuits overloaded in both system intact N-0 and first contingency N-1 conditions. Even when the number of circuits overloaded does not increase, the quantity of overloads increases. Figure 4.6 summarizes the additional feeder circuit capacity (in MW) needed to mitigate the overloads detailed in Figure 4.5. A single new 12 MW feeder circuit will serve 9 MW of load at 75% utilization.

Figure 4.6: Summary of Feeder Circuit Capacity Required to Mitigate Overloads

Minimum Number of Feeders Required to Correct N-0 and N-1 Overloads									
	2000	**2004**	**2006**	**2008**	**2009**	**2013**	**2018**	**2023**	**2028**
N-0 Deficiency (MW)	15.8	17.0	12.2	7.6	9.2	14.1	24.3	37.2	52.6
Minimum # of New Feeders Needed	2	2	2	2	2	2	3	5	7
N-1 Deficiency (MW)	47.3	51.0	54.7	38.7	46.4	58.3	73.9	94.1	113.8
Minimum # of New Feeders Needed	6	6	7	5	6	7	9	11	13

Note: Minimum number of feeders assumes 12 MW feeder circuits loaded to 75% or less.

This analysis shows that there is currently a deficit of approximately 55 MW in the Focused Study Area based on the 2006 peak loading and the system capacity under N-1 conditions. 2006 loading levels represent established overloads for connected load that exists on the electrical system and peak loading that has been previously reached under the most recent hottest weather conditions. By 2018, these overloads are forecast to increase to 74 MW.

Areas like south Minneapolis that experience strong and steady growth and redevelopment go through several stages of overload operating conditions, starting with isolated feeder circuit overloads and progressing to widespread overloads that exceed substation transformer capacity limits.

Isolated feeder overloads, which can be characterized by average feeder utilization percentage less than 75% when substation transformer utilization is also 75% or less, typically occur when there is redevelopment that increases load demand within a small part of the distribution system. While the average utilization percentage generally indicates the loading level of the entire Focused Study Area, feeders that are located geographically distant from each other can have either satisfactory capacity to serve customer load or alternately measure severe overloads. This variant is often caused by customer load mobility that can be characterized by new load or area redevelopment and revitalization.

There are many locations over the past several years in south Minneapolis where several single-family homes in a primarily residential area have been redeveloped as a multi-story, multi-residence building with new commercial or retail businesses on the first floor. This can increase the distribution customer loads to as much as 10 times the previous load. There are examples of this near Franklin and Nicollet and near the Veterans Administration Hospital in the Focused Study Area. Load increases in existing commercial or industrial areas as new owners occupy and redevelop or expand an existing building or area. After a new customer purchased a former Midtown manufacturing facility and constructed a new building, existing load at the property more than doubled.

Widespread feeder overloads, which can be characterized by average feeder utilization percentage of more than 75% when substation transformer utilization is more than 75%, typically occur in distribution areas due to a combination of customer addition of spot loads and focused redevelopment by existing customers, developers or City initiatives. Distribution systems that start out with adequate N-1 and N-0 capacity, can quickly progress beyond isolated overloads when a large part of the distribution system is redeveloped or focused redevelopment is targeted in an area or along a corridor.

Expansion of medical related customers along Chicago Avenue north of Lake Street, the multi-year redevelopment of Lake Street progressing east from Interstate 35W, redevelopment along the new Hiawatha Avenue light rail corridor, and the area wide re-insulation accompanied by 100% air conditioning saturation along higher airport noise corridors are examples that resulted in widespread feeder circuit overloads in south Minneapolis.

To better illustrate the number, concentration and location of the historical and forecasted overloads, Planning Engineers developed distribution system maps depicting the overloaded feeders in N-0 system intact and N-1 first contingency operating conditions for loads above 75% of capacity limits in 2006 and future forecast years 2009 through 2028. These distribution system maps are in Appendix C. Two of those maps are depicted in Figures 4.7 and 4.8, respectively. The color codes in the distribution system maps represent rows in the Figure 4.5 table for the labeled years as follows:

> <u># Severe > 115%, N-0 Overloads</u>: The quantity of feeder circuits that are severely overloaded under system intact conditions are identified as shown in red.

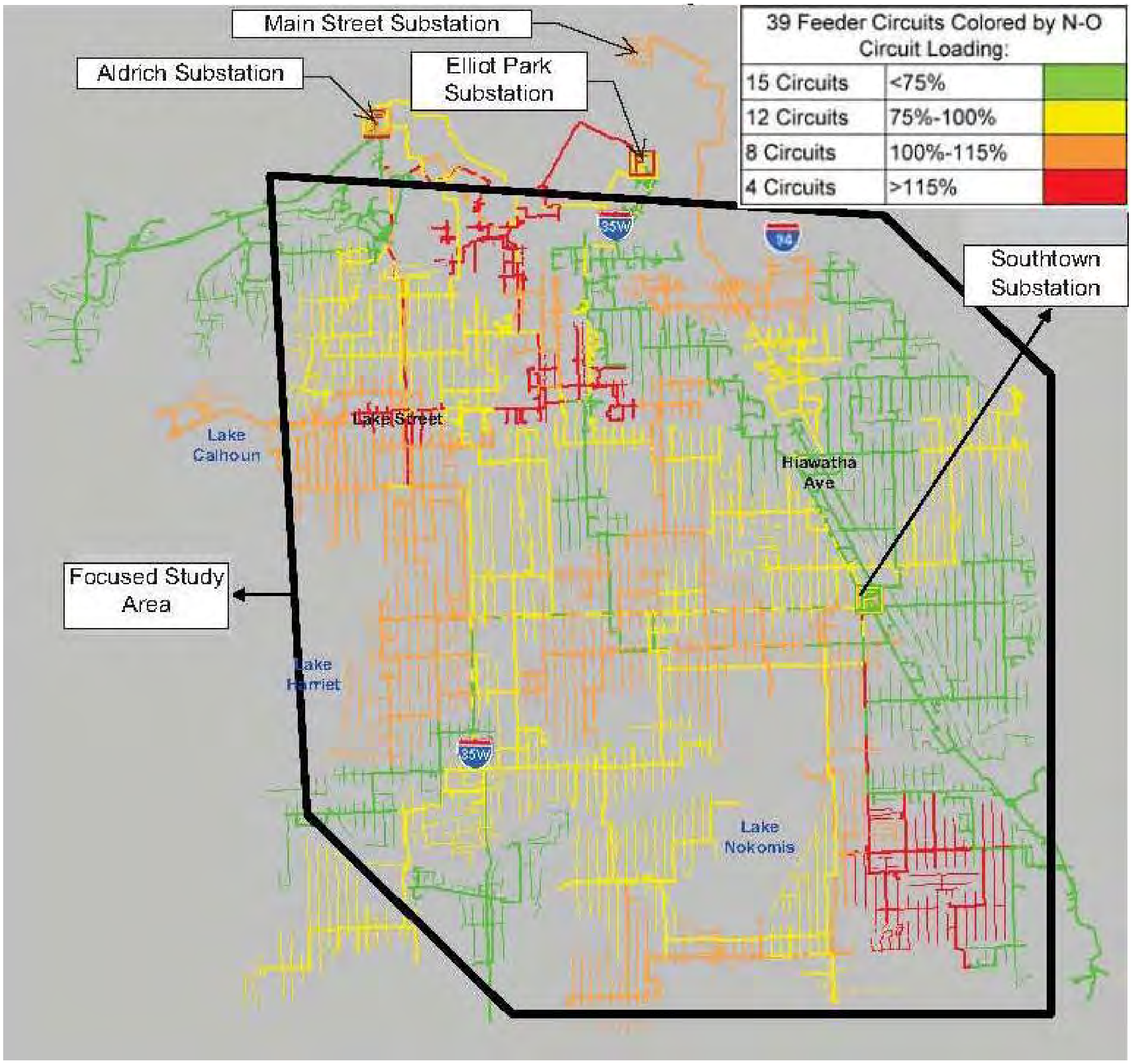
> <u># of Circuits, N-0 Overloads</u>: The quantity of feeder circuits that are overloaded under system intact conditions are identified as shown in orange and red depending on the severity of the overload with red feeder circuits having the most severe overloads.

MW > 100%, N-0 Overloads: The sum of the system intact overloads, in MW for the number of circuits that are identified as overloaded and shown in orange and red.

Circuits > 75%, N-1 Conditions: The quantity of feeder circuits that are loaded above 75% capacity indicating first contingency overload conditions are identified as shown in yellow, orange, and red. Yellow circuits are feeder circuits with first contingency overloads.

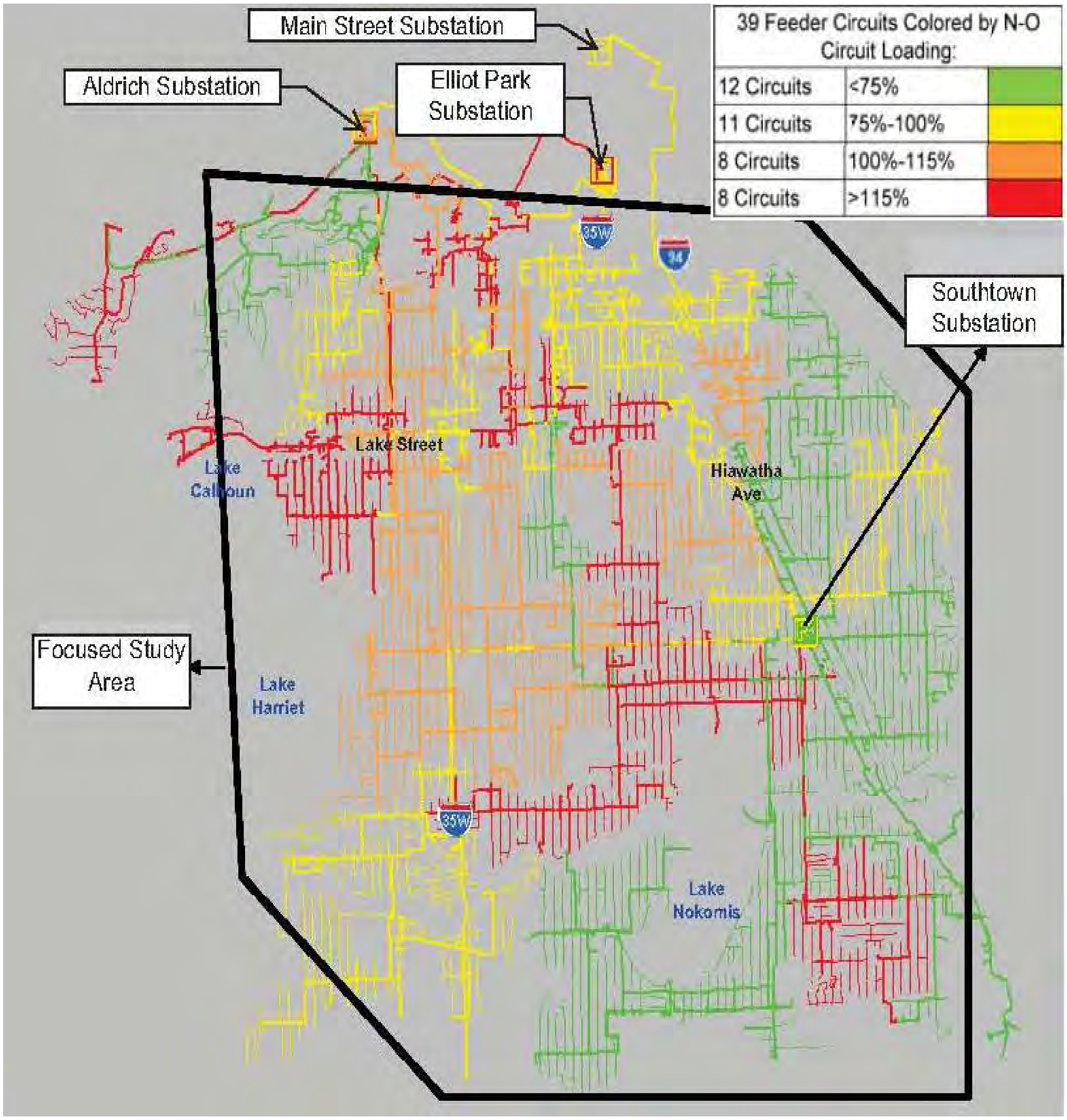
MW > 75%, N-1 Conditions: The sum of the first contingency overloads, in MW for the number of circuits that are identified as overloaded and shown in yellow, orange, and red.

Figure 4.7: Focused Study Area 2006 N-0 Feeder Circuit Risks – System Intact



Above Figure 4.7 shows that of the 39 feeder circuits in the Focused Study Area, in 2006 under system intact N-0 conditions, 15 feeders were utilized at less than 75%, 12 feeders were utilized between 75%-100%, eight feeders were utilized between 100%-115%, and four circuits were utilized at greater than 115%. Note that many of the most severe overloads occur along previously identified areas of more concentrated load and faster load growth.

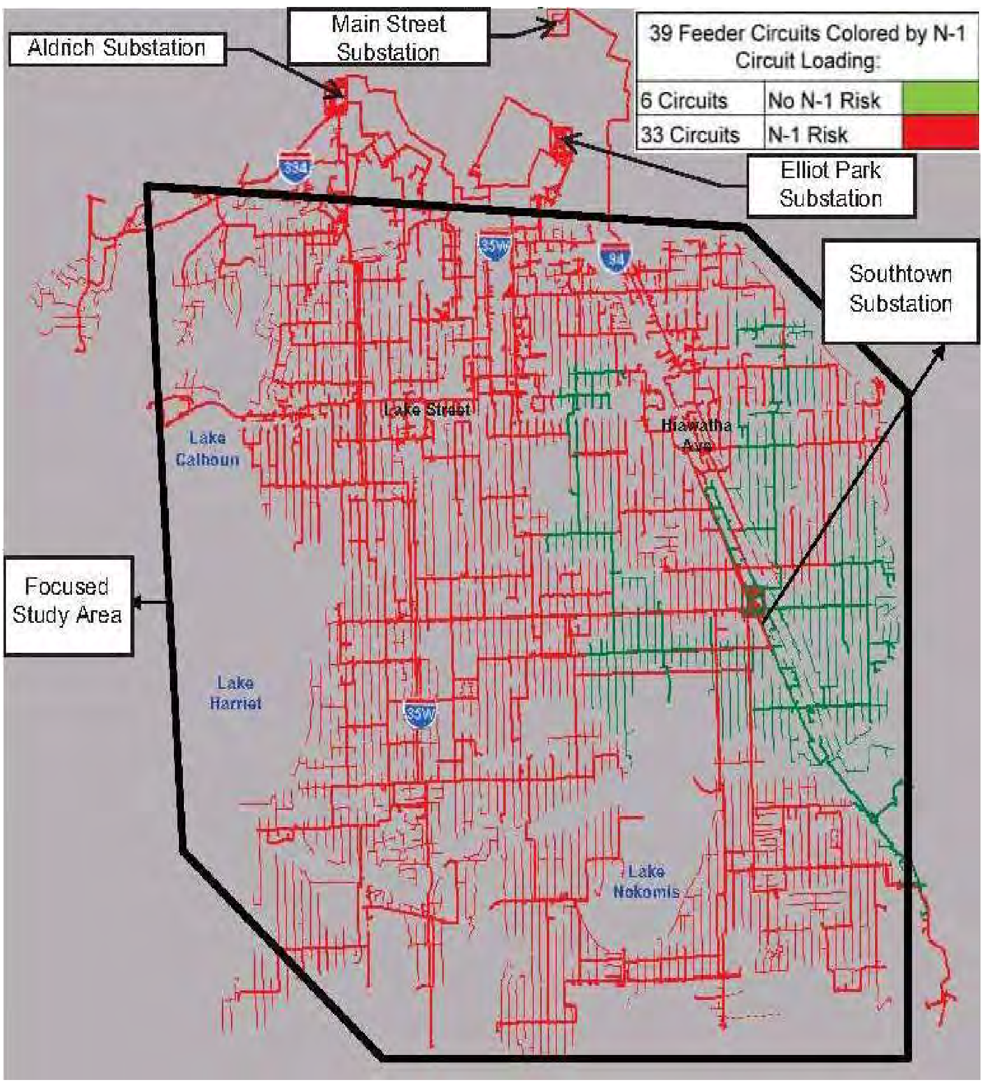
Figure 4.8: Focused Study Area 2018 N-0 Feeder Circuit Risks – System Intact



Above Figure 4.8 shows that of the 39 feeder circuits in the Focused Study Area, based on 2018 forecasted load under system intact N-0 conditions, 27 feeders will be overloaded. The 27 overloaded feeders consist of 11 feeders utilized between 75%-100%, eight feeders utilized between 100%-115%, and eight circuits utilized at greater than 115%.

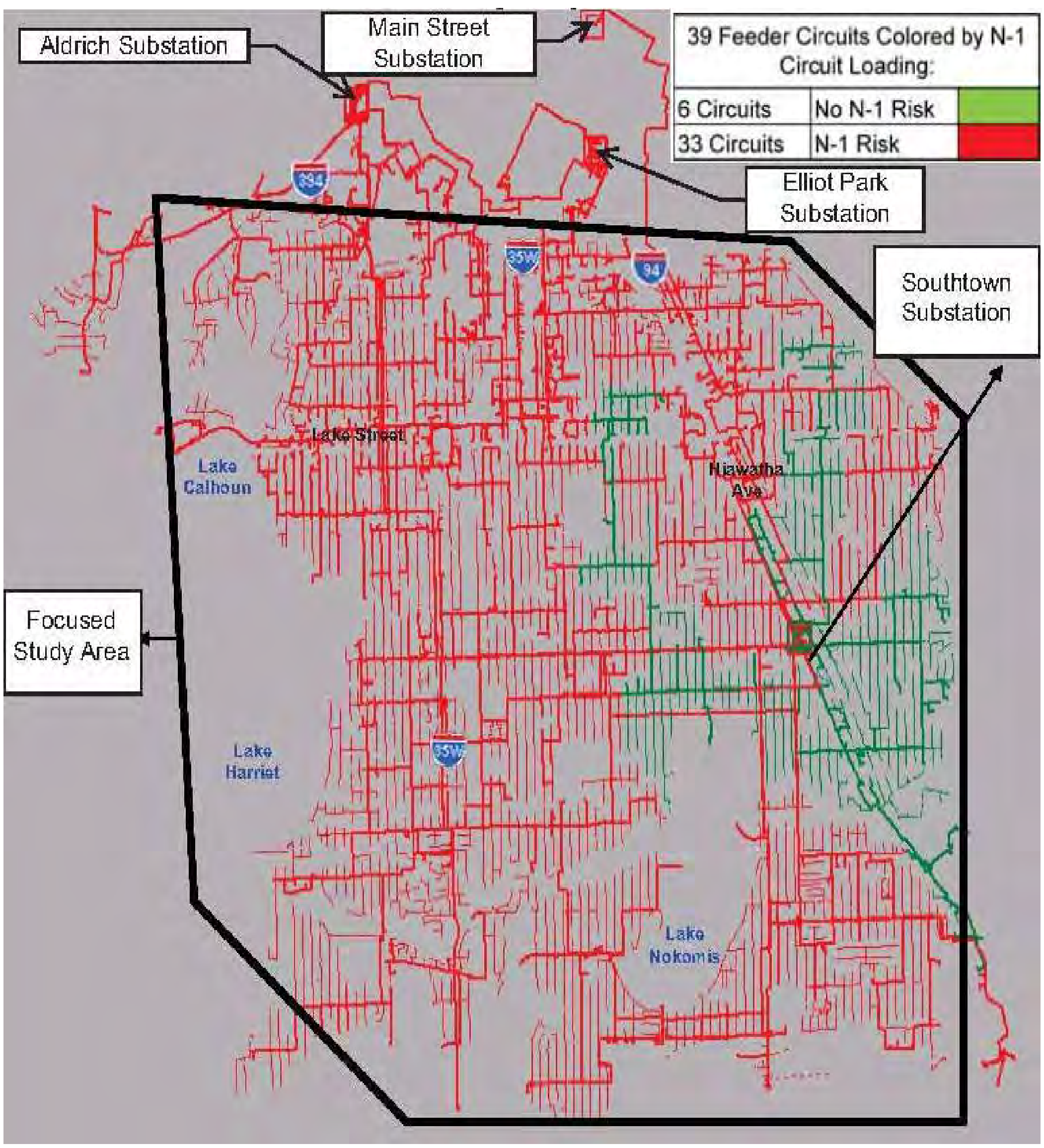
Overloads are even more widespread across the 39 feeder circuits in the Focused Study Area under N-1 loading conditions. Figures 4.9 and 4.10 color codes represent first contingency overloads existing for 2006 and forecasted for 2018. A comparison of Figures 4.9 and 4.10 shows that forecasted load levels, which are conservatively based on the cooler loads of 2008 and take into consideration possible customer conservation and the impacts of a slow economy, reach 2006 historic peak load levels again in 2018, resulting in the similar N-1 overload conditions. When a typical single feeder circuit fails during peak loading conditions, the main-line of the failed circuit is switched into three sections and each one of the three sections is transferred to a separate adjacent feeder circuit. Adjacent feeders must not be already encumbered by the load of a prior feeder circuit failure or scheduled switching event. The N-1 data provided in this section of the Study for the 39 feeder circuits serving the Focused Study Area are based on the loss of a single mainline feeder circuit. The 33 of 39 circuits that will experience an overload under first contingency conditions are shown in red. Feeder circuits shown in red demonstrate the cumulative affect on the 39 feeder circuits of switching the load from any single feeder circuit failure during peak loading conditions.

Figure 4.9: Focused Study Area 2006 N-1 Feeder Circuit Risks – Single Contingency



Above Figure 4.9 shows that of the 39 feeder circuits in the Focused Study Area, in 2006 under single contingency N-1 conditions, 33 feeders would be at risk for experiencing overload conditions.

Figure 4.10: Focused Study Area 2018 N-1 Feeder Circuit Risks – Single Contingency



Above Figure 4.10 shows that of the 39 feeder circuits in the Focused Study Area, under 2018 forecasted load under single contingency N-1 conditions, 33 feeders would be at risk for experiencing overload conditions. Figure 4.10 shows that 2018 forecasted load levels, which are conservatively based on the cooler loads of 2008 and take into consideration possible customer conservation and the impacts of a slow economy, reach 2006 historic peak load levels again and result in the similar N-1 overload conditions.

The data demonstrate that the Focused Study Area has been experiencing higher than optimal utilization rates on its feeders and transformers for the past decade. Absent additional system improvements in the area, these high utilization rates will increase the number and duration of overloads on feeders. Based on this analysis, Distribution Planning concluded that to ensure continued reliable service in the area, additional improvements are required.

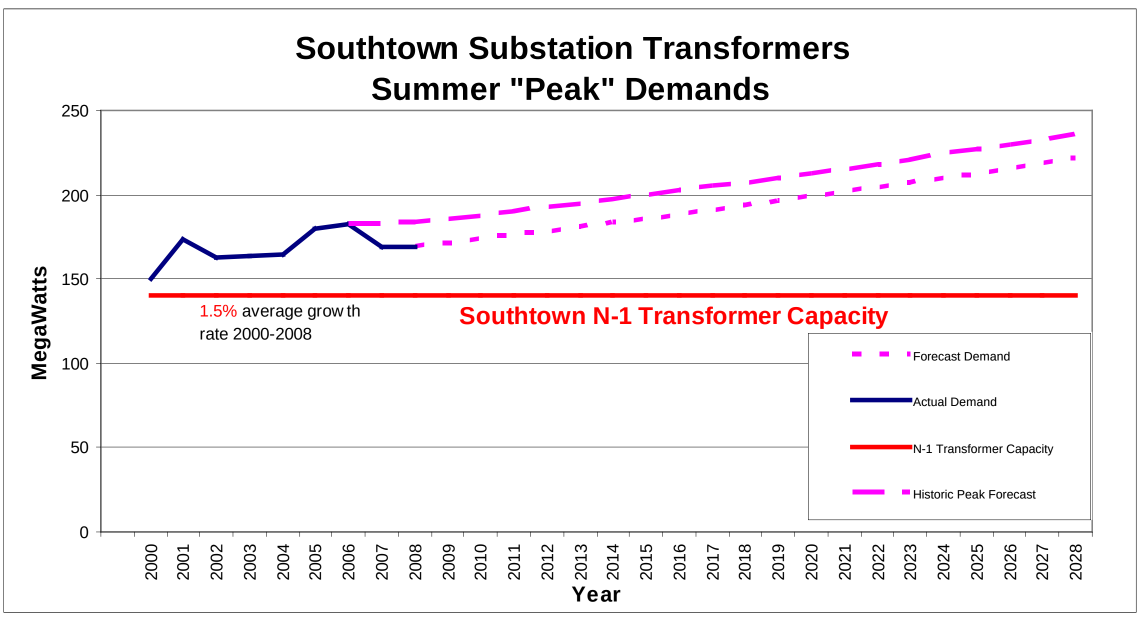
4.2 SOUTHTOWN SUBSTATION TRANSFORMERS

After examining feeder circuit peak demands, Distribution Planning Engineers looked at the loading levels for the three transformers housed at the Southtown Substation. Southtown Substation is the only substation that is in the Focused Study Area and is completely dedicated to serving Focused Study Area load.

4.2.1 Southtown Substation Transformer Historical Load and Load Forecasts

Figure 4.11 shows the conservative load growth ("forecast demand") on the three substation transformers at the Southtown Substation from 2000 through 2028 as well as the upper limit forecast load based on 2006 peak load levels ("historic peak forecast"). Southtown Substation transformer historical and forecasted load levels are similar to those for the 39 feeder circuits. The historical and forecasted loads for the three Southtown Substation transformers serving the Focused Study Area from 2000 through 2028 are included in Appendix D.

Figure 4.11: Historical and Forecasted Load Growth on Three Substation Transformers at Southtown Substation in Focused Study Area



Southtown Substation transformer loads fluctuate in a bandwidth of 11 to 14 MW between historic peak load years in 2001 and 2006 and lower peak load levels of succeeding years. Actual peak load levels will likely fall between the conservative forecast demand used in this Study and the historic peak forecast load levels illustrated in the above figure.

4.2.2 Southtown Substation Transformer Overloads and Utilization Percentages

As part of the analysis, Planning Engineers reviewed the loading and utilization rates of the Southtown Substation. The transformer utilization for the three Southtown Substation transformers from 2000 to 2028 is shown in Figure 4.12. This figure illustrates the range of overloads at Southtown Substation transformers according to forecast load levels based on lower peak loads of 2008 and forecast latent load levels of the 2006 historic peak load year. Even when using conservative peak load levels from 2008, forecasted load levels still exceed desirable loading levels for the Southtown Substation transformers. The range of likely transformer utilization falls between the dashed lines of the conservative forecasted demand and the historic peak forecast load levels.

Figure 4.12: Focused Study Area – Southtown Substation Transformers, Utilization Percentage

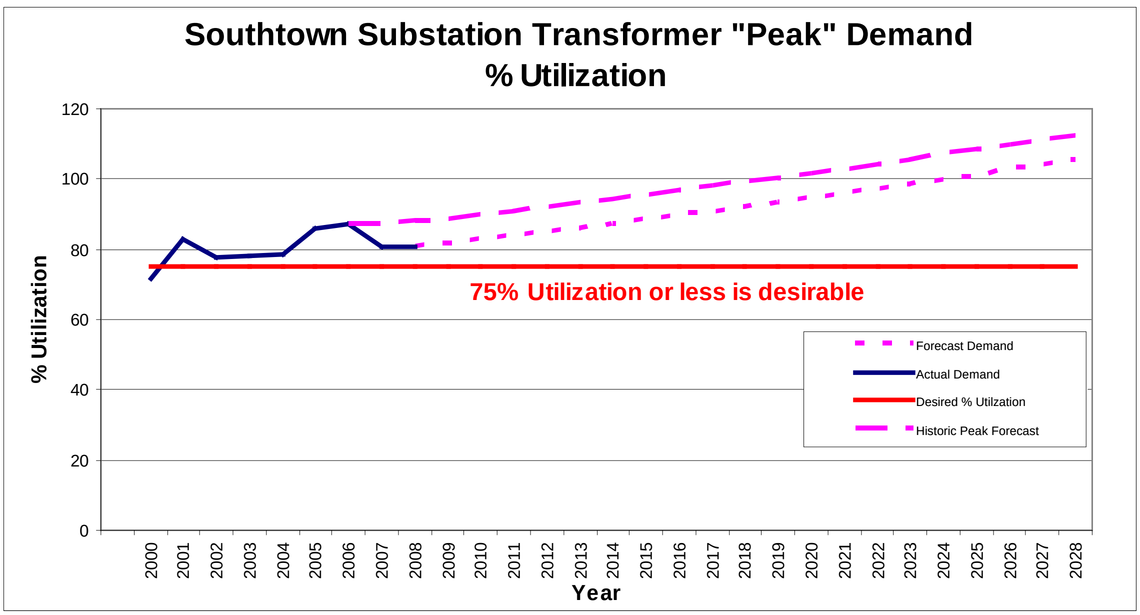


Figure 4.13 provides the historical and anticipated utilization percentages and overloads for the transformers at the Southtown Substation, which is the only substation within and completely dedicated to serving load in the Focused Study Area, for various years between 2000 and 2028.

Figure 4.13: Summary of Southtown Substation Transformer Utilization and Overloads

Southtown – One (1) Substation View Substation Transformer Utilization and Overloads									
	2000	**2004**	**2006**	**2008**	**2009**	**2013**	**2018**	**2023**	**2028**
# of Transformers	3	3	3	3	3	3	3	3	3
MW Normal Capacity	214.1	214.1	214.1	214.1	214.1	214.1	214.1	214.1	214.1
Actual Loads			**Peak Year**						
% Growth	1.5% Average Annual Growth Rate 8 years from 2000 to 2006								
% Utilization	72%	78%	87%	81%					
# Transformers	3	3	3	3					
N-1 MW Overload	9.9	24.1	42.4	28.5					
Historic Trend Forecast Overloads									
% Growth					1.4% Average Annual forecast Rate -2009 to 2028				
% Utilization					82%	86%	92%	99%	105%
# Transformers N-1					3	3	3	3	3
N-1 MW Overload					30.6	40.1	52.7	66.2	80.6
0.5% Growth Forecast Overloads			**Peak Year**						
% Utilization					81%	83%	85%	87%	89%
# Transformers N-1					3	3	3	3	3
N-1 MW Overload					29.4	32.8	37.2	41.7	46.3

The table entries were calculated using the Southtown Substation transformer forecasts included in Appendix D.

Southtown Substation transformer utilization percentage was 87% in historic peak year 2006 and 81% in the cooler temperature year 2008. Both load levels surpass the 75% utilization planning criteria for substation transformer loading levels. Southtown Substation is presently at its maximum design capacity. These high utilization rates and forecast increasing peak transformer loads indicate longer peak periods of transformer N-1 overloads. Based on this analysis, Distribution Planning concluded that Southtown transformers are not capable of serving more customer load.

5.0 ANALYSIS OF THE GREATER SOUTH MINNEAPOLIS ELECTRIC DISTRIBUTION DELIVERY SYSTEM

After determining that the south Minneapolis electric distribution delivery system in the Focused Study Area has an existing feeder circuit capacity deficit of 55 MW and that this deficit is only expected to increase in future years, Distribution Planning examined the Southtown Substation transformer capacity.

In 2006, Southtown transformer utilization was at 87% with N-1 overloads of more than 43 MW. Southtown transformer 10 year load forecasts are for 92% utilization with N-1 forecast overloads of more than 50 MW by 2018. Based on these load levels and the fact that Southtown Substation is already at its ultimate design capacity, Planning Engineers broadened the scope of their analysis to include the Greater Study Area in order to determine, in part, the availability of additional capacity near the Focused Study Area.

5.1 HISTORICAL LOAD AND LOAD FORECASTS

Historic substation transformer demands (2000 through 2008) were used as a basis to forecast each of the 15 substation transformer loads in the Greater Study Area. Distribution Planning Engineers used DAA, which supports multi-year analyses, to forecast distribution substation transformer loads from 2009 to 2028, using historical growth rates and knowledge of anticipated future load levels.

The Greater Study Area includes the 15 substation transformers comprising the five (5) Metro West substations that ring the Focused Study Area (Aldrich, Elliot Park, St Louis Park, Wilson, Southtown). Similar to feeder circuit peak loads in the Focused Study Area, transformer peak loads in the Greater Study Area occurred in 2001 and again in the 2005/2006 timeframe.

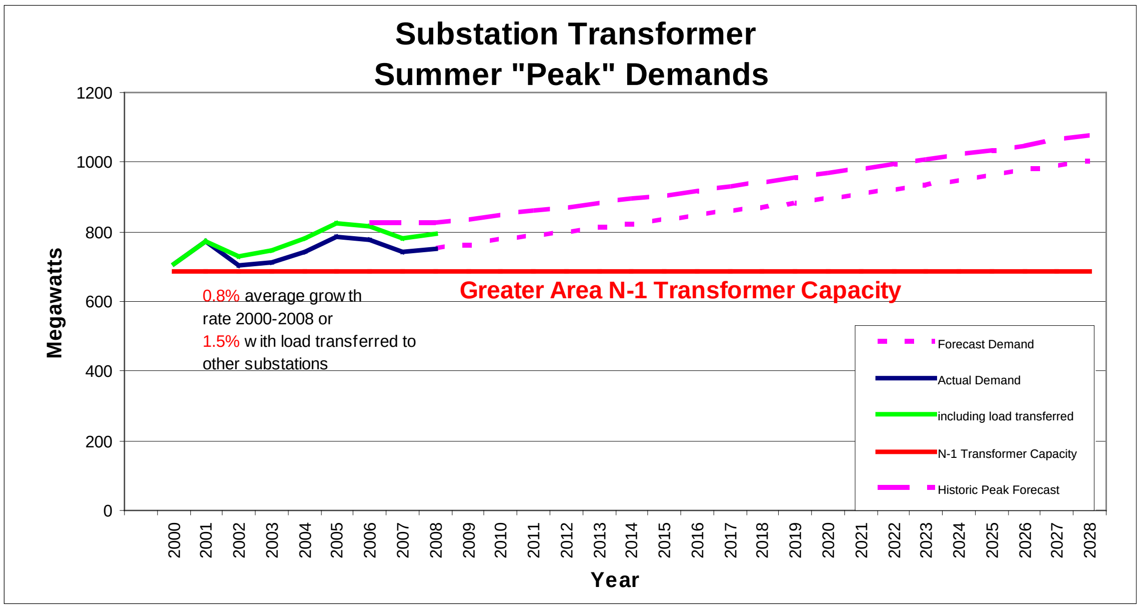
Each distribution substation in the Greater Study Area has a demand meter for each transformer located in the substation, which is read monthly, and the data is recorded in Passport. These meters record the monthly peak for the substation transformer. All affected distribution substation transformers also have a SCADA system connection that monitors the real time load on the transformer. Similar to the distribution feeders, this system feeds a SCADA data warehouse and the DAA warehouse where hourly data is stored so Electric Capacity Planning and Field Operations can view the substation transformer's load history. Each transformer's peak in a multi-transformer substation is non coincident.

Each of the 15 distribution substation transformers in the five substations serve multiple feeder circuits. Substation transformer peak load is proportional but not equal to the sum of the feeder circuit peak loads served from that substation transformer. The detail of substation transformer loading is a larger granularity than feeder circuit loads with a corresponding greater impact on customer service.

Each distribution substation transformer in the Greater Study Area serves the aggregate load of the connected down-line feeder circuits of that transformer. While each of the feeder circuits has a non-coincident peak load that the feeder circuit must be capable of serving, the combination of multiple feeders serves the diversified load of the aggregated feeders. Since the substation transformers serve diversified feeder load, the non-coincident transformer load is less than the sum of the feeder peak loads.

The historical and forecasted loads for the 15 substation transformers serving the Greater Study Area from 2000 through 2028 are provided in Appendix D to this Study. Figure 5.1 is a linear depiction of the load growth on the 15 substation transformers in the Greater Study Area from 2000 through 2028.

Figure 5.1: Greater Study Area – Historical and Forecasted Loads



The lower dashed line shows the forecast peak load levels from 2008 peak loads that are also in Appendix D, while the upper dashed line shows loads forecast based on 2006 historic peak load levels. The actual demand peaks in Figure 5.1 are not adjusted for load originally served by the 15 transformers in 2000 and transferred away through 2008. The sum of these peaks increased an average of 0.8% annually.

The figure also includes calculations of the 15 transformer load adjusted to include the load that had to be transferred from Aldrich and St. Louis Park substations to new substations outside of the Greater Study Area. The adjusted sum of the measured peaks increase an average of 1.5% per year from 2000 through 2008.

Figure 5.2 summarizes the amount of Non-Coincident Substation Transformer Load that has been transferred since 2000.

Figure 5.2: Transformer Load Transferred from Greater Study Area Since 2000

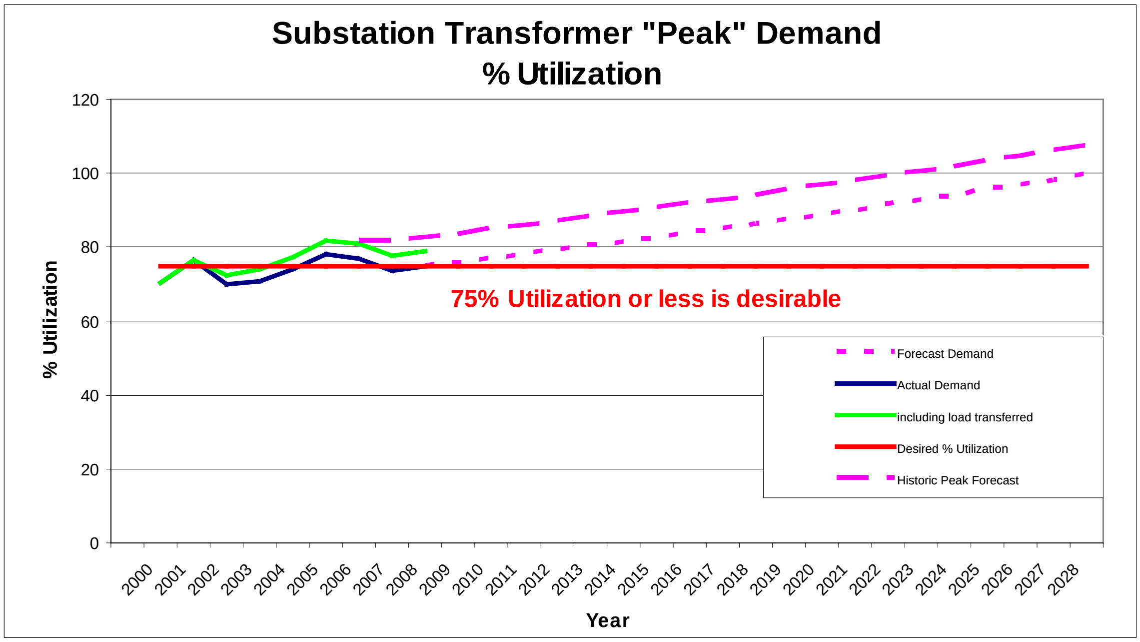
Load Adjustments due to Load Transfers to Adjacent Substations	Number of Feeder Circuits	Load (in kW) Transferred Away	Adjusted % Utilized of Transformer Normal Capacity
From Aldrich to West River Road – 2000 to 2008 Cedar Lake – 2001 to 2008	 4 1	 + >20,000 + > 6,000	
From St Louis Park to 35 kV – 2000 to 2005 Cedar Lake – 2001 to 2008	 3 3	 + >12,000 + >14,000	
Total Load Transferred Away	**11**	+ >52,000	
Impact on Greater Study Area without Transfers	**121**	Increase to >795,000	Increase to > 79%

Comparison of transformer load levels for the Greater Study Area to transformer load levels for the Southtown Substation, provided in Section 4.0, shows a similar load growth pattern from 2000 through 2008 with increasing peaks in 2001, and 2005/2006. The Southtown Substation load growth, at an average of 1.5% growth per year, mirrors the adjusted 15 transformer 1.5% per year growth and reflects a lower, more diversified growth rate than the 1.7% historical rate of non-coincident feeder circuits. Load diversity results in a transformer peak load that is slightly less than the sum of all of the feeder circuit peak loads fed from the substation transformer due to the feeder circuits reaching their individual peaks at different times.

5.2 TRANSFORMER OVERLOADS AND UTILIZATION

Planning Engineers compiled the transformer loading and utilization data for the 15 substation transformers in the Greater Study Area and found that utilization rates began exceeding 75% beginning in 2001 and have increased to 77% in 2006. Greater Study Area transformer N-1 overloads have increased both in number and duration since that time.

Figure 5.3: Greater Study Area – Substation Transformer Bank Utilization Percentage



As shown in Figure 5.3, the Greater Study Area substation transformer peak utilization percentage first exceeded 75% during 2001 peak loading. Despite load transfers of more than 52,000 MW from 2000 through 2008 to new West River Road and Cedar Lake substation transformers, average peak utilization percentage has exceeded 75% since 2004.

Substation transformer contingency overloads, which can be characterized by average feeder utilization percentage increasing above 75% and substation transformer utilization simultaneously more than 75%, typically occur in distribution areas where many and continued distribution fixes to widespread overloads use up existing feeder circuits and consume distribution substation transformer capacity. Distribution systems that experience feeder circuit N-1 and N-0 overloads soon measure substation transformer N-1 overloads of increasing amounts for longer durations. Southtown substation transformers, located in the only substation in the Focused Study Area, experienced 87% utilization in 2006 and 81% utilization in 2008 as a result of the cooler weather and reduced air conditioning usage.

Figure 5.4 summarizes the utilization percentages and anticipated overloads for the 15 substation transformers in the Greater Study Area for various years between 2000 and 2028.

Figure 5.4: Summary of Substation Transformer Utilization and Overloads of the Five Substations Serving Greater Study Area Load

Greater Study Area – Fifteen (15) Transformers Substation Transformer Utilization and Overloads									
	2000	**2004**	**2006**	**2008**	**2009**	**2013**	**2018**	**2023**	**2028**
# of Transformers	15	15	15	15	15	15	15	15	15
MW Normal Capacity	1,007.4	1,007.4	1,007.4	1,007.4	1,007.4	1,007.4	1,007.4	1,007.4	1,007.4
Actual Loads			**Peak Year**						
% Growth	1.5% Average Annual Growth Rate 8 years from 2000 to 2008 **								
% Utilization	70%	74%	77%	75%					
# of Transformers with N-1 Overloads	12	9	9	12					
N-1 MW Overload	46.5	82.7	102.9	71.7					
Historic Trend Forecast Overloads									
% Growth					1.4% Average Annual Forecast Growth Rate 2009 to 2028				
% Utilization					76%	80%	86%	93%	100%
# Transformers N-1					12	15	15	15	15
N-1 MW Overload					81.5	124.5	184.4	248.8	318.3
0.5% Growth Forecast Overloads			**Peak Year**						
% Utilization					75%	77%	79%	81%	83%
# Transformers N-1					9	12	12	15	15
N-1 MW Overload					71.0	87.2	103.2	126.6	147.1

Note ** The actual load growth shown in the table above does not account for load transfers of more than 42,000 kW from Aldrich and St Louis Park substations to the new West River Road and Cedar Lake Substations built in 2001 and 2003, respectively.

Southtown Substation transformer utilization in 2008 reached 81% (see Figure 4.13). Aldrich Substation capacity, at 62% utilization in 2008, cannot be further utilized due to full feeder circuit routes into the Greater Study Area. Peak transformer loading for the entire area above 75% utilization demonstrates that it is no longer feasible to transfer load away from the Southtown Substation transformers.

Planning Engineers generated graphics that illustrate the transformer overloads tabulated above and that provide a geographic based perspective of the present and forecast substation transformer utilization and overloads under single contingency (N-1) scenarios. These figures illustrate the geographic placement and loading level by color of substation transformers described in the table of Figure 5.4 in the Greater Study Area. Colors are used to represent substation transformer loading levels and identify overloads under N-1 first contingency operating conditions for load capacity limits in 2006 and future forecast years 2009 through 2028. The complete set of these graphics is provided in Appendix E.

Substation transformer N-1 loading levels for all distribution transformers of the same distribution voltage (13.8 kV) are addressed together because the means to transfer large amounts of load between substation transformers is built into the substation design. Substation transformer loading levels for a substation are planned for N-1 conditions resulting from the worst case possibility of one transformer (the largest transformer if the transformers are different capacities) out of service during peak loading. The maximum amount of transformer capacity that can be served from all transformers grouped together in a substation under N-1 conditions is also known as substation firm capacity. The N-1 data provided in this section of the Study for substation transformers in the Greater Study Area are based on the loss of the single transformer in a substation.

Two of the transformer overload graphics are depicted in Figures 5.5 and 5.6, respectively. The color codes in the graphics depict varying amounts of load described in the chart at Figure 5.3 and the table at the Figure 5.4 for the labeled years as follows:

> <u>Not Overloaded</u> - The feeder circuits emanating from the substation transformers that are not overloaded during N-1 conditions are shown in green. The quantity of substation transformers that are not overloaded is listed.
>
> <u>≤ 10 MW Overloads in Yellow</u> - The feeder circuits that are overloaded by 10 MW or less under N-1 conditions are yellow. The number of substation transformers that are overloaded by less that 10 MW are listed. 10 MW is the maximum amount of load that can be transferred by utilizing field switching in about 2 hours.
>
> <u>10 to 25 MW Overloads in Orange</u> - The feeder circuits that are overloaded by less than 25 MW but more than 10 MW are orange. The quantity of substation transformers that are overloaded by 10 to 25 MW is listed. 25 MW is the typical amount of load that can be served by a mobile transformer installation. A mobile transformer can sometimes be installed as quickly as 24 hours under emergency conditions.
>
> <u>Severe Overloads > 25 MW in Red</u> - The feeder circuits that are overloaded by more than 25 MW are red. The quantity of substation transformers that are overloaded by more than 25 MW is listed. Typically, more than 25 MW of load cannot be restored in less than 24 hours if a large substation transformer fails and could result in extended customer outages.

Figure 5.5 shows first contingency N-1 substation transformer loading from 2006. Aldrich and Elliot Park substation transformers do not reflect first contingency overload. St. Louis

Park has N-1 overload of less than 10 MW. And both Wilson and Southtown substation transformers have N-1 overloads of more than 25 MW.

Figure 5.5: Greater Study Area 2006 N-1 Substation Transformer Risks – Single Contingency

Colored by Substation:		
0	6 Transformers	
0 to 10 MW	3 Transformers	
10 MW to 25 MW		
> 25 MW	6 Transformers	

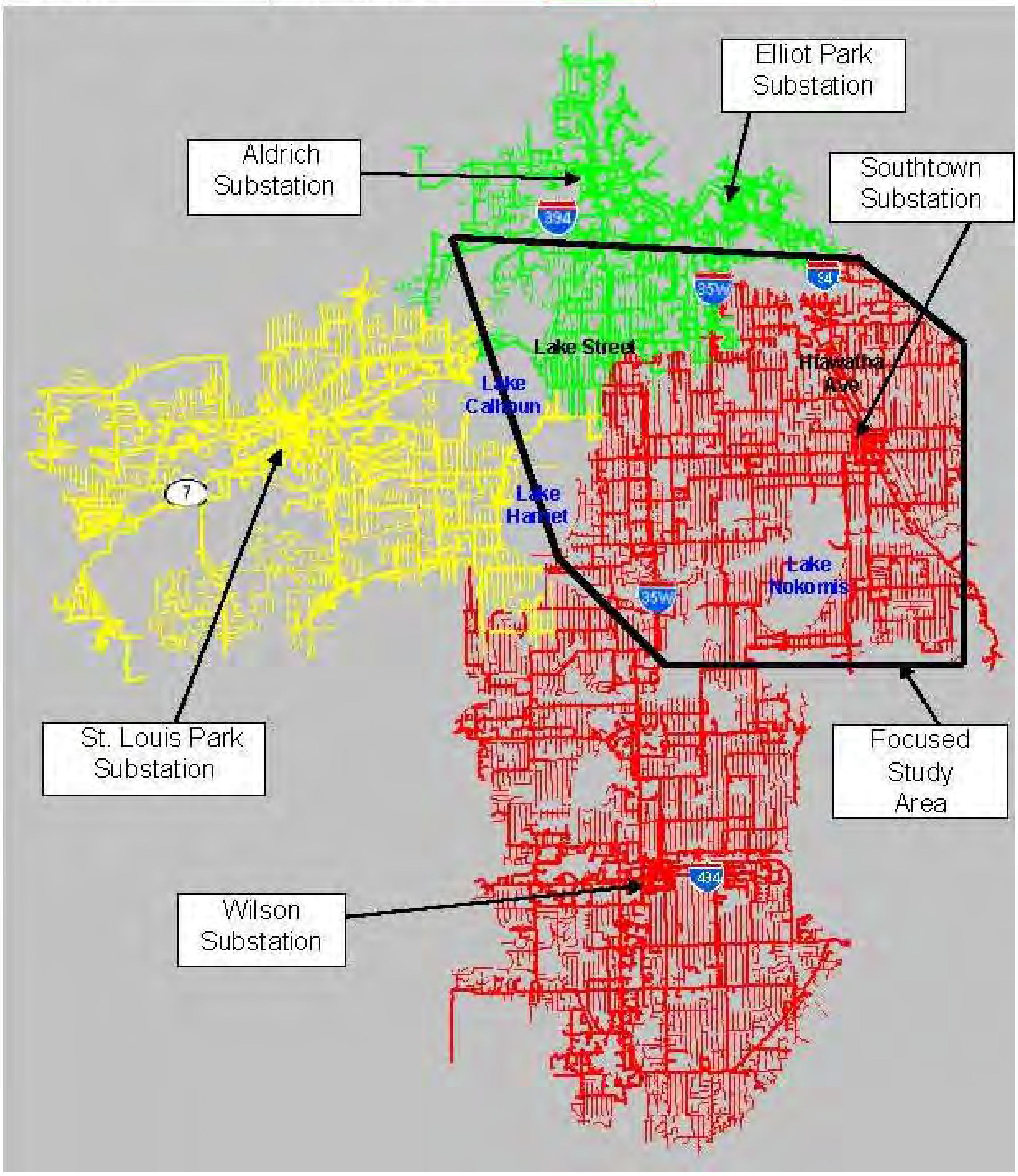


Figure 5.6 has increasing first contingency N-1 overloads in 2018 over 2006 levels. Within 10 years, Elliot Park Substation transformers have up to 10 MW overload, Aldrich Substation transformers have 10 MW to 25 MW overloads, and St. Louis Park have more than 25 MW overload while both Southtown and Wilson substation transformers have overloads that are greater than 25 MW each and are more severe than 2006 levels.

Figure 5.6: Greater Study Area 2018 N-1 Substation Transformer Risks – Single Contingency

Colored by Substation:		
0	0 Transformers	
0 to 10 MW	3 Transformers	
10 MW to 25 MW	3 Transformers	
> 25 MW	9 Transformers	

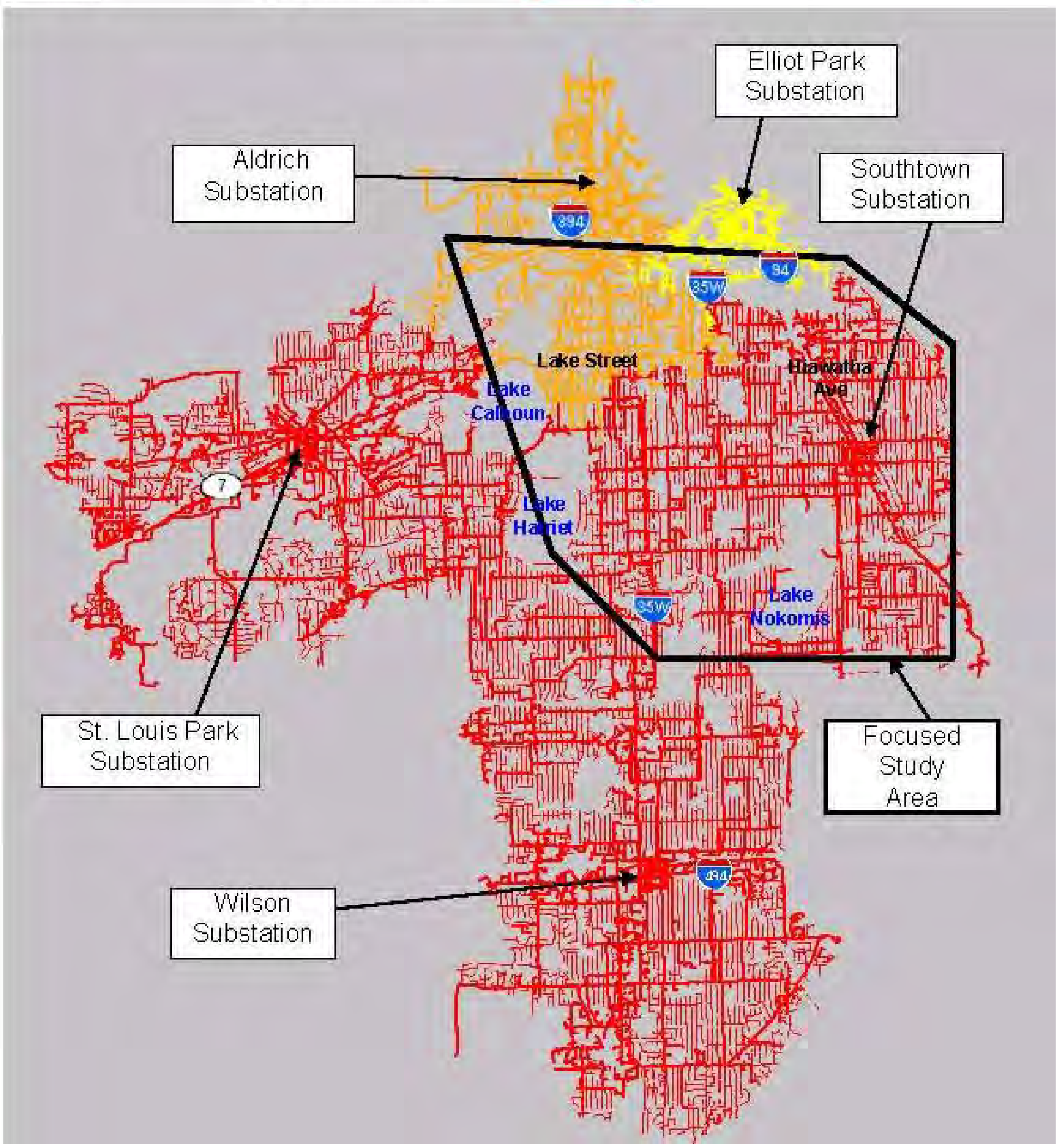


Figure 5.7 summarizes the additional substation transformer capacity (in MW) needed to mitigate the overloads detailed in Figure 5.4. A single new 50 MVA substation transformer will serve 36.75 MW of load at 75% utilization.

Figure 5.7: Summary of Substation Transformer Capacity Required to Mitigate Overloads

Minimum Number of Substation Transformers Required to Correct Southtown Transformer N-1 Overloads									
	2000	**2004**	**2006**	**2008**	**2009**	**2013**	**2018**	**2023**	**2028**
N-1 Deficiency (MW)	9.9	24.1	42.4	28.5	30.6	40.1	52.7	66.2	80.6
Minimum # of New Transformers* Needed	1	1	2	2	2	2	2	2	3

*Assumes 50 MVA transformers with 75% or less utilization.

Figure 5.7 shows that there is an existing need for two new transformers in the Focused Study Area since 2006. Even though conservative load forecasts are lower than 2006 levels, 2006 historic peak load levels remain as latent load that is likely to recur, and even exceed 2006 levels due to additional customer load, when future years reach temperature levels of the summer of 2006. As load grows, it is anticipated that additional transformers will be needed in future years. Figure 5.7 is based on forecasted load growth, and the timing of the need for additional transformers in the future is subject to change based on actual future load growth data. Any substations constructed to house the two currently needed transformers, however, should be designed to accommodate the likely future inclusion of additional transformers.

6.0 ANALYSIS OF ALTERNATIVES

After identifying system deficiencies, Planning Engineers identified potential solutions to provide necessary additional capacity to the Focused Study Area. Planning Engineers first considered distribution level alternatives including adding feeders, extending feeders and expanding existing substations. Planning Engineers concluded that these alternatives would not meet identified needs because these typical strategies had already been exhausted and were no longer sufficient to address these overloads. Planning Engineers then evaluated alternatives that would bring new distribution sources into the Focused Study Area.

6.1 DISTRIBUTION LEVEL ALTERNATIVES IMPLEMENTED IN THE FOCUSED STUDY AREA

Over the past decade, Distribution Planning Engineers implemented an array of distribution level alternatives in the Focused Study Area. Engineers applied these alternatives in proportion to the amount and frequency of overloads as identified by the annually measured feeder circuit and substation transformer overloads. Alternatives implemented in the last decade used feeder circuit and substation transformer capacity by fully utilizing ultimate substation design capacities in a way that did not require a new transmission line source to address the distribution delivery system needs.

Distribution capacity planning methods address and solve a continuum of distribution equipment overload problems, including isolated feeder overloads, widespread feeder overloads, and substation transformer contingency overloads associated with widespread feeder overloads. These were described in more detail in Sections 4.0 and 5.0.

Alternatives implemented in the last decade to address continuing overloads in the Focused Study Area are described briefly in the sections below and in more detail in Appendix A. Alternatives include reinforcing existing feeder circuits to address isolated feeder circuit overloads, adding or extending new feeder circuits and adding substation transformer capacity up to the ultimate substation design capacity to address more widespread overloads.

6.1.1 Reinforcing Existing Feeder Circuits

Feeder circuit improvements used to address isolated Focused Study Area feeder overloads included reinforcing at least seven (7) existing feeder circuits by increasing wire size or doubling-up wires, adding at least a dozen capacitor banks, converting three 4 kV substations to 13.8 kV, targeting overloaded customer transformer areas by adding or upsizing more than 150 customer serving transformers, and rearranging at least nine (9) feeder circuits by moving increased customer demand from an overloaded feeder to an adjacent feeder circuit with existing capacity. Alternatives implemented from 2001 to 2008 to reinforce existing feeder circuits in the Focused Study Area are detailed in Appendix A.

6.1.2 Adding New or Extending Feeder Circuits

Feeder circuit improvements used to address widespread Focused Study Area feeder overloads and some substation transformer contingency overloads included replacing at least six feeder circuits and more than 120 cables of existing overloaded and damaged feeder equipment with new equipment capable of delivering equal or higher capacity, and adding four (4) Southtown and two (2) Elliot Park feeder circuits from substation transformers that have more capacity in the Focused Study Area and longer feeder circuits from adjacent substations. Alternatives implemented from 2001 to 2008 to add and extend feeder circuits in the Focused Study Area are detailed in Appendix A.

Underground feeder circuits from Aldrich, Elliot Park, and Southtown substations now fill existing duct lines to their thermal capacity, and there is no more room in utility easement or street right-of-way routes for additional duct lines from these substations to the distribution load. See Section 2.3.2 for a detailed description of limits to concentrated feeder installations.

New feeder circuits from Southtown Substation in the Focused Study Area and substations in the Greater Study Area have consumed all available substation transformer capacity, or filled all feeder circuit routes or both. Planning Engineers have determined that all reinforcing and new feeder circuit improvement alternatives in and around the Focused Study Area are exhausted.

6.1.3 Expanding Existing Substations to Ultimate Design Capacity

As Planning Engineers fully utilize available feeder circuit capacity and then substation transformer capacity to serve customer load, the next logical step is to increase the number and size of substation transformers to the substation ultimate design capacity. In the five substations of the Greater Study Area, expansion beyond ultimate design capacity is limited by several factors, including:

- Substation expansion is physically limited,
- Substation equipment is electrically limited inside the substation and
- Physical distance from substations to customer load concentrations.

Distribution Planning Engineers examined each of the five substations in the Greater Study Area, evaluating each substation's capacity, utilization percentage and whether a substation could presently serve or be expanded to serve additional load in the Focused Study Area. The following is a summary of Distribution Planning's analysis for each of the five substations.[2]

[2] Again, Main Street Substation was not considered in the Greater Study Area as a source of load relief. The one feeder circuit from the Main Street substation presently serving customer load in the Focused Study Area, is not part of future plans to serve load in the Focused Study Area. The one (1) Main Street substation feeder circuit traverses several miles and crosses the Mississippi River to reach the study area. All Main Street feeder circuits crossing the Mississippi River were vulnerable and were damaged when the Interstate 35W bridge collapsed in 2007. There are no additional feeder circuit routes available in the congested duct lines between Main Street Substation and overloaded feeder circuits in the Focused Study Area.

The one feeder circuit emanating from Main Street substation that serves customer load in the Focused Study Area was at 86% utilization in 2008; the N-1 overload of 1,592 kW requires load relief. This Main Street feeder circuit presently passes other Main Street and Elliot Park feeder circuits that are overloaded on the route from the Main Street substation to the part of the study area where it serves customer load. The one Main Street

Aldrich Substation

Aldrich Substation presently has three (3) 115/13.8 kV 70 MVA substation transformers installed and is constructed to the ultimate design capacity. This substation overloaded in 1999, 2000 and 2001. In 2001, peak loads levels were more than 15,000 kW over the Aldrich Substation transformer N-1 capacity. Load relief from the new West River Road Substation[3] beginning in 2001 and the new Cedar Lake Substation[4] beginning in 2003 reduced utilization to 65% in 2008 which is 3,618 kW under the N-1 capacity. This capacity will be consumed in less than two years at the 1.3% forecast growth rate. Additional capacity or load relief is needed at Aldrich Substation after 2011.

Even if there were available Aldrich transformer capacity to serve load in the Focused Study Area, existing feeder circuit and duct line (required for concentrations of feeders) routes are full. Conventional methods for new duct line routes needed to cross over the Lowry Hill tunnel or be constructed through downtown Minneapolis and across bridges over interstates 94 and 35W are exhausted.

Elliot Park Substation

Elliot Park Substation presently has three (3) 115/13.8 kV 47 MVA substation transformers installed. Elliot Park Substation transformers utilization of 77% in 2007, are within 3,168 kW of the substation N-1 limit. Some load relief of about 12,000 kW will occur in 2009 due to feeder circuit repairs to damage from the Interstate 35W bridge collapse in 2007. The capacity made available from repairs is already designated to relieve existing overloaded Elliot Park feeder circuits outside the Focused Study Area and future downtown Minneapolis load growth to the west of the substation location.

Even if there were available capacity to serve load in the Focused Study Area, new feeder circuit and duct line (required for concentrations of feeders) routes that need to cross

feeder circuit in the Focused Study Area has feeder circuit ties to Southtown and Elliot Park feeder circuits that are presently overloaded and require load relief.

[3] West River Road substation is located north of Aldrich substation near the intersection of Plymouth Ave and West River Road northeast of downtown Minneapolis. The substation was constructed to provide load relief primarily to Aldrich and Fifth Street substations and help provide future electrical energy to the growing customer demand north of Minneapolis and in downtown Minneapolis. The two West River Road substation transformers, which were added in 2001, delivered 42,115 kVA of electrical power in 2008 at peak loading; More than 20,000 kW of peak load has been transferred from overloaded Aldrich substation feeder circuits and substation transformers beginning in 2001.

[4] Cedar Lake substation is located north of St Louis Park substation near the intersection of Cedar Lake Road and Edgewood Ave in St Louis Park. The substation was constructed to provide load relief primarily to St Louis Park, Medicine Lake, and Aldrich substations and help provide future electrical energy to growing customer demand along Interstate 394 west of Penn Ave. The first Cedar Lake substation transformer, added in 2003, and the second substation transformer, added in 2008, delivered 30,510 kW of electrical power in 2008 at peak loading; more than 20,000 kW of peak load has been transferred from Aldrich (6000 kW), and St Louis Park (14,000 kW) substation feeder circuits and substation transformers beginning in 2003.

through downtown Minneapolis and across bridges over the interstates 94 and 35W commons are not possible because existing duct lines and duct line routes are physically full.

Southtown Substation

Southtown Substation presently has three (3) 115/13.8 kV substation transformers (2-70 MVA, 1-62.5 MVA) installed and is constructed to ultimate design capacity. The substation transformers reached 83% utilization in 2001, exceeding substation N-1 capacity by more than 33,000 kW. The 23 feeder circuits emanating from this substation increased substation transformer utilization to 87% in 2006, remaining at 81%, 29,102 kW above substation transformer N-1 limits in 2008. These overloads continue, despite feeder circuit load transfers to Aldrich and Elliot Park substations and cooler temperatures in 2008 when compared to 2005 and 2006.

The three (3) Southtown Substation transformers have 2008 N-1 overloads of more than 29,000 kW. In 2006 Southtown Substation transformers experienced a higher peak load year due to higher temperatures and correspondingly higher air conditioning loads with N-1 overloads of more than 43,000 kW. Southtown Substation transformers are expected to experience peak loading at or above 2006 levels when economic conditions improve and future year temperatures reach 2006 levels.

Southtown Substation capacity can be increased by about 4,000 kW by replacing the smallest substation transformer with the maximum size that can be installed in the substation. This capacity increase, which would reduce N-1 transformer overloads to about 39,000 kW and costing more than $1.5 million, is not cost effective. Even if the substation transformer capacity upgrade were funded, 2008 feeder circuit N-0 overloads totaling more than 7,500 kW and N-1 overloads totaling more than 38,700 kW in the Focused Study Area are not reduced.

St. Louis Park Substation

The St. Louis Park Substation currently serves less than 500 kW, a statistically insignificant amount of customer load in the Focused Study Area. The substation presently has three (3) 115/13.8 kV 70 MVA substation transformers installed and is constructed to the ultimate design capacity for substation transformers. This substation overloaded in 1999, and at 71% utilization in 2001 was more than 12,000 kW over the substation transformer N-1 capacity.

Peak loading has declined from 75% in 2005, with N-1 overloads of 22,445 kW to 66% (N-1 overload of 1,632 kW) in 2008 due to load relief from new circuits built to the west of the substation beginning in 1995 and the new Cedar Lake Substation feeders beginning in 2003, cooler weather than 2005 / 2006, and a slower economy. Plans are to continue to use Cedar Lake Substation transformers and feeder circuits to relieve some of the St Louis Park Substation transformer and feeder circuit overloads.

Even if there were available capacity to serve load in the Focused Study Area, new feeder circuit and duct line (required for concentrations of feeders) routes would need to cross through more than four miles of suburban St. Louis Park and Minneapolis, which would increase line losses. Duct line routes are full close to the St Louis Park Substation. Feeder concentrations in duct lines would need to be constructed crossing Highway 100 by modifying existing highway bridges or installing duct line casings underneath Highway 100. Duct routes would cross though congested or full routes along streets both north and south of Lake Calhoun.

Wilson Substation

The Wilson Substation serves less than 1,200 kW, a statistically insignificant amount of customer load in the Study Area. The substation presently has three (3) 115/13.8 kV 70 MVA substation transformers installed and is constructed to the ultimate design capacity for substation transformers. A substation project started in 2006, which completed feeder circuit reconfigurations in 2007, replaced obsolete substation equipment and resulted in the present substation configuration.

This substation overloaded prior to 1999, and at 87% utilization in 2001, saw N-1 substation transformer overloads of more than 42,000 kW. Despite the Wilson Substation improvement project in 2005 through 2007, 2008 transformer utilization reached 86% with N-1 substation transformer overloads of more than 39,000 kW. Wilson Substation transformers have no capacity presently available to relieve the Focused Study Area.

Even if there were available capacity to serve load in the Focused Study Area, new feeder circuit and duct line (required for concentrations of feeders) routes would need to cross bridges over or boring under Interstate 494 and Crosstown freeway (county road 62), and be installed through suburban Richfield and Minneapolis to reach the Focused Study Area.

After considering whether the Focused Study Area load could be served from existing substations in or adjacent to the Focused Study Area, Planning Engineers determined that these substations were either already at capacity or had capacity that was already designated to serve load in other areas.

6.1.4 Feeder and Substation Transformer Additions, Expansions Are Exhausted

The ability to serve the increasing load in the Focused Study Area with additional feeder circuits from the Greater Study Area are exhausted. Existing substation transformer capacity and existing substations in the Greater Study Area cannot be expanded with additional transformers. As discussed in Sections 4.0 and 5.0, peak feeder and transformer loads for the Focused Study Area will likely reach levels in the range between the conservative forecast and historic peak forecast lines.

Measured 2007 and 2008 peak loads are lower, in part, due to cooler summer temperatures than 2005 or 2006. Impacts of the economy are factored into load forecasts that do not reach 2006 levels until about 2012 or 2013. Unpredictable and cyclic conditions such as a multiple day or week long period of high temperatures and high humidity similar to 2001/2002 and 2006 could result in load levels that exceed forecasted and 2006 actual peak load levels.

Feeder circuits 2008 peak loads in the Study Area average 76% utilization, with 24 of 39 circuits overloaded by more than 38 MW during N-0 or N-1 conditions. Measured loads that are down by 16 MW from the historic, weather related peak of 2006, are expected to meet and exceed 2006 peak load levels when summer temperature patterns again occur at 2006 levels.

Three (3) Southtown Substation transformer (the only transformers in the Study Area) 2008 peak loads average 81%, with the substation overloaded by more than 29 MW during N-1 conditions. Fifteen (15) substation transformer 2008 peak loads average 75%, with the five substations overloaded by more than 71 MW during N-1 conditions.

6.2 NEW SUBSTATION ALTERNATIVES

After concluding that distribution level additions and improvements would not meet the identified need for the Focused Study Area, Planning Engineers considered the addition of new distribution sources (*i.e.*, substation transformers with associated feeder circuits) to meet the electricity demands of the Focused Study Area. Ideally, new distribution sources should be located as close as possible to the "center-of-mass" for the electric load that they will serve. Installing substation transformers close to the load "center-of-mass" minimizes line losses, reduces system intact voltage problems, and reduces exposure of longer feeder circuits and outages associated with more feeder circuit exposure.

Planning Engineers considered four alternatives for bringing new distribution sources into the Focused Study Area and increase the capacity of the system to address system deficiencies and provide additional capacity for future growth. Each alternative consists of incremental installation plans from initial installation through the alternative's full design capacity. Identified final improvements for each alternative in 2023 are expected to provide the necessary capacity to the year 2028. The Planning Engineers compared the alternatives at their full design capacity. The four alternatives are as follows:

- New Source Alternative-1 ("A1"): Hiawatha and Midtown 115/13.8 kV distribution substations and two looped 115 kV transmission lines
- New Source Alternative -2 ("A2"): Hiawatha Substation and West Midtown Substation 115/13.8 kV distribution substations and two looped 115 kV transmission lines
- New Source Alternative -3 ("A3"): Hiawatha Substation 13.8 kV distribution substation
- New Source Alternative -4 ("A4"): Hiawatha 13.8 kV distribution and 34.5 kV sub-transmission with three substations in Midtown for 13.8 kV distribution

A1 and A2 are considered standard installation. A3 and A4 are considered non-standard installation because they involve using multiple distribution voltage express feeder circuits at 13.8 kV or 34.5 kV to move power from a distant substation transformer location instead of using a 115 kV transmission line to transmit power.

6.2.1 Criteria Used to Develop and Compare Alternatives

Distribution Planning Engineers evaluated and compared the effectiveness of each of the four alternatives to address the identified system deficiencies according to the following objective criteria: System Performance, Operability, Future Growth, Cost, and Electrical Losses, which are described in more detail below.

All four alternatives have the ability to meet existing and forecast capacity requirements. To facilitate a comparison of the alternatives, A1, A2, A3, and A4 were developed to equally fix N-0 and N-1 overloaded feeder circuits and N-1 substation transformer overloads in the Focused Study Area and install additional infrastructure in the year needed to fix forecast overloads.

6.2.1.1 System Performance

System performance is how the physical infrastructure addition of an alternative impacts energy delivery to distribution customers. Frequency of outages has been found to correlate to circuit length with longer feeders experiencing more outages than shorter feeders. Each unit of length of a feeder circuit generally has comparable exposure due to common outage causes, including underground circuit outages caused by public damage (*e.g.*, customer dig-ins to cable), equipment failure; and overhead circuit outages caused by acts of nature (*e.g.*, lightning).

SynerGEE system models of 13.8 kV feeder circuits indicate that fully loaded 12,000 kW circuits more than approximately four miles long with the load at the end of the feeder cannot maintain nominal voltage within required +/-5% limits. Experience with Elliot Park, Southtown, and Aldrich substation feeder circuits since reaching 2005/2006 loading levels on the existing distribution system demonstrated that required minimum voltage levels cannot be maintained under first contingency N-1 conditions. A large hospital and other voltage sensitive customers in the vicinity of Chicago Avenue and Lake Street load corridors have experienced unacceptably low voltages under first contingency conditions.

Accordingly, for purposes of this Study, performance is based on the equipment and control systems required to maintain customer nominal voltage, and customer exposure to outages as differentiated by the length of the feeder circuit from the substation transformer to the customer.

6.2.1.2 Operability

Operability is how the alternative impacts Xcel Energy distribution equipment, operating crews and construction crews operating the distribution system during normal and contingency operations. Operability is evaluated based on system planning criteria that represent the robust capability of the distribution response as described by feeder circuit and substation transformer N-0 and N-1 percent utilization and ease of operation as impacted by integration with the installed distribution delivery system. Integration of non-standard equipment using new and untested technology in the first several generations of implementation are often complicated to operate, or have unanticipated difficulties that require additional engineering to solve problems, additional expenditures, additional equipment, new operating techniques and crew training. New technologies often require several generations of changes to reach simplicity of operation required to maintain present levels of customer service and reliability.

6.2.1.3 Future Growth

Future growth is how the alternative facilitates and enables future infrastructure additions required to serve future customer demand. Possibility for future growth is enhanced by an alternative that addresses future customer demand with the least cost amount of additional distribution infrastructure.

For example, when considering a standard solution, an alternative that locates a substation nearest the load center and has room to add feeder circuits and substation transformers has better future growth possibilities than an alternative that requires adding another substation with an additional transmission line into the Focused Study Area.

6.2.1.4 Cost

Cost is the total cost of the proposed alternative based on indicative estimates and may change with estimate refinement. Cost is the present value of all anticipated expenditures required for an alternative to serve the forecast customer loads through 2028.

6.2.1.5 Electrical Losses

Electrical losses are most often discussed in reference to the additional amount of generation required to make up for the incremental line losses. Increased efficiency in the electrical delivery system reduces the amount of generation needed to serve load. Electrical losses also impact the amount of distribution system equipment by requiring incrementally increased amounts of electrical feeder circuits and substation transformers to make up for electrical energy lost by transporting electrical energy at distribution voltages when compared to using transmission line voltages.

6.2.2 Standard Alternatives

6.2.2.1 A1: Hiawatha and Midtown 115/13.8 kV Distribution Substations and Looped 115 kV Transmission Lines

This option initially included a standard installation with an ultimate design capacity of six (6) distribution substation transformers with a total of 30 feeder circuits located at two new substation locations. As initially designed, each substation location would have included a standard installation of three (3) substation transformers and up to fifteen (15) feeder circuits. Subsequently, this option was modified to include an ultimate design capacity of five distribution substation transformers with a total of 30 feeder circuits located at two new substation locations.

One substation would be located near the existing site of the former Hiawatha Substation which requires a short 115 kV transmission line extension to tap the existing Elliot Park – Southtown 115 kV transmission line into the substation site. This substation would have an ultimate design capacity for a total of three 50 MVA substation transformers and up to 15 feeder circuits.

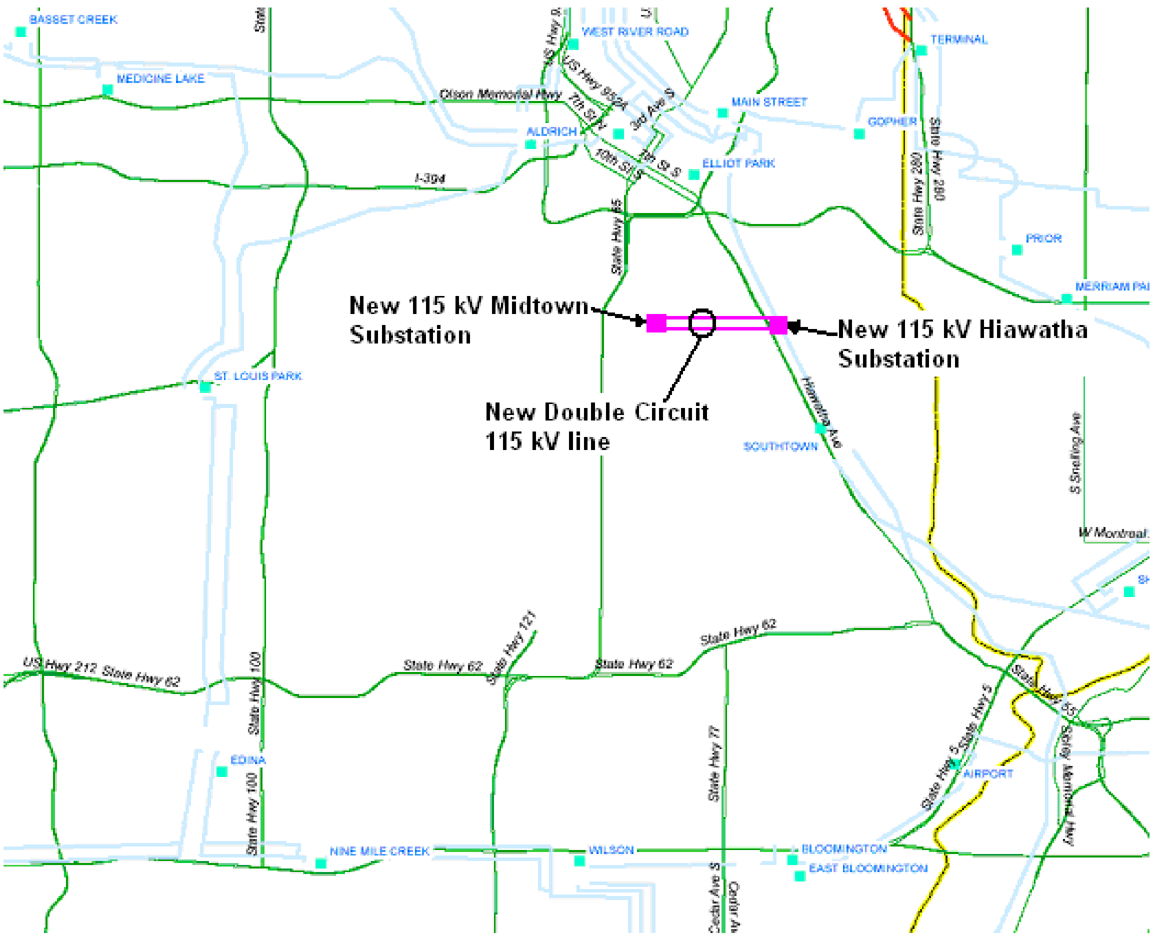
The second new substation would be located close to the identified load center and nexus of feeder circuits that need additional capacity, which is west of Chicago Avenue and east of I-

35W in the Midtown area. This proposed substation would have an ultimate design capacity of two 70 MVA substation transformers, instead of the standard three 50 MVA substation transformers, and up to 15 feeder circuits. The Midtown substation taps the existing Elliot Park – Southtown 115 kV transmission line. Two additional transmission lines would be located between the Hiawatha Avenue and the new Midtown area substations.

The initial installation includes a single substation transformer and five (5) associated feeder circuits installed at each of two substation locations.

Figure 6.1 illustrates the A1 configuration.

Figure 6.1: A1 – Hiawatha and Midtown 115/13.8 kV Distribution Substations and Looped Transmission Lines



A1 best satisfies the Planning Engineers' criteria. With respect to System Performance, A1 installs additional substation transformer capacity at two new substations at or near the identified load center in the Focused Study Area. As a result, A1 requires shorter feeder circuits to serve load from these two new substations. Shorter feeder circuits consist of less equipment, have fewer elements that can fail, and have less exposure to external factors that increase the chance of feeder outages. A1 is capable of maintaining adequate voltage on feeder circuits. A1 also has the best operability over the other alternatives. A1 is an extension of the existing simple distribution system and provides for a large number of standard options that could be quickly implemented under contingency conditions. With respect to Future Growth, A1 provides possibilities for future capacity additions in an area expected to experience significant growth in electricity demand. A1 addresses future load serving needs.

A1, at ultimate design capacity, is estimated to cost approximately $55.9 million and is the lowest cost alternative. Staging costs include the following:

- 2010
  - Hiawatha 115 kV substation - $14,300,000
  - Midtown 115 kV substation - $11,120,000
  - Double circuit 115 kV line between Hiawatha-Midtown - $3,310,000
  - Distribution duct and feeder circuits - $4,650,000
  - Total Distribution Costs - $33,380,000
- 2016
  - 2nd substation transformer added at Midtown - $6,570,000
  - Distribution duct and feeder circuits - $1,950,000
  - Total Distribution Costs - $8,520,000
- 2017
  - 2nd substation transformer added at Hiawatha - $5,175,000
  - Distribution duct and feeder circuits - $3,150,000
  - Total Distribution Costs - $8,325,000
- 2023
  - 3rd substation transformer added at Hiawatha - $3,930,000
  - Distribution duct and feeder circuits - $1,700,000
  - Total Distribution Costs - $5,630,000

Cost information for A1 is provided in Appendix G.

With respect to electrical losses, A1 has the lowest line losses because it utilizes 115 kV transmission lines to transmit power from Hiawatha Avenue to the load center. A1 is the lowest loss and A3 the highest loss alternative of A1 through A4. By using SynerGEE and performing a load flow the loss difference between A1 and A3 at peak was determined and found to be around 1 MW. This 1 MW is the same as the MW $\text{reduction}_{\text{PEAK}}$ value that is discussed in Appendix F. Over the 20-year view of this Study there would be approximately 42,000 MWh in savings, which correlates to 40,000 tons of CO_2 in savings and $3.8 million saved.

6.2.2.2 A2: Hiawatha and West Midtown 115/13.8 kV Distribution Substations and Looped 115 kV Transmission Lines

This option includes an ultimate design capacity of six (6) distribution substation transformers with a total of 30 feeder circuits located at two new substation locations. Each substation location includes three (3) substation transformers and up to fifteen (15) feeder circuits.

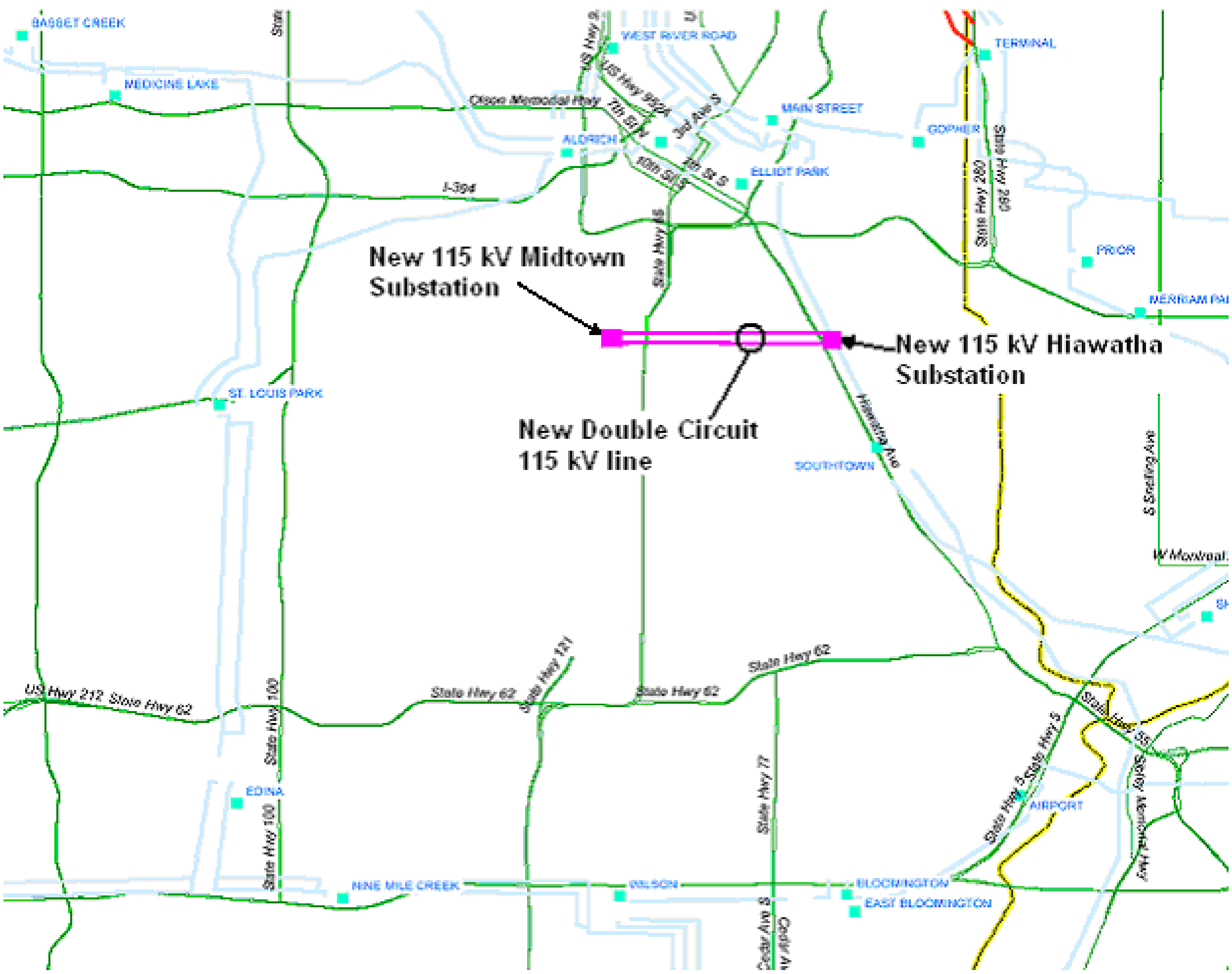
One substation would be located near the existing site of the former Hiawatha Substation which requires a short 115 kV transmission line extension to tap the existing Elliot Park – Southtown 115 kV transmission line into the substation site.

The second new substation would be located west of the Interstate 35W in the Midtown area. The Midtown substation taps the existing Elliot Park – Southtown 115 kV transmission line. Two additional transmission lines would be located between the Hiawatha Avenue and the new Midtown area substations.

The initial installation includes a single substation transformer and five (5) associated feeder circuits installed at two substation locations.

Figure 6.2 illustrates the A2 configuration.

Figure 6.2: A2 – Hiawatha and West Midtown 115/13.8 kV Distribution Substations and Looped 115 kV Transmission Lines



A2 meets the various criteria by which Planning Engineers compared each alternative. With respect to System Performance, A2 installs additional substation transformer capacity at two new substations, one of which would be located west of Interstate 35W in the Midtown area, a greater distance than the substations under A1 from the identified load center in the Focused Study Area. As a result, A2 requires slightly longer feeder circuits than A1 to serve load, and therefore, is subject to slightly greater exposure to conditions that could lead to line failures. With respect to Operability, similar to A1, A2 is an extension of the existing distribution system and provides for a large number of standard options that could be quickly implemented under contingency conditions. With respect to Future Growth, A2 provides possibilities for future capacity additions in an area expected to experience significant growth in electricity demand, but requires more infrastructure than A1. A2 addresses future load serving needs.

A2 is estimated to cost approximately $60.6 million. Staging costs include the following:

- 2010
  - Hiawatha 115 kV substation - $14,300,000
  - Midtown 115 kV Substation - $17,130,000
  - Double Circuit 115 kV line between Hiawatha-Midtown - $6,320,000
  - Distribution duct and feeder circuits - $4,650,000
  - Total Distribution Costs - $42,400,000
- 2016
  - 2nd substation transformer added at Midtown - $2,000,000
  - Distribution duct and feeder circuits - $2,250,000
  - Total Distribution Costs - $4,250,000
- 2017
  - 2nd substation transformer added at Hiawatha - $5,175,000
  - Distribution duct and feeder circuits - $3,150,000
  - Total Distribution Costs - $8,325,000
- 2023
  - 3rd substation transformer added at Hiawatha - $3,930,000
  - Distribution duct and feeder circuits - $1,700,000
  - Total Distribution Costs - $5,630,000

A2 costs more than A1 due to a higher transmission line cost for a longer 115 kV line, higher site development costs, and higher feeder circuit costs. Cost information for A2 is provided in Appendix G.

With respect to electrical losses, A2 has the second lowest line losses of the four alternatives because it utilizes 115 kV transmission lines to transmit power from Hiawatha Avenue to the west of the load center.

6.2.3 Non-Standard Alternatives – Use Distribution Voltages Instead of Transmission Voltages to Transmit Power to the Midtown Area

6.2.3.1 A3: Hiawatha 13.8 kV Distribution and Express 13.8 kV Feeders to the Load Center

This option includes an ultimate design capacity of six (6) distribution substation transformers with a total of thirty (30) feeder circuits located at one new substation location.

Three of the substation transformers at 115/13.8 kV serve fifteen (15) 13.8 kV feeder circuits that serve customer loads directly from the substation location.

Three of the substation transformers serve fifteen (15) feeder circuits that are express circuits installed in duct banks from the Hiawatha Substation site to the nexus of the 13.8 kV feeder circuits located near the existing former Oakland Substation in the Midtown area.

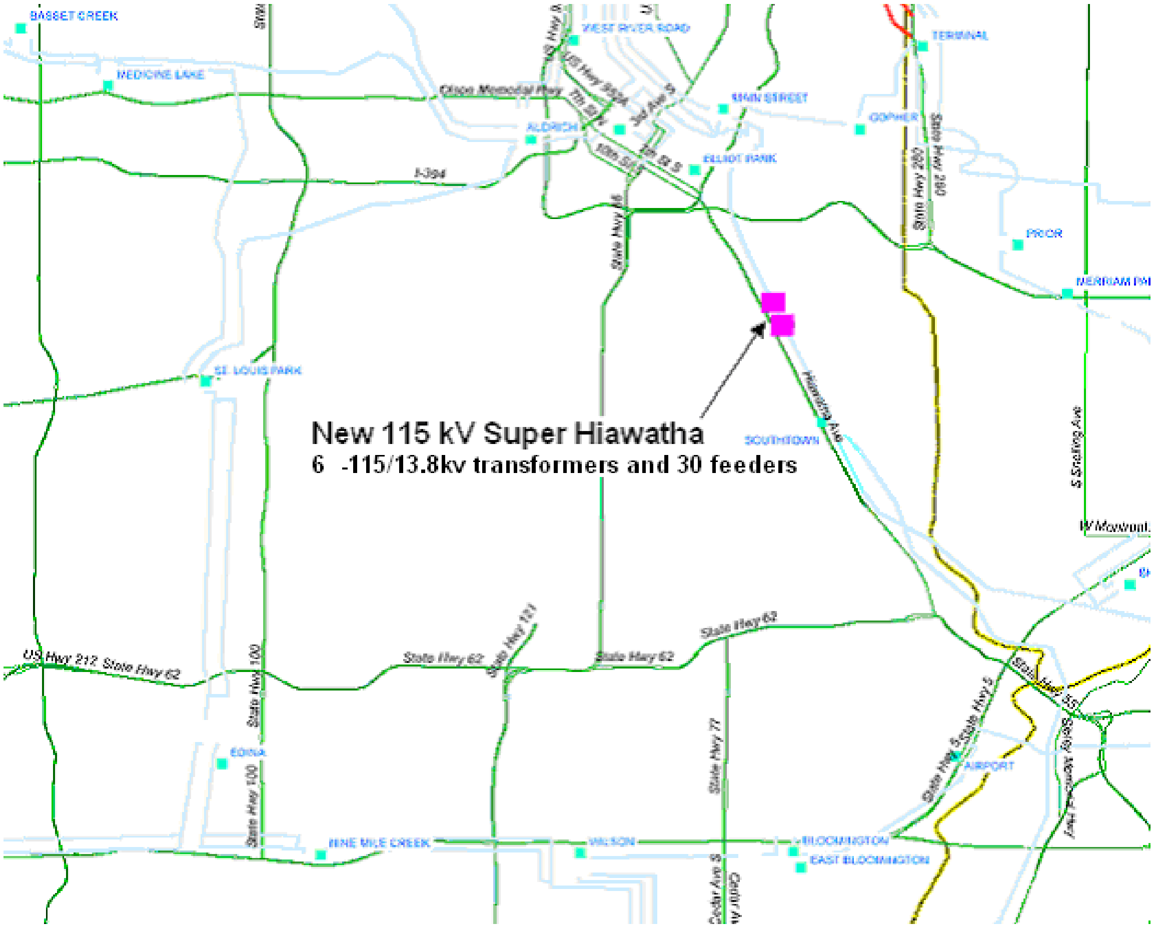
A distribution substation with an ultimate capacity of six (6) distribution transformers and 30 feeder circuits with 15 express feeder circuits instead of a 115 kV transmission line is a non-standard installation.

One substation would be located near the existing site of the former Hiawatha Substation which requires a short transmission line extension to tap the existing Elliot Park – Southtown 115 kV transmission line into the substation site and more extensive 115 kV equipment installation in the substation to enable the installation of six (6) substation transformers. The proposed site requires a larger physical size than the substation considered in A1 or A2.

The initial installation includes two substation transformers and ten associated feeder circuits at one substation site. The first 115/13.8 kV transformer with 5 associated feeder circuits would serve distribution customer load directly from the substation location. The second 115/13.8 kV transformer, also installed in the same substation site has five (5) 13.8 kV express feeders installed in at least 12,000 feet long manhole and duct bank(s) installed from Hiawatha Substation site to the nexus of feeder circuits at the existing former Oakland Substation site near Oakland Avenue and 29th Street in the Midtown area. The length of the duct line and express feeders will be determined by the exact location of the Hiawatha Substation. The five 13.8 kV feeder circuits are connected to existing feeders at the former Oakland Substation site.

Figure 6.3 illustrates the A3 configuration.

Figure 6.3: A3 – Large Hiawatha 115/13.8 kV Distribution Substation and 13.8 kV Express Feeders



With respect to System Performance, A3 does not meet voltage requirements. A load flow run on the system model configured for A3 indicated system-intact N-0 voltage problems on two of the express feeders constructed to serve customer load west of the load center. These heavily loaded feeders would serve loads as far as four miles from the distribution substation, and the feeders do not maintain voltages that comply with the tolerances for voltage at the customer meter (±5% of 120 volt nominal) as stated in American National Standards Institute ("ANSI") Standard C84.1 entitled Electric Power Systems and Equipment – Voltage Ratings (60 Hertz). A3 feeder circuits also do not meet minimum voltage requirements under N-1, first contingency conditions. A3 has the longest feeder circuits of the four alternatives. Longer feeder circuits consist of more equipment, have more elements that can fail, and have more exposure to external factors that increase the chance of feeder outages. A3 is the worst alternative with respect to System Performance.

With respect to Operability, A3 uses standard distribution delivery components in a non-standard way, making A3 more vulnerable during overload and outage conditions. A3 also uses long express feeder circuits that require many more components to keep in running order and fully operational during all possible conditions.

With respect to Future Growth, A3 provides roughly equal possibilities for future capacity additions as do A1 and A2 in an area expected to experience significant growth in electricity demand. A3 addresses future load serving needs.

A3 is estimated to cost approximately $60 million and is the third most expensive alternative. Staging costs include the following:

- 2010
  - Hiawatha 115 kV substation - $15,160,000
  - Distribution duct and feeder circuits - $6,650,000
  - Total Distribution Costs - $21,810,000
- 2016
  - 3rd substation transformer added at Hiawatha - $5,210,000
  - Distribution duct and feeder circuits - $8,000,000
  - Total Distribution Costs - $13,210,000
- 2017
  - 4th substation transformer added at Hiawatha - $4,530,000
  - Distribution duct and feeder circuits - $10,400,000
  - Total Distribution Costs - $14,930,000
- 2023
  - 5th substation transformer added at Hiawatha - $7,900,000
  - Distribution duct and feeder circuits - $2,200,000
  - Total Distribution Costs - $10,100,000

Cost information for A3 is provided in Appendix G.

With respect to electrical losses, A3 results in more electrical losses than either A1 or A2 because it requires one substation and utilizes 13.8 kV feeder circuits instead of 115 kV transmission lines to transmit power from Hiawatha substation to the load center near the existing former Oakland substation. By using SynerGEE and performing a load flow the loss difference between A3 and A1 peak was determined to be around 1 MW. This 1 MW is the same as the MW $\text{reduction}_{\text{PEAK}}$ value that was discussed in Appendix F describing electric losses. Over the 20-year view of this Study there would be approximately 42,000 MWh in additional cost to A3 above A1, which correlates to 40,000 tons of CO_2 in cost and $3.8 million higher cost.

6.2.3.2 A4: Hiawatha 13.8 kV Distribution and 34.5 kV Sub-Transmission with Three Substations in Midtown for 13.8 kV Distribution

This option includes an ultimate design capacity of 14 distribution substation transformers with a total of 37 feeder circuits located at four new substation locations.

The first substation location contains six substation transformers. Three of the substation transformers at 115/13.8 kV serve fifteen (15) 13.8 kV feeder circuits that serve customer loads directly from the substation location. Three of the substation transformers at 115/34.5 kV serve six (6) 34.5 kV feeder circuits that are express circuits installed in duct banks from the Hiawatha Substation site to the three 34.5/13.8 kV substations.

The second substation location contains four substation transformers. The third and fourth substation locations each contain two substation transformers. The three 34.5/13.8 kV substations each are distribution substations fed from 34.5 kV sub-transmission voltage lines. The six (6) 34.5 kV express feeders are installed along an approximately six mile route instead of installing 115 kV transmission lines and a second new transformer located in the Midtown area.

Substation one would be located near the existing site of the former Hiawatha Substation which requires a short transmission line extension to tap the existing Elliot Park – Southtown 115 kV transmission line into the substation site and a more extensive 115 kV equipment installation in the substation to enable the installation of six (6) substation transformers. This substation has an ultimate substation capacity of six (6) substation transformers with three (3) 115/13.8 kV and three (3) 115/34.5 kV. The proposed site requires a larger physical size than the substation considered in A1 or A2.

Substation two, located near the existing site of the former Oakland Substation, has an ultimate capacity of four (4) 34.5/13.8 kV distribution substation transformers which feed eight (8) 13.8 kV feeder circuits. 34.5 kV feeder circuits will be installed in a duct bank about 18,000 feet long from the Hiawatha Substation site to the existing former Oakland Substation site near Oakland Ave and 29th Street. The Oakland Substation site is at the nexus of 13.8 kV feeder circuits nearest the load center in Midtown.

Substation three, located near the existing site of the former Garfield Substation, has an ultimate capacity of two (2) 34.5/13.8 kV distribution substation transformers which feed four (4) 13.8 kV feeder circuits. Two 34.5 kV feeder circuits will be installed in a duct bank about 24,000 feet from the Hiawatha Substation site to the existing former Garfield Substation site west of Interstate 35W near Garfield Ave and 33rd St in the south Minneapolis area.

Substation four, located near the existing site of the former Nicollet Substation, has an ultimate capacity of two (2) 34.5/13.8 kV distribution substation transformers which feed four (4) 13.8 kV feeder circuits. Two 34.5/13.8 kV feeder circuits will be installed in a duct bank about 36,000 feet from the Hiawatha Substation site to the existing former Nicollet Substation site west of Interstate 35W near Nicollet Ave and 47th Street in the south Minneapolis area.

A distribution substation with an ultimate capacity of six distribution transformers and 37 feeder circuits with six (6) 34.5 kV express feeder circuits instead of a 115 kV transmission line is a non-standard installation.

The initial installation requires five substation transformers and fourteen associated feeder circuits; ten (10) feeder circuits at 13.8 kV and four (4) feeder circuits at 34.5 kV at two of the four new substation sites.

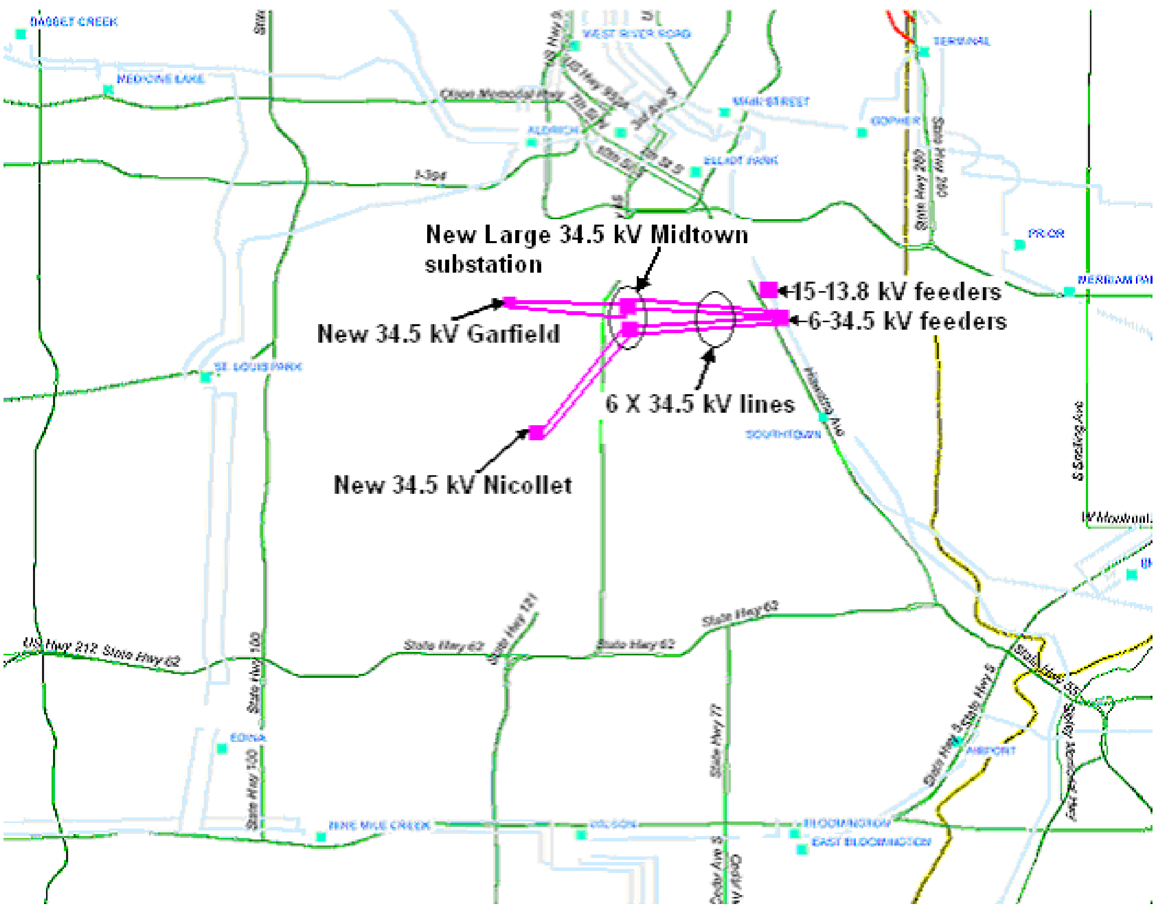
The first 115/13.8 kV transformer is installed at Hiawatha Substation site with five associated feeder circuits that serve distribution customer load directly from the substation location. The second and third 115/34.5 kV transformers are also installed at the Hiawatha substation site with four (4) 34.5 kV express feeders installed in multi-feeder express duct bank(s).

Two 34.5 kV feeder circuits will be installed in a duct bank from the Hiawatha Substation site to the Oakland Substation site. Two 34.5 kV feeder circuits will be installed in a duct bank from the Hiawatha Substation site to the existing former Garfield Substation site west of Interstate 35W.

The fourth and fifth 34.5/13.8 kV transformers are installed near the existing Oakland Substation site and the existing Garfield Substation site, respectively. Each substation transformer is installed in a distribution substation that is fed by a primary and a backup 34.5 kV circuit. The Oakland Substation site will initially serve three (3) 13.8 kV feeder circuits and the Garfield Substation site will initially serve two (2) 13.8 kV feeder circuits.

Figure 6.4 illustrates the configuration of A4.

Figure 6.4: A4 – Large Hiawatha 115/13.8 kV Distribution Substation with 34.5 kV Sub-transmission and Three 13.8 kV Distribution Substations



With respect to System Performance, A4, which installs four substations and uses 34.5 kV as sub-transmission to transmit power, has more exposure to line failures than A1 or A2 due to adding 34.5 kV circuits between the substation and the customer. A4 is capable of maintaining adequate voltage on feeder circuits but is the most complex of the alternatives and requires the most equipment. With respect to Operability, A4 is the worst alternative based on this criterion because it introduces a new distribution voltage and adds another level of transformation at additional 34.5/13.8 kV substations, making operations more difficult and complex.

With respect to Future Growth, A4 is difficult to integrate into the existing distribution delivery system and so would require additional 34.5 kV infrastructure to assist in serving future load, which is possible, but not as easily done as by A1 and A2.

A4 is estimated to cost approximately $122 million. Staging costs include the following:

- 2010
  - Hiawatha 115 kV substation - $25,125,000
  - Oakland 34.5 kV substation - $13,490,000
  - Distribution duct and feeder circuits - $22,500,000
  - Total Distribution Costs - $61,115,000
- 2016
  - 4th substation transformer added at Hiawatha - $9,250,000
  - Garfield 34.5 kV substation - $7,965,000
  - Distribution duct and feeder circuits - $4,950,000
  - Total Distribution Costs - $22,165,000
- 2017
  - 5th substation transformer added at Hiawatha - $7,470,000
  - Nicollet 34.5 kV substation - $11,435,000
  - Distribution duct and feeder circuits - $8,400,000
  - Total Distribution Costs - $27,305,000
- 2023
  - 6th substation transformer added at Hiawatha - $9,715,000
  - Distribution duct and feeder circuits – $1,700,000
  - Total Distribution Costs - $11,415,000

A4 is the highest cost alternative. Cost information for A4 is provided in Appendix G.

With respect to Electrical Losses, A4 has the third highest losses of the four alternatives. A4, which uses 34.5 kV circuits instead of 115 kV transmission lines to transmit power has lower losses than using 13.8 kV, but adds the cost of losses of a second voltage transformation.

6.2.4 Preferred New Distribution Source Alternative

Distribution Planning compared each new source alternative relative to all new source alternatives with respect to each evaluation criteria. The results of the comparison are summarized in the decision matrix in Figure 6.5. Note that A1 has the highest total score using all the criteria and is the preferred alternative.

Figure 6.5: Alternatives Comparison Matrix

ALTERNATIVES / COMPARISON CRITERIA	Alternative 1- 2-13.8 kV subs	Alternative 2- 2 subs, 1 west	Alternative 3- 1 sub-13.8 transmit	Alternative 4- 4 subs-34.5 transmit
1-Distribution System Performance	4	3	0	2
2-Operability	3	3	2	1
3- Future Growth	4	3	2	1
4- Cost	4	2	3	1
5-Electrical Losses	4	3	1	2
TOTAL	19	15	7	6
			Not Feasible	

Note: Higher number ranking is a better alternative (*i.e.*, 4 is best). A zero score indicates the alternative is not feasible due to not meeting minimum required standards.

Based on the above analysis, Planning Engineers determined that A1 is the preferred new source alternative because it best satisfies the five established distribution planning criteria. A1 locates a new distribution substation closest to the greatest amount of customer load. A1 has the shortest feeder circuits, resulting in the least amount of customer exposure to outages and the best system performance. It uses the smallest addition of proven reliable elements to relieve existing overloads, resulting in the highest operability of the alternatives considered. The Midtown Substation location proposed in A1 is closest to planned future load growth, so it has the best potential to adapt to future growth. A1 is the least expensive to construct and has the lowest electrical losses, making it the most cost effective and efficient option of the four alternatives that are capable of meeting south Minneapolis customer load requirements.

Transmission Planning Engineers also evaluated the alternatives and determined that double-circuiting the two 115 kV transmission lines connecting the two substations in A1 would not impair the performance of the facilities with respect to the distribution capacity need.

7.0 RECOMMENDATION

Distribution Planning recommends A1 to meet the identified capacity needs on the south Minneapolis electrical distribution delivery system in the Focused Study Area. To confirm that A1 will mitigate the feeder overloads in the Focused Study Area, Distribution Planning Engineers analyzed how the distribution system would function after construction of the first phase of A1.

Figure 7.1 displays the area of load served by the two new substation transformers in the context of the Greater Study Area

Figure 7.1: Post-Proposed Project Installation: Load Served by New Hiawatha and Midtown Substations

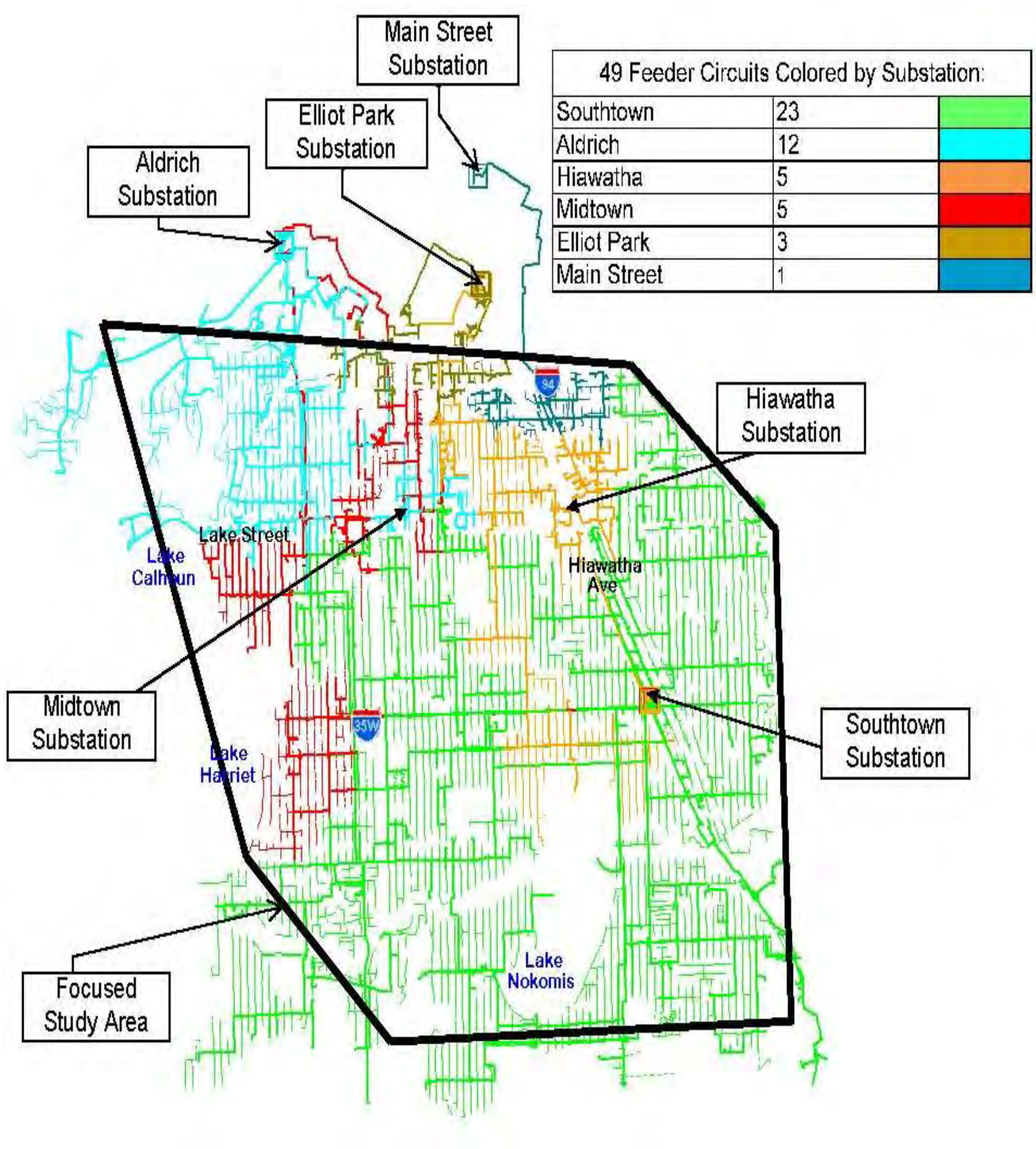
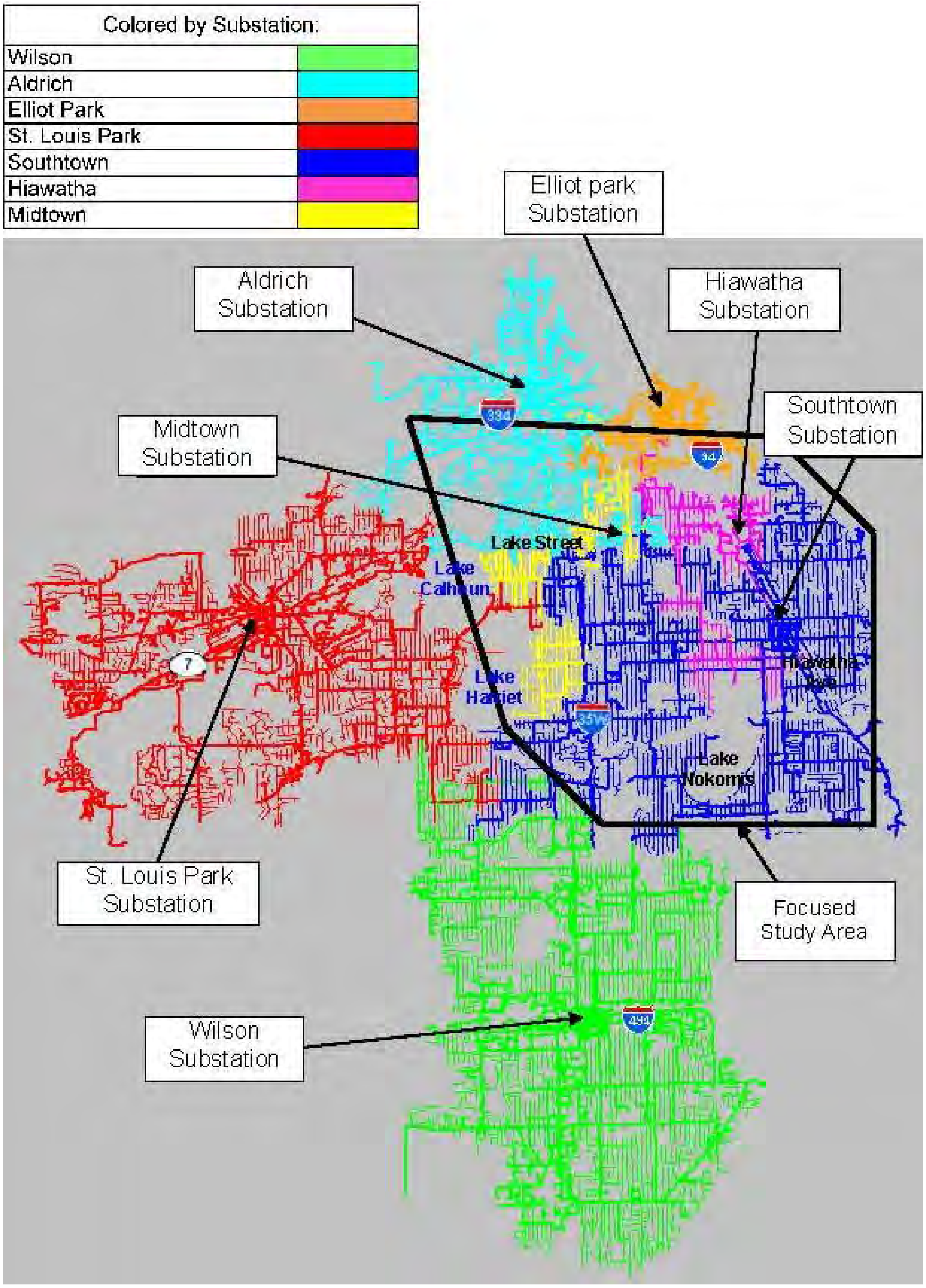


Figure 7.2 displays the area of load served by the ten (10) new feeder circuits from two (2) new substation transformers at two new substations that comprise A1 in the context of the Focused Study Area

Figure 7.2: Post-Proposed Project Installation: Load Served by 49 Feeder Circuits in Focused Study Area

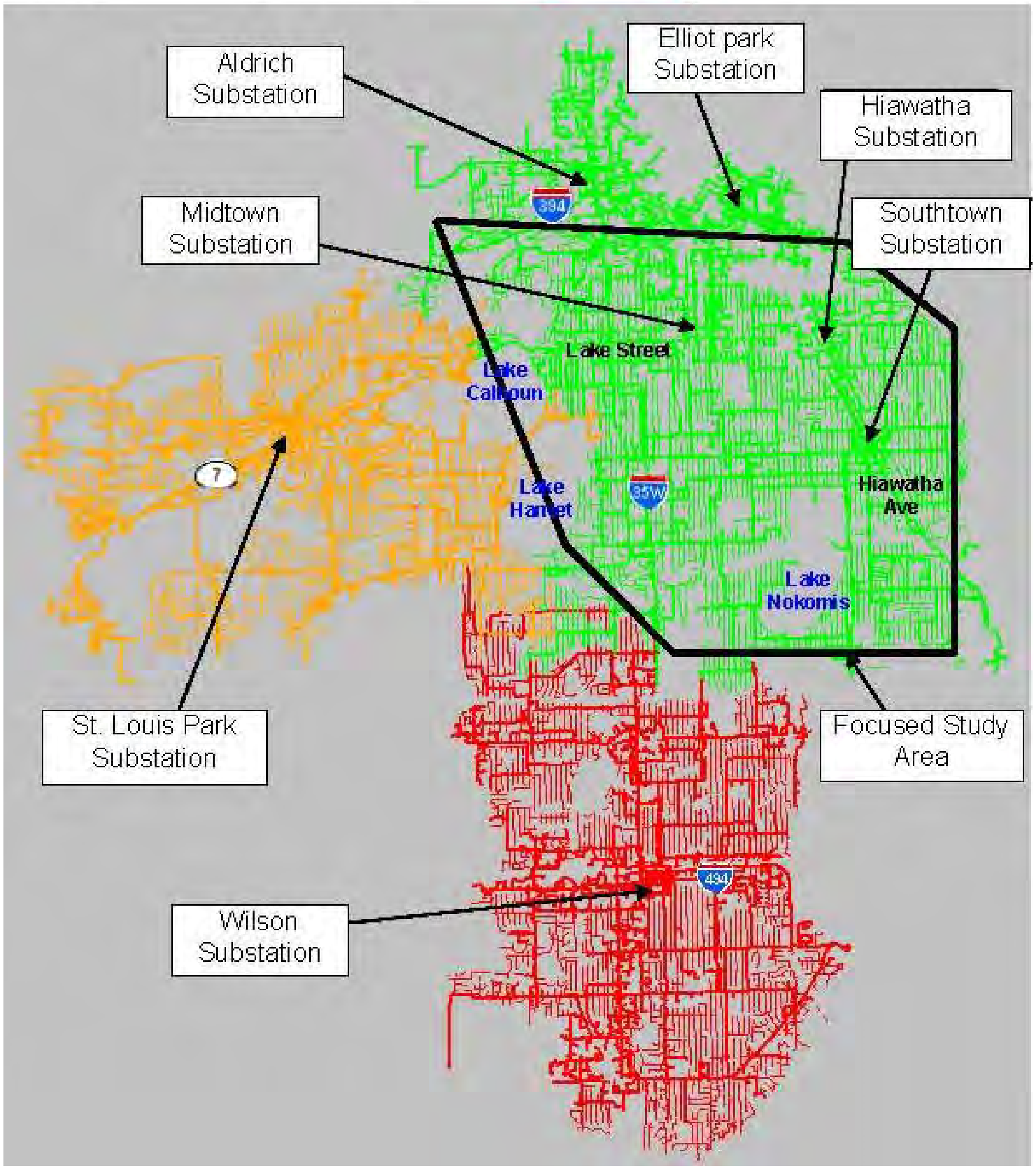


Contingency overloads of Southtown and Aldrich substation transformers are solved by the addition of the two new substation transformers. The overloaded transformers at St Louis Park and Wilson substations are beyond the range of feeder circuits from the new substations and are not impacted by the new substations in the Midtown area. Forecast substation overloads for the duration of the study period can be solved by adding substation transformers to the recommended substations within the initial fenced limits of the new substations.

Figure 7.3 displays the overloaded transformers in the Greater Study Area after the two new substation transformers and ten new feeder circuits are installed.

Figure 7.3: Post-Proposed Project Installation: 2010 N-1 Contingency Substation Transformer Risks

Colored by Substation:		
0	11 Transformers	
0 to 10 MW		
10 MW to 25 MW	3 Transformers	
> 25 MW	3 Transformers	

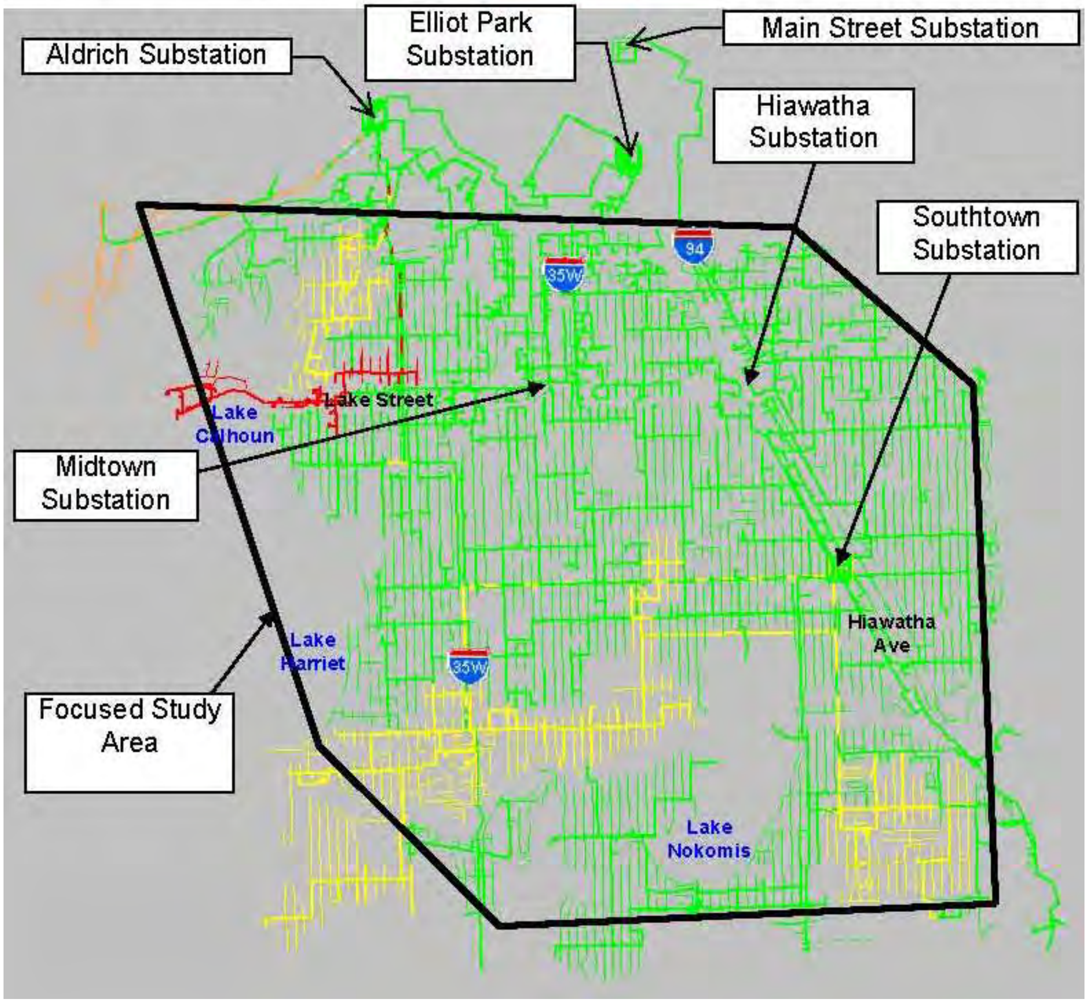


All N-0 system intact overloads in the Focused Study Area can be solved by the addition of the ten new feeder circuits. There are no system intact overloads on 43 of 49 feeder circuits due to the additional circuits. The six (6) remaining overloads shown from Aldrich and Southtown substations will be solved by a cascaded sequence of rerouting and reconfiguring feeder circuits that are directly relieved by the new feeder circuits.

Figure 7.4 shows the N-0 feeder circuit overloads solved directly by the ten new feeder circuits of the recommended alternative.

Figure 7.4: Post-Proposed Project Installation: 2010 N-0 Feeder Circuit Risks

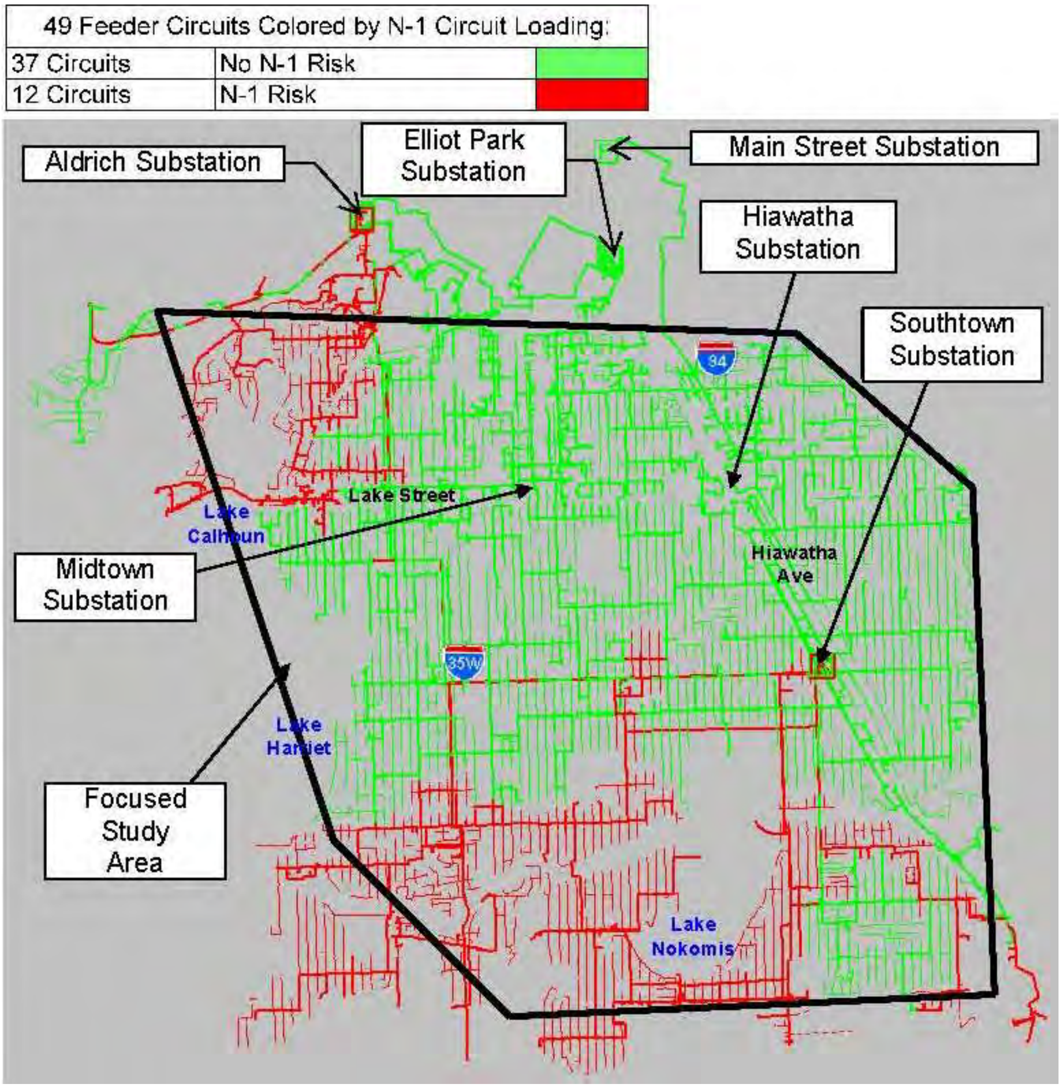
49 Feeder Circuits Colored by N-0 Circuit Loading:		
43 Circuits	<75%	
4 Circuits	75%-100%	
1 Circuit	100%-115%	
1 Circuit	>115%	



The majority of the N-1 first contingency overloads can be solved by the addition of the ten new feeder circuits. Thirty seven (37) of the 49 feeder circuits have no N-1 overload after the addition of 10 new feeder circuits. Rerouting and reconfiguring feeder circuits solves 7 more N-1 overloads that are closest to Southtown and Aldrich substations. Remaining N-1 feeder circuit overloads are beyond the reach of the new and existing substation and feeder circuit additions in the Study Area.

Figure 7.5 shows that the ten new feeder circuits of A1 directly solve the N-1 first contingency feeder circuit overloads.

Figure 7.5: Post-Proposed Project Installation: 2010 N-1 Feeder Circuit Risks



Distribution Planning recommends that the first phase of A1 be constructed to be in-service by 2010/2011.

Appendix A: History of Feeder Circuit Improvements to South Minneapolis Distribution Delivery System to Serve Focused Study Area

To address the increasing demand in the south Minneapolis area, in particular the Focused Study Area, Distribution Planning Engineers have implemented substantial improvements to correct existing feeder circuit overloads, including those listed below:

Reinforced Existing Feeder Circuits to Serve Increasing Customer Load

Feeder circuit reinforcements in the Focused Study Area from 2002 through 2005 include:

Installed larger overhead wire on feeder circuits along 21st Street east of Chicago Avenue and underground on Chicago Avenue south of 19th Street (ELP62).

Installed double underground cable circuits on 42nd Street to west and north (SOU83, SOU86).

Installed double overhead wire on 10th Avenue and Elliot north of 42nd to Lake Street (SOU84, ALD81).

Installed double underground cable and double deck overhead circuits south (SOU61, SOU64).

Rearranged Feeder Circuits to Get Capacity to Overloads

Feeder circuit rearrangements in the Focused Study Area from 2002 through 2007 in specific areas in response to specific load additions include:

Chicago Ave (SOU66, ELP84)

New Southtown Circuit east (SOU69)

Uptown, Lake St (ALD72, ALD92)

Veterans Administration Hospital, Hiawatha Ave (SOU65, SOU76)

Abbott Hospital (SOU84, ALD81)

Midtown Exchange (SOU81)

Feeder Circuit Solutions to Address Widespread Feeder Circuit Overloads

Feeder circuit condition based equipment replacement for feeder circuits located in the Focused Study Area from 2001 through 2006 include:

2001 to 2004 – Identified and aggressively replaced more than 120 damaged feeder circuit cables in the south Minneapolis Study Area.

Replaced overhead feeder wire south (SOU79)

Replaced feeder cable north (SOU66, SOU68)

Replaced feeder cable south (SOU65, SOU76)

Replaced overhead feeder wire north (SOU60)

Other Improvements to the Electrical System

Distribution system improvements from 2001 to 2008 in the Focused Study Area include:

Addition of capacitor banks to maintain voltage on deficient feeder circuits

Annual Feeder Circuit Reliability Reviews included multiple circuits in the study area

Line clearance (tree trimming) of multiple overhead feeder circuits selected based on a combination of time since last line clearance and feeder circuit performance

Converted 4 kV substations to standard system voltage (Garfield – 2003, Oakland - 2005, Nicollet – 2006)

Targeted distribution transformer overloads (on the pole in the alley) caused by MAC sound reduction air conditioner additions, and

Reduced peak related outages (due to bigger transformers and more transformers on poles and on pads serving each block).

New Feeder Circuits

Feeder circuit additions and adding new feeder breakers equipment to re-commission previously decommissioned substation feeders in the Focused Study Area from 2002 through 2006 include:

New Elliot Park Circuit south (ELP81)

New Elliot Park Circuit south (ELP84)

New Southtown Circuit east (SOU69)

New Southtown Circuit west (SOU78)

New Southtown Circuit north (SOU79)

New Southtown Circuit north (SOU88)

Appendix B: Feeder Circuit Forecasts for Focused Study Area

South Minneapolis STUDY

Feeder Circuit Load (kVA) History and Forecast

Appendix B, Table 1

Historical Peak Loads / Forecast Peak Loads

Feeder	00 Cap	04 Cap	2008 Capacity	2000 Peak	2001 Peak	2002 Peak	2003 Peak	2004 Peak	2005 Peak	2006 Peak	2007 Peak	2008 Peak	2009 Fcst	2010	2011	2012	2013	2018	2023	2028	% Growth		SOU	ALD	ELP	MST
ALD071	7600	7600	7600	10135	10100	10800	9900	8100	8330	8550	8560	6191	7284	7393	7504	7617	7731	8328	8971	9664	1.077222			1		
ALD072	7600	7600	7600	9514	9600	10900	9600	10700	10910	7930	7730	7770	8048	8128	8209	8292	8374	9246	10209	11272	1.104132			1		
ALD073	7600	7600	7600	8697	9600	12900	12600	10100	5490	6050	5660	5690	5947	6006	6066	6127	6188	6504	6836	7185	1.051067			1		
ALD074	7600	7600	7600	7513	1950	2000	2600	6700	7730	6710	5950	5720	6527	6592	6658	6725	6792	7139	7504	7887	1.05109			1		
ALD081	7800	7800	7800	8412	5300	6700	8300	6700	6960	10940	10220	10630	10736	10844	10952	11062	11172	11742	12341	12971	1.05102			1		
ALD083	9600	9600	9600	7799	6700	9500	3700	4800	4970	5280	5180	4980	5230	5282	5335	5388	5442	5720	6012	6319	1.051084			1		
ALD085	9894	9894	9894	9800	9800	11000	10200	6100	6100	9070	8380	7770	8148	8229	8311	8395	8479	8911	9365	9842	1.050949			1		
ALD088	10100	10100	10100	5798	4600	4600	9200	5100	7700	6140	6190	6050	6110	6172	6233	6296	6359	6683	7024	7381	1.050951			1		
ALD091	7700	7700	7700	8493	6700	6700	8800	9300	9450	9120	8520	7490	7565	7641	7717	7794	7872	8442	9053	9709	1.072409			1		
ALD092	10100	10100	10100	8657	9000	9000	9200	12500	12930	10480	10370	12480	13105	13236	13368	13502	13637	14333	15065	15833	1.051038			1		
ALD093	7700	7700	7700	6942	7800	9000	1200	2000	2490	5510	3950	8220	8302	8385	8469	8554	8639	9080	9544	10031	1.051048			1		
ALD095	10690	10690	10690	12413	14000	15900	14000	13100	14420	9940	11800	9285	9424	9566	9709	9855	10003	10663	11367	12117	1.06598			1		
ELP071	7700	7700	7700	9800	10500	11500	10200	7100	6960	10320	9430	8733	8818	8906	8996	9085	9176	9644	10136	10653	1.051003				1	
ELP081		10197	10197	0	0	0	0	7600	11700	8860	8360	7620	7696	7773	7851	7929	8009	8417	8846	9296	1.050943				1	
ELP084		10575	10575	0	0	0	3000	6500	7200	6620	7180	7070	7176	7284	7393	7504	7616	8282	9006	9794	1.087447				1	
MST074	10600	10600	10600	8167	10800	8000	8000	9400	10190	10574	9670	9117	9208	9300	9393	9487	9582	10071	10585	11125	1.051033					1
SOU060	10200	10200	10200	5880	6600	6900	7500	8200	6220	6807	6220	4890	4939	4988	5038	5089	5139	5402	5678	5969	1.051177		1			
SOU061		14300	14300	1225	3200	0	5100	5100	11930	13109	11497	8950	8995	9040	9085	9130	9176	9408	9646	9890	1.025283		1			
SOU063	12500	12500	12500	8412	8800	10700	12500	9600	12630	10050	8463	10167	10269	10371	10475	10580	10686	11231	11804	12406	1.051001		1			
SOU064	13900	13900	13900	10628	12600	16900	16900	14000	12430	13990	8870	8521	7189	7333	7483	7633	7782	8592	9486	10474	1.104086		1			
SOU065	9600	9600	9600	4982	6800	9500	6100	6100	6710	7059	6205	6341	6404	6468	6533	6598	6664	7004	7361	7737	1.05102		1			
SOU066	9400	9400	9400	2695	5000	7700	5100	5100	5700	6933	5040	6394	7322	7468	7618	7770	7925	8750	9661	10667	1.104101		1			
SOU068	10000	10000	10000	8657	10300	10700	10400	10800	9450	9642	9691	9584	9680	9777	9874	9973	10073	10587	11127	11695	1.051027		1			
SOU069	13900	13900	13900	8085	8500	8500	7000	4600	5970	5146	4544	3981	4319	4363	4406	4450	4495	4724	4965	5218	1.050945		1			
SOU072	10200	10200	10200	8085	8100	8100	10500	10300	7460	7240	8090	8001	8081	8162	8243	8326	8409	8838	9289	9763	1.051017		1			
SOU073	11400	11400	11400	7187	7600	7700	7500	7500	12430	12500	11882	12196	12436	12686	12945	13204	13463	14857	16395	18093	1.103543		1			
SOU075	9300	9300	9300	10372	10800	12500	13000	10900	8500	9231	9156	9011	9591	9783	9979	10178	10382	11462	12654	13971	1.104026		1			
SOU076	8600	8600	8600	8657	11100	12200	10500	7400	8450	10196	8603	7778	8334	8500	8670	8844	9021	9959	10995	12138	1.10398		1			
SOU077	13600	13600	13600	7758	8700	9200	9200	11400	10940	10837	10429	10914	11023	11133	11245	11357	11471	12056	12671	13317	1.050998		1			
SOU078			13900	2450	3700	0	0	0	4970	5205	5620	5884	6002	6122	6244	6369	6496	7173	7921	8746	1.104218		1			
SOU079			13500	2450	5100	1300	0	0	7460	7778	7793	7152	7674	7750	7828	7906	7985	8392	8820	9269	1.050971		1			
SOU081	8600	8600	8600	9188	10000	10700	11200	6800	6710	7933	7186	7860	8017	8178	8341	8508	8678	9581	10578	11679	1.104056		1			
SOU082	8000	8000	8000	11678	11800	12900	10200	10200	6710	5554	5487	5690	5804	5920	6038	6159	6282	6936	7658	8455	1.104107		1			
SOU083	14000	14000	14000	6043	6200	6700	7600	8800	12780	14662	12186	12779	12907	13036	13166	13298	13431	14116	14836	15593	1.051001		1			
SOU084	12500	12500	12500	8330	9900	9500	10000	7700	8950	8205	7822	7472	7547	7622	7698	7775	7853	8254	8675	9118	1.051063		1			
SOU085	13900	13900	13900	8032	9100	9000	9400	6200	7060	7110	7584	8545	8630	8717	8804	8892	8981	9439	9920	10426	1.050997		1			
SOU086	12500	12500	12500	5553	11500	11500	7500	7300	9940	10662	10766	12104	12225	12347	12471	12595	12721	13370	14052	14769	1.051018		1			
SOU087	9200	9200	9200	7105	7600	9500	8300	8100	9450	9341	9176	8040	8201	8365	8532	8703	8877	9801	10821	11948	1.104089		1			
SOU088			13900	0	0	0	0	0	0	6510	6220	5928	5987	6047	6108	6169	6230	6419	6614	6814	1.030337		1			
Capacity	333584	368656	409956	33	36	34	35	36	38	39	39	39	39									39	23	12	3	1
# Fdrs	33	36	39																							

Feeder	00 Cap	04 Cap	2008 Capacity	2000	2001	2002	2003	2004 peak	2005 Peak	2006 Peak	2007 Peak	2008 Peak	2009 Fcst	2010	2011	2012	2013	2018	2023	2028			SOU	ALD	ELP	MST
MVA	333584	368656	409956	275592	299450	320200	306000	291900	326380	337794	315680	312998	320939	326923	330999	335130	339304	361574	385513	411260		312998	188182	92276	23423	9117
MW	326912	361283	401757	270080	293461	313796	299880	286062	319852	331038	309366	306738	314520	320385	324379	328427	332518	354343	377803	403035		306738	184418	90430	22955	8935
kVA/ Feeder		39		8351	8318	9418	8743	8108	8589	8661	8094	8026	8229	8383	8487	8593	8700	9271	9885	10545		308538	59.8%	29.3%	7.4%	2.9%
		8yr % Growth										1.7%										Totals				
		annual % Growth																								
	DAA kVA Annual Growth			-14708	23858	20750	-14200	-14100	34480	11414	-22114	-2682	7941	5984	4076	4131	4174	22270	23939	25748						
	DAA % Annual Growth Rate			-4.0%	6.4%	5.6%	-4.1%	-4.0%	9.4%	2.9%	-5.4%	-0.7%	1.9%	1.9%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%						
	DAA % Utilization			83%	80%	93%	86%	79%	83%	83%	77%	76%	78%	80%	81%	82%	83%	88%	94%	100%						
DAA	kVA Over 75%			-3926	19933	61833	39101	17354	31284	32273	8213	5531	13472	19456	23532	27663	31837	54107	78046	103793						
MW				-3847	19534	60596	38319	17006	30658	31627	8049	5420	13203	19067	23061	27110	31200	53025	76485	101718						
	Demand for 1/2% Annual Grow											312998	314563	316136	317716	319305	320902	329005	337313	345830						
	1/2% Growth Rate % Utilizatio											76%	77%	77%	78%	78%	78%	80%	82%	84%						
Peak	Difference (In kVA) from DAA t											0	6376	10787	13283	15825	18402	32569	48200	65430						
Grows																										
1/2%	kVA Over 75%											5531	7096	8669	10249	11838	13435	21538	29846	38363						
MW												5420	6954	8495	10044	11601	13166	21107	29249	37596						

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Feeder Circuit Loads - Historic Based Forecast : N-0, N-1 Analysis

Appendix B, Table 2

2009

Feeder	00 Cap	04 Cap	2008 Capacity	2008 % Load	N-0 % Load	N-0 kVA >100%	N-0 kVA >75%	N-0 R >= 115	N-0 O	N-0 A	N-0 G	N-1 R	N-1 kVA over
ALD071	7600	7600	7600	81%	96%		1584			1		1	6393
ALD072	7600	7600	7600	102%	106%	448	2348		1			1	2068
ALD073	7600	7600	7600	75%	78%		247			1		1	4195
ALD074	7600	7600	7600	75%	86%		827			1		1	5267
ALD081	7800	7800	7800	136%	138%	2936	4886	1				1	6092
ALD083	9600	9600	9600	52%	54%						1	1	1258
ALD085	9894	9894	9894	79%	82%		728			1		1	2923
ALD088	10100	10100	10100	60%	60%						1	1	1134
ALD091	7700	7700	7700	97%	98%		1790			1		1	1347
ALD092	10100	10100	10100	124%	130%	3005	5530	1				1	5586
ALD093	7700	7700	7700	107%	108%	602	2527		1				
ALD095	10690	10690	10690	87%	88%		1407			1		1	5660
ELP071	7700	7700	7700	113%	115%	1118	3043	1				1	791
ELP081		10197	10197	75%	75%		48			1		1	2477
ELP084		10575	10575	67%	68%						1	1	3101
MST074	10600	10600	10600	86%	87%		1258			1		1	1592
SOU060	10200	10200	10200	48%	48%						1		
SOU061		14300	14300	63%	63%						1	1	2418
SOU063	12500	12500	12500	81%	82%		894			1		1	6887
SOU064	13900	13900	13900	61%	52%						1	1	3734
SOU065	9600	9600	9600	66%	67%						1	1	2015
SOU066	9400	9400	9400	68%	78%		272			1		1	3516
SOU068	10000	10000	10000	96%	97%		2180			1		1	400
SOU069	13900	13900	13900	29%	31%						1		
SOU072	10200	10200	10200	78%	79%		431			1		1	2744
SOU073	11400	11400	11400	107%	109%	1036	3886	1				1	2613
SOU075	9300	9300	9300	97%	103%	291	2616		1			1	879
SOU076	8600	8600	8600	90%	97%		1884			1		1	533
SOU077	13600	13600	13600	80%	81%		823			1		1	810
SOU078			13900	42%	43%						1		
SOU079			13500	53%	57%						1		
SOU081	8600	8600	8600	91%	93%		1567			1		1	2579
SOU082	8000	8000	8000	71%	73%						1	1	2818
SOU083	14000	14000	14000	91%	92%		2407			1		1	6644
SOU084	12500	12500	12500	60%	60%						1	1	4859
SOU085	13900	13900	13900	61%	62%						1		
SOU086	12500	12500	12500	97%	98%		2850			1		1	8126
SOU087	9200	9200	9200	87%	89%		1301			1		1	4132
SOU088			13900	43%	43%						1		
Capacity	333584	368656	409956										
# Fdrs	33	36	39										
Feeder	00 Cap	04 Cap	2008 Capacity	2008 % Load	% Load	kVA >100%	kVA >75%	R >= 115	O	A	G	R	kVA over
MVA	333584	368656	409956	76%	78%	9436	47333	4	3	18	14	32	105591
MW	326912	361283	401757			9247	46387				39		103479
kVA/ Feeder		39				3	21						
		8yr % Growth											
		annual % Growth											
	DAA kVA Annual Growth					4	4						
	DAA % Annual Growth Rate					7	25						
	DAA % Utilization					3145	2254						
DAA	kVA Over 75%												
MW						3082	2209						
	Demand for 1/2% Annual Growth Rate					1348	1893						
	1/2% Growth Rate % Utilization												
Peak	Difference (in kVA) from DAA to 1/2%												
Grows													
1/2%	kVA Over 75%												
MW						1321	1855						

2013

Feeder	N-0 % Load	N-0 kVA >100%	N-0 kVA >75%	N-0 R >= 115	N-0 O	N-0 A	N-0 G	N-1 R	N-1 kVA over
ALD071	102%	131	2031		1			1	9153
ALD072	110%	774	2674		1			1	3842
ALD073	81%		488			1		1	4698
ALD074	89%		1092			1		1	5796
ALD081	143%	3372	5322	1				1	6918
ALD083	57%						1	1	3020
ALD085	86%		1059			1		1	5198
ALD088	63%						1	1	2031
ALD091	102%	172	2097		1			1	3587
ALD092	135%	3537	6062	1				1	8023
ALD093	112%	939	2864		1			1	3079
ALD095	94%		1986			1		1	7149
ELP071	119%	1476	3401	1				1	2346
ELP081	79%		361			1		1	6470
ELP084	72%						1	1	3803
MST074	90%		1632			1		1	2989
SOU060	50%						1		
SOU061	64%						1	1	2923
SOU063	85%		1311			1		1	7977
SOU064	56%					1		1	4042
SOU065	69%						1	1	3315
SOU066	84%		875			1		1	5036
SOU068	101%	73	2573		1			1	940
SOU069	32%						1		
SOU072	82%		759			1		1	3836
SOU073	118%	2063	4913	1				1	4750
SOU075	112%	1082	3407		1			1	2729
SOU076	105%	421	2571		1			1	3124
SOU077	84%		1271			1		1	1123
SOU078	47%						1		
SOU079	59%						1		
SOU081	101%	78	2228		1			1	2012
SOU082	79%		282			1		1	3410
SOU083	96%		2931			1		1	8437
SOU084	63%						1	1	8741
SOU085	65%						1		
SOU086	102%	221	3346		1			1	9443
SOU087	96%		1977			1		1	4770
SOU088							1		
Feeder	% Load	kVA >100%	kVA >75%	R >= 115	O	A	G	R	kVA over
MVA	83%	14339	59512	4	9	14	12	33	154710
MW		14052	58322				39		151616
kVA/ Feeder		13	23						
DAA kVA Annual Growth		4	4						
DAA % Annual Growth Rate		17	27						
DAA % Utilization		1103	2587						
MW		1081	2536						
Demand for 1/2% Annual Growth Rate		843	2204						
MW		827	2160						

2018

Feeder	N-0 % Load	N-0 kVA >100%	N-0 kVA >75%	N-0 R >= 115	N-0 O	N-0 A	N-0 G	N-1 R	N-1 kVA over
ALD071	110%	728	2628		1			1	9492
ALD072	122%	1646	3546	1				1	6307
ALD073	86%		804			1		1	6449
ALD074	94%		1439			1		1	6346
ALD081	151%	3942	5892	1				1	8150
ALD083	60%						1	1	4319
ALD085	90%					1		1	7748
ALD088	66%						1	1	3257
ALD091	110%	742	2667		1			1	4608
ALD092	142%	4233	6758	1				1	11297
ALD093	118%	1380	3305	1				1	3392
ALD095	100%		2646		1			1	9158
ELP071	125%	1944	3869	1				1	3808
ELP081	83%		769			1		1	7486
ELP084	78%		351			1		1	4400
MST074	95%		2121			1		1	3514
SOU060	53%						1		
SOU061	66%						1	1	3730
SOU063	90%		1856			1		1	8384
SOU064	62%						1	1	4463
SOU065	73%						1	1	3392
SOU066	93%		1700			1		1	5170
SOU068	106%	587	3087		1			1	1656
SOU069	34%						1		
SOU072	87%		1188			1		1	5425
SOU073	130%	3457	6307	1				1	5484
SOU075	123%	2162	4487	1				1	2559
SOU076	116%	1359	3509	1				1	3383
SOU077	89%		1856			1		1	2760
SOU078	52%						1		
SOU079	62%						1		
SOU081	111%	981	3131		1			1	2552
SOU082	87%		936			1		1	3584
SOU083	101%	116	3616		1			1	9574
SOU084	66%						1	1	9573
SOU085	68%						1		
SOU086	107%	870	3995		1			1	11178
SOU087	107%	601	2901		1			1	5185
SOU088	46%						1		
Feeder	% Load	kVA >100%	kVA >75%	R >= 115	O	A	G	R	kVA over
MVA	88%	24748	75364	8	8	11	12	33	####
MW		24253	73856				39		####
kVA/ Feeder		8	19						
DAA kVA Annual Growth		8	8						
DAA % Annual Growth Rate		16	27						
DAA % Utilization		3094	3967						
MW		3032	3887						
Demand for 1/2% Annual Growth Rate		1547	2791						
MW		1516	2735						

2023 and 2028

Feeder	2023 N-0 % Load	2023 N-0 kVA >100 %	2023 N-0 kVA >75%	2023 N-0 R >= 115	2023 N-0 O	2023 N-0 A	2023 N-0 G	2028 N-0 % Load	2028 N-0 kVA >100 %	2028 N-0 kVA >75%	2028 N-0 R >= 115	2028 N-0 O	2028 N-0 A	2028 N-0 G
ALD071	118%	1371	3271	1				127%	2064	3964	1			
ALD072	134%	2609	4509	1				148%	3672	5572	1			
ALD073	90%		1136			1		95%	-415	1485		1		
ALD074	99%		1804			1		104%	287	2187		1		
ALD081	158%	4541	6491	1				166%	5171	7121	1			
ALD083	63%						1	66%						1
ALD085	95%		1945			1		99%		2422			1	
ALD088	70%						1	73%						1
ALD091	118%	1353	3278	1				126%	2009	3934	1			
ALD092	149%	4965	7490	1				157%	5733	8258	1			
ALD093	124%	1844	3769	1				130%	2331	4256	1			
ALD095	106%	677	3349		1			113%	1427	4099		1		
ELP071	132%	2436	4361	1				138%	2953	4878	1			
ELP081	87%		1198			1		91%		1649			1	
ELP084	85%		1075			1		93%		1863			1	
MST074	100%		2635		1			105%	525	3175		1		
SOU060	56%						1	59%						1
SOU061	67%						1	69%		-835			1	
SOU063	94%		2429			1		99%	-94	3031		1		
SOU064	68%						1	75%		49			1	
SOU065	77%		161			1		81%		537			1	
SOU066	103%	261	2611		1			113%	1267	3617		1		
SOU068	111%	1127	3627		1			117%	1695	4195	1			
SOU069	36%						1	38%						1
SOU072	91%		1639			1		96%		2113			1	
SOU073	144%	4995	7845	1				159%	6693	9543	1			
SOU075	136%	3354	5679	1				150%	4671	6996	1			
SOU076	128%	2395	4545	1				141%	3538	5688	1			
SOU077	93%		2471			1		98%		3117			1	
SOU078	57%						1	63%						1
SOU079	65%						1	69%						1
SOU081	123%	1978	4128	1				136%	3079	5229	1			
SOU082	96%		1658			1		106%	455	2455		1		
SOU083	106%	836	4336		1			111%	1593	5093	1			
SOU084	69%						1	73%						1
SOU085	71%						1	75%		1			1	
SOU086	112%	1552	4677		1			118%	2269	5394	1			
SOU087	118%	1621	3921	1				130%	2748	5048	1			
SOU088	48%						1	49%						1
Feeder	% Load	kVA >100 %	kVA >75%	R >= 115	O	A	G	% Load	kVA >100 %	kVA >75%	R >= 115	O	A	G
MVA	94%	37914	96037	12	6	10	11	100%	53668	116130	15	7	9	8
MW		37156	94116				39		52595	113807				39
kVA/ Feeder		6	16						7	16				
DAA kVA Annual Growth		12	12						15	15				
DAA % Annual Growth Rate		18	28						22	31				
DAA % Utilization		6319	6002						7667	7258				
MW		6193	5882						7514	7113				
Demand for 1/2% Annual Growth Rate		2106	3430						2439	3746				
MW		2064	3361						2391	3671				

South Minneapolis STUDY

Feeder Circuit Loads - Historical Analysis

Appendix A, Table 3

				2000 N-0							2004 N-0							2006 N-0							2006 N-1		2008-DAA N-0						
Feeder	00 Cap	04 Cap	2008 Capacity	% Load	kVA >100%	kVA >75%	R>= 115	O	A	G	% Load	kVA >100%	kVA >75%	R>= 115	O	A	G	% Load	kVA >100%	kVA >75%	R>= 115	O	A	G	R	kVA over	% Load	kVA >100%	kVA >75%	R>= 115	O	A	G
ALD071	7600	7600	7600	133%	2535	4435	1				107%	500	2400		1			113%	950	2850		1			1	12567	81%		491			1	
ALD072	7600	7600	7600	125%	1914	3814	1				141%	3100	5000	1				104%	330	2230		1			1	5587	102%	170	2070		1		
ALD073	7600	7600	7600	114%	1097	2997			1		133%	2500	4400			1		80%		350			1		1	7896	75%					1	
ALD074	7600	7600	7600	99%		1813			1		88%		1000			1		88%		1010			1		1	6023	75%		20			1	
ALD081	7800	7800	7800	108%	612	2562		1			86%		850			1		140%	3140	5090	1				1	6587	136%	2830	4780	1			
ALD083	9600	9600	9600	81%		599			1		50%						1	55%						1	1	981	52%						1
ALD085	9894	9894	9894	99%		2380			1		62%						1	92%		1650			1		1	4153	79%		350			1	
ALD088	10100	10100	10100	57%						1	50%						1	61%						1	1	2543	60%						1
ALD091	7700	7700	7700	110%	793	2718		1			121%	1600	3525	1				118%	1420	3345	1				1	2046	97%		1715			1	
ALD092	10100	10100	10100	86%		1082			1		124%	2400	4925	1				104%	380	2905		1			1	7183	124%	2380	4905	1			
ALD093	7700	7700	7700	90%		1167			1		26%						1	72%						1	1	697	107%	520	2445		1		
ALD095	10690	10690	10690	116%	1723	4396	1				123%	2410	5083	1				93%		1923			1		1	6104	87%		1268			1	
ELP071	7700	7700	7700	127%	2100	4025	1				92%		1325			1		134%	2620	4545	1				1	1645	113%	1033	2958		1		
ELP081		10197	10197	0%							75%					1		87%		1212			1		1	737	75%					1	
ELP084		10575	10575	0%							61%						1	63%						1	1	957	67%						1
MST074	10600	10600	10600	77%		217			1		89%		1450			1		100%				1			1	6702	86%					1	
SOU060	10200	10200	10200	58%						1	80%		550				1	67%						1			48%						1
SOU061		14300	14300	9%							36%						1	92%		2384			1		1	9989	63%						1
SOU063	12500	12500	12500	67%						1	77%		225			1		80%		675			1		1	5661	81%		792			1	
SOU064	13900	13900	13900	76%		203			1		101%	100	3575		1			101%	90	3565		1			1	8760	61%						1
SOU065	9600	9600	9600	52%						1	64%						1	74%						1	1	6902	66%						1
SOU066	9400	9400	9400	29%						1	54%						1	74%						1	1	4367	68%						1
SOU068	10000	10000	10000	87%		1157			1		108%	800	3300		1			96%		2142			1		1	2562	96%		2084			1	
SOU069	13900	13900	13900	58%						1	33%						1	37%						1			29%						1
SOU072	10200	10200	10200	79%		435			1		101%	100	2650		1			71%						1	1	6420	78%		351			1	
SOU073	11400	11400	11400	63%						1	66%						1	110%	1100	3950		1					107%	796	3646		1		
SOU075	9300	9300	9300	112%	1072	3397		1			117%	1600	3925	1				99%		2256			1		1	5128	97%		2036			1	
SOU076	8600	8600	8600	101%	57	2207		1			86%		950			1		119%	1596	3746	1				1	8356	90%		1328			1	
SOU077	13600	13600	13600	57%						1	84%		1200			1		80%		637			1		1	2760	80%		714			1	
SOU078			13900	18%							0%						1	37%						1			42%						1
SOU079			13500	18%							0%						1	58%						1			53%						1
SOU081	8600	8600	8600	107%	588	2738		1			79%		350			1		92%		1483			1		1	3368	91%		1410			1	
SOU082	8000	8000	8000	146%	3678	5678	1				128%	2200	4200	1				69%						1	1	4442	71%						1
SOU083	14000	14000	14000	43%						1	63%						1	105%	662	4162		1			1	8020	91%		2279			1	
SOU084	12500	12500	12500	67%						1	62%						1	66%						1	1	9335	60%						1
SOU085	13900	13900	13900	58%						1	45%						1	51%						1			61%						1
SOU086	12500	12500	12500	44%						1	58%						1	85%		1287			1		1	9922	97%		2729			1	
SOU087	9200	9200	9200	77%		205			1		88%		1200			1		102%	141	2441		1			1	4533	87%		1140			1	
SOU088			13900	0%							0%						1	47%						1	1	787	43%						1
Capacity	333584	368656	409956																														
# Fdrs	33	36	39																						R	kVA over							
Feeder	00 Cap	04 Cap	2008 Capacity	% Load	kVA >100%	kVA >75%	>= 115	R	A	G	% Load	kVA >100%	kVA >75%	>= 115	R	A	G	% Load	kVA >100%	kVA >75%	>= 115	R	A	G			% Load	kVA >100%	kVA >75%	>= 115	R	A	G
																									33	173720							
MVA	333584	368656	409956	83%	16169	48224	5	5	11	12	79%	17310	52083	6	4	11	18	82%	12429	55837	4	8	12	15		170246	76%	7729	39510	2	4	18	15
MW	326912	361283	401757		15846	47260				33		16964	51041				39		12180	54721				39				7574	38720				39
kVA/ Feeder		39																															
		8yr % Growth																															
		annual % Growth																															
	DAA kVA Annual Growth																																
	DAA % Annual Growth Rate																																
	DAA % Utilization																																
DAA	kVA Over 75%																																
MW																																	
	Demand for 1/2% Annual Grow																																
	1/2% Growth Rate % Utilizatio																																
Peak	Difference (in kVA) from DAA t																																
Grows																																	
1/2%	kVA Over 75%																																
MW																																	

South Minneapolis STUDY

Feeder Circuit Load - 1/2% Growth Scenario Forecast : N-0, N-1 Analysis

Appendix B, Table 4

2008 N-0

Feeder	00 Cap	04 Cap	2008 Capacity	Load	% Load	kVA >100%	kVA >75%	R>= 115	O	A	G
ALD071	7600	7600	7600	6191	81%		491			1	
ALD072	7600	7600	7600	7770	102%	170	2070		1		
ALD073	7600	7600	7600	5690	75%					1	
ALD074	7600	7600	7600	5720	75%		20			1	
ALD081	7800	7800	7800	10630	136%	2830	4780	1			
ALD083	9600	9600	9600	4980	52%						1
ALD085	9894	9894	9894	7770	79%		350			1	
ALD088	10100	10100	10100	6050	60%						1
ALD091	7700	7700	7700	7490	97%		1715			1	
ALD092	10100	10100	10100	12480	124%	2380	4905	1			
ALD093	7700	7700	7700	8220	107%	520	2445		1		
ALD095	10690	10690	10690	9285	87%		1268			1	
ELP071	7700	7700	7700	8733	113%	1033	2958		1		
ELP081		10197	10197	7620	75%					1	
ELP084		10575	10575	7070	67%						1
MST074	10600	10600	10600	9117	86%		1167			1	
SOU060	10200	10200	10200	4890	48%						1
SOU061		14300	14300	8950	63%						1
SOU063	12500	12500	12500	10167	81%		792			1	
SOU064	13900	13900	13900	8521	61%						1
SOU065	9600	9600	9600	6341	66%						1
SOU066	9400	9400	9400	6394	68%						1
SOU068	10000	10000	10000	9584	96%		2084			1	
SOU069	13900	13900	13900	3981	29%						1
SOU072	10200	10200	10200	8001	78%		351			1	
SOU073	11400	11400	11400	12196	107%	796	3646		1		
SOU075	9300	9300	9300	9011	97%		2036			1	
SOU076	8600	8600	8600	7778	90%		1328			1	
SOU077	13600	13600	13600	10914	80%		714			1	
SOU078			13900	5884	42%						1
SOU079			13500	7152	53%						1
SOU081	8600	8600	8600	7860	91%		1410			1	
SOU082	8000	8000	8000	5690	71%						1
SOU083	14000	14000	14000	12779	91%		2279			1	
SOU084	12500	12500	12500	7472	60%						1
SOU085	13900	13900	13900	8545	61%						1
SOU086	12500	12500	12500	12104	97%		2729			1	
SOU087	9200	9200	9200	8040	87%		1140			1	
SOU088			13900	5928	43%						1
Capacity	333584	368656	409956								
# Fdrs	33	36	39								
Feeder	00 Cap	04 Cap	2008 Capacity		% Load	kVA >100%	kVA >75%	>= 115	R	A	G
MVA	333584	368656	409956	312998	76%	7729	40677	2	4	18	15
MW	326912	361283	401757	306738		7574	39863				39
kVA/ Feeder		39									
		8yr % Growth									
		annual % Growth									
	DAA kVA Annual Growth										
	DAA % Annual Growth Rate										
	DAA % Utilization										
DAA	kVA Over 75%										
MW											
	Demand for 1/2% Annual Grow										
	1/2% Growth Rate % Utilizatio										
Peak	Difference (in kVA) from DAA t										
Grows											
1/2%	kVA Over 75%										
MW											

2009-1/2% N-0

Feeder	Load	% Load	kVA >100%	kVA >75%	R>= 115	O	A	G
ALD071	6222	82%		522			1	
ALD072	7809	103%	209	2109		1		
ALD073	5718	75%		18			1	
ALD074	5749	76%		49			1	
ALD081	10683	137%	2883	4833	1			
ALD083	5005	52%						1
ALD085	7809	79%		388			1	
ALD088	6080	60%						1
ALD091	7527	98%		1752			1	
ALD092	12542	124%	2442	4967	1			
ALD093	8261	107%	561	2486		1		
ALD095	9331	87%		1314			1	
ELP071	8777	114%	1077	3002		1		
ELP081	7658	75%		10			1	
ELP084	7105	67%						1
MST074	9163	86%		1213			1	
SOU060	4914	48%						1
SOU061	8995	63%						1
SOU063	10218	82%		843			1	
SOU064	8564	62%						1
SOU065	6373	66%						1
SOU066	6426	68%						1
SOU068	9632	96%		2132			1	
SOU069	4001	29%						1
SOU072	8041	79%		391			1	
SOU073	12257	108%	857	3707		1		
SOU075	9056	97%		2081			1	
SOU076	7817	91%		1367			1	
SOU077	10969	81%		769			1	
SOU078	5913	43%						1
SOU079	7188	53%						1
SOU081	7899	92%		1449			1	
SOU082	5718	71%						1
SOU083	12843	92%		2343			1	
SOU084	7509	60%						1
SOU085	8588	62%						1
SOU086	12165	97%		2790			1	
SOU087	8080	88%		1180			1	
SOU088	5958	43%						1
Feeder		% Load	kVA >100%	kVA >75%	>= 115	R	A	G
MVA	314563	77%	8029	41715	2	4	18	15
MW	308272		7869	40881				39

2013-1/2% N-0

Feeder	Load	% Load	kVA >100%	kVA >75%	R>= 115	O	A	G
ALD071	6379	84%		679			1	
ALD072	8006	105%	406	2306		1		
ALD073	5863	77%		163			1	
ALD074	5894	78%		194			1	
ALD081	10953	140%	3153	5103	1			
ALD083	5131	53%						1
ALD085	8006	81%		586			1	
ALD088	6234	62%						1
ALD091	7718	100%	18	1943		1		
ALD092	12859	127%	2759	5284	1			
ALD093	8470	110%	770	2695		1		
ALD095	9567	89%		1550			1	
ELP071	8998	117%	1298	3223	1			
ELP081	7851	77%		204			1	
ELP084	7285	69%						1
MST074	9394	89%		1444			1	
SOU060	5039	49%						1
SOU061	9222	64%						1
SOU063	10476	84%		1101			1	
SOU064	8780	63%						1
SOU065	6534	68%						1
SOU066	6588	70%						1
SOU068	9875	99%		2375			1	
SOU069	4102	30%						1
SOU072	8244	81%		594			1	
SOU073	12566	110%	1166	4016		1		
SOU075	9285	100%		2310		1		
SOU076	8014	93%		1564			1	
SOU077	11246	83%		1046			1	
SOU078	6063	44%						1
SOU079	7369	55%						1
SOU081	8099	94%		1649			1	
SOU082	5863	73%						1
SOU083	13167	94%		2667			1	
SOU084	7699	62%						1
SOU085	8805	63%						1
SOU086	12472	100%		3097		1		
SOU087	8284	90%	-916	1384			1	
SOU088	6108	44%						1
Feeder		% Load	kVA >100%	kVA >75%	>= 115	R	A	G
MVA	322506	79%	8654	47175	3	6	15	15
MW	316056		8481	46231				39

2018-1/2% N-0

Feeder	Load	% Load	kVA >100%	kVA >75%	R>= 115	O	A	G
ALD071	6540	86%		840			1	
ALD072	8208	108%	608	2508		1		
ALD073	6011	79%		311			1	
ALD074	6043	80%		343			1	
ALD081	11229	144%	3429	5379	1			
ALD083	5261	55%						1
ALD085	8208	83%		788			1	
ALD088	6391	63%						1
ALD091	7912	103%	212	2137		1		
ALD092	13184	131%	3084	5609	1			
ALD093	8684	113%	984	2909		1		
ALD095	9809	92%		1791			1	
ELP071	9226	120%	1526	3451	1			
ELP081	8050	79%		402			1	
ELP084	7469	71%						1
MST074	9631	91%		1681			1	
SOU060	5166	51%						1
SOU061	9455	66%						1
SOU063	10740	86%		1365			1	
SOU064	9002	65%						1
SOU065	6699	70%						1
SOU066	6755	72%						1
SOU068	10124	101%	124	2624		1		
SOU069	4206	30%						1
SOU072	8452	83%		802			1	
SOU073	12884	113%	1484	4334		1		
SOU075	9519	102%	219	2544		1		
SOU076	8217	96%		1767			1	
SOU077	11530	85%		1330			1	
SOU078	6216	45%						1
SOU079	7555	56%						1
SOU081	8303	97%		1853			1	
SOU082	6011	75%		11			1	
SOU083	13500	96%		3000			1	
SOU084	7893	63%						1
SOU085	9027	65%						1
SOU086	12787	102%	287	3412		1		
SOU087	8493	92%		1593			1	
SOU088	6262	45%						1
Feeder		% Load	kVA >100%	kVA >75%	>= 115	R	A	G
MVA	330650	81%	11957	52784	3	7	15	14
MW	324037		11718	51728				39

2023-1/2% N-0

Feeder	Load	% Load	kVA >100%	kVA >75%	R>= 115	O	A	G
ALD071	6705	88%		1005			1	
ALD072	8415	111%	815	2715		1		
ALD073	6163	81%		463			1	
ALD074	6195	82%		495			1	
ALD081	11513	148%	3713	5663	1			
ALD083	5394	56%						1
ALD085	8415	85%		995			1	
ALD088	6553	65%						1
ALD091	8112	105%	412	2337		1		
ALD092	13517	134%	3417	5942	1			
ALD093	8903	116%	1203	3128	1			
ALD095	10056	94%		2039			1	
ELP071	9458	123%	1758	3683	1			
ELP081	8253	81%		605			1	
ELP084	7657	72%						1
MST074	9874	93%		1924			1	
SOU060	5296	52%						1
SOU061	9693	68%						1
SOU063	11012	88%		1637			1	
SOU064	9229	66%						1
SOU065	6868	72%						1
SOU066	6925	74%						1
SOU068	10380	104%	380	2880		1		
SOU069	4312	31%						1
SOU072	8666	85%		1016			1	
SOU073	13209	116%	1809	4659	1			
SOU075	9760	105%	460	2785		1		
SOU076	8424	98%		1974			1	
SOU077	11821	87%		1621			1	
SOU078	6373	46%						1
SOU079	7746	57%						1
SOU081	8513	99%		2063			1	
SOU082	6163	77%		163			1	
SOU083	13841	99%		3341			1	
SOU084	8093	65%						1
SOU085	9255	67%						1
SOU086	13109	105%	609	3734		1		
SOU087	8708	95%		1808			1	
SOU088	6420	46%						1
Feeder		% Load	kVA >100%	kVA >75%	>= 115	R	A	G
MVA	338999	83%	14577	58675	5	5	15	14
MW	332219		14286	57501				39

2028-1/2% N-0

Feeder	Load	% Load	kVA >100%	kVA >75%	R>= 115	O	A	G
ALD071	6875	90%		1175			1	
ALD072	8628	114%	1028	2928	1			
ALD073	6318	83%		618			1	
ALD074	6352	84%		652			1	
ALD081	11804	151%	4004	5954	1			
ALD083	5530	58%						1
ALD085	8628	87%		1207			1	
ALD088	6718	67%						1
ALD091	8317	108%	617	2542		1		
ALD092	13858	137%	3758	6283	1			
ALD093	9128	119%	1428	3353	1			
ALD095	10310	96%		2293			1	
ELP071	9697	126%	1997	3922	1			
ELP081	8461	83%		814			1	
ELP084	7851	74%						1
MST074	10124	96%		2174			1	
SOU060	5430	53%						1
SOU061	9938	69%						1
SOU063	11290	90%		1915			1	
SOU064	9462	68%						1
SOU065	7041	73%						1
SOU066	7100	76%		50			1	
SOU068	10642	106%	642	3142		1		
SOU069	4421	32%						1
SOU072	8884	87%		1234			1	
SOU073	13543	119%	2143	4993	1			
SOU075	10006	108%	706	3031		1		
SOU076	8637	100%	37	2187		1		
SOU077	12119	89%		1919			1	
SOU078	6534	47%						1
SOU079	7942	59%						1
SOU081	8728	101%	128	2278		1		
SOU082	6318	79%		318			1	
SOU083	14190	101%	190	3690		1		
SOU084	8297	66%						1
SOU085	9489	68%						1
SOU086	13441	108%	941	4066		1		
SOU087	8928	97%		2028			1	
SOU088	6583	47%						1
Feeder		% Load	kVA >100%	kVA >75%	>= 115	R	A	G
MVA	347559	85%	17618	64764	6	7	13	13
MW	340608		17266	63469				39

Appendix C: Distribution System Maps of 39 Feeder Circuits Serving the Focused Study Area

Figure C.1: Focused Study Area 2006 N-0 Feeder Circuit Risks – System Intact

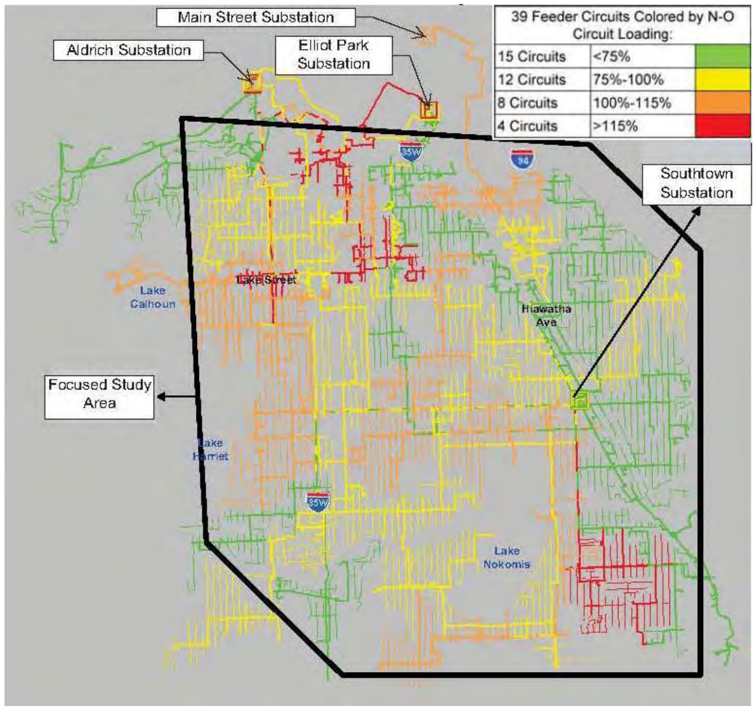


Figure C.2: Focused Study Area 2009 N-0 Feeder Circuit Risks – System Intact

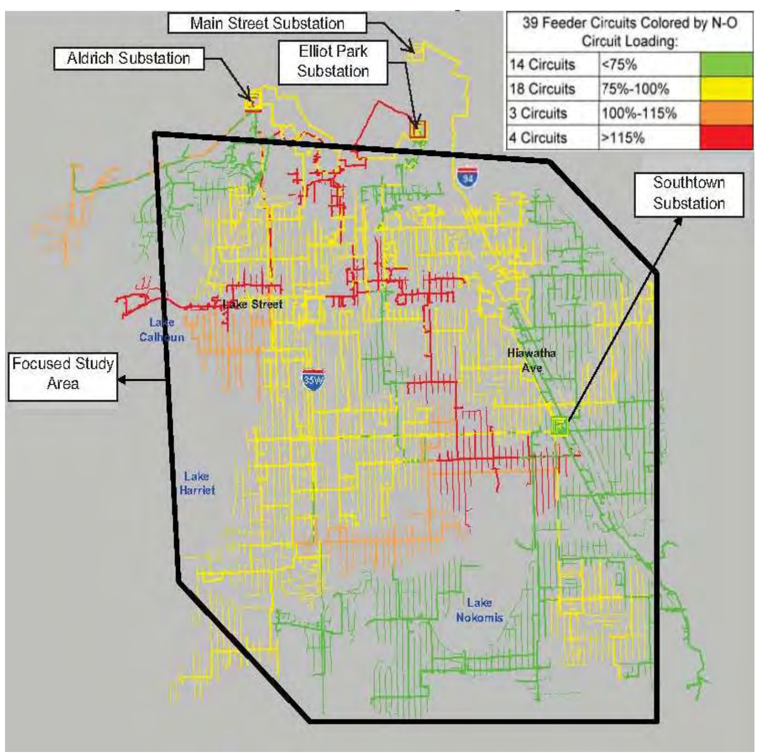


Figure C.3: Focused Study Area 2013 N-0 Feeder Circuit Risks – System Intact

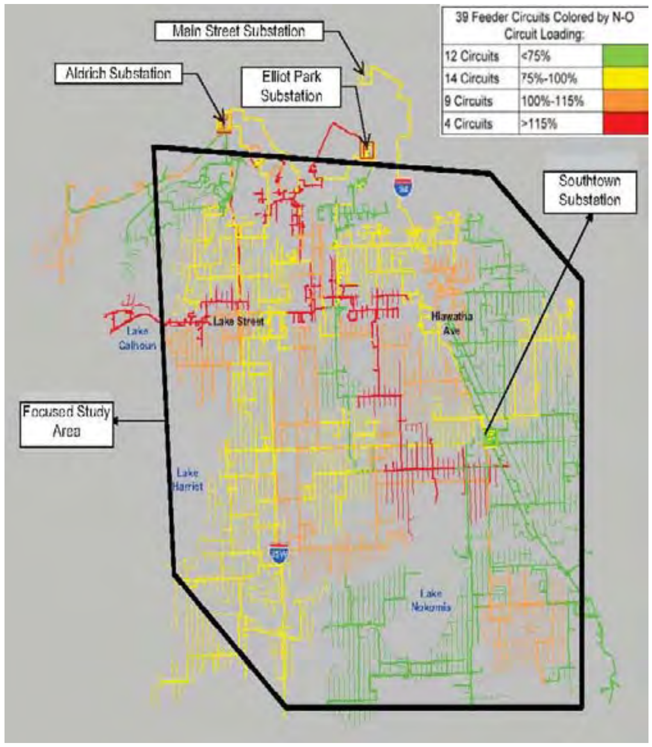


Figure C.4: Focused Study Area 2018 N-0 Feeder Circuit Risks – System Intact

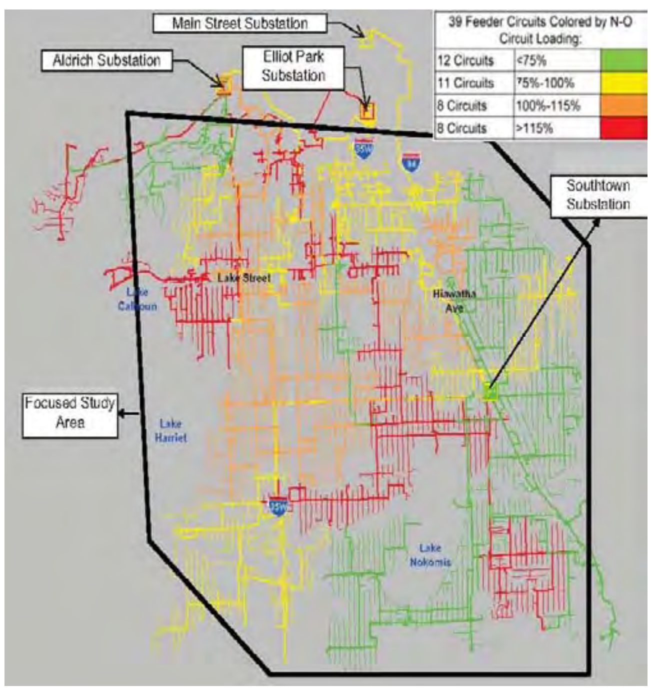


Figure C.5: Focused Study Area 2023 N-0 Feeder Circuit Risks – System Intact

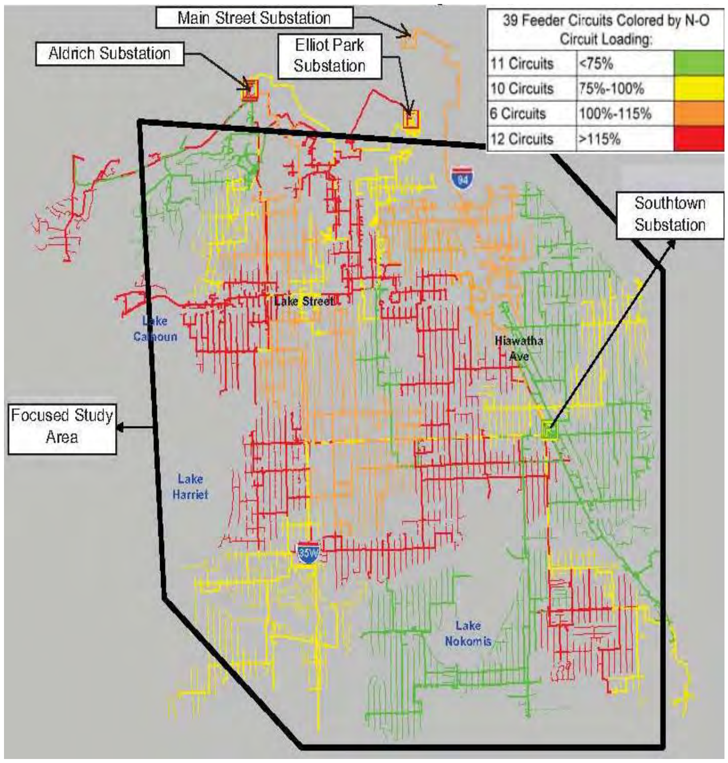


Figure C.6: Focused Study Area 2028 N-0 Feeder Circuit Risks – System Intact

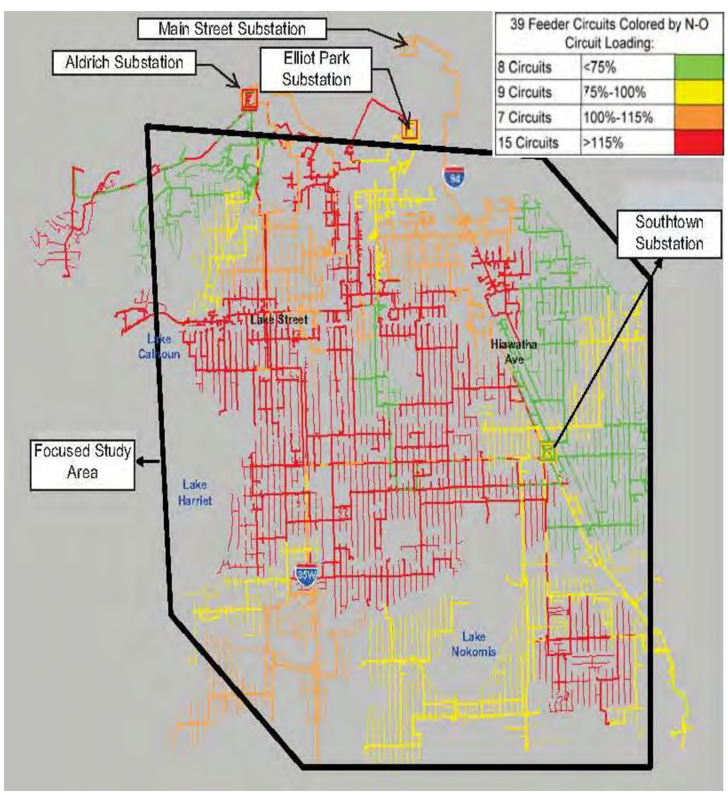


Figure C.7: Focused Study Area 2006 N-1 Feeder Circuit Risks – Single Contingency

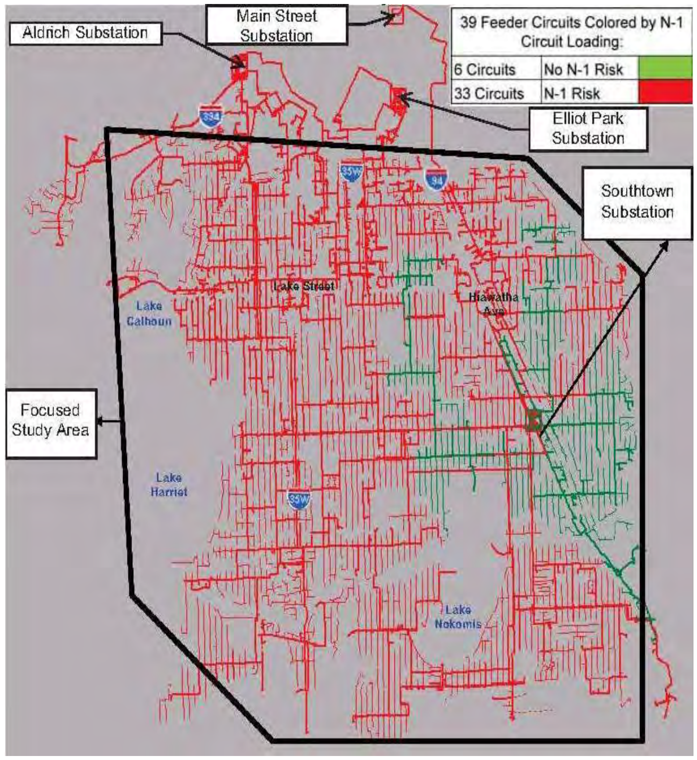


Figure C.8: Focused Study Area 2009 N-1 Feeder Circuit Risks – Single Contingency

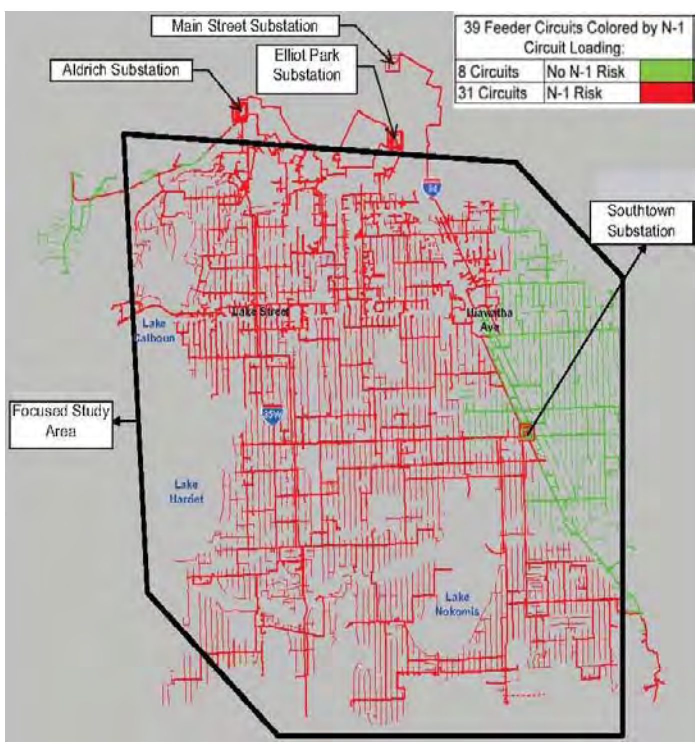
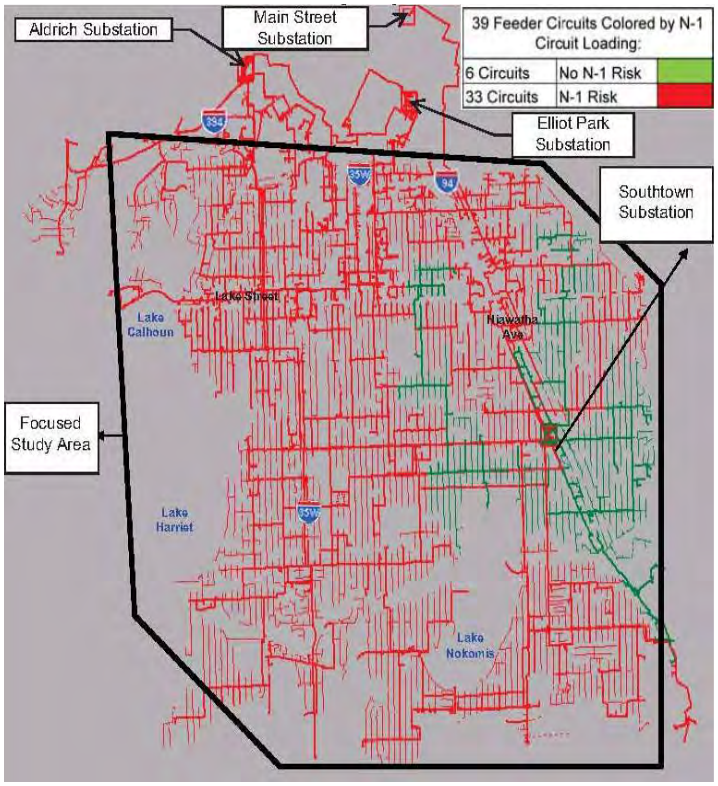


Figure C.9: Focused Study Area 2018 N-1 Feeder Circuit Risks – Single Contingency



Appendix D: Substation Transformer Forecasts for Greater Study Area

South Minneapolis STUDY

Greater Area - Substation Transformer Load History, Forecast

Appendix D, Table 1

	# of feeders	Nameplate	Normal	2000 Peak	2001 Peak	2002 Peak	2003 Peak	2004 peak	2005 Peak	2006 Peak	2007 Peak	2008 Peak	2009 Fcst	2010	2011	2012	2013	2018	2023	2028	
SOUTR1			71709	44100	59600	59100	65800	63000	64000	66260	56100	54400	54683	55323	55974	56632	57295	60770	64456	68365	1.060651
SOUTR2			74099	49000	53900	48000	46300	55000	57500	55490	54714	55270	56195	57081	57987	58904	59832	64737	70044	75786	1.08198
SOUTR3			68327	60400	63700	59000	55000	50000	62146	62970	61910	62850	63773	64613	65466	66331	67209	71683	76455	81544	1.066568
ALDTR2	5	70000	71709	32200	32000	38000	36700	38200	34603	28970	29690	27730	30192	30576	30965	31360	31760	34256	36948	39852	1.078589
ALDTR3	8	70000	71709	55600	55500	50400	51000	40300	43000	47260	52960	49220	52218	52736	53264	54180	54731	57500	60409	63465	1.050593
ALDTR4	8	70000	71709	66400	71300	50300	46300	57000	58268	56870	55430	62880	62217	64739	65479	66213	66956	70799	74863	79159	1.057396
ELPTR1	6	47000	51054	31900	34300	34300	30200	34000	37785	33730	34420	38140	34951	35396	35845	36302	36766	39186	41765	44514	1.065822
ELPTR2	6	47000	51870	30600	32700	31400	29000	32900	33000	32520	36210	37910	34307	34649	34995	35345	35699	37520	39434	41445	1.05101
ELPTR3	7	47000	51054	29800	32100	28000	26000	33000	42632	47180	37031	42910	41372	43655	44282	44920	45568	49030	52755	56763	1.075974
SOUTR1	8	70000	71709	44100	59600	59100	65800	63000	64000	66880	56100	54400	54683	55323	55974	56632	57295	60770	64456	68365	1.060651
SOUTR2	7	70000	74099	49000	53900	48000	46300	55000	57500	56600	54714	55270	56195	57081	57987	58904	59832	64737	70044	75786	1.08198
SOUTR3	8	62500	68327	60400	63700	59000	55000	50000	62146	63230	61910	62850	63773	64613	65466	66331	67209	71683	76455	81544	1.066568
SLPTR4	7	70000	76527	51400	44000	49000	53000	54800	62146	57430	53340	53840	56759	57768	58808	59872	60951	66629	72836	79621	1.093157
SLPTR5	7	70000	71709	52300	54700	48700	53500	56300	54000	45940	53360	51790	54009	55013	56036	57079	58142	63773	69949	76724	1.096849
SLPTR6	7	70000	71709	45700	57200	43900	46500	46600	49717	49710	41030	39420	40818	41578	42349	43138	43939	48177	52824	57919	1.096452
WILTR1	1	42000	42183	37600	42500	38100	40200	34800	42350	0	0	0	0								
WILTR2	1	42000	42183	24000	27000	22600	29700	42000	31270	0	0	0	0								
WILTR3	9	70000	71709	63000	68600	65800	65100	67000	75440	74810	63260	65450	68576	69633	70707	71799	72909	78741	85040	91842	1.07999
WILTR4	9	70000	76527	49000	57200	51300	52500	54700	55540	68190	69636	70690	71900	73044	74208	75394	76602	82987	89904	97398	1.083353
WILTR5	8	70000	76527					0	0	62070	57214	56052	55015	55687	56368	57057	57756	61394	65261	69372	1.062989
Big Box Total			1112314	723000	786300	717900	726800	759600	803397	791390	756305	768552	776985	791491	802733	814526	826115	887182	952943	1023771	
1/2% Growth											795347	799324	803320	807337	811374	815430	819508	840201	861417	883169	
ALD	21	210000	215127	154200	158800	138700	134000	135500	135871	133100	138080	139830	144627	148051	149708	151753	153447	162555	172220	182477	
ELP	19	141000	153978	92300	99100	93700	85200	99900	113417	113430	107661	118960	110630	113700	115122	116567	118033	125736	133954	142723	
SOU	23	202500	214135	153500	177200	166100	167100	168000	183646	186710	172724	172520	174651	177017	179427	181867	184336	197190	210955	225696	
SLP	21	210000	219945	149400	155900	141600	153000	157700	165863	153080	147730	145050	151586	154359	157193	160089	163032	178579	195609	214264	
WIL	26	210000	224763	173600	195300	177800	187500	198500	204600	205070	190110	192192	195491	198364	201283	204250	207267	223122	240205	258612	
Big Total	110	973500	1027948	723000	786300	717900	726800	759600	803397	791390	756305	768552	776985	791491	802733	814526	826115	887182	952943	1023771	
SOU Tota	23	210000	214135	153500	177200	166100	167100	168000	183646	186710	172724	172520	174651	177017	179427	181867	184336	197190	210955	225696	
Big MW		954030	1007389	708540	770574	703542	712264	744408	787329	775562	741179	753181	761445	775661	786678	798235	809593	869438	933884	1003295	
SOU MW		205800	209852	150430	173656	162778	163758	164640	179973	182976	169270	169070	171158	173477	175838	178230	180649	193246	206736	221182	
% Utilization-big box				70%	76%	70%	71%	74%	78%	77%	74%	75%	76%	77%	78%	79%	80%	86%	93%	100%	
No 35kV																					
1/2% SOU Growth													173383	174250	175121	175996	176876	181343	185922	190617	
1/2% Big Box Growth													772395	776257	780138	784039	787959	807856	828255	849170	
1/2%SOU MW													169915	170765	171618	172476	173339	177716	182203	186804	
1/2%Big MW													756947	760732	764535	768358	772200	791699	811690	832186	
% Utilization-big box 1/2 % growth				70%	76%	70%	71%	74%	78%	77%	74%	75%	75%	76%	76%	76%	77%	79%	81%	83%	

Loads converted to MW

	2008	2009	2013	2018	2023	2028
ALD	137033	141734	145090	146714	148718	150378
ELP	116581	108417	111426	112820	114236	115672
SOU	169070	171158	173477	175838	178230	180649
SLP	142149	148554	151272	154049	156887	159771
WIL	188348	191581	194397	197257	200165	203122
Big Total	753181	761445	775661	786678	798235	809593

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Greater Area - Substation Transformer Load Analysis

Appendix D, Table 2

		Nameplate	Normal	2000 Peak	2001 Peak	2002 Peak	2003 Peak	2004 peak	2005 Peak	2006 Peak	2007 Peak	2008 Peak	2009 Fcst	2010	2011	2012	2013	2018	2023	2028			
Nameplate	ALD			210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000			
	ELP			141000	141000	141000	141000	141000	141000	141000	141000	141000	141000	141000	141000	141000	141000	141000	141000	141000			
	SOU			202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500			
	SLP			210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000			
	WIL			210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000			
Total										973500	973500	973500	973500										
Normal	ALD			215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127			
	ELP			153978	153978	153978	153978	153978	153978	153978	153978	153978	153978	153978	153978	153978	153978	153978	153978	153978			
	SOU			214135	214135	214135	214135	214135	214135	214135	214135	214135	214135	214135	214135	214135	214135	214135	214135	214135			
	SLP			219945	219945	219945	219945	219945	219945	219945	219945	219945	219945	219945	219945	219945	219945	219945	219945	219945			
	WIL			224763	224763	224763	224763	224763	224763	224763	224763	224763	224763	224763	224763	224763	224763	224763	224763	224763			
Total				1027948	1027948	1027948	1027948	1027948	1027948	1027948	1027948	1027948	1027948	1027948	1027948	1027948	1027948	1027948	1027948	1027948			
1 Cycle	ALD			215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127			
	ELP			174537	174537	174537	174537	174537	174537	174537	174537	174537	174537	174537	174537	174537	174537	174537	174537	174537			
	SOU			217517	217517	217517	217517	217517	217517	217517	217517	217517	217517	217517	217517	217517	217517	217517	217517	217517			
	SLP			224688	224688	224688	224688	224688	224688	224688	224688	224688	224688	224688	224688	224688	224688	224688	224688	224688			
	WIL			239761	239761	239761	239761	239761	239761	239761	239761	239761	239761	239761	239761	239761	239761	239761	239761	239761			
Total										1071630	1071630	1071630	1071630										
N-1 Capacity	ALD			143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418			
	ELP			115792	115792	115792	115792	115792	115792	115792	115792	115792	115792	115792	115792	115792	115792	115792	115792	115792			
	SOU			143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418			
	SLP			143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418			
	WIL			152979	152979	152979	152979	152979	152979	152979	152979	152979	152979	152979	152979	152979	152979	152979	152979	152979			
Total										699025	699025	699025	699025										
% Utilization	ALD			72%	74%	64%	62%	63%	63%	62%	64%	65%	67%	69%	70%	71%	71%	76%	80%	85%			
	ELP			60%	64%	61%	55%	65%	74%	74%	70%	77%	72%	74%	75%	76%	77%	82%	87%	93%			
	SOU			72%	83%	78%	78%	78%	86%	87%	81%	81%	82%	83%	84%	85%	86%	92%	99%	105%			
	SLP			68%	71%	64%	70%	72%	75%	70%	67%	66%	69%	70%	71%	73%	74%	81%	89%	97%			
	WIL			77%	87%	79%	83%	88%	91%	91%	85%	86%	87%	88%	90%	91%	92%	99%	107%	115%			
Total				70%	76%	70%	71%	74%	78%	77%	74%	75%	76%	77%	78%	79%	80%	86%	93%	100%			
% Growth	ALD			-5.7%	3.0%	-12.7%	-3.4%	1.1%	0.3%	-2.0%	3.7%	1.3%	3.4%	2.4%	1.1%	1.4%	1.1%	1.2%	1.2%	1.2%			
	ELP			0.5%	7.4%	-5.4%	-9.1%	17.3%	13.5%	0.0%	-5.1%	10.5%	-7.0%	2.8%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%			
	SOU			0.4%	15.4%	-6.3%	0.6%	0.5%	9.3%	1.7%	-7.5%	-0.1%	1.2%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%			
	SLP			-10.3%	4.4%	-9.2%	8.1%	3.1%	5.2%	-7.7%	-3.5%	-1.8%	4.5%	1.8%	1.8%	1.8%	1.8%	1.9%	1.9%	1.9%			
	WIL			-1.8%	12.5%	-9.0%	5.5%	5.9%	3.1%	0.2%	-7.3%	1.1%	1.7%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%			
Total				-3.8%	8.8%	-8.7%	1.2%	4.5%	5.8%	-1.5%	-4.4%	1.6%	1.1%	1.9%	1.4%	1.5%	1.4%	1.5%	1.5%	1.5%			
N-0 Overload	ALD					2.9%	2.3%	2.0%	3.4%	3.2%	2.2%	1.4%											
	ELP					-1.5%	-0.8%	0.2%	1.2%	0.8%	0.7%	0.3%											
	SOU																			11561			
	SLP																						
	WIL																		15442	33849			
Total				0	0	0	0	0	0	0	0	0							15442	45409			
N-1 Overload	ALD			10782	15382								1209	4633	6290	8335	10029	19137	28802	39059			
	ELP											3168			-670	775	2241	9944	18162	26931			
	SOU			10082	33782	22682	23682	24582	40228	43292	29306	29102	31233	33599	36009	38449	40918	53772	67537	82278			
	SLP			5982	12482		9582	14282	22445	9662	4312	1632	8168	10941	13775	16671	19614	35161	52191	70846			
	WIL			20621	42321	24821	34521	45521	51621	52091	37131	39213	42512	45385	48304	51271	54288	70143	87226	105633			
Total				47467	103967	47503	67785	84385	114294	105045	70749	73115	83122	94558	103708	115501	127090	188157	253918	324746			
N-1 Overload MW	ALD			10566	15074	0	0	0	0	0	0	0	1185	4540	6164	8168	9828	18754	28226	38277			
	ELP			0	0	0	0	0	0	0	0	3105	0	0	-657	760	2196	9745	17799	26392			
	SOU			9880	33106	22228	23208	24090	39423	42426	28720	28520	30608	32927	35289	37680	40100	52697	66186	80632			
	SLP			5862	12232	0	9390	13996	21996	9469	4226	1599	8005	10722	13500	16338	19222	34458	51147	69429			
	WIL			20209	41475	24325	33831	44611	50589	51049	36388	38429	41662	44477	47338	50246	53202	68740	85481	103520			
Total MW				46518	101888	46553	66429	82697	112008	102944	69334	71653	81460	92667	101634	113191	124548	184394	248839	318251			
Feeder	Big Box	Sm box	Capacity	2000	2001	2002	2003	2004 peak	2005 Peak	2006 Peak	2007 Peak	2008 Peak	2009 Fcst	2010	2011	2012	2013	2018	2023	2028	ALD	ELP	MST

South Minneapolis STUDY

Greater Area - Substation Transformer Loads - 1/2% Growth Forecast

Appendix D, Table 3

	# of feeders	Nameplate	Normal	1 Cycle	2006 Peak	2007	2008		2009 1/2% Fcst	2010 1/2% Fcst	2011 1/2% Fcst	2012 1/2% Fcst	2013 1/2% Fcst	2018 1/2% Fcst	2023 1/2% Fcst	2028 1/2% Fcst
SOUTR1			71709	76%	66260	56100	54400		54672	54945	55220	55496	55774	57182	58626	60106
SOUTR2			74099	75%	55490	54714	55270		55546	55824	56103	56384	56666	58097	59564	61068
SOUTR3			68327	92%	62970	61910	62850		63164	63480	63797	64116	64437	66064	67732	69443
													0	0	0	0
ALDTR2	5	70000	71709	71709	28970	29690	27730		27869	28008	28148	28289	28430	29148	29884	30639
ALDTR3	8	70000	71709	71709	47260	52960	49220		49466	49713	49962	50212	50463	51737	53044	54383
ALDTR4	8	70000	71709	71709	56870	55430	62880		63194	63510	63828	64147	64468	66096	67765	69476
ELPTR1	6	47000	51054	57896	33730	34420	38140		38331	38522	38715	38909	39103	40090	41103	42141
ELPTR2	6	47000	51870	58745	32520	36210	37910		38100	38290	38481	38674	38867	39849	40855	41887
ELPTR3	7	47000	51054	57896	47180	37031	42910		43125	43340	43557	43775	43994	45104	46243	47411
SOUTR1	8	70000	71709	71709	66880	56100	54400		54672	54945	55220	55496	55774	57182	58626	60106
SOUTR2	7	70000	74099	74099	56600	54714	55270		55546	55824	56103	56384	56666	58097	59564	61068
SOUTR3	8	62500	68327	71709	63230	61910	62850		63164	63480	63797	64116	64437	66064	67732	69443
SLPTR4	7	70000	76527	81270	57430	53340	53840		54109	54380	54652	54925	55200	56593	58022	59488
SLPTR5	7	70000	71709	71709	45940	53360	51790		52049	52309	52571	52834	53098	54439	55813	57223
SLPTR6	7	70000	71709	71709	49710	41030	39420		39617	39815	40014	40214	40415	41436	42482	43555
WILTR1	1	42000	42183	45658	0	0	0		0	0	0	0	0	0	0	0
WILTR2	1	42000	42183	45658	0	0	0		0	0	0	0	0	0	0	0
WILTR3	9	70000	71709	71709	74810	63260	65450		65777	66106	66437	66769	67103	68797	70534	72315
WILTR4	9	70000	76527	86782	68190	69636	70690		71043	71399	71756	72114	72475	74305	76181	78105
WILTR5	8	70000	76527	81270	62070	57214	56052		56332	56614	56897	57181	57467	58919	60406	61932
Big Box Total			1112314	1	791390	756305	768552		772395	776257	780138	784039	787959	807856	828255	849170
1/2% Growth																
ALD	21	210000	215127	215127	133100	138080	139830	18%	140529	141232	141938	142648	143361	146981	150692	154498
ELP	19	141000	153978	174537	113430	107661	118960	15%	119555	120153	120753	121357	121964	125044	128201	131438
SOU	23	202500	214135	217517	186710	172724	172520	22%	173383	174250	175121	175996	176876	181343	185922	190617
SLP	21	210000	219945	224688	153080	147730	145050	19%	145775	146504	147237	147973	148713	152468	156318	160265
WIL	26	210000	224763	239761	205070	190110	192192	25%	193153	194119	195089	196065	197045	202021	207122	212352
Big Total	110	973500	1027948	75%	791390	756305	768552	100%	772395	776257	780138	784039	787959	807856	828255	849170
SOU Tota	23	210000	214135	81%	153080	147730	145050		145775	146504	147237	147973	148713	152468	156318	160265
Big MW		954030	1007389		775562	741179	753181		756947	760732	764535	768358	772200	791699	811690	832186
SOU MW		205800	209852		150018	144775	142149		142860	143574	144292	145013	145738	149419	153192	157060
% Utilization-big box						ALD MW	137033									
No 35kV						ELP MW	116581									
1/2% SOU Growth						SOU MW	169070									
1/2% Big Box Growth						SLP MW	142149									
1/2%SOU MW						WIL MW	188348									
1/2%Big MW							753181									
% Utilization-big box 1/2 % growth					77%	74%	75%									

South Minneapolis STUDY

Greater Area - Substation Transformer Loads - 1/2% Growth Analysis

Appendix D, Table 4

		Nameplate	Normal	1 Cycle	2006 Peak	2007 1/2% Fcst	2008 1/2% Fcst	2009 1/2% Fcst	2010	2011	2012	2013	2018	2023	2028
Nameplate	ALD				210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000
	ELP				141000	141000	141000	141000	141000	141000	141000	141000	141000	141000	141000
	SOU				202500	202500	202500	202500	202500	202500	202500	202500	202500	202500	202500
	SLP				210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000
	WIL				210000	210000	210000	210000	210000	210000	210000	210000	210000	210000	210000
Total					973500	973500	973500	973500	973500	973500	973500	973500	973500	973500	973500
Normal	ALD				215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127
	ELP				153978	153978	153978	153978	153978	153978	153978	153978	153978	153978	153978
	SOU				214135	214135	214135	214135	214135	214135	214135	214135	214135	214135	214135
	SLP				219945	219945	219945	219945	219945	219945	219945	219945	219945	219945	219945
	WIL				224763	224763	224763	224763	224763	224763	224763	224763	224763	224763	224763
Total					1027948	1027948	1027948	1027948	1027948	1027948	1027948	1027948	1027948	1027948	1027948
1 Cycle	ALD				215127	215127	215127	215127	215127	215127	215127	215127	215127	215127	215127
	ELP				174537	174537	174537	174537	174537	174537	174537	174537	174537	174537	174537
	SOU				217517	217517	217517	217517	217517	217517	217517	217517	217517	217517	217517
	SLP				224688	224688	224688	224688	224688	224688	224688	224688	224688	224688	224688
	WIL				239761	239761	239761	239761	239761	239761	239761	239761	239761	239761	239761
Total					1071630	1071630	1071630	1071630	1071630	1071630	1071630	1071630	1071630	1071630	1071630
N-1 Capacity	ALD				143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418
	ELP				115792	115792	115792	115792	115792	115792	115792	115792	115792	115792	115792
	SOU				143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418
	SLP				143418	143418	143418	143418	143418	143418	143418	143418	143418	143418	143418
	WIL				152979	152979	152979	152979	152979	152979	152979	152979	152979	152979	152979
Total					699025	699025	699025	699025	699025	699025	699025	699025	699025	699025	699025
% Utilization	ALD				62%	64%	65%	65%	66%	66%	66%	67%	68%	70%	72%
	ELP				74%	70%	77%	78%	78%	78%	79%	79%	81%	83%	85%
	SOU				87%	81%	81%	81%	81%	82%	82%	83%	85%	87%	89%
	SLP				70%	67%	66%	66%	67%	67%	67%	68%	69%	71%	73%
	WIL				91%	85%	86%	86%	86%	87%	87%	88%	90%	92%	94%
Total					77%	74%	75%	75%	76%	76%	76%	77%	79%	81%	83%
% Growth	ALD					3.7%	1.3%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
	ELP					-5.1%	10.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
	SOU					-7.5%	-0.1%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
	SLP					-3.5%	-1.8%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
	WIL					-7.3%	1.1%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%
Total															
N-0 Overload	ALD														
	ELP														
	SOU														
	SLP														
	WIL														
Total															
N-1 Overload	ALD													7274	11080
	ELP									4961	5565	6172	9252	12409	15646
	SOU				43292	29306	29102	29965	30832	31703	32578	33458	37925	42504	47199
	SLP				9662	4312	1632	2357	3086	3819	4555	5295	9050	12900	16847
	WIL				52091	37131	39213	40174	41140	42110	43086	44066	49042	54143	59373
Total					105045	70749	69947	72496	75057	82593	85784	88991	105268	129230	150145
N-1 Overload MW	ALD				0	0	0	0	0	0	0	0	0	7129	10858
	ELP				0	0	0	0	0	4862	5454	6048	9067	12161	15333
	SOU				42426	28720	28520	29365	30215	31069	31927	32789	37166	41654	46255
	SLP				9469	4226	1599	2310	3024	3742	4464	5189	8869	12642	16510
	WIL				51049	36388	38429	39370	40317	41268	42224	43185	48061	53060	58186
Total MW					102944	69334	68548	71046	73556	80941	84068	87211	103163	126646	147142

Feeder	Big Box	Sm box	Capacity	2008 % Load	2006 Peak	2007 1/2% Fcst	2008 1/2% Fcst	2009 1/2% Fcst	2010	2011	2012	2013	2018	2023	2028	>= 115	R	A	G	R	kVA over	% Load	kVA >100 %	kVA >75%	>= 115	R	A	G	% Load	kVA >100 %	kVA >75%	>= 115	R	A	G

Appendix E: Distribution System Graphics of 15 Transformers and Associated Feeder Circuits Serving the Greater Study Area

Figure E.1: Greater Study Area 2006 N-1 Substation Transformer Risks – Single Contingency

Colored by Substation:		
0	6 Transformers	
0 to 10 MW	3 Transformers	
10 MW to 25 MW		
> 25 MW	6 Transformers	

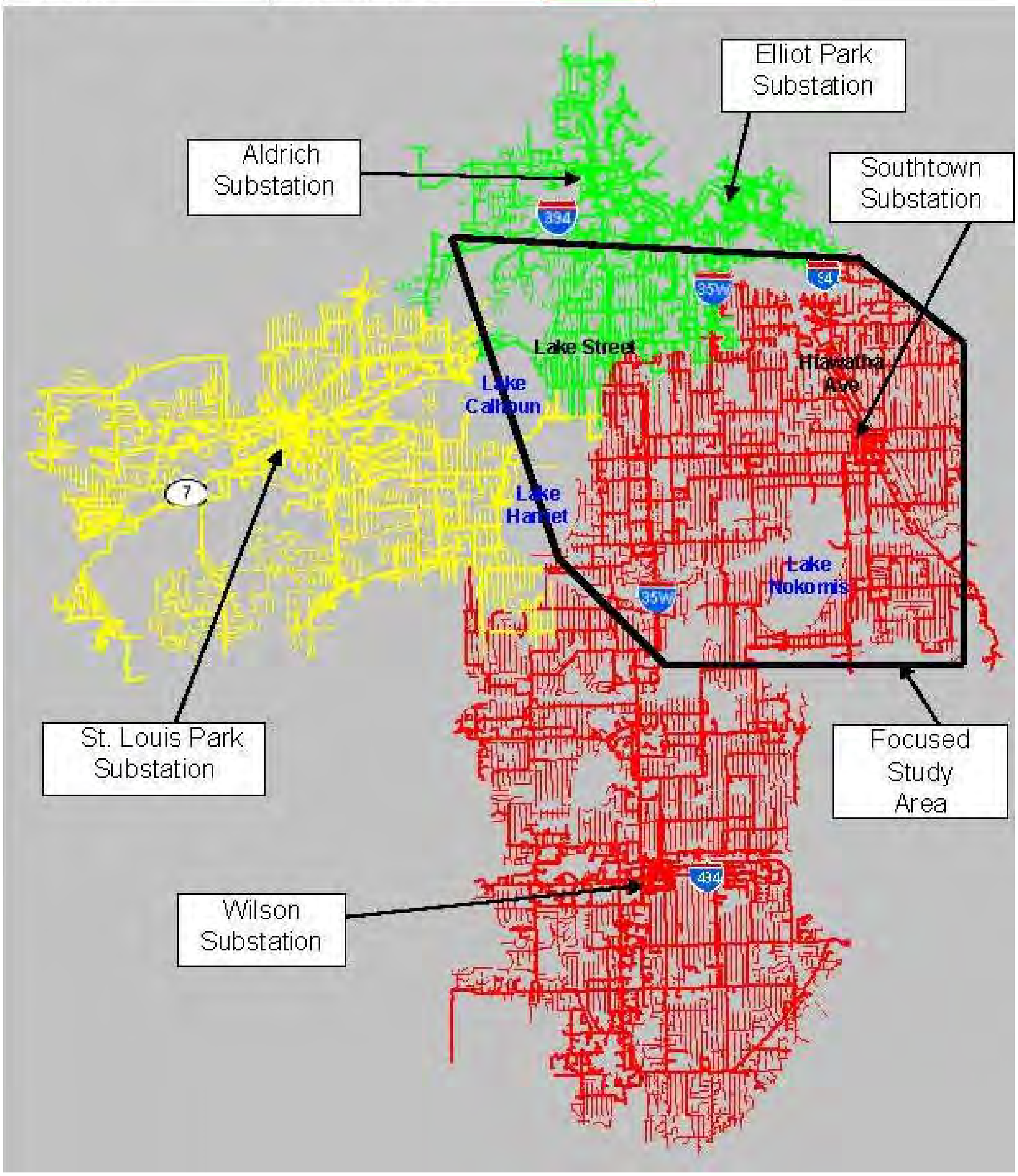


Figure E.2: Greater Study Area 2009 N-1 Substation Transformer Risks – Single Contingency

Colored by Substation:		
0	3 Transformers	
0 to 10 MW	6 Transformers	
10 MW to 25 MW	0 Transformers	
> 25 MW	6 Transformers	

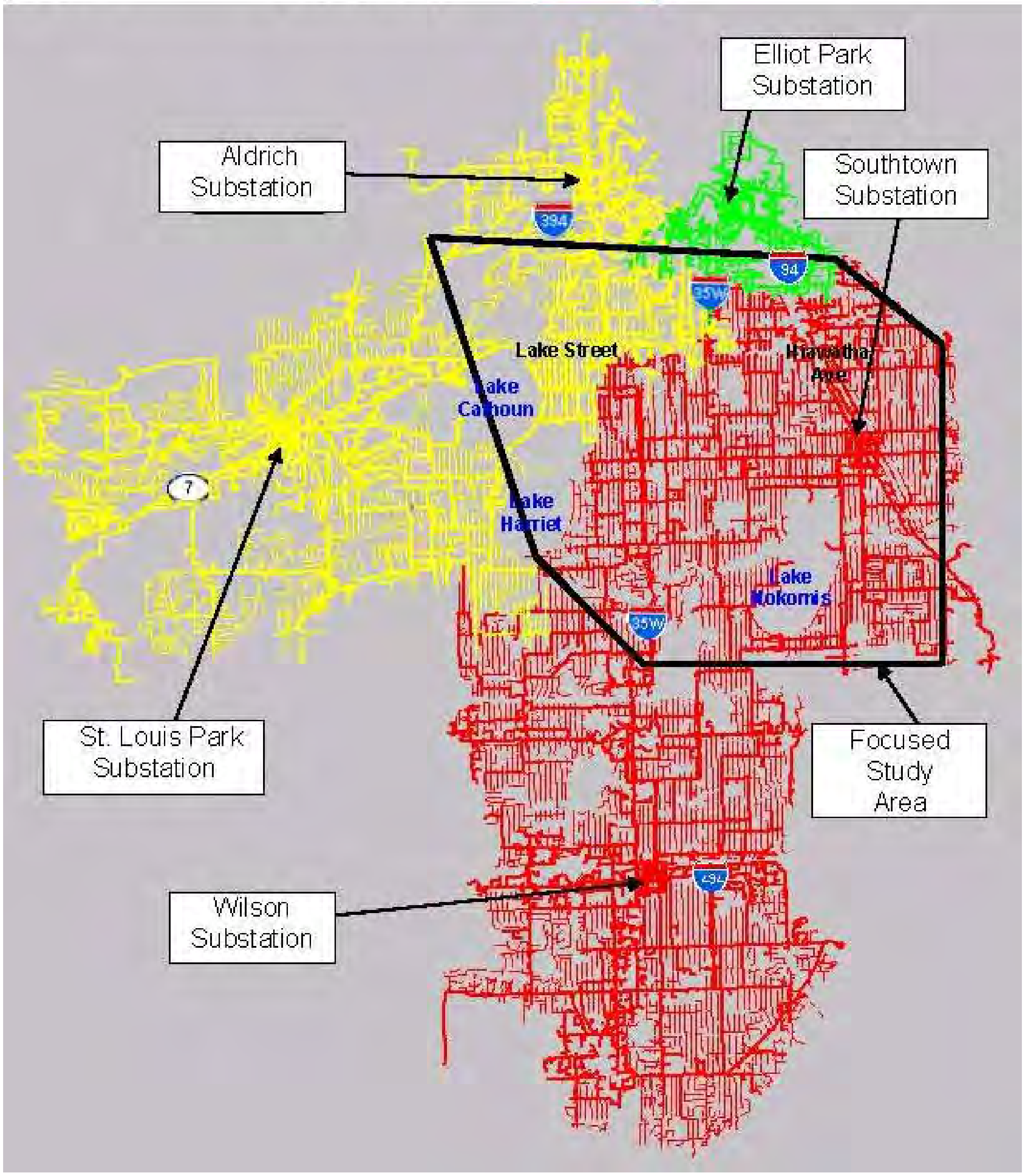


Figure E.3: Greater Study Area 2013 N-1 Substation Transformer Risks – Single Contingency

Colored by Substation:		
0	0 Transformers	
0 to 10 MW	3 Transformers	
10 MW to 25 MW	6 Transformers	
> 25 MW	6 Transformers	

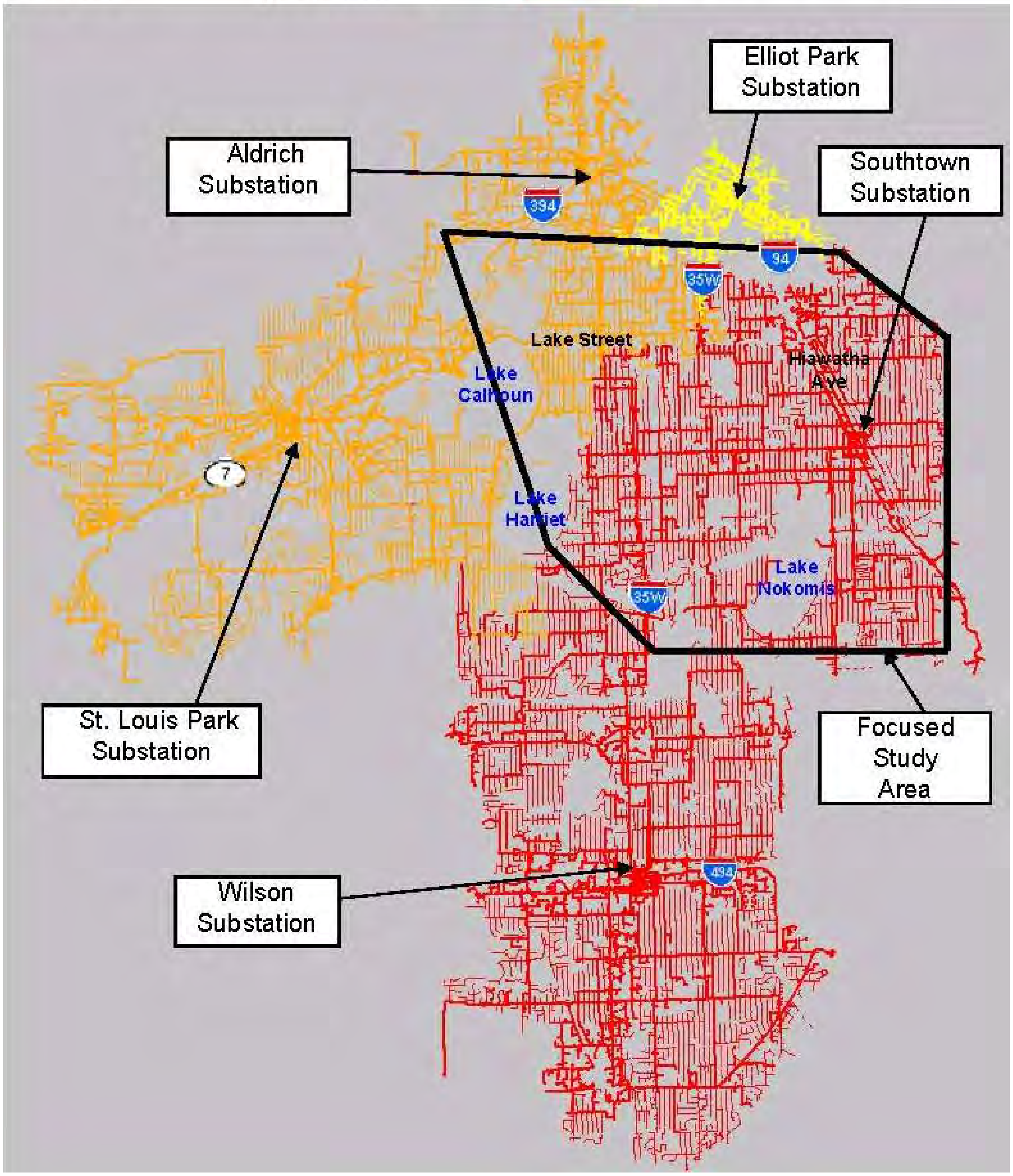


Figure E.4: Greater Study Area 2018 N-1 Substation Transformer Risks – Single Contingency

Colored by Substation:		
0	0 Transformers	
0 to 10 MW	3 Transformers	
10 MW to 25 MW	3 Transformers	
> 25 MW	9 Transformers	

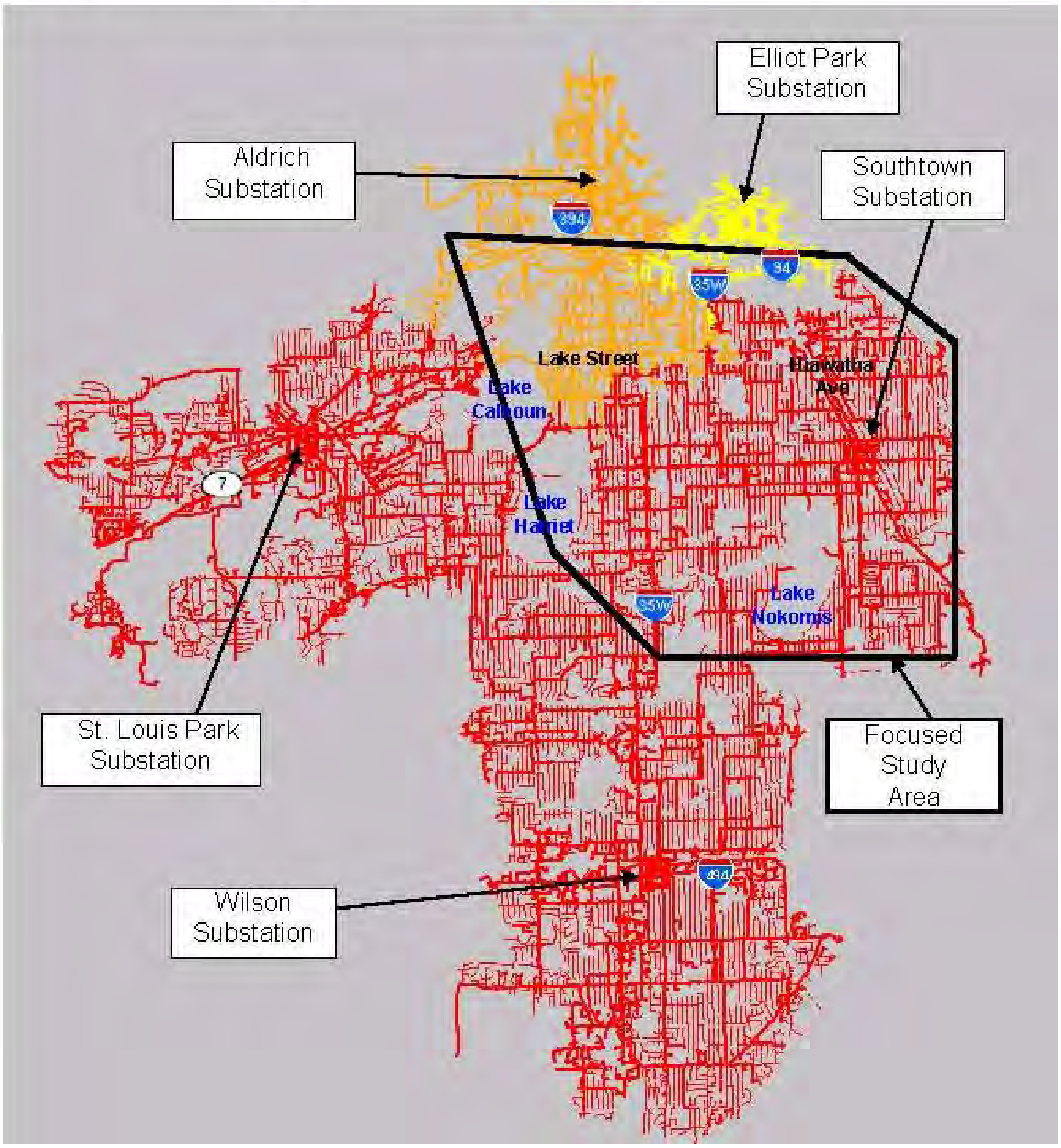


Figure E.5: Greater Study Area 2023 N-1 Substation Transformer Risks – Single Contingency

Colored by Substation:		
0	0 Transformers	
0 to 10 MW	0 Transformers	
10 MW to 25 MW	3 Transformers	
> 25 MW	12 Transformers	

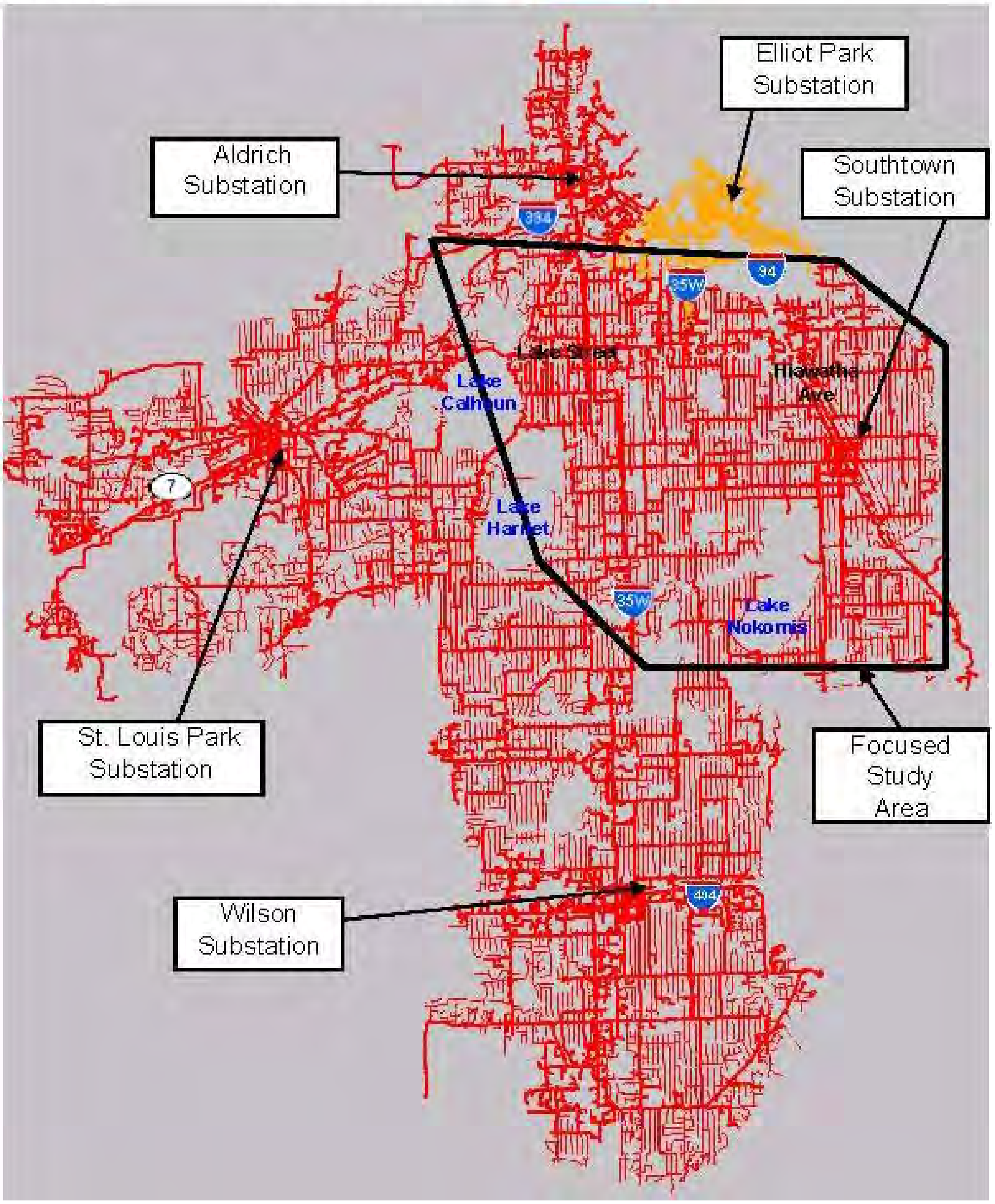
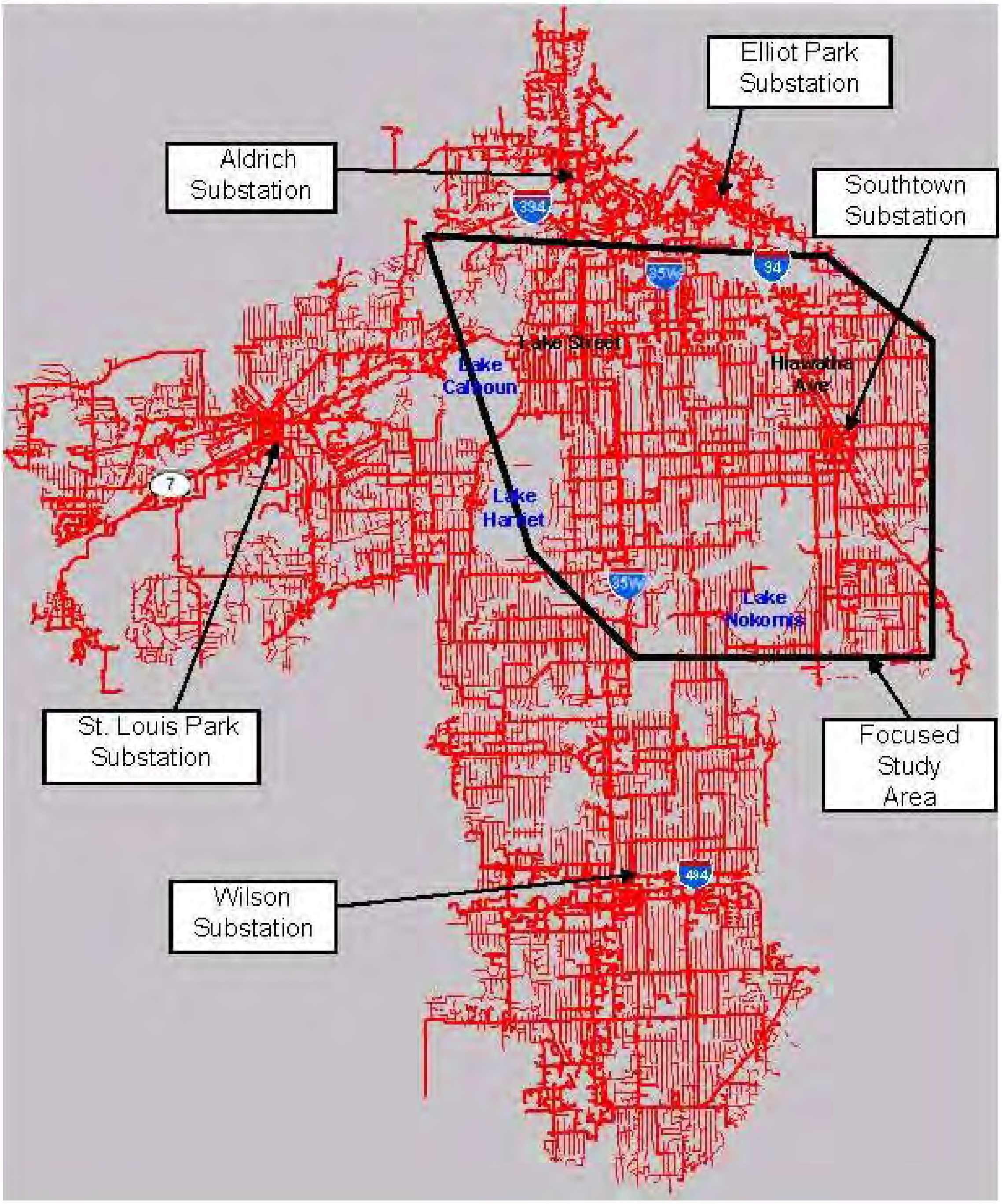


Figure E.6: Greater Study Area 2028 N-1 Substation Transformer Risks – Single Contingency

Colored by Substation:		
0		
0 to 10 MW	0 Transformers	
10 MW to 25 MW	0 Transformers	
> 25 MW	15 Transformers	



Appendix F: Explanation of Loss Analysis:

Losses are power that dissipates in electric conductors due to a materials resistance. The amount of loss is greatly reduced by lowering the current flowing through a line and shortening the length of a line. For the South Minneapolis 20 Year plan losses were evaluated for different mitigations to risks in the area. The cost of purchasing generation at marginal prices for capacity and energy were evaluated. These savings were factored into the economic analysis.

To develop the savings associated with reducing losses, an evaluation technique was developed. Load duration curves for residential areas, commercial and residential areas, commercial and industrial areas, and industrial areas were considered. The different load duration curves lead to different load factors, which represent the comparison of average demand of a transformer or feeder to its peak demand. The formula for this is shown below in Equation 1.

$$LoadFactor = \frac{Demand_{AVG}}{Demand_{PEAK}}$$

Equation 1: Load Factor Development

From the load factor, the loss factor can then be calculated. The loss factor relates the amount of losses in the peak case to the expected amount of losses at an average level throughout the year. Equations 2 thru 4 below detail the calculation of the loss factor. Equation 3 demonstrates the correlation between load and current. As the load increases the loading on the distribution lines will increase in equal proportions. Due to this relationship Equation 4 can be applied to get the loss factor. This development comes from the standard loss formula in Equation 2.

$$Losses = I^2 R$$

Equation 2: Power Loss Formula

$$Load \propto I$$

Equation 3: Correlation between load and current

$$LossFactor = LoadFactor^2$$

Equation 4: Loss Factor Development

The loss factor is then used to calculate energy use. The total yearly savings can then be calculated by using Equation 5. This equation includes the cost of energy and capacity, which were supplied by Xcel Energy's resource planning department. For the economic analysis, this formula was applied each year.

$$\$Savings / Year = [MWreduction_{PEAK} * LossFactor * 8760 * (\$ / MWH)] + [MWreduction_{PEAK} * \$20{,}000]$$

Equation 5: Savings Calculation

From this data one could also calculate the MWH Loss Savings annually as well as the tons of CO_2 saved. Equations 6 and 7 below show these calculations.

$$MWHSavings / Year = MWreduction_{PEAK} * LossFactor * 8760$$

Equation 6: Annual MWH Loss Savings

$$CO_2 Savings / Year = \frac{(MWHSavings / Year)}{(2MWH / TonCoal)} * \frac{(1.86tonCO_2)}{TonCoal}$$

Equation 7: Annual CO_2 Savings in Tons

There are essentially two different types of alternatives being considered to address the risks on the distribution system in South Minneapolis:

- Build Two Substations: Build a Hiawatha Substation and a Midtown Substation with five feeders at each substation.

- Build One Substation: Build only a Hiawatha Substation. This single Hiawatha Substation would have ten feeders total. There will be five feeders to address the same areas as the Hiawatha Substation in the first option and five feeders to address the same areas as the Midtown Substation in the first option. The feeders addressing the Midtown area would be pulled in duct lines using 1000Al-paralleled cable for 15,000 feet.

The second alternative will introduce more losses than the first option because of the longer length of the feeders. Using this assertion the loss analysis done bases its evaluations on the difference in losses between the plans or the loss savings by going with the two-substation option.

By using SynerGEE and performing a load flow the loss difference between the two alternatives at peak was determined and found to be around 1 MW. This 1 MW is the same as the MW $reduction_{PEAK}$ value that was discussed in the previous section. With this value and considering several different loss factors based on the type of load on a circuit, i.e. residential, commercial, industrial, the Figure F.1 was developed.

Figure F.1: Loss Savings

South Minneapolis Loss Study

Feeder Load Composition	Type of Loss Savings	2010	Thru 2013	Thru 2018	Thru 2023	Thru 2028
Residential	MWH Savings	350	1160	3864	6867	10701
	Total Dollars Savings	$47,920	$203,005	$494,438	$881,284	$1,407,212
	CO_2 Savings Tons	326	1079	3594	6386	9952
	MWH Savings	788	2610	8693	15452	24077
	Total Dollars Savings	$82,820	$349,008	$836,820	$1,492,924	$2,402,752
	CO_2 Savings Tons	733	2427	8084	14370	22392
Commercial/Residential Mix						
	MWH Savings	1402	4639	15455	27469	42803
	Total Dollars Savings	$131,679	$553,412	$1,316,156	$2,349,219	$3,796,509
	CO_2 Savings Tons	1304	4314	14373	25546	39807
	MWH Savings	2190	7249	24148	42921	66880
	Total Dollars Savings	$194,499	$816,218	$1,932,445	$3,450,170	$5,588,481
Commercial/Industrial Mix	CO_2 Savings Tons	2037	6742	22458	39917	62198
	MWH Savings	3154	10439	34773	61806	96308
	Total Dollars Savings	$271,279	$1,137,424	$2,685,688	$4,795,777	$7,778,669
	CO_2 Savings Tons	2933	9708	32339	57480	89566
	MWH Savings	4292	14208	47330	84125	131086
	Total Dollars Savings	$362,018	$1,517,032	$3,575,883	$6,386,040	$10,367,074
Industrial	CO_2 Savings Tons	3992	13213	44017	78236	121910

Since the load in the Focused Study Area is neither purely residential, nor purely commercial, nor purely industrial, a matrix was created to illustrate the ranges of loss savings that could be expected depending on the type of load. The best generalization for the type of load in this area would be a commercial and residential mix with very little industrial load and thus correspond to the yellow highlighted section of Figure F.1.

From Figure F.1, one can see that by going with the two-substation plan described in alternative 1 as opposed to the single substation described in alternative 3 there are significant loss savings to be had. Over the 20-year view of this study there would be approximately 42,000 MWH in savings, which correlates to 40,000 tons of CO2 in savings and $3.8 million saved.

Appendix G: Cost Information (cost reflects millions (+,000)) for South Minneapolis Alternatives 1-4

YEAR	Feeder Load (MVA)	Alternative 1 -A1 Hiawatha and Midtown 115/13.8 kV with two looped 115 kV transmission lines	Alternative 2 -A2 Hiawatha and west Midtown 115/13.8 kV with two looped 115 kV transmission lines	Alternative 3 -A3 Hiawatha 115/13.8 kV and express 13.8 kV Feeders to the Load Center (nonstandard)	Alternative 4 -A4 Hiawatha 115/13.8 kV and 115/34.5 kV, 34.5 kV sub-transmission with three midtown substations for 13.8 kV distribution (non-standard)
2000	275592				
2001	299450				
2002	320200				
2003	306000				
2004	291900				
2005	326380				
2006	337794				
2007	315680				
2008	312998				
2009	320939				
* 2010	326923	$33,380	$42,400	$21,810	$61,115
2011	330999				
2012	335130				
2013	339304				
2014	343600				
2015	348000				
* 2016	352500	$8,520	$4,250	$13,210	$22,165
* 2017	357000	$8,325	$8,325	$14,930	$27,305
2018	361574				
2019	366200				
2020	371000				
2021	375700				
2022	380600				
* 2023	385513	$5,630	$5,630	$10,100	$11,415
2024	390500				
2025	395600				
2026	400700				
2027	406000				
2028	411300				
		$55,855	$60,605	$60,050	$122,000

Note: Cost is shown in the year that the peak load forecast requires capacity addition.

Costs are based on indicative estimates which may change due to estimate refinement.

Plymouth and Medina Electrical System Assessment

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June 1, 2016

Contents

1.0: Executive Summary

The Plymouth and Medina Electrical System Assessment ("Report") was completed as part of the Company's continued efforts to study alternatives available to address the reliability issues in the Plymouth area in accordance with the Minnesota Public Utilities Commission's May 2014 order in Docket Nos. E002/TL-11-152 and ET2/CN-12-113. The electrical improvements examined in this Report are needed to address distinct deficiencies on the distribution and transmission systems in the Plymouth area. Since both transmission and distribution needs are dependent on each other, the solution that is implemented must solve both of these system's identified needs. Therefore, all alternatives proposed in this study are configured to solve both distribution and transmission needs for 20 years based on 1% load growth in the Transmission Area of Concern. This Report also identified conceptual solutions for the 20-40 year timeframe, given 1% load growth. If the Transmission Area of Concern experiences a higher than 1% load growth, these solutions may need to be implemented earlier than 20-40 years. However, if the Transmission Area of Concern experiences a lower than 1% load growth, these solutions will last longer than 20-40 years.

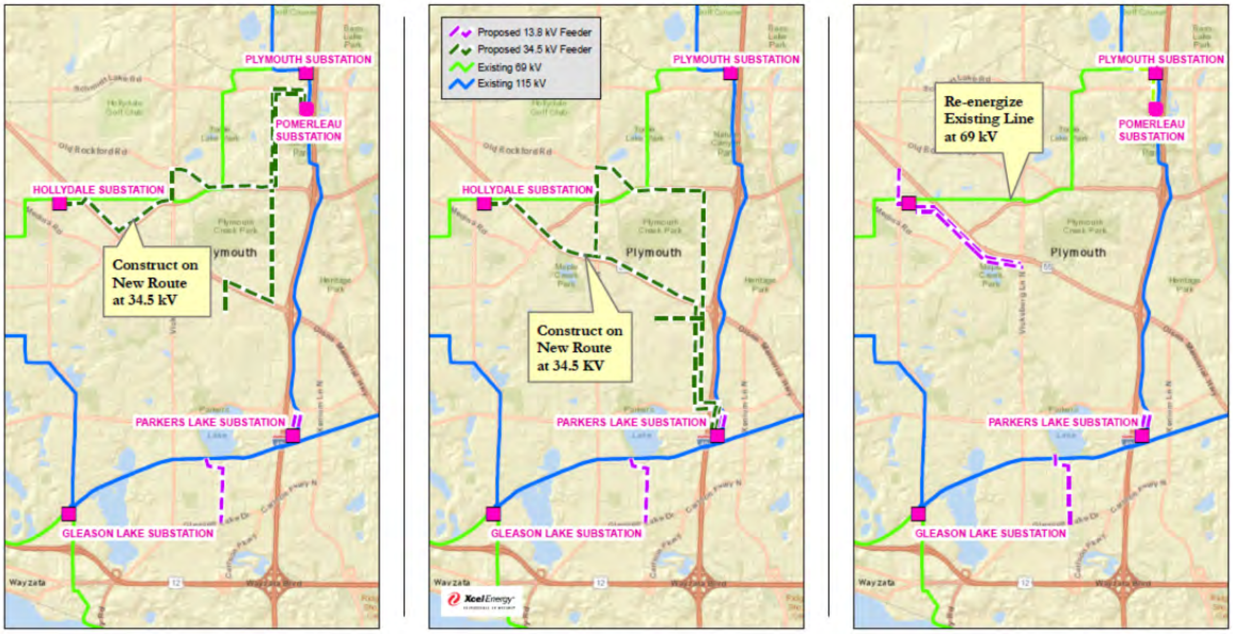
The distribution need is driven by a deficit in the distribution system's load serving capability of a Focused Study Area centered around western Plymouth. The distribution delivery system in the Focused Study Area has experienced steady load growth in recent years and is forecasted to exceed the capability of the existing distribution feeders by 30 MW in 2016. Additionally, the load is forecasted to exceed the capacity of the existing substation transformers in the Focused Study Area by 11 MW in 2016. These capacity issues could lead to an increase in the duration of outages during contingency operation as the load in the Focused Study Area continues to grow in the future.

The transmission need is driven by increasing demand on the distribution system and deficiencies on the transmission system under contingency conditions to serve the load in the Transmission Area of Concern. As the load on the distribution system in the Transmission Area of Concern grows, the transmission need to serve that load increases. The transmission system capabilities are forecasted to be exceeded by 13 MW in 2016

System alternatives presented in this study solve the capacity issues identified on the distribution system and the contingency issues identified on the transmission system. All three alternatives assume that the Gleason Lake to Parkers Lake 115 kV double circuit line is rebuilt to two single circuits, due to the condition of the existing line, and that a 40 MVAR capacitor bank is installed at the Gleason Lake substation. Maps of the near-term facilities in each alternative are shown in Figure 1.1, followed by a description of the required facilities for each alternative.

Figure 1.1: Maps of Near-term Facilities for each Alternative

Alternative A **Alternative B** **Alternative C**



Note: All three alternatives include the age and condition rebuild of the Gleason Lake to Parkers Lake 115 kV double circuit lines rebuilt to two single circuits and a 40 MVAR capacitor bank installed at Gleason Lake substation.

Alternative A:

- Construct Pomerleau Lake 115/34.5 kV substation
- Construct two 34.5 kV feeders out of Pomerleau Lake going west
- Reinforce existing feeders and construct an extension of one 13.8 kV feeder at Parkers Lake

Alternative B:

- Expand Parkers Lake substation
- Construct two 34.5 kV feeders out of the expansion at Parkers Lake going west
- Reinforce existing feeders and construct an extension of one 13.8 kV feeder at Parkers Lake

Alternative C:

- Expand Hollydale substation to accommodate three additional 13.8 kV feeders
- Construct Pomerleau Lake 115/69 kV substation
- Construct a short extension of the existing 69 kV line to Pomerleau Lake; re-energize Hollydale-Pomerleau Lake 69 kV line, Medina-Hollydale 69 kV line remains energized
- Reinforce existing feeders and construct an extension of one 13.8 kV feeder at Parkers Lake

Alternatives A and B utilize 34.5 kV feeder lines while Alternative C utilizes 13.8 kV feeder lines. Both alternatives that include 34.5 kV feeders (Alternatives A and B) require 12 pad mounted step-down transformers and 12 pad mounted switching cabinets to interconnect with the existing 13.8 kV system. Figure 1.2 includes a detailed comparison of the three alternatives.

Figure 1.2: Evaluation and Comparison of System Alternatives.

	Evaluation of Alternatives	Impacts	Performance
Plymouth Area Alternatives	**Alternative A** Construct 34.5 kV distribution lines from new Pomerleau Lake Substation to Hollydale Substation	• 8 miles near-term (9 miles long-term) of new distribution line o 1 mile where no lines currently exist o 7 miles near-term (8 miles long-term) where there are already lines • 145 homes along new distribution line routes • 12 new pad-mounted transformers (approximately 9x11x10 feet) & up to 12 switching cabinets (5x6x7 feet) • New Pomerleau Lake substation site	• Provides good solution for near-term (roughly 20 years). • Pomerleau Lake Substation makes future improvements to meet future needs east of I-494 less challenging and expensive. • Provides limited ability to efficiently increase load serving capacity long-term to serve additional electrical demand
Plymouth Area Alternatives	**Alternative B** Construct 34.5 kV distribution lines from Parkers Lake Substation to Hollydale Substation	• 10 miles near-term (11 miles long-term) of new distribution line o 0 miles where no lines currently exist o 10 miles near-term (11 miles long-term) where there are already lines • 98 homes along new distribution line routes • 12 new pad-mounted transformers (approximately 9x11x10 feet) & up to 12 switching cabinets (5x6x7 feet) • Expansion of Parkers Lake Substation site would occur on privately-owned land (parking lot, drainage easement) • No new substation site	• Provides adequate solution for near-term (roughly 20 years) • Additional improvements will be needed east of I-494 and will be more challenging and expensive without a new Pomerleau Lake Substation. • Does not provide ability to efficiently increase capacity if needed in the long-term to serve additional electrical demand. • A large amount of load would be served from Parkers Lake Substation which increases reliability risk.
Plymouth Area Alternatives	**Alternative C** Re-energize existing 69 kV line east of Hollydale Substation and construct 13.8 kV distribution lines from Hollydale Substation & 0.7 miles of 69 kV line to connect existing line to new Pomerleau Lake Substation.	• 4 miles of new distribution line o 0 miles where no lines exist o 4 miles were there are already lines • 26 homes along new distribution line routes • 0.7 miles of new transmission line • No new pad-mounted transformers needed • Vegetation management required on unmaintained 69 kV line right-of-way east of Hollydale Substation (4 miles / approximately 63 residential lots) • New Pomerleau Lake Substation site	• Provides good solution for near-term (roughly 20 years). • Pomerleau Lake Substation makes additional improvement needs east of I-494 less challenging and expensive. • Provides ability to efficiently increase capacity if needed in the long-term to serve additional electrical demand.

The best performing alternative from an engineering perspective for the Transmission Area of Concern and Focused Study Area is Alternative C, due to the system flexibility, lowest capital investment, and least amount of new infrastructure. Alternative A is the next best solution due to the system flexibility to serve additional load that is provided with the addition of Pomerleau Lake substation . However, all three alternatives were designed to comparably meet the immediate, near-term, and long-term load serving needs in the Transmission Area of Concern and Focused Study Area. Since all three alternatives are comparable solutions, input on non-engineering factors will be gathered during the permitting process that will help determine which alternative is selected for construction.

2.0: Project History.

2.1: Initial Electrical Studies

In 2005 and 2006, the distribution system in Plymouth experienced historic peak loads and Xcel Energy's distribution planning engineers observed that the existing distribution system was inadequate to serve these load levels. As a result, Xcel Energy's distribution planning engineers began to study long-term solutions to address the distribution needs in this area. In 2010, distribution planning published the *Plymouth Load Serving Study* which was a compilation of various study efforts undertaken since historic peak levels were reached in 2005 and 2006. The *Plymouth Load Serving Study* evaluated three alternatives to address the need for a new source to the Plymouth distribution system. These alternatives were evaluated based on system performance, operability, future growth, cost, and electrical losses. The *Plymouth Load Serving Study* concluded that the best performing alternative included constructing a new 115 kV transmission line between a new substation near Schmidt Lake Road and Interstate 494 and the existing Hollydale and Medina substations and modifications of associated transmission facilities (Alternative A1).

In response to a request from distribution planning for additional load serving capacity at the Hollydale Substation, Xcel Energy's transmission planners published the *Hollydale/Meadow Lake Load Serving Study* in June 2011. This study evaluated three transmission alternatives to provide additional capacity to the Hollydale Substation and the impact of these alternatives on the area transmission system. This study also documented that because of load growth in the western metro area, particularly outside the I-494 loop, that the transmission system in the studied area is very near its load serving capacity. This study also identified the loss of the Gleason Lake to Parkers Lake 115/115 kV double circuit line as a key contingency that must be considered when determining which alternative to select to provide a new connection to the Hollydale Substation. In evaluating the needs of distribution and transmission, this study concluded that Alternative A1 was the best transmission alternative based on power performance, price, distribution system losses, the ability to provide additional capacity at the Hollydale Substation, and future expansion capability.

2.2: Route Permit and Certificate of Need Proceedings

On June 30, 2011, Xcel Energy and Great River Energy filed an application with the Minnesota Public Utilities Commission (Commission) for a route permit for the Hollydale 115 kV Transmission Project. As proposed in this route permit application, the Hollydale 115 kV Transmission Project included the rebuild of 8 miles of existing 69 kV transmission line to 115 kV capacity in the cities of Medina and Plymouth and constructing 0.8 miles of new 115 kV transmission line and a new substation near Schmidt Lake Road and Interstate 494 (Hollydale Project). The proposed facilities were intended to meet both the distribution and transmission needs of the studied area through the mid-century based on forecasted load growth.

On August 25, 2011, the Commission accepted the Route Permit application as substantially complete and authorized the Minnesota Department of Commerce to process the application under the alternative permitting process set forth in Minnesota Rules 7850.2800 to 7850.3900.

In October 2011, a public information and environmental scoping meeting was held to provide information about the Hollydale Project and to identify issues and alternatives to study in the environmental assessment (EA). This scoping meeting was attended by 250 to 300 people and over 450 written comments were submitted.

On December 7, 2011, the Department issued a scoping decision that included 26 route alternatives to be evaluated in the EA. While the Hollydale Project as proposed included less than 10 miles of new 115 kV transmission facilities and would not have required a Certificate of Need under Minnesota Statutes §§ 216B.243, subd. 2 and 216B.2421, subd. 2(3), several of the route alternatives included in the scoping decision would have required a Certificate of Need if they were selected by the Commission. Given the possibility of the Commission selecting a route that would have required a Certificate of Need, Xcel Energy and Great River Energy filed a Certificate of Need Application for the Hollydale Project on July 2, 2012.

During the Certificate of Need proceeding, Xcel Energy prepared the Hollydale Need Addendum (Addendum) to evaluate how distribution alternatives put forth during that proceeding performed compared to the Hollydale Project. The study further evaluated the three alternatives initially proposed in the *Plymouth Load Serving Study* as well as two new alternatives. The Addendum was filed in January 2013 and recommended approval of the Hollydale Project.

2.3: Hollydale Law

During the 2013 legislative session, the Minnesota legislature passed a law, 2013 Minnesota Laws Chapter 57 Section 2, which established a Certificate of Need requirement and modified need criteria for the Hollydale Project (Hollydale Law). Specifically, the Hollydale Law, enacted on May 14, 2013, requires the Commission to review the Hollydale Project in a Certificate of Need proceeding regardless of the final length of the transmission line. In addition, the Hollydale Law, requires that prior to issuing a Certificate of Need that the Commission must find "by clear and convincing evidence that there is no feasible and available distribution level alternative to the transmission line. In making its findings the [C]omission shall consider the factors provided in applicable law and rules including, without limitations, cost-effectiveness, energy conservation, and the protection or enhancement of environmental quality." The Hollydale Law also suspended the Route Permit proceeding until the Commission determines that the Hollydale Project is needed.

2.4: Additional Electrical Studies

To comply with the Hollydale Law, Xcel Energy filed a supplement to the Certificate of Need Application in August 2013 (Supplement). The Supplement evaluated the Hollydale Project compared to 15 other alternative projects to meet the distribution and transmission needs in

Plymouth and Medina. These 15 alternatives included a distribution only alternative, alternatives that required no new transmission in the studied area, alternatives that defer construction of transmission until a later date, and the originally proposed Hollydale Project. The Supplement evaluated these alternatives based on technical feasibility, cost effectiveness, and other Certificate of Need criteria.

After compiling peak load data for the summer of 2013, Xcel Energy updated the information in the Supplement in the *Hollydale Project 2013 Peak Voltage Analysis* (Peak Analysis) filed in October 2013.

2.5: Withdrawal of Route Permit and Certificate of Need Applications

In November 2013, public hearings were held on the Certificate of Need application. Approximately 300 people attended these hearings to express their concerns about the Hollydale Project and the preferred route.

On December 10, 2013, Xcel Energy and Great River Energy filed a petition requesting permission to withdraw the pending Certificate of Need and Route Permit applications for the Hollydale Project. The petition noted that during the Certificate of Need and Route Permit proceedings, landowners, parties, and other stakeholders had expressed concern about route preferred by the companies for the new 115 kV line. In this petition, the companies requested permission to withdraw these pending applications to allow time to develop other alternatives to meet the electrical needs of the community that would be more acceptable to the community.

2.6: Commission Order on Withdrawal

On May 12, 2014, the Commission issued an order granting Xcel Energy and Great River Energy's request to withdraw the pending applications for the Hollydale Project. The Commission's order also acknowledged that there are electrical issues in Plymouth and Medina that remain to be addressed. The Commission's order required the companies to "demonstrate the need for any new transmission they propose for the Plymouth or Medina project area." The Commission order further required that the companies file updates (six months after the date of the order and then quarterly thereafter) documenting their public outreach efforts, improvements made to the distribution system, load-serving capacity of the distribution system, and a report of demand-side management and other resources to address the reliability needs of the area.

3.0: Study Scope

This study is part of Xcel Energy's continued study of the electrical needs of the Plymouth and Medina areas and the Company's continued evaluation of different alternatives to meet those needs.

4.0: Need Overview

The alternative proposed in this Report are needed to address two distinct needs. The distribution need is driven by a deficit in the distribution system's load serving capability of a Focused Study Area centered around the western Plymouth area. The transmission need is driven by load growth on the distribution system in a larger area than the distribution Focused Study Area (Transmission Area of Concern) and deficiencies on the transmission system under contingency conditions to serve this load. As the load on the distribution system in the Transmission Area of Concern grows, the transmission need to serve that load increases. Since the two needs are so interrelated, the solution that is implemented must solve both of the identified needs. Therefore, all solutions proposed in this study solve both distribution and transmission needs.

4.1: Distribution Need.

4.1.1: Principles of Distribution Planning

(a) Distribution System Overview

Distribution feeder circuits for standard service to customers are designed as radial circuits. Therefore, the failure of any single critical element of the feeder circuit causes a customer outage, which is an allowed outcome for a distribution system. Feeders are designed to facilitate restoration of mainline capacity and restoration of service to most customers with simple manual field switching with some exceptions. The distribution system is planned to generally facilitate single-contingency switching to restore outages within approximately one hour.

(b) Distribution Substations

Xcel Energy plans and constructs distribution substations with a physical footprint sized for the ultimate substation design. The maximum ultimate design capacity established in Xcel Energy planning criteria is three transformers at the same distribution voltage.[1] This maximum size balances substation and feeder circuit costs with customer service considerations including limitations of feeder circuit routes emanating from substations, circuit exposure of long feeder circuits, ease of operation, cost of operation, customer outage restoration, and the electrical losses. Over time, transformers and feeder circuits are incrementally added within the established footprint until the substation is built to ultimate design capacity.

(c) Distribution Feeder Circuits System Intact and First Contingency Planning

Normal operation (also called system intact or N-0 operation) is the condition under which all-electric infrastructure equipment is fully functional. First contingency operation (also called N-1 or contingency operation) is the condition under which a single element (feeder circuit or distribution substation transformer) is out of service. Each distribution main feeder is generally composed of three equal sections. A feeder circuit should be loaded to no more than 75% of capacity during N-0 conditions. For example, a 12 MVA feeder circuit is designed to be loaded to 9 MVA during normal operating conditions. To achieve this goal, a main feeder is generally designed so that each section is loaded to approximately 25% of the total capacity for the main feeder. This loading level provides reserve capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions.

Figure 4.1 depicts a main feeder circuit, including the breaker and the three sections. The red and green lines in the diagram represent switches that can be activated to isolate or connect sections of a feeder line.

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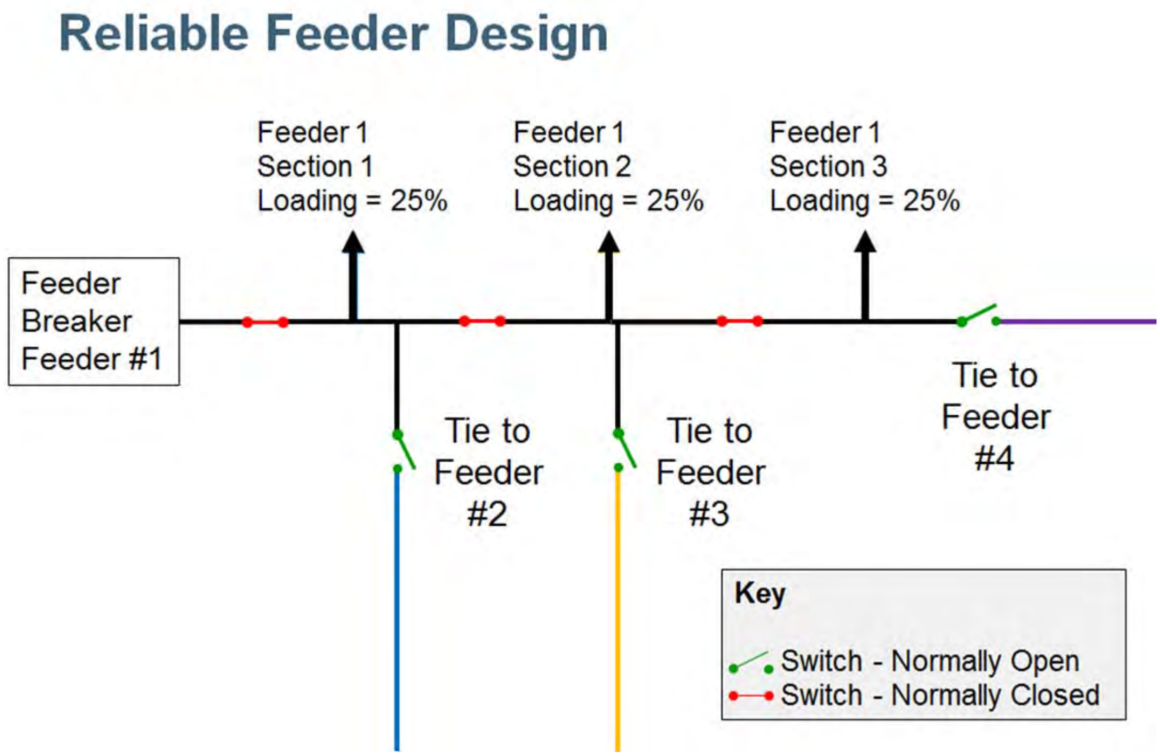
[1] There is one exception to this criteria. In downtown Minneapolis, the Fifth Street Substation houses four transformers to serve the significant load.

Figure 4.1: Typical Distribution Feeder Circuit Mainline with Three Sections Capable of System Intact N-0 and First Contingency N-1 Operations



(d) Distribution System Design and Operation

Distribution system load is planned, measured, and forecasted with the goal to serve all customer electric load under system intact and first contingency conditions. A distribution delivery system that has adequate N-1 capacity is one in which all customer load can be restored through distribution system reconfiguration by means of electrical switching in the event of the outage of any single element.

Adequate N-1 substation transformer capacity, no feeder normal (N-0) overloads, and adequate field tie capability for feeder first contingency (N-1) distribution restoration are key design and operation objectives. To achieve these objectives, Xcel Energy uses distribution planning criteria to achieve uniform development of Xcel Energy's distribution systems. Distribution Planning considers these criteria when identifying deficiencies with existing distribution systems and identifying improvements to address the identified deficiencies.

(e) Planning Criteria, Distribution Feeder Circuits

While the distribution guidelines vary depending on the specific distribution system, there are several basic design guidelines that apply to all areas of Xcel Energy's distribution system. They are as follows:

- Voltage at the customer meter will be maintained within 5% of nominal voltage, which is typically 120 volts.

- Voltage imbalance goals on the feeder circuits are less than or equal to 3%. Feeder circuits deliver three-phase load from a distribution substation transformer to customers. Three-phase electrical motors and other equipment are designed to operate best when the voltage on all of the three phases is the same or balanced.

- The currents on each of the three phases of a feeder circuit are balanced to the greatest extent possible to minimize the total neutral current at the feeder breaker. When phase currents are balanced, more power can be delivered through the feeders.

- Under system intact, N-0 operating conditions, typical feeder circuits should be loaded to less than 75% of capacity. Xcel Energy developed this standard to help ensure that service to customers can be maintained in an N-1 condition or contingency. If feeder circuits were loaded to their maximum capacity and there were an outage, the remaining system components would not be able to make up for the loss because adding load to the remaining feeder circuits would cause them to overload. By targeting a 75% loading level, there is generally sufficient remaining capacity on the system to cover an outage of an adjacent feeder with minimal service interruptions. A typical feeder circuit capable of delivering 12 MVA, for example, is normally loaded to 9 MVA and loaded up to 12 MVA under N-1 conditions.

(f) Limitations to Installing Feeder Circuits

Spatial and thermal limits restrict the number of feeder circuits that may be installed between a distribution substation transformer and customer load. Consequently, this limits substation size. Normal overhead construction is one feeder circuit on a pole line; high density overhead construction is two feeder circuits on a single pole line (double deck construction). When overhead feeder circuit routes are full, the next cost effective installation is to bury the cable in an established utility easement. Thermal limits require certain minimum spacing between multiple feeder circuit main line cables. Thermal limits for primary distribution lines are defined in Electric Distribution Bulletins ("EDB"): UND6 and CAL2 for underground and the Construction & Design Manual C-26 for overhead.

When new feeder circuits are added to a mature distribution system, minimum spacing between feeder circuit main line cables sometimes cannot be achieved because of right-of-way limitations or a high concentration of feeder cables. Adding express feeders to serve distant high-load concentrations requires cable installation across distribution service areas where they do not serve any customer load. Cable spacing limitations and/or feeder cable concentrations frequently occur where many feeder cables must be installed in the same corridor near distribution substations or when crossing natural or manmade barriers.

When feeder cables are concentrated, they are most often installed underground in groups (banks) of pipes encased in concrete that are commonly called "duct banks". When feeder circuits are concentrated in duct banks, those cables encounter more severe thermal limits than multiple buried underground feeder circuits. Planning Engineers use CYMCAP software for determining maximum N-0 and N-1 feeder circuit cable capacities for circuits installed in duct banks.

When underground feeders fill existing duct lines to the rated thermal capacity, and there is no more room in utility easement or street right-of-way routes for additional duct lines from a substation to the distribution load, feeder circuit routing options are exhausted.

(g) Planning Criteria, Distribution Substation Transformers

Transformers have nameplate ratings that identify capacity limits. Xcel Energy's Transformer Loading Guide provides the recommended limits for loading substation transformers adjusted for altitude, average ambient temperature, winding taps-in-use, etc. The Transformer Loading Guide is based upon the American National Standards Institute/Institute of Electrical and Electronic Engineers ("ANSI/IEEE") standard for transformer loading, ANSI/IEEE P77.92.

The Xcel Energy Transformer Loading Guide consists of a set of hottest-spot and top-oil temperatures and a generalized interpretation of the loading level equivalents of those temperatures. The top-oil and hottest-spot temperatures in the Xcel Energy Transformer Loading Guide are the criteria used by Substation Maintenance engineers to determine Normal and Single-Cycle transformer loading limits that Capacity Planning Engineers use for transformer loading analysis. When internal transformer temperatures exceed pre-determined design maximum load limits, the transformer sustains irreparable damage, which is commonly referred to as equipment "loss-of-life". Loss-of-life refers to the shortening of the equipment design life that leads to premature transformer degradation and failure.

Transformer design life is determined by the longevity of all of the transformer components. At a basic level most substation transformers have a high voltage coil of conductor and a low voltage coil electrically insulated from each other and submerged in a tank of oil. Transformer operation generates heat; the more load transformed from one voltage to the other, the more heat; too much heat damages the insulation and connections inside the transformer. Hottest-spot temperatures refer to the places inside the transformer that have the greatest heat, and top-oil temperature limits refer to the maximum design limits of the material and components inside the transformer.

To ensure maximum life and the ability to reliably serve customers, Xcel Energy's loading objective for transformers is 75% of normal rating or lower under system intact conditions. Substation transformer utilization rates below 75% are indicative of a robust distribution system that has multiple restoration options in the event of a substation transformer becoming unavailable because of an equipment failure or required maintenance and construction. The higher the transformer utilization, the higher the risk that service will be interrupted in the event of a transformer outage.

(h) Ongoing Distribution System Reliability Assessment

Distribution Planning regularly evaluates loads to determine overloads. Mitigations (projects) are developed to address the overloads. In general, infrastructure additions that address overloaded distribution system elements is an ongoing process.

Distribution Planning annually compares feeder circuit historical and forecast peak load demands to distribution feeder circuit maximum loading limits to identify feeder circuits overloaded under system intact (N-0) conditions and feeder circuits overloaded under single contingency (N-1) conditions during peak loading.

Distribution Planning also annually compares substation transformer historical and forecasted peak load demands on substation transformers to capacity load limits under system intact (N-0) and single contingency (N-1) conditions. Distribution Planning provides distribution substation transformer loads to the Transmission Planning Department ("Transmission Planning"). Distribution and transmission planners routinely coordinate to identify distribution load impacts to the transmission system.

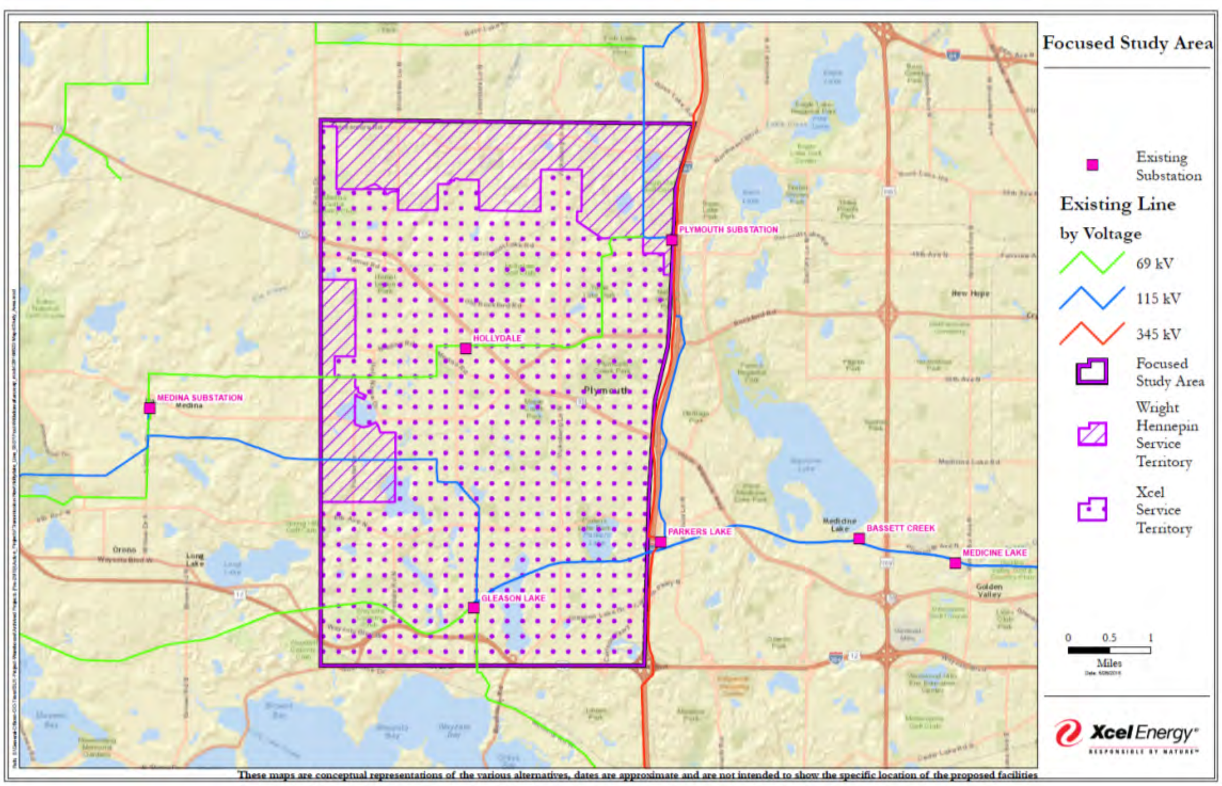
Distribution Planning then quantifies the amount of overload and the duration of peak loading for feeder circuit and substation transformer overloads under system intact (N-0) and single contingency (N-1) conditions, determines the approximate cost of mitigating the overloads, and identifies the most critical distribution system needs.

When Distribution Planning determines that a distribution system requires additional capacity from a new distribution source, it makes a formal request to Transmission Planning to interconnect to the transmission system. Transmission Planning takes the request and Distribution Planning and Transmission Planning coordinate to develop several alternatives that will address the distribution system deficiencies. Transmission Planning performs analyses to determine the impact of the selected alternatives on the transmission system.

4.1.2: Hollydale Focused Study Area Distribution System Difficiencies

The Focused Study Area comprises approximately 24-square miles in Plymouth and is depicted in Figure 4.2. The Focused Study Area distribution load is primarily fed from three 115 kV transmission lines: (1) Medina – Gleason Lake, (2) Gleason Lake – Parkers Lake, and (3) Parkers Lake – Medicine Lake. Thirteen feeder circuits emanating from three substations (Gleason Lake, Hollydale, and Parkers Lake) serve the Focused Study Area.

Figure 4.2: Map of Focused Study Area.



The current demand for power in the Focused Study Area exceeds the capabilities of the existing electrical system. In 2014, the most recent peak year, the distribution feeders in the Focused Study Area reached an actual non-coincident peak loading of 121 MW. In 2015, the distribution feeders in the Focused Study Area reached an actual non-coincident peak loading of 110 MW. In 2014, the two Gleason Lake 13.8 kV transformers peaked at 44 MW and the one 34.5 kV Gleason Lake transformer peaked at 45 MW. In 2015, the two Gleason Lake 13.8 kV transformers peaked at 41 MW and the one 34.5 kV Gleason Lake transformer peaked at 40 MW. In 2014, the peak loads exceeded the distribution systems' planned contingency capacity by 11 MW on the 34.5 kV transformer, a total of 14 MW on the 13.8 kV feeders and 13 MW on the 34.5 kV feeders (rounded).

The 2014 peaks were similar to peaks in the recent years of 2011, 2012 and 2013, while the 2015 peaks were abnormally low. The decrease in load from 2014 to 2015 is likely due to cooler weather during the summer of 2015. It can be expected that when typical warm temperatures return in future summers, feeder and transformer loads will meet or exceed historic peak load levels. The feeder peak loading reached 122 MW in 2011, 124 MW in 2012 and 123 MW in 2013. At the Gleason Lake substation, for the 13.8 kV transformers the historic peak was 49 MW in 2011 and for the 34.5 kV transformer the historic peak was 46 MW in 2013.

In 2006, the peak loads exceeded the distribution system's capacity. After these historical peak loads were experienced, it became apparent that the distribution system in the area was becoming increasingly vulnerable to more frequent and longer duration overloads. As a result, in 2008, Xcel Energy intensified its analysis of the distribution system to develop a long-term solution to serve the growing load. A distribution study and the subsequent Certificate of Need, Addendum and Supplement documented the load serving needs and identified various solutions. In this update, the more recent peak loads will be used to show the load serving needs.

4.1.3: Distribution Feeders in the Focused Study Area

The distribution system in the Focused Study Area consists of eleven 13.8 kV feeders and two 34.5 kV feeders. Of the 13.8 kV feeders, six are sourced from Parkers Lake substation, three from Gleason Lake substation and two from Hollydale substation. The two 34.5 kV feeders are sourced from Gleason Lake substation. The entire Hollydale substation is fed by one of the Gleason Lake 34.5 kV feeders.

For the 13.8 kV feeders, at projected peak load in 2016, some of these are currently experiencing overloads under normal configuration. Overloads also occur under contingency configuration while picking up load after the outage of an adjacent feeder. Overloads reduce the life of distribution system devices. Overhead wires can sag and potentially create clearance concerns; underground cables become distorted, which reduces the capability of the insulation. Other distribution equipment can overheat and not operate properly. If an overload is high enough in magnitude or sustained for long enough in duration, an overhead line will melt, leading to a failure and then an outage.

There are two 13.8 kV feeders with overloads ranging from 104% to 111%. Based on typical utilization limits, there is a deficit of about 14 MW of load in total on individual 13.8 kV feeders under contingency conditions. For the 34.5 kV feeders, at peak load none are currently experiencing overloads under normal configuration but do have overloads under contingency configuration while picking up load after the outage of an adjacent feeder. Based on typical utilization limits, there is a deficit of about 16 MW total load on individual 34.5 kV feeders under contingency conditions in 2016.

The loading (utilization) of feeders will continue to increase and is forecasted to grow at approximately 1% per year in the coming years. While utilization varies from 54% to 111% on individual feeders the current utilization for the total of all 13.8 kV feeders in the Focus Study Area is at 79%. Assuming an evenly loaded system the desired utilization is 75%. This indicates that even if it were physically possible to reconfigure the load such that all feeders are evenly loaded, the system would still exceed the desired utilization. Therefore, the entire area load needs additional capacity. As load grows, individual feeder loads will be rearranged to reduce specific overloads but considered as a whole, the distribution system in the Focused Study Area is short of capacity. As load grows and utilization increases the ability to rearrange feeders to serve load during normal and contingency conditions decreases.

4.1.4: Distribution Substation Transformers in the Focused Study Area

The distribution system substation transformers in the Focused Study Area consist of two 13.8 kV transformers and one 34.5 kV transformer. Both are located at the Gleason Lake substation. For the 13.8 kV transformers, at peak load in 2016, there will be no overloads under normal configuration. Under contingency configuration while picking up load after the outage of an adjacent transformer, there is only about 1 MW of additional capacity available before a deficit occurs. For the 34.5 kV transformer, at peak load in 2016 there is no overload under normal configuration but there is an overload under contingency configuration while picking up load after an outage of this transformer. Since there is only one 34.5 kV transformer at the Gleason Lake substation, for loss of the transformer all load must be transferred to 34.5 kV feeders at nearby substations through existing feeder ties. Based on the currently available 34.5 kV transfers, there is a deficit of about 14 MW under contingency in 2016.

4.2: Transmission Need.

4.2.1: Planning criteria

The Transmission need in the Transmission Area of Concern is driven by the need to comply with NSP Transmission Planning Criteria under NERC TPL Standards. The NSP Transmission Planning Criteria is available at www.misoenergy.org. The criteria for voltage and thermal limitations are listed below in Table 4.1.

Voltage Criteria

Table 4.1: Voltage Planning Criteria

	Maximum voltage (p.u.)	Minimum voltage (p.u.)	Maximum voltage (p.u.)	Minimum voltage (p.u.)
Facility	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 load serving buses, pre and post contingent voltage of above .90 PU would be acceptable.
**For all Category A, B and C contingencies, except Category P6. After a Category P6 contingency, generator bus voltage would be allowed to drop to 0.92 PU.

Line loading criteria

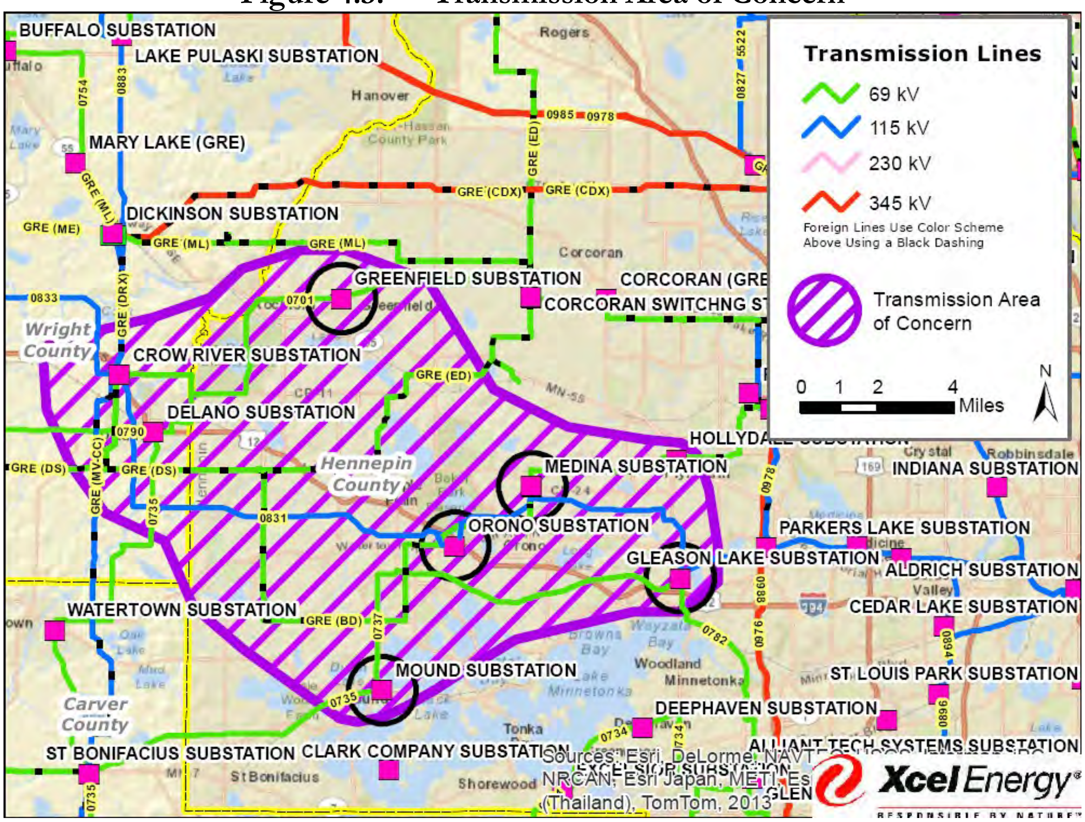
The ratings for facilities owned by NSP are specified in the NSP Ratings Database. The winter and summer ratings of facilities account for the thermal limit of all equipment, and relay loadability limits, as specified in NERC FAC-008 and FAC-009 standards.

When planning NSP's system for system intact conditions, 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 should be 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.

4.2.2: Transmission Area of Concern Difficiencies

The transmission system in the western metro around the cities of Plymouth, Medina, and Minnetonka stretching west to Greenfield has reached its load serving limits. This region will be referred to going forward as the Transmission Area of Concern and is served by five substations: Gleason Lake, Greenfield, Medina, Mound, and Orono. Figure 4.3 below shows a map of the Transmission Area of Concern.

Figure 4.3: Transmission Area of Concern



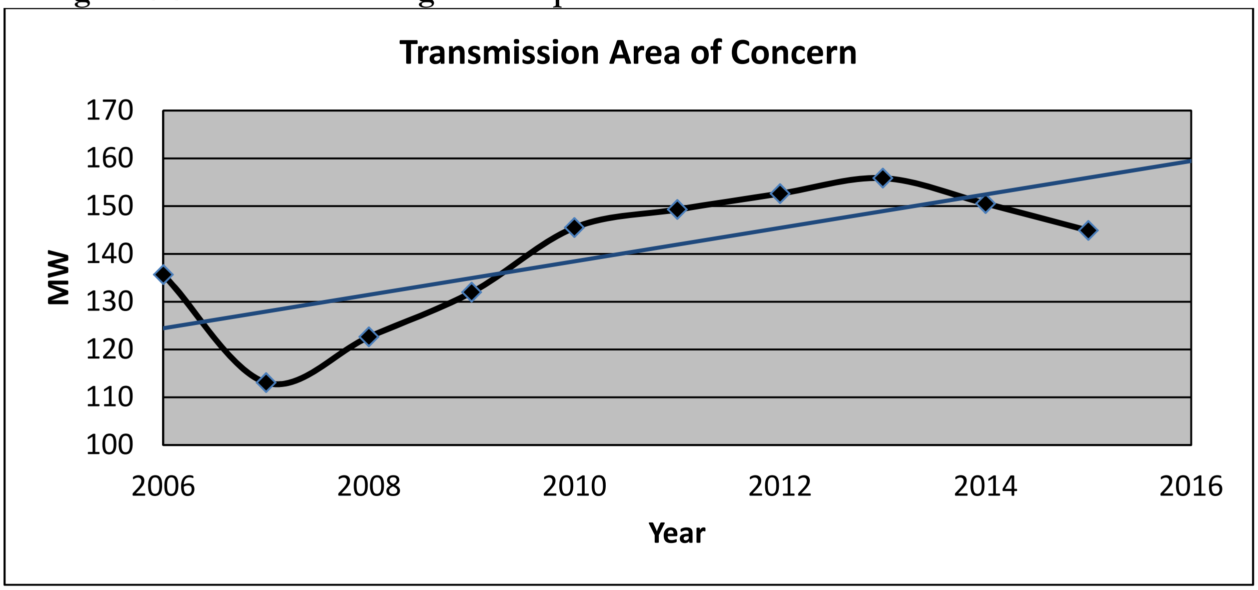
The load in the Transmission Area of Concern peaked in 2013. The load level achieved in 2013 exceeded the capabilities of the transmission system under contingency. Due to this potential NERC violation, Xcel Energy installed Under Voltage Load Shedding (UVLS) to protect the transmission system until a permanent solution is built. The peak load in this area for the last ten years is listed below in Table 4.2:

Table 4.2: Historic peak load in the Transmission Area of Concern.

Transmission Area of Concern	
Year	**MW**
2015	144.90
2014	150.54
2013	155.86
2012	152.62
2011	149.29
2010	145.51
2009	131.97
2008	122.63
2007	113.07
2006	135.67

Figure 4.4 below shows the peak loads for the last ten years plotted. The trend line in blue shows the overall load growth trend in Transmission Area of Concern.

Figure 4.4: Chart showing historic peak loads in the Transmission Area of Concern.

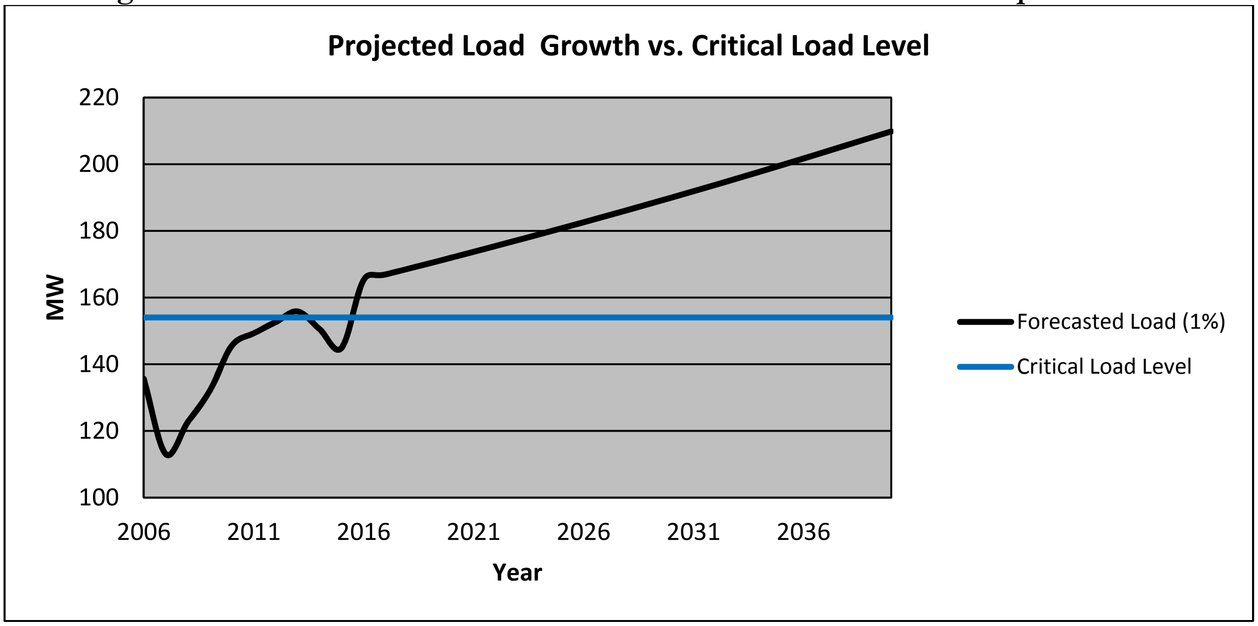


The historical load in the Transmission Area of Concern shows strong load growth, while showing the financial crisis that the US experienced in 2007-2008 which temporarily reduced peak load during that period. The trend line above represents approximately 3.5% load growth; however Xcel Energy believes this is not sustainable over the next 40 years. Since this study is looking at 40 years, a load growth rate of 1% will be analyzed. Note that the load growth is not as important as the total load served in the Transmission Area of Concern. If load growth occurs faster or slower than the analyzed rates, the need year of additional facilities will change accordingly.

Figure 4.5 below shows the peak loads for the last ten years and the future projected loads on a single plot. Power flow simulations were used to identify voltage violations in the Transmission Area of Concern, occurring at 153 MW of area load. This critical load level of 153 MW in the

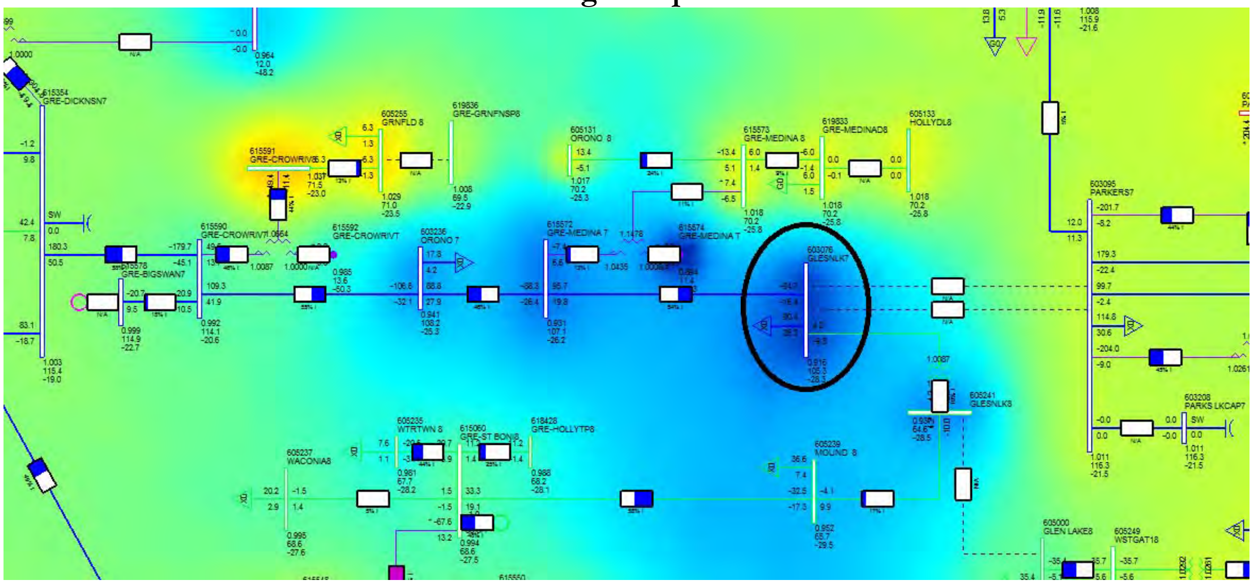
Transmission Area of Concern, which triggers the transmission need, is indicated by the blue line in the figure. The critical load level is independent of load growth and simply states the amount of load which triggers needed system improvements. The black line shows the forecasted loads in the Transmission Area of Concern using a 1% load growth after known load additions have been taken into account. As can be seen in the graph, the critical load level is exceeded in 2016 and beyond.

Figure 4.5: Transmission Area of Concern historic and forecasted peak loads.



Under system peak conditions, the critical contingency condition in the Transmission Area of Concern is the Gleason Lake – Parkers Lake 115 kV double circuit line outage. During this condition, the entire Transmission Area of Concern load is served from a 115 kV path from Dickinson in the west and a 69 kV path connecting to St. Bonifacius in the south. These two sources are not strong enough to support the large load at Gleason Lake, which is located the furthest distance from either source. Figure 4.6 shows the area in a power flow simulation tool which shows the Transmission Area of Concern under the critical condition during a simulated 2013 peak (156 MW). Under this critical condition, the load at Gleason Lake is below acceptable voltage levels. Note that blue means low voltage and red means high voltage, the color gets darker as the voltage gets more severe. Gleason Lake substation is circled in black.

Figure 4.6: Power flow results for Transmission Area of Concern under critical condition during 2013 peak.



5.0: Analysis of the Plymouth Electric Distribution Delivery System in the Focused Study Area

5.1: Feeder circuits

Distribution Planning assessed the electric distribution delivery system's ability to serve existing and future electricity loads in the Focused Study Area by evaluating the historical and forecasted load levels and utilization rates of the 13 feeder circuits (11-13.8kV and 2-34.5kV) that serve the Focused Study Area over a period of 20 years (*i.e.*, target year of 2036). The Planning Engineers then identified existing and anticipated capacity deficiencies resulting in overloads during N–0 (system-intact) and N–1 (single contingency) operating conditions.

In conducting this Study, Planning Engineers relied on the following resources:

- Synergi Electric software package. Synergi is a software tool that can be used to explore and analyze feeder circuit reconfigurations. When historical peak load data is added from the Distribution Asset Analysis ("DAA") software package, Synergi is capable of providing load flow and voltage regulation analysis. Synergi is a tool that can generate geographically correct pictures of tabular feeder circuit loading data. This functionality has been achieved through the implementation of a Geographical Information System ("GIS") extraction process. Through this process, each piece of equipment on a feeder, including conductor sections, service transformers, switches, fuses, capacitor banks, etc., is extracted from the GIS and tied to an individual record that contains information about its size, phasing, and location along the feeder. All distribution feeders that are part of the Focused Study Area were extracted from the GIS software and imported into Synergi.
- Xcel Energy Distribution Planning Load Forecast for N-0 feeder circuit and substation transformer analysis. Planning Engineers used DAA to record historical non-coincident peak

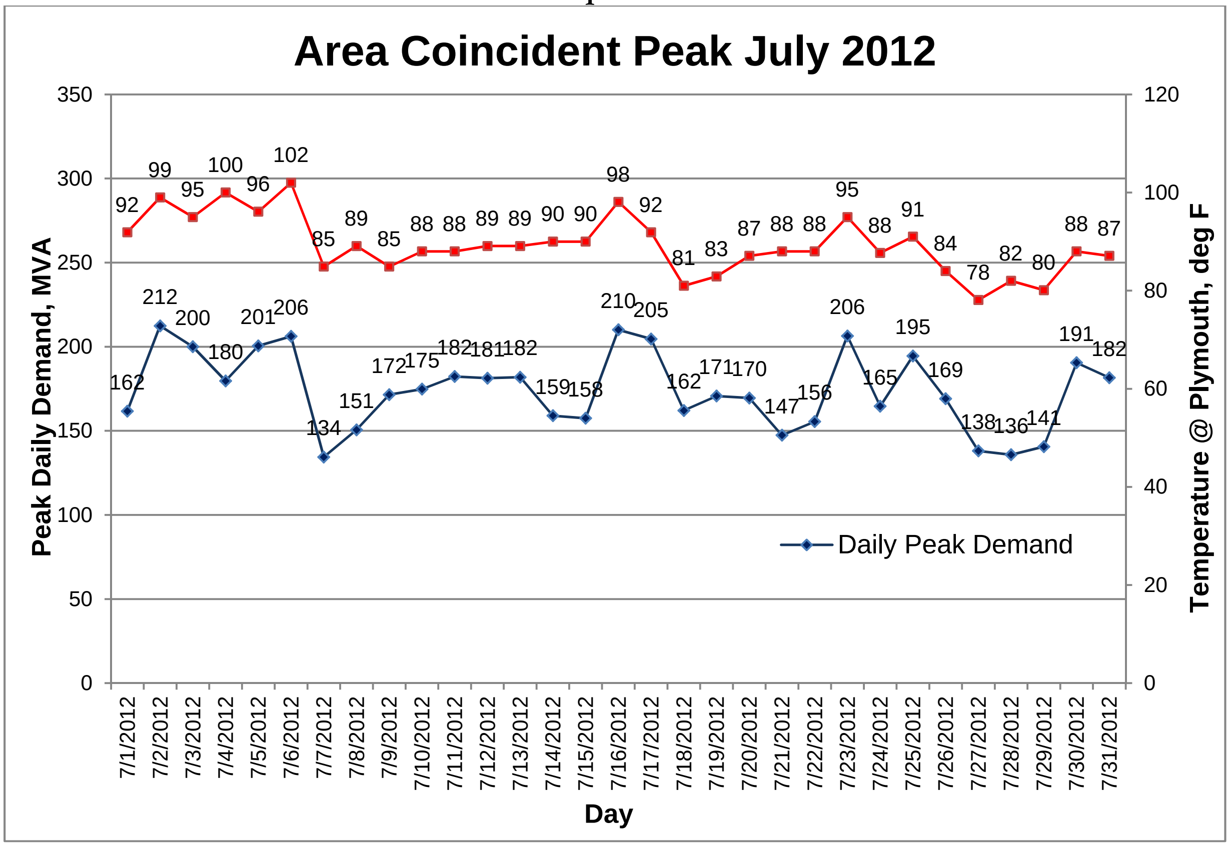
loads on distribution feeder circuits and distribution substation transformers. Distribution Planning Engineers annually examine each distribution feeder circuit and distribution substation transformer for peak loading. They use specific knowledge of distribution equipment, local government plans and customer loads to forecast future electrical load growth. Planning Engineers consider many types of information for the best possible future load forecasts including: historical load growth, customer planned load additions, circuit and other distribution equipment additions, circuit reconfigurations, and local government sponsored development or redevelopment.

- Xcel Energy Feeder Status Sheets for feeder circuit N-1 load allocation and N-1 analysis. Planning Engineers used Feeder Status Sheet software ("FSS") to allocate measured peak loads to main line feeder sections. Engineers validate and record feeder main line additions and reconfigurations using this tool. They analyze the N-1, first contingency breakdown of each distribution feeder circuit for the forecasted years.
- Xcel Energy Substation One Line Drawings. Planning Engineers used Xcel Energy Computer Aided Design software ("CAD") to develop CAD drawings modified by substation engineers as needed to reflect present substation configurations.
- Xcel Energy Distribution Feeder Maps. Planning Engineers used Xcel Energy CAD software to develop CAD drawings to reflect present feeder circuit mainline and tap configuration.
- Plymouth Maps. Planning Engineers used Internet live search maps to make a map of the area, GIS software and Synergi software tool to make geographic based pictures of the feeder circuit configuration and to illustrate feeder circuit loading levels.

5.1.1: Feeder Circuit Historical Load

Feeder circuit peak loading in the Plymouth area is measured during the summer. Both feeder circuit and substation transformer load correlates to summer temperatures based on customer air conditioning usage in response to summer temperatures. This is illustrated in Figure 5.1, which compares the Gleason Lake and Parkers Lake substation transformer measured peak load and outside temperature during July 2012.

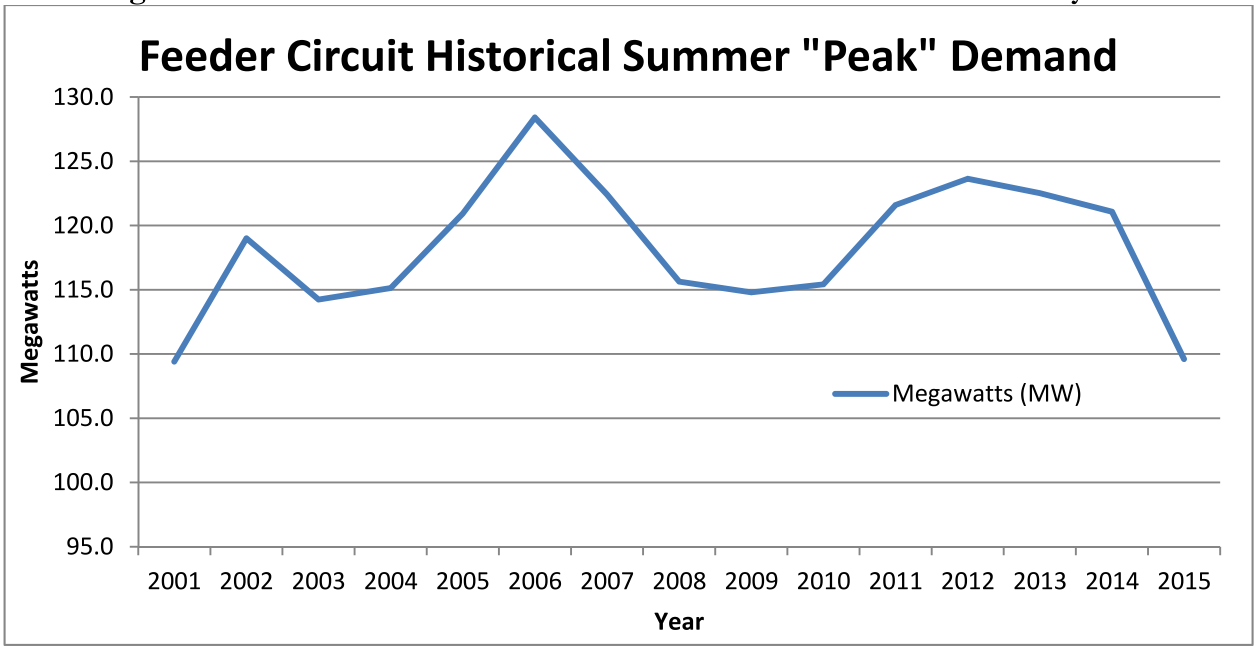
Figure 5.1: July 2012 Gleason Lake and Parkers Lake Substation Peak Load and Outside Temperatures



Each distribution feeder in the Plymouth area has three phase meters located in the substation, which are read monthly and the data recorded in Passport, a record-keeping software. These meters record the monthly peak for the feeder. The distribution feeders in the Focused Study Area also have a SCADA system that monitors the real time average or three phase amps on the feeder. This system feeds a SCADA data warehouse and the DAA warehouse where hourly data is stored so the feeder load history can be viewed by Electric System Planning and Field Operations. When three phase load data is available, the highest recorded phase measurement is used in the distribution forecast. Each feeder circuit non-coincident peak history from 2001 through 2015 is used to forecast 2016 through 2036 peak loads.

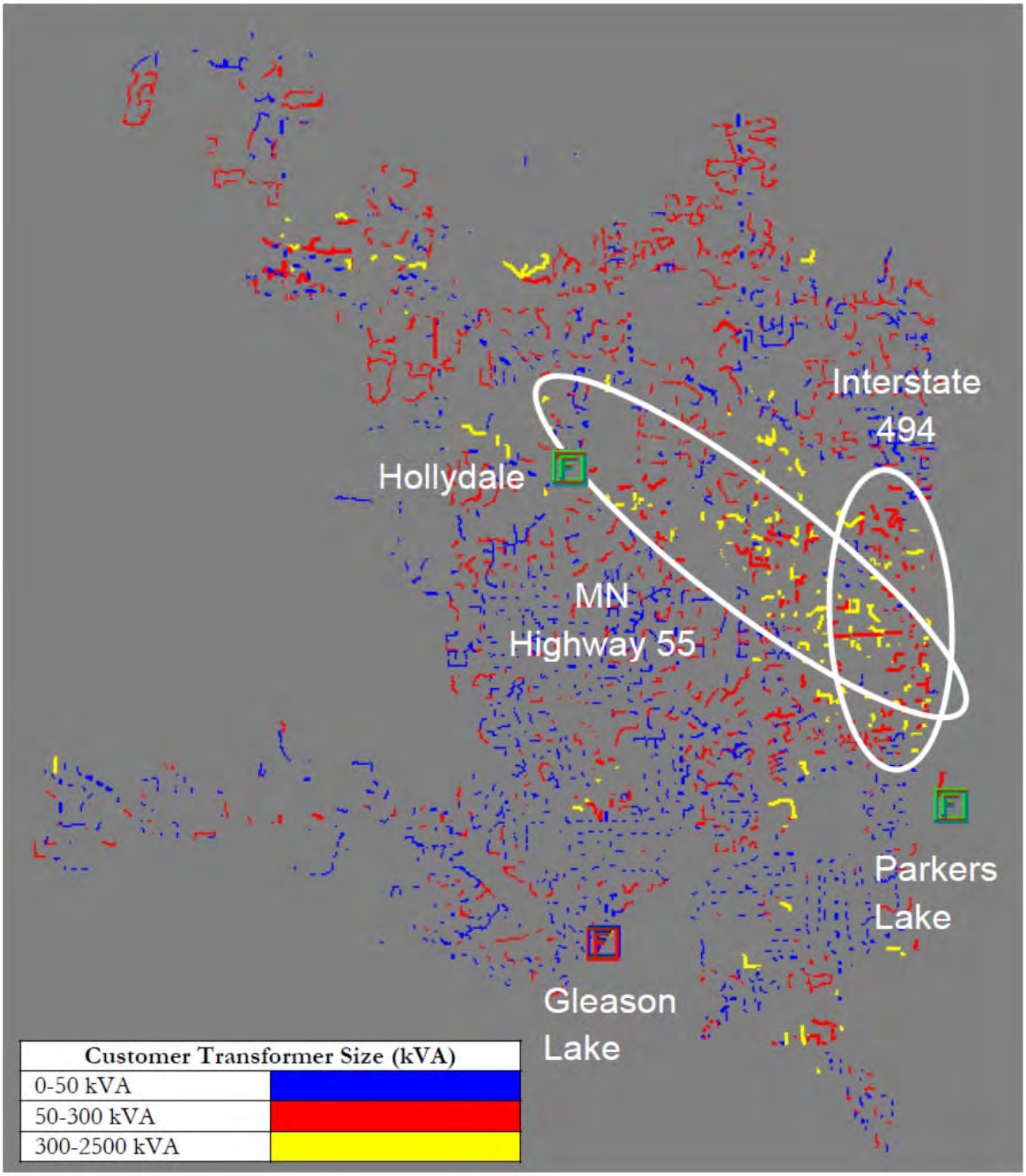
Measured peak loads fluctuate from year to year due to the impacts of the duration and intensity of hot weather and customer air conditioning usage. In the Focused Study Area, feeder circuit load fluctuates in a bandwidth of 5 MW to 14 MW from cooler years to historic peaks occurring in 2002, 2006 and 2012. Even though the measured peak load decreases in cooler years, the historic peak represents latent load levels that will recur in years that have higher temperatures. The measured peak load for feeders increased an average of 0.8% per year in the eight years between 2001 and 2014, the most recent peak year. The historical loads for the feeder circuits serving the Focused Study Area from 2001 through 2015 are shown below in Figure 5.2 and are also detailed in Appendix B.

Figure 5.2: Historical Summer "Peak" Demand for the Focused Study Area



In addition to peak loads, Planning Engineers researched existing customer load density. Individual distribution transformers serve a single customer or multiple customers. As customer load grows in developed areas such as the Focused Study Area, distribution transformers are changed to higher capacity equipment when customer demand exceeds the capacity of the original transformer. Distribution transformers are an excellent indicator of customer electrical loading and peak electrical demand. Figure 5.3 is a graphic, developed using Synergi software, illustrating distribution transformer installation by size (which indicates present customer load density) in the Focused Study Area.

Figure 5.3: Distribution Transformer Sizes (Which Is Indicative of Customer Load Density) in Focused Study Area



The customer load serving transformers shown in Figure 5.3 are colored based on the size of the transformer. The largest commercial customers in Plymouth are shown in yellow. Customers in large multi-residence buildings (more than 100 units), large multi-use buildings, large retail stores, or corporate data centers typically have one or more transformers depicted as yellow dots. Customers in small and mid-sized commercial buildings, including retail stores and restaurants are served by smaller transformers that are shown as red. Residential customers and other lowest usage customers are shown in blue. Red and yellow show high density load corridors along MN Highway 55 and Interstate 494.

5.1.2: Feeder Circuit Load Forecasts

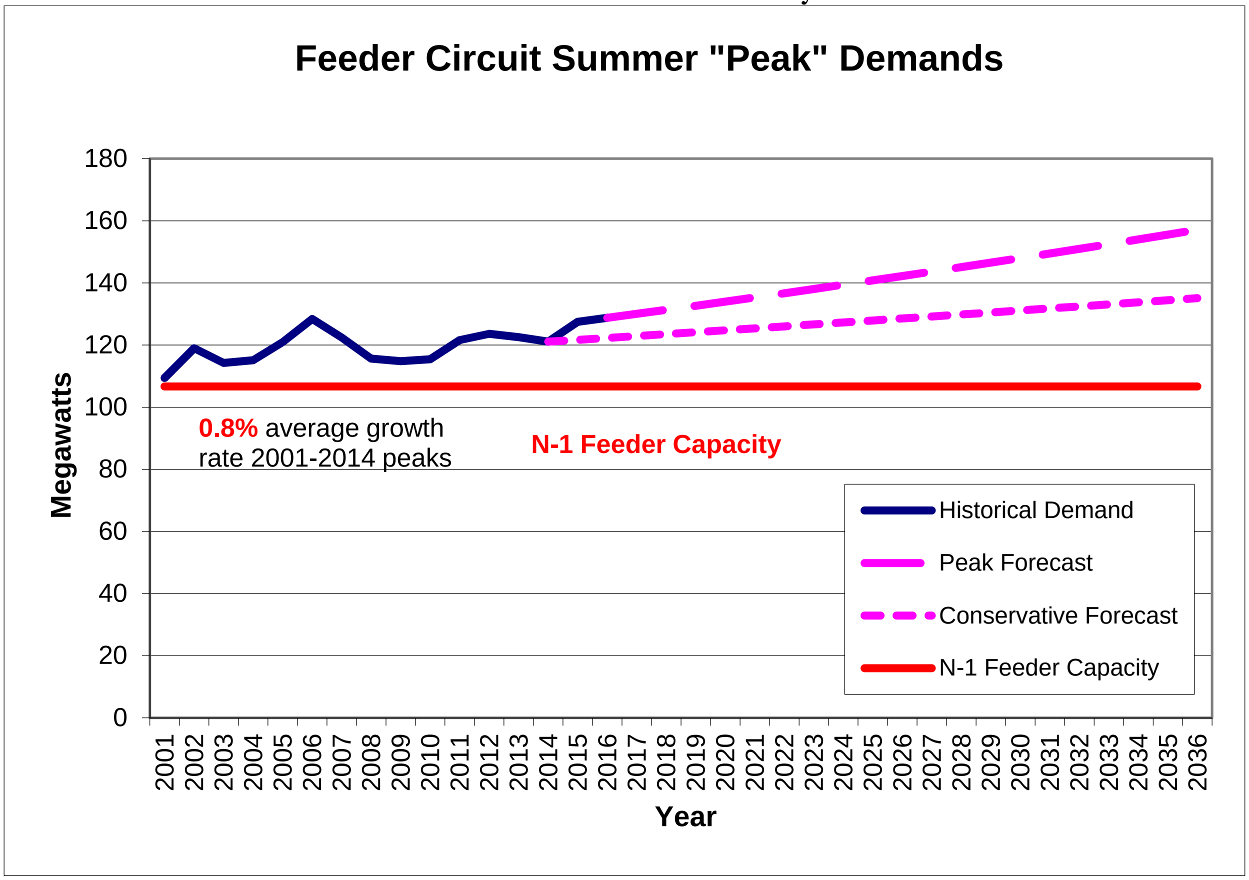
The feeder circuit load is forecasted for each feeder circuit. Feeder circuit load forecast evaluation uses a trending method, which considers a combination of historical growth, customer reported load additions, local government and developer projects or plans, and any additional information that impacts the circuit load growth. The table entries were calculated using the individual feeder circuit forecasts provided in Appendix B.

The historical data analysis of Focused Study Area in the previous section combined the 13.8 kV areas and 34.5 kV areas in order to gain an accurate representation of historical load growth within the Focused Study Area from 2001-2015. The historical load data indicated that the load has been growing within the Focused Study Area over the last decade. To analyze the distribution system for the future and to identify the capacity needs, the 13.8 kV and 34.5 kV areas as identified in Section 3.1 of this Study, also need to be analyzed separately for N-1 contingency capacity. The 34.5 kV feeder analysis includes the embedded Hollydale 13.8 kV feeder load to reflect the impact of the 34.5 kV source at Hollydale.

Distribution Planning took a conservative outlook for forecasting feeder circuit load for this Study because of anticipated customer conservation and a soft economy. Distribution Planning forecasted the feeder loads in 2016 based on recent 2011 to 2013 historic peaks and used a growth rate of 1.0% to forecast load levels on the eleven 13.8 kV feeders and two 34.5 kV feeders for the next 20 years, representing growth in demand of approximately 28 MW by 2036.

Figure 5.4 is a linear depictions of the load growth on the eleven 13.8 kV feeder circuits and the two 34.5 kV feeder circuits in the Focused Study Area from 2001 through 2036. The "Conservative Forecast" line depicts loads forecast based on the lower year peak loads from 2014 and with a 0.5% growth rate. The upper limit peak load forecast is also shown ("Peak Forecast") from 2016 based on 2011 to 2013 historic peak loads for the feeders. By 2036, this upper limit forecast is 14 MW above the conservative peak load forecasts shown in the figure. Actual peak loads will likely fall between the conservative forecast demand and the historic peak levels. Average load growth for the time period is calculated by comparing total non-coincident feeder circuit loads from the beginning to the end of the comparison period.

Figure 5.4: Historical and Forecasted Load Growth on Eleven 13.8 kV and Two 34.5 kV Feeder Circuits in Focused Study Area



Over time, demand on the distribution system generally trends upward, with some dips due to weather or economic downturns. The historic downturns have been followed by increases in demand that reach levels equal to or greater than the prior peak. For example, from the year 2002 to the year 2004, demand declined. Then, from the year 2004 to the year 2006, demand increased again reaching a new peak. From year 2006 to 2009, there was a similar decline in demand from the 2006 peak. Again, from the year 2010 to the year 2012, demand increased, reaching a new peak. For the years 2014 a small dip was again seen. It can be reasonably expected that higher summer peak load levels will recur within the next several years once temperatures approach the same levels that occurred in the 2012 summer season.

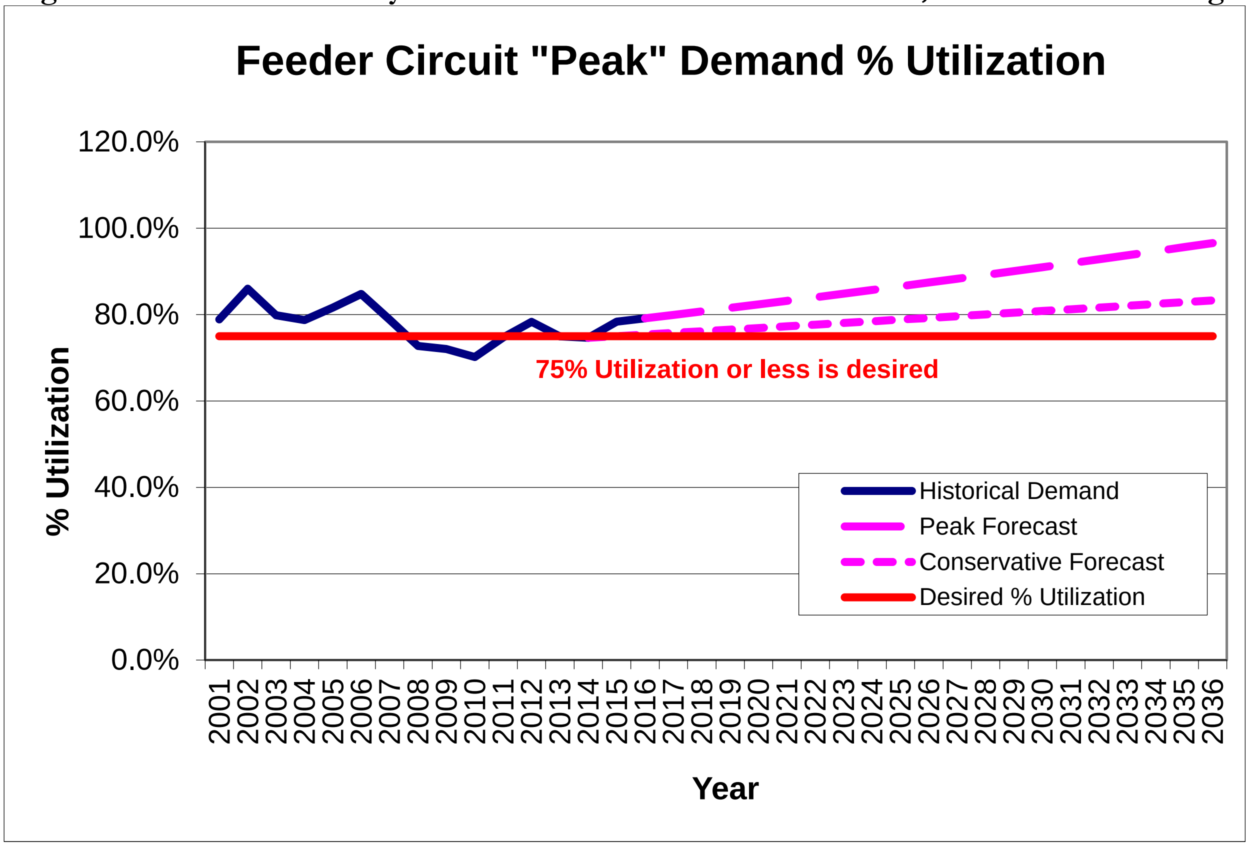
5.1.3: Feeder Circuit Overloads and Utilization Percentages

As discussed in Section 4.1, Distribution Planning aims to maintain utilization rates at or below 75% on distribution feeder circuits to help ensure a robust distribution system capable of providing electrical service under first contingency N-1 conditions. This desired loading level of 75% only applies to the 13.8 kV feeder circuits, the 34.5 kV feeder circuits have a unique configuration and therefore have a different desired loading level. There are only two 34.5 kV feeder circuits in this geographical area and therefore the feeder circuits only have one tie for backup during a contingency situation, while the 13.8 kV feeders generally have 3 ties, as described in Section 4.1. Since the 34.5 kV feeder circuits only have one tie as opposed to three, their desired loading level is 50%. At 50% utilization, each feeder circuit can fully back the other one up during N-1 conditions.

To assess the robustness of the system in the Focused Study Area over time, Planning Engineers analyzed the historical utilization rates and projected utilization rates of the 13.8 kV and 34.5 kV feeder circuits based on forecast demand. Planning Engineers examined the historical loading and utilization of the eleven 13.8 kV feeder circuits and two 34.5 kV feeder circuits that serve Focused Study Area load. Figure 5.5 and Figure 5.6 show the conservative forecast linear growth ("Conservative Forecast") of feeder circuit utilization for the eleven 13.8 kV and two 34.5 kV feeder circuits between 2001 and 2036 as well as the upper-limit peak load forecast ("Peak Forecast") based on historic peak load levels forecasted to 2016.

The feeder circuit load history shown is actual average non-coincident peak loading of the eleven 13.8 kV feeder circuits and the two 34.5 kV feeder circuits measured at the beginning of the feeder circuit in the substation. The sum of the individual feeder circuit peak loads is compared to the sum of the individual feeder circuit capacities to calculate feeder circuit utilization each year.

Figure 5.5: Focused Study Area – Eleven 13.8 kV Feeder Circuits, Utilization Percentage



The above analysis demonstrates a capacity need on the 13.8 kV distribution system within the Focused Study Area. Utilization rates of the 13.8 kV feeder circuits have exceeded the desired 75% utilization level most years since 2001. Even using the more conservative forecast based on the lower summer peaks of 2014, average utilization rates on the 13.8 kV feeder circuits will exceed 80% by approximately 2036 unless system improvements are made. A peak load forecast starting from 2016 based on the recent 2011-2013 peak levels provides an upper forecast limit well above the conservative forecast utilization levels in Figure 5.5.

Figure 5.6: Focused Study Area – Two 34.5 kV Feeder Circuits, Utilization Percentage

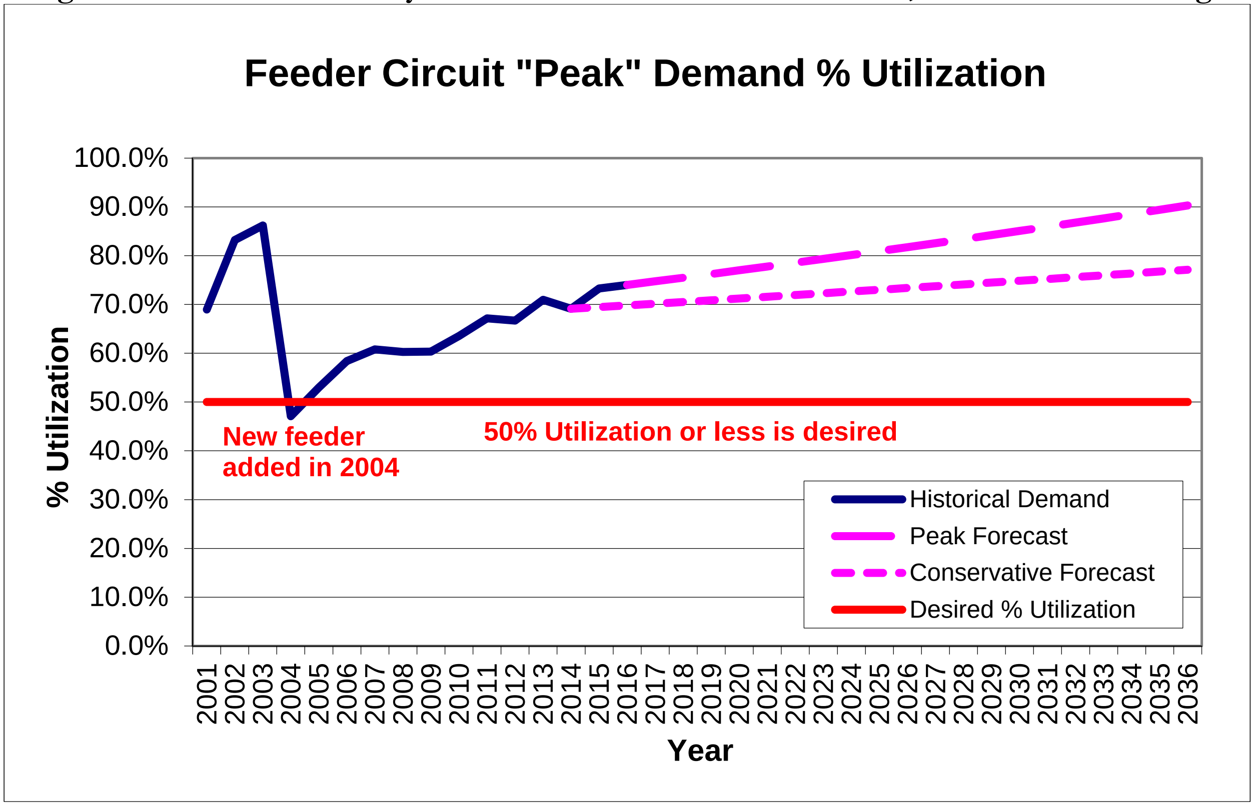


Figure 5.6 shows the same analysis of the 34.5 kV feeder circuits as depicted in Figure 5.5 for the 13.8 kV feeder circuits. This analysis also demonstrates a capacity need on the 34.5 kV distribution system within the Focused Study Area. The change in utilization from 2003 to 2004, is due to the addition of the second 34.5 kV feeder circuit in the Focused Study Area. Even with this capacity addition, peak load levels still continued to exceed the desired 50% loading level. Just as on the 13.8 kV distribution system within the Focused Study Area, these utilization levels are only projected to increase unless system improvements are made.

More than the 13.8 kV feeders in Figure 5.5, Figure 5.6 shows that demand on the 34.5 kV system generally trends upward. Unlike the 13.8 kV feeders, there are no significant dips due to weather or economic downturns, indicating that the 34.5 kV system has experienced significant growth over the last decade. It can be expected that steady growth on the existing load should be expected to occur especially since the 34.5 kV system serves several new load growth areas.

Figure 5.7: Focused Study Area – Two 34.5 kV Feeder Circuits without Hollydale 13.8 kV load

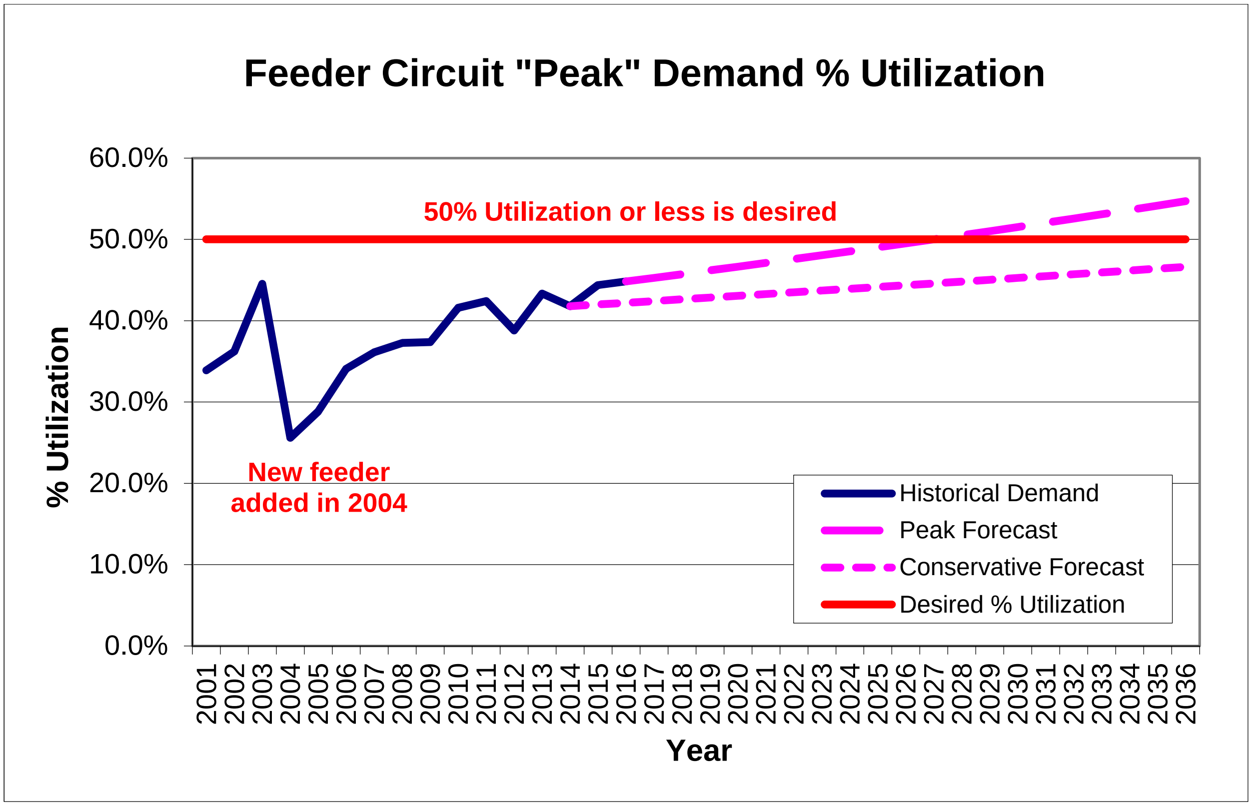


Figure 5.7 shows an analysis of the 34.5 kV feeder circuits as depicted in Figure 5.6 but without the two 13.8 kV feeder circuits, HOL061 and HOL062, sourced from a 34.5 kV feeder at Hollydale substation. This analysis also demonstrates a capacity need on the 34.5 kV distribution system within the Focused Study Area even without the Hollydale load. If there was another source to serve Hollydale substation, the peak load levels are still forecasted to exceed the desired 50% loading level.

Table 5.1 and Table 5.2 provide additional detail on the historical and anticipated utilization percentages and overloads for the eleven 13.8 kV feeder circuits and two 34.5 kV feeder circuits in the Focused Study Area for various years between 2001 and 2036.

Table 5.1: Summary of Feeder Circuit Utilization and Overloads for the Eleven 13.8 kV Feeder Circuits in the Focused Study Area

Historical and Peak Forecast Feeder Circuit Utilization and Overloads									
	2001	**2006**	**2012**	**2014**	**2016**	**2020**	**2025**	**2030**	**2036**
# of Circuits	11	11	11	11	11	11	11	11	11

MW Capacity	124	124	124	124	124	124	124	124	124
Feeder Actual	2001-2014 Average								
% Growth	-0.4%								
% Utilization	81%	87%	80%	81%					
Forecast					2016-2036 Average				
% Growth					1.0%			1.0%	
% Utilization					81%	84%	88%	93%	98%
N-0 Overloads									
# Severe >115%	0	2	0	1	0	1	1	2	4
# of Circuits > 100%	2	4	4	3	2	4	5	5	5
MW > 100%	1.4	5.3	2.1	2.3	1.6	3.1	5.3	8.3	12.1
N-1 Conditions									
# of Circuits > 75%	7	7	5	5	6	6	6	7	8
MW > 75%	15.0	19.1	13.5	14.0	13.6	16.1	19.4	23.2	28.5

Table 5.2: Summary of Feeder Circuit Utilization and Overloads for the Two 34.5 kV Feeder Circuits in the Focused Study Area

Historical and Peak Forecast Feeder Circuit Utilization and Overloads									
	2001	**2006**	**2012**	**2014**	**2016**	**2020**	**2025**	**2030**	**2036**
# of Circuits	1	2	2	2	2	2	2	2	2

MW Capacity	34	68	68	68	68	68	68	68	68
Feeder Actual	2001-2014 Average								
% Growth	7.7%								
% Utilization	69%	58%	67%	69%					
Forecast					2016-2036 Average				
% Growth					1.0%			1.0%	
% Utilization					74%	77%	81%	85%	90%
N-0 Overloads									
# Severe >115%	0	0	0	0	0	0	0	0	0
# of Circuits >100%	0	0	0	0	0	0	1	1	1
MW > 100%	0	0	0	0	0	0	1.3	3.1	5.4
N-1 Conditions									
# of Circuits > 50%	1	1	1	2	2	2	2	2	2
MW > 50%	6.5	5.7	11.4	13.0	16.4	18.4	21.1	23.9	27.5

The information in Table 5.1 and Table 5.2, which was extracted from the detailed feeder circuit forecast data in Appendix B, shows that the Focused Study Area distribution system experienced stable or steady peak growth in the decade leading up to 2014 loads that increasingly exceeded circuit capacities with increasing numbers of circuits overloaded in both system intact N-0 and first contingency N-1 conditions for the 34.5 kV feeders since they serve more of the new load areas and were used to relieve the 13.8 kV feeders. Table 5.3 summarizes the additional feeder circuit capacity (in MW) needed to mitigate the overloads detailed in Table 5.1 and Table 5.2. The assumption was made for purposes of analysis new feeders would be 13.8 kV and if 34.5 kV distribution system was expanded a comparable amount would be added. A single new 13.8 kV feeder circuit will have 13.6 MW of capacity and will serve 10 MW of load at 75% utilization. A single new 34.5 kV feeder circuit will have 34 MW of capacity and will serve 17 MW of load at 50% utilization.

Table 5.3: Summary of Feeder Circuit Capacity Required to Mitigate the Feeder Circuit Overloads

Minimum Number of Feeders Required to Correct N-0 and N-1 Overloads									
	2001	**2006**	**2012**	**2014**	**2016**	**2020**	**2025**	**2030**	**2036**
N-0 Deficiency (MW)	1.4	5.3	2.1	2.3	1.6	3.1	6.6	11.4	17.5
Minimum # of New Feeders Needed	1	1	1	1	1	1	1	1	2
N-1 Deficiency (MW)	21.5	24.8	24.9	27.0	30.0	34.5	40.5	47.1	56.0
Minimum # of New Feeders Needed	3	3	3	3	3	4	4	5	6

Note: Minimum number of feeders assumes 13.6 MW feeder circuits loaded to 75% or less.

This analysis shows that there is currently a total deficit of approximately 30 MW in the Focused Study Area based on the individual feeder 2016 peak load forecast and the feeder capacities under N-1 conditions. 2016 loading levels represent established overloads for connected load that exists on the electrical system, forecasted growth and peak loading that has been previously reached under the most recent hottest weather conditions. Using conservative forecasting methods, which use the cooler summer peaks of 2014 as a starting point; by 2036, the area deficit based on evenly loaded feeders will be 29 MW, essentially returning to the 2016 total deficit level.

Areas like Plymouth that experience strong and steady growth and redevelopment go through several stages of overload operating conditions, starting with isolated feeder circuit overloads and progressing to widespread overloads that exceed substation transformer capacity limits.

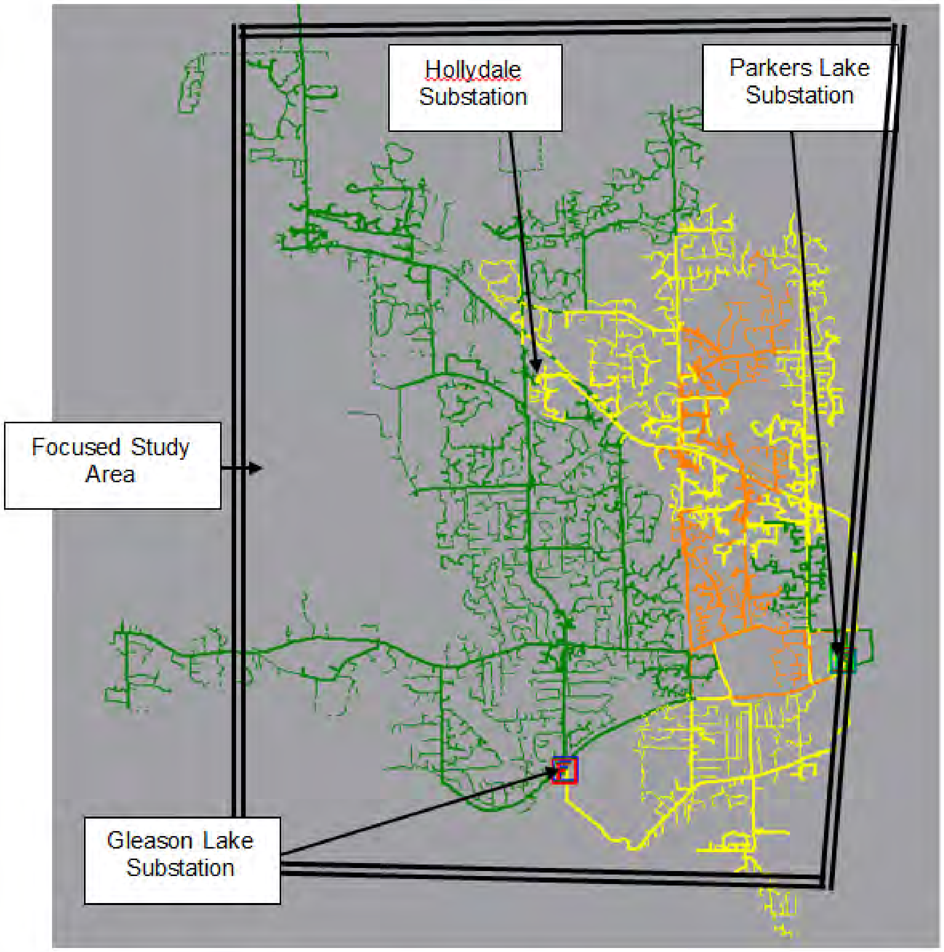
Isolated feeder overloads, which can be characterized by average feeder utilization percentage less than 75% (50% on the 34.5 kV distribution system), typically occur when there is redevelopment that increases load demand within a small part of the distribution system. While the average utilization percentage generally indicates the loading level of the entire Focused Study Area, feeders that are located geographically distant from each other can have either satisfactory capacity to serve customer load or alternately measure severe overloads. This variant is often caused by customer load mobility that can be characterized by new load or area redevelopment and revitalization.

Widespread feeder overloads, which can be characterized by average feeder utilization percentage of more than 75% (50% on the 34.5 kV distribution system), typically occur in distribution areas due to a combination of customer addition of spot loads and focused redevelopment by existing customers, developers or City initiatives. Distribution systems that start out with adequate N-1 and N-0 capacity, can quickly progress beyond isolated overloads when a large part of the distribution system is redeveloped or focused redevelopment is targeted in an area or along a corridor.

To better illustrate the number, concentration and location of the historical and forecasted overloads, Planning Engineers developed distribution system maps depicting the overloaded feeder circuits in N-0 system intact and N-1 first contingency operating conditions for 2016 and future forecast year 2036 based on the peak forecast. These distribution system maps are depicted in Figure 5.8 and Figure 5.9 for N-0 and Figure 5.10 and Figure 5.11 for N-1. The color codes in the distribution system maps represent rows in Table 5.1 and Table 5.2 for the labeled years as follows:

- # Severe > 115%, N-0 Overloads: The quantity of feeder circuits that are severely overloaded under system intact conditions are identified as shown in red.
- # of Circuits >100%, N-0 Overloads: The quantity of feeder circuits that are overloaded under system intact conditions are identified as shown in orange and red depending on the severity of the overload with red feeder circuits having the most severe overloads.
- # Circuits > 75%, N-0 Conditions: The quantity of feeder circuits that are loaded above 75% capacity indicating first contingency overload conditions are identified as shown in yellow, orange, and red. Yellow circuits are feeder circuits with the lowest first contingency overloads.
- # Circuits < 75%, N-0 Conditions: The quantity of feeder circuits that are loaded below 75% capacity indicating no first contingency overload conditions are identified as shown in green.
- # Circuits > 75%, N-1 Conditions: The quantity of feeder circuits that are loaded above 75% capacity indicating first contingency overload conditions are identified as shown in red.
- # Circuits < 75%, N-1 Conditions: The quantity of feeder circuits that are loaded below 75% capacity indicating no first contingency overload conditions are identified as shown in green.

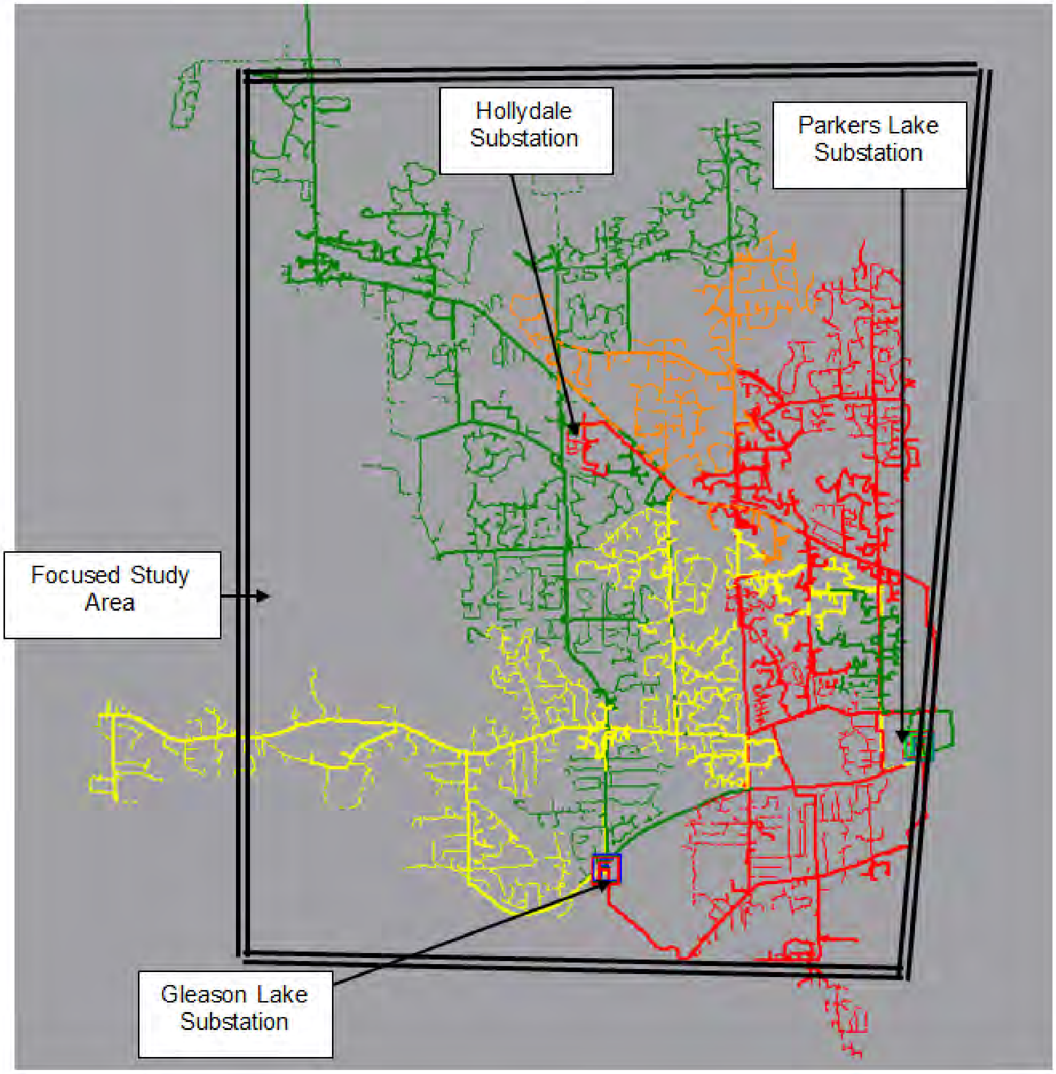
Figure 5.8: Focused Study Area 2016 N-0 Feeder Circuit Loading – System Intact



Feeder Circuits Colored by N-0 Circuit Loading:		
5 Circuits	<75% or<50%	
6 Circuits	50or75%-100%	
2 Circuits	100%-115%	
0 Circuits	>115%	

Figure 5.8 shows that of the thirteen feeder circuits in the Focused Study Area, in the forecasted feeder peak year of 2016, under system intact N-0 conditions, 5 feeders were utilized at less than 50% or 75%, 6 feeders were utilized between 50% or 75%-100%, 2 feeders were utilized between 100%-115%, and 0 circuits were utilized at greater than 115%. Note that many of the most severe overloads occur along previously identified areas of more concentrated load and faster load growth.

Figure 5.9: Focused Study Area 2036 N-0 Feeder Circuit Loading – System Intact

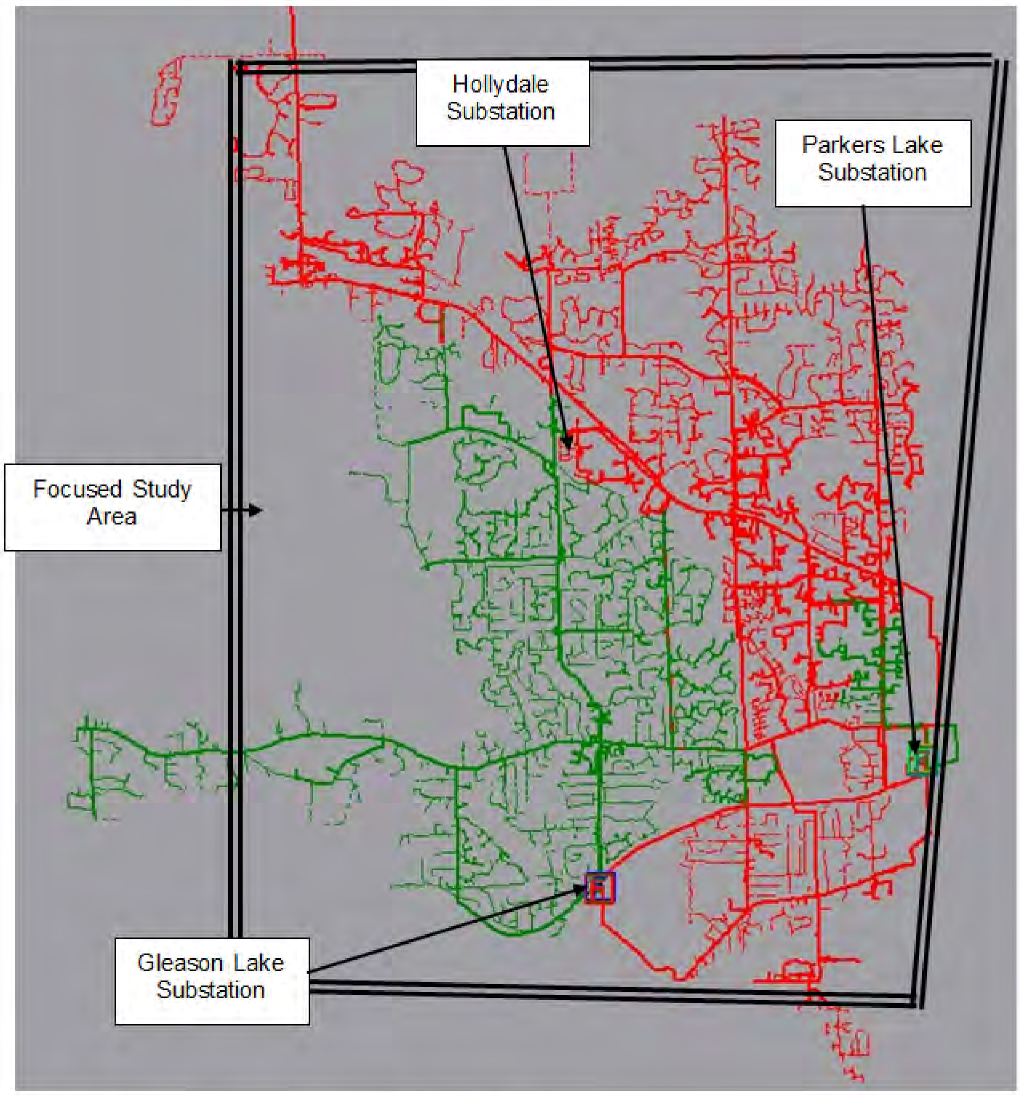


Feeder Circuits Colored by N-0 Circuit Loading:		
3 Circuits	<75%or<50%	
4 Circuits	50or75%-100%	
2 Circuit	100%-115%	
4 Circuits	>115%	

Figure 5.9 shows that of the thirteen feeder circuits in the Focused Study Area, based on 2036 forecasted load under system intact N-0 conditions, 6 feeders will be overloaded. The 6 overloaded feeders consist of 2 feeders utilized between 100%-115%, and 4 circuits utilized at greater than 115%.

Overloads are even more widespread across the feeder circuits in the Focused Study Area under N-1 loading conditions. Figure 5.10 and Figure 5.11 color codes represent first contingency overloads existing for 2016 and forecasted for 2036. A comparison of Figure 5.10 and Figure 5.11 shows that forecasted load levels result in increasing N-1 overload conditions. When a typical single feeder circuit fails during peak loading conditions, the main-line of the failed circuit is switched into three sections (the whole feeder is switched on a 34.5 kV feeder) and each one of the three sections is transferred to a separate adjacent feeder circuit. Adjacent feeders must not be already encumbered by the load of a prior feeder circuit failure or scheduled switching event. The N-1 data provided in this section of the Study for the feeder circuits serving the Focused Study Area are based on the loss of a single mainline feeder circuit. The circuits that will experience an overload under first contingency conditions are shown in red. Feeder circuits shown in red demonstrate the cumulative effect on the feeder circuits of switching the load from any single feeder circuit failure during peak loading conditions.

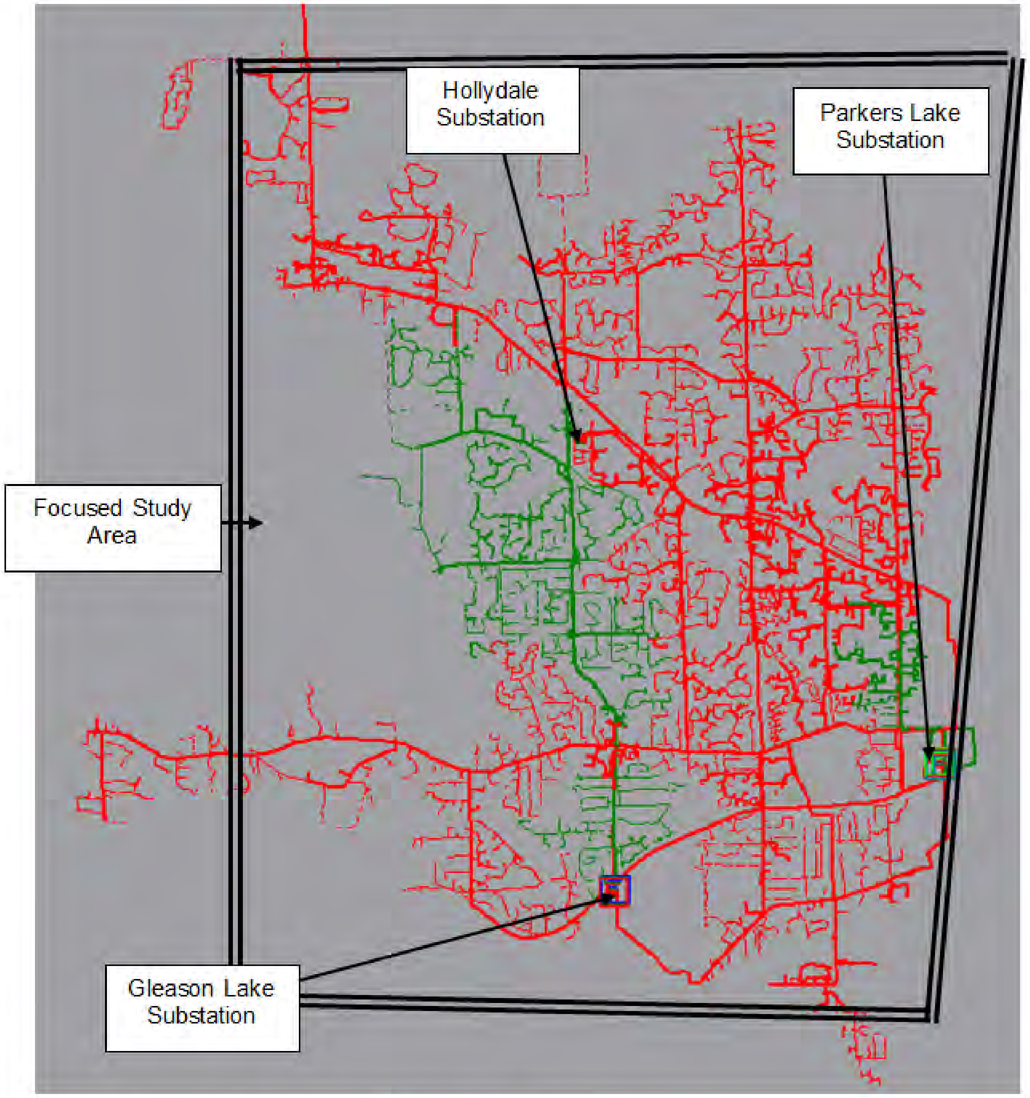
Figure 5.10: Focused Study Area 2016 N-1 Feeder Circuit Loading – Single Contingency



Feeder Circuits Colored by N-1 Circuit Loading:		
5 Circuits	No N-1 Risk	(green)
8 Circuits	N-1 Risk	(red)

Above Figure 5.10 shows that of the 13 feeder circuits in the Focused Study Area, in 2016 under single contingency N-1 conditions, 8 feeders would be at risk for experiencing overload conditions.

Figure 5.11: Focused Study Area 2036 N-1 Feeder Circuit Loading – Single Contingency



Feeder Circuits Colored by N-1 Circuit Loading:		
3 Circuits	No N-1 Risk	
10 Circuits	N-1 Risk	

Above Figure 5.11 shows that of the thirteen feeder circuits in the Focused Study Area, under 2036 forecasted load under single contingency N-1 conditions, 10 feeders would be at risk for experiencing overload conditions.

The data demonstrates that the Focused Study Area has been experiencing higher than optimal utilization rates on its feeders for over a decade. Without additional capacity additions in the area, these high utilization rates will increase the number and duration of overloads on feeders. Based on this analysis, Distribution Planning concluded that to ensure continued reliable service in the area, additional improvements are required.

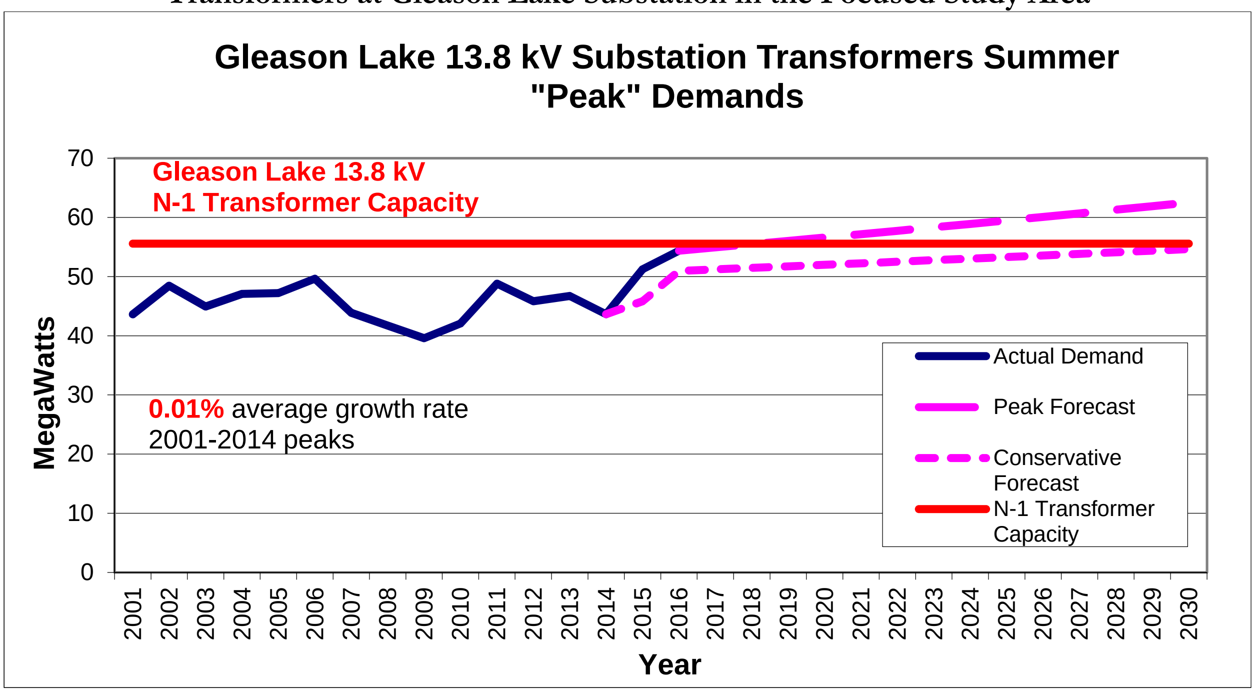
5.2: Gleason Lake Substation Transformers

After examining feeder circuit peak demands, Distribution Planning Engineers looked at the loading levels for the two 13.8 kV transformers and the one 34.5 kV transformer housed at the Gleason Lake Substation. Gleason Lake Substation is the only substation served by transmission that is in the Focused Study Area. Hollydale substation also lies within the Focused Study Area however, as discussed earlier, its ability to provide additional capacity is dependent on the available 34.5 kV capacity at Gleason Lake substation

5.2.1: Gleason Lake Substation Transformer Historical Load and Load Forecasts

The historical and forecasted loads for the two 13.8 kV and one 34.5 kV Gleason Lake Substation transformers serving the Focused Study Area from 2001 through 2036 are included in Appendix A and B. Figure 5.12 shows the conservative load growth ("Conservative Forecast") on the two 13.8 kV substation transformers at the Gleason Lake Substation from 2001 through 2036 as well as the upper limit forecast load based on 2016 forecast peak load levels ("Peak Forecast").

Figure 5.12: Historical and Forecasted Load Growth on Two 13.8 kV Substation Transformers at Gleason Lake Substation in the Focused Study Area



Gleason Lake Substation transformer loads fluctuate in a narrow bandwidth between historic peak load years in 2002, 2006 and 2011 and lower peak load levels during other years. The significant load increase in 2015 and 2016 is from a known large development in Wayzata. Actual peak load levels will likely fall between the conservative forecast demand and the historic peak forecast load levels illustrated in the above figure.

Above Figure 5.12 indicates that historically the 13.8 kV load levels at Gleason Lake substation have approached the N-1 substation limit, but have not exceeded the limit. Using the peak forecast demand load projections, there is roughly only 1 MW of additional load serving capacity on the 13.8 kV Gleason Lake distribution system in 2016. Using the conservative forecast demand load projections, there is roughly 5 MW of additional load serving capacity on the 13.8 kV Gleason Lake distribution system in 2016. Earlier analysis in Table 5.1 demonstrates that even with this 5 MW of additional load serving capacity, the capacity deficiencies on the 13.8 kV distribution system within the Focused Study Area cannot be fully solved.

Figure 5.13 shows the same analysis done on the 34.5 kV substation transformer at Gleason Lake substation.

Figure 5.13: Historical and Forecasted Load Growth on One 34.5 kV Substation Transformers at Gleason Lake Substation in the Focused Study Area

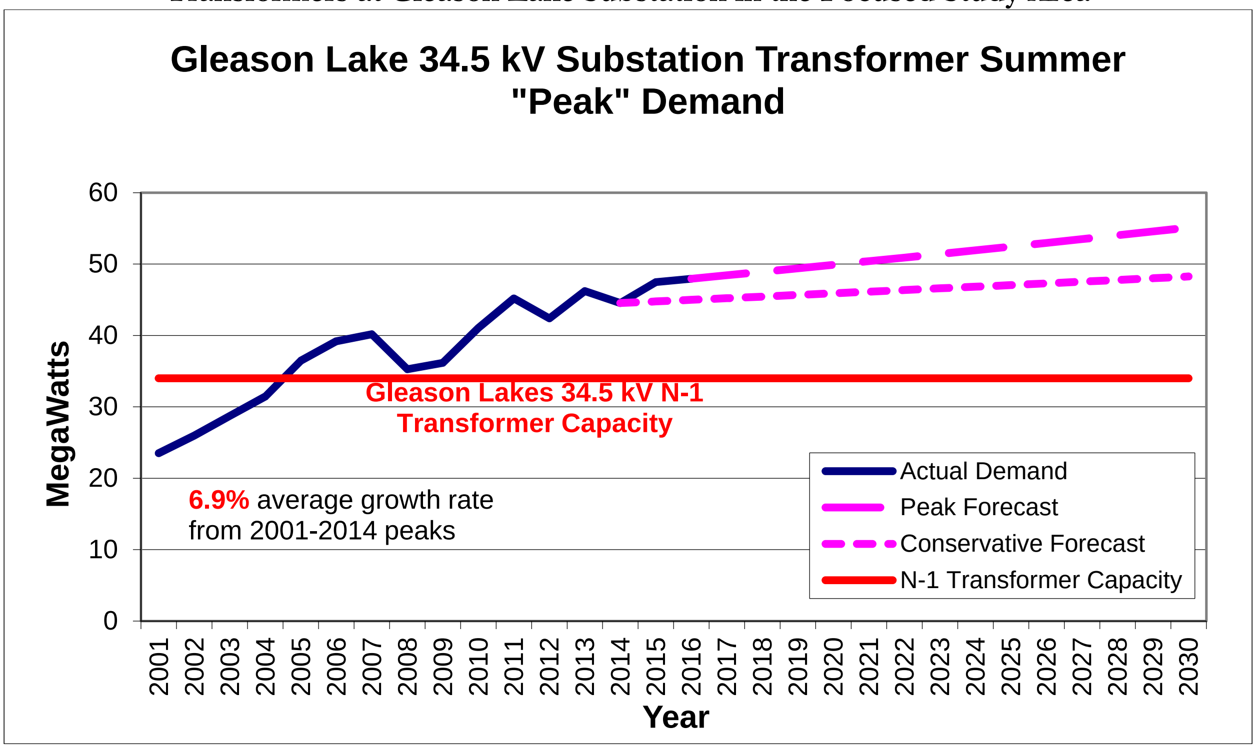


Figure 5.13 shows that the 34.5 kV substation transformer at Gleason Lake substation has experienced loading a larger load growth compared to the 13.8 kV substation transformers. The load on the 34.5 kV substation transformer has exceeded the N-1 limit. Using the peak forecast demand load projections, the load serving capacity is exceeded by roughly 14 MW on the 34.5 kV Gleason Lake transformer in 2016. Using the conservative forecast demand load projections the load serving capacity is exceeded by roughly 11 MW on the 34.5 kV Gleason Lake transformer in 2016. Using the peak or conservative forecast demand projections, there is no additional load serving capacity on the 34.5 kV Gleason Lake distribution system. As previously stated, there is not enough capacity to solve the deficiencies on the distribution system in the Focused Study Area. Combining the shortage of load serving capacity on the 34.5 kV substation transformer with the available capacity on the 13.8 kV substation transformers, the deficiencies cannot be fully solved.

With Gleason Lake substation presently at its maximum design capacity, coupled with the analysis above, Distribution Planning concluded that Gleason Lake substation transformers do not have the required capacity to solve the capacity issues within the Focused Study Area.

6.0: Transmission Reliability Analysis

6.1: NERC Criteria

For this study, North American Electric Reliability Corporation (NERC) TPL-001-4 Standard Category P0-P7 contingencies were analyzed. Table 6.1 below shows the table of NERC Definitions for TPL-001-4 Standard Category P0-P7 contingencies, which is available at www.nerc.com.

Table 6.1: NERC TPL-001-4 Category P0-P7 Definitions

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			
P4 Multiple Contingency *(Fault plus*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on	SLG	EHV	No[9]	No

stuck breaker[10])		one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section		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

6.2: Models

The base steady state model used in this study was a MRO 2014 series 2015 Summer Peak model. The only topology changes made were to correct the transformer tap ratio at Gleason Lake and lock the Dickinson cap. The Dickinson capacitor was locked off due to the recommendation of Great River Energy, the company who owns and operates Dickinson substation. To create the primary case used in this study, the loads in the base model were changed to mimic the 2013 peak loads for the Transmission Area of Concern and then scaled to meet the latest forecast for a 2016 case. All future cases were scaled based on this 2016 case.

No dynamic models were used and no dynamic analysis was completed as part of this study because engineering judgment determined dynamic simulations were not required.

No short circuit models were used and no short circuit analysis was completed as part of this study because engineering judgment determined a short circuit study was not required at this time.

6.3: Load Forecast for Transmission Area of Concern

Table 6.2 includes the forecasted loads in MW from the 2015 Distribution Forecast. These forecasted values were used in the transmission planning study. Note that Table 6.2 has a 1% load growth rate. Table 6.3 has a 2% growth rate and was used as a sensitivity in the transmission planning analysis.

Table 6.2: Forecasted loads in MW in the Transmission Area of Concern using a 1% growth rate

1% Growth	Gleason Lake	Medina	Mound	Orono	Greenfield	Total
2016	97.8	6.3	38.8	17.8	4.6	165.3
2017	98.8	6.4	39.2	18.0	4.6	166.9
2020	101.8	6.6	40.3	18.5	4.8	172.0
2025	107.0	6.9	42.4	19.5	5.0	180.8
2030	112.5	7.2	44.6	20.4	5.3	190.0
2035	118.2	7.6	46.8	21.5	5.6	199.7
2040	124.2	8.0	49.2	22.6	5.8	209.9

Table 6.3: Forecasted loads in MW in the Transmission Area of Concern using a 2% growth rate

2% Growth	Gleason Lake	Medina	Mound	Orono	Greenfield	Total
2016	97.8	6.3	38.8	17.8	4.6	165.3
2017	98.8	6.4	39.2	18.0	4.6	166.9
2020	104.9	6.8	41.5	19.1	4.9	177.2
2025	115.8	7.5	45.9	21.1	5.4	195.6
2030	127.8	8.2	50.6	23.2	6.0	216.0
2035	141.1	9.1	55.9	25.7	6.6	238.4
2040	155.8	10.0	61.7	28.3	7.3	263.3

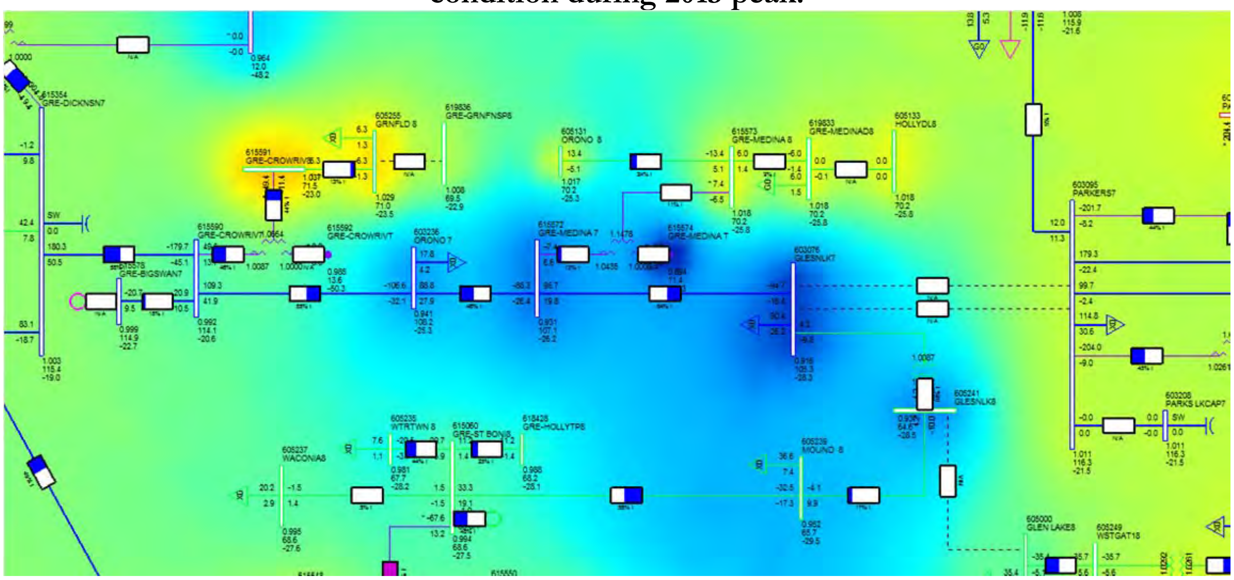
6.4: Powerflow Analysis

6.4.1: Worst Contingencies

Three contingencies were identified during the ACCC analysis as causing thermal or voltage violations. The first contingency, showing violations at 153 MW, is a Category P7 which results in the loss of the Gleason Lake – Parkers Lake 115 kV double circuit line causing low voltage at Gleason Lake substation (Contingency #1). The second, showing violations at 153 MW, is a Category P6 which results in the loss of both Gleason Lake – Parkers Lake 115 kV lines causing low voltage at Gleason Lake substation (Contingency #2). The third, showing violations around 195 MW, is a Category P6 which includes the loss of the Dickinson 345/115 kV transformer coupled with the loss of one Gleason Lake – Parkers Lake 115 kV, which causes the other Gleason Lake – Parkers Lake 115 kV line to overload (Contingency #3). The difference between Contingency #1, Contingency #2, and Contingency #3 is that Contingency #1 is a single initiating event and no system adjustments are allowed. Contingency #2 and Contingency #3 include the loss of two system elements, with system adjustment in between each event.

Figure 6.1 shows the Transmission Area of Concern in a power flow simulation tool under the critical condition of Contingency #1 during a simulated 2013 peak (156 MW). Under this critical condition, the load at Gleason Lake is below acceptable voltage levels. Note that blue means low voltage and red means high voltage, the color gets darker as the voltage gets more severe.

Figure 6.1: Power flow results for the Transmission Area of Concern under the critical condition during 2013 peak.

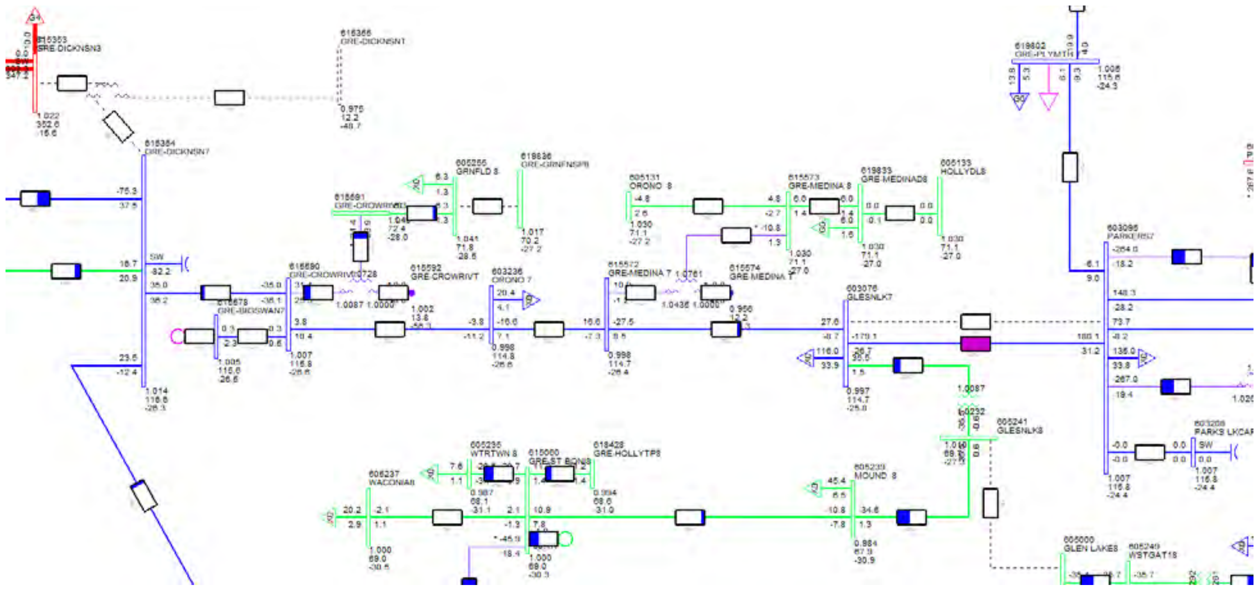


Due to the low voltage at Gleason Lake under the critical condition, Under Voltage Load Shedding (UVLS) has been installed at Gleason Lake until a permanent project is constructed. The UVLS will automatically shed customer load if triggered. Currently there are two feeders on the first step of this UVLS, which totals as much as 41 MW on peak. As load grows in the Gleason Lake area, the amount of load on UVLS would likely increase.

Since Contingency #1 and Contingency #2 are very similar conditions, but Contingency #1 is more limiting, the initial analysis focused on Contingency #1 as the critical condition. Contingency #2 becomes the critical condition if Contingency #1 is eliminated.

Contingency #3 is a P6 contingency resulting in loss of Dickinson 345/115 kV transformer along with one Gleason Lake – Parkers Lake 115 kV line. Under this P6 condition, the loading on the remaining Gleason Lake – Parkers Lake 115 kV line is above its thermal loading emergency rating. Figure 6.2 shows the Transmission Area of Concern in a power flow simulation for Contingency #3. This overload occurs at approximately 195 MW, which equates to 2025 if 2% load growth is assumed and 2032 if 1% load growth is assumed. Note that the Dickinson capacitor bank is operated on because the contingency includes the loss of the 345 kV transformer, which is the reason why the capacitor bank was installed.

Figure 6.2: Power flow results for the Transmission Area of Concern under the P6 condition



6.4.2: Possible Solution Components

As part of this study, two high level ways to solve the identified distribution and transmission deficiencies were identified; move load away from the existing transmission line onto a different transmission line or re-energize an existing transmission line and provide distribution with a new source into the area. Additionally, the age and condition of existing transmission lines in the area were analyzed for potential advancements. Listed below are the components that were used to form the final alternatives listed in Chapter 7.

(a) Separate Gleason Lake – Parkers Lake 115 kV Double Circuit Line

During the analysis into the condition of the existing transmission lines, the Gleason Lake – Parkers Lake double circuit 115 kV line was identified as a line in need of replacement. Advancing the rebuild of this line to two single, paralleled circuit lines will eliminate Contingency #1 as the lines would no longer be on the same structure. Additionally, rebuilding the Gleason Lake – Parkers Lake 115 kV lines to single circuits will alleviate the thermal violations in Contingency #3, as the lines would be rebuilt using larger conductor.

(b) Gleason Lake Capacitor Bank

In general, adding a capacitor bank on the system is the easiest way to alleviate low voltage problems, assuming there are not too many capacitor banks already installed. For the Transmission Area of Concern, the ideal location for a capacitor bank is at Gleason Lake. Gleason Lake is the most effective location on the system to boost the voltage due to the large load located there and the fact that it is at the end of a long radial under the critical contingency. The issue with locating a capacitor bank at Gleason Lake is that under the critical contingency, the voltage rise would likely exceed our requirements. In order to mitigate this voltage rise concern, the installation of a capacitor bank at Gleason Lake would need to be combined with the Gleason Lake – Parkers Lake line rebuild component. Combining these two components allows for the capacitor bank to be switched without any voltage concerns, since the capacitor bank would be switched into service during the system adjustment period allowed between P6 contingencies. The Gleason Lake capacitor bank was sized as an ultimate of 60 MVAR, but the installation of only 40 MVAR. Installing 40 MVAR gives the system operators the appropriate capacitor bank size for now and the flexibility to add more in the future if necessary.

(c) Distribution Load Transfers

To make all alternatives last for the long-term, additional load must be transferred away from the Transmission Area of Concern to a nearby transmission line. Table 6.4 shows approximately when load would need to be transferred by distribution, based on the most logically transfers available. These load transfers assume that the Gleason Lake – Parkers Lake line rebuild and Gleason Lake 40 MVAR capacitor bank are completed. After these two are completed, the Transmission Area of Concern would be able to serve approximately 210 MW. The load transfers would occur in blocks and the target years are based on when the area would exceed the load serving threshold and therefore need a block of load transferred. Note that all transfers are moving load away from Gleason Lake since there is no other substation in the Transmission Area of Concern where transferring load is feasible. The two possible locations for the load transfers are Parkers Lake and a new substation called Pomerleau Lake on the Plymouth to Parkers Lake 115 kV line.

Table 6.4: Approximate timing for load transfers away from Gleason Lake under various load growth scenarios

Distribution Load Transfers	Load Growth		
	1%	1.5%	2%
18 MW	2040	2032	2028
10 MW	2048	2037	2032
19 MW	2052	2040	2034
30 MW	---	2045	2038

Figure 6.3 and Figure 6.4 provide an example of how the distribution transfers could work together with the 40 MVAR Gleason Lake capacitor bank and rebuilding the Gleason Lake – Parkers Lake 115 kV double circuit to two separate circuits. Figure 6.3 shows the Transmission Area of Concern at 210 MW with a low voltage problem. Figure 6.3 assumes the installation of the capacitor bank at Gleason Lake and the rebuild of the Gleason Lake to Parkers Lake 115 kV lines to separate circuits.

Figure 6.3: Contingency #2: Transmission Area of Concern at 210 MW

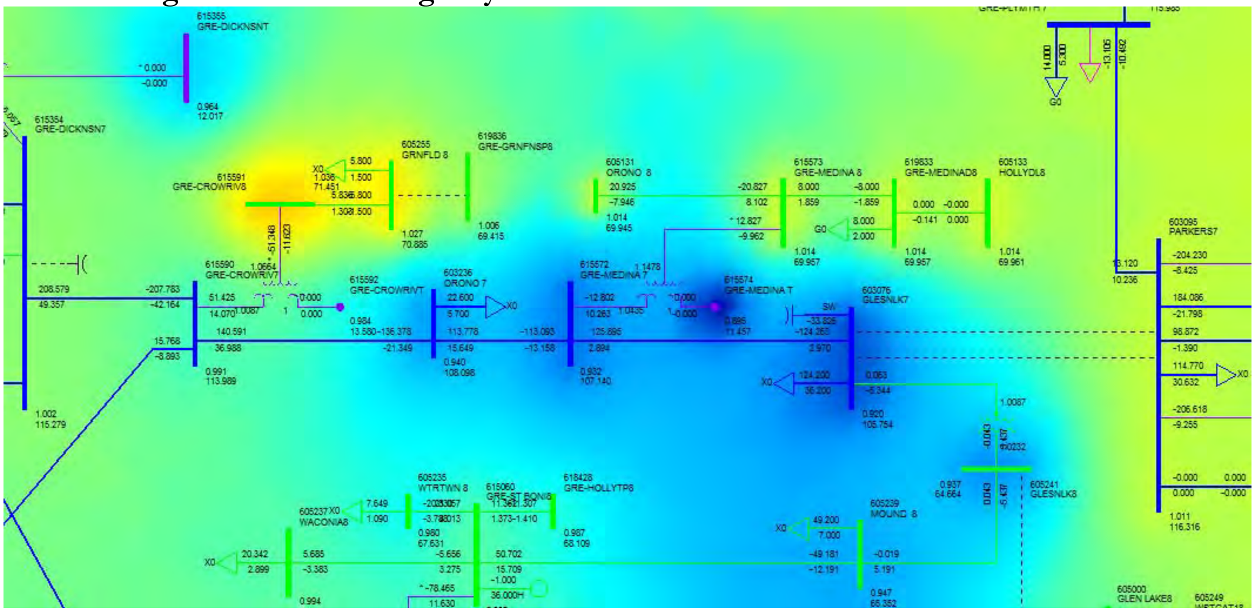
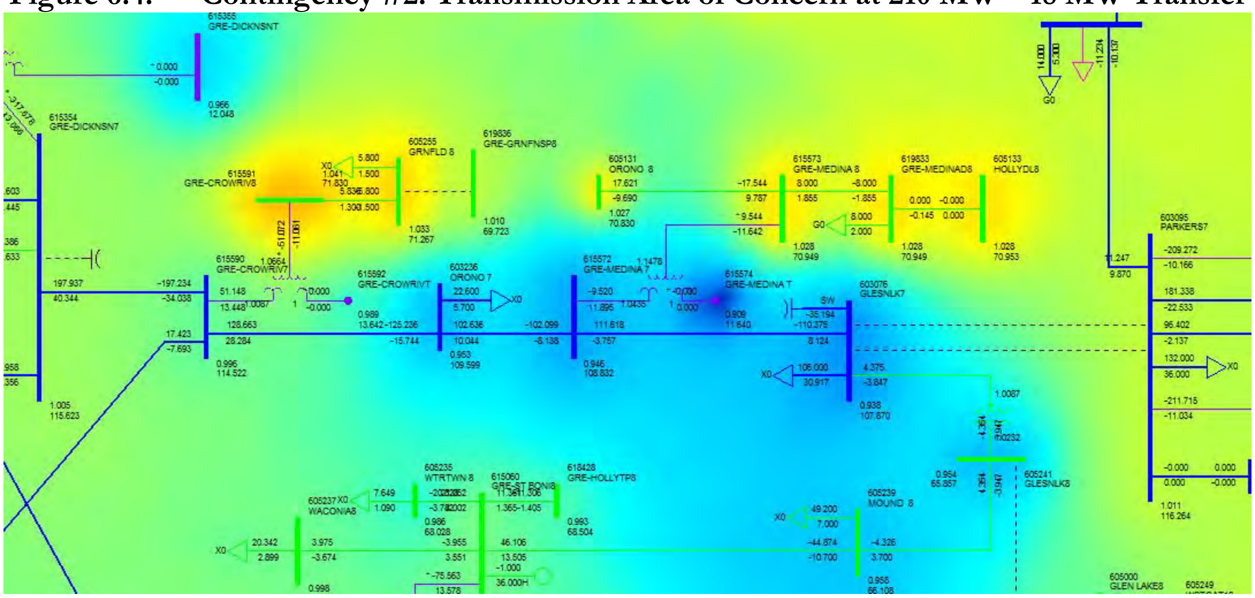


Figure 6.4 shows the same situation after the first phase of distribution transfers (totaling 18 MW) has occurred.

Figure 6.4: Contingency #2: Transmission Area of Concern at 210 MW – 18 MW Transfer



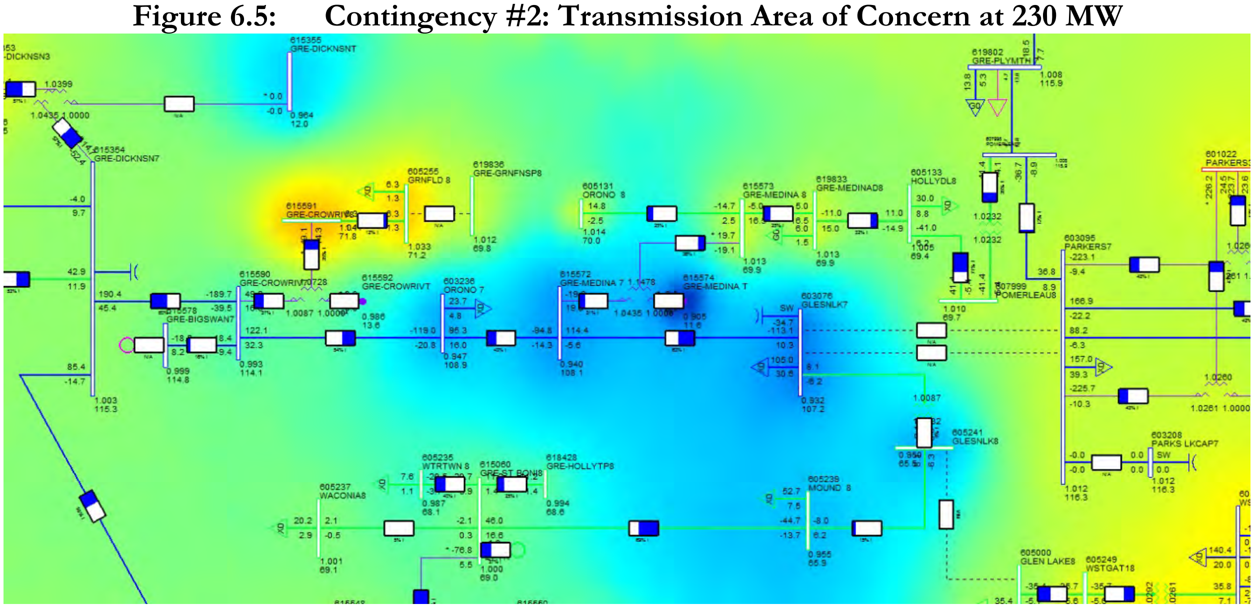
After the load transfer, the system does not have any voltage concerns. However, transferring load for transmission issues is unusual and requires new infrastructure to be built somewhere else to handle the transferred load.

(d) Re-energization of the 69 kV Line East of Hollydale

Similar to the distribution load transfers, this component would be used to move load off of the Transmission Area of Concern transmission lines. However, re-energizing the existing 69 kV line east of Hollydale would achieve this by adding a new source into the area and energizing the Hollydale substation from 69 kV instead of the current 34.5 kV. This component would also work in conjunction with the installation of a Gleason Lake 40 MVAR capacitor bank and rebuilding the Gleason Lake – Parkers Lake 115 kV double circuit line to two separate circuits. In order for the existing Hollydale 69 kV line to be re-energized, a small portion of new 69 kV line and a new substation called Pomerleau Lake would need to be constructed. The new Pomerleau Lake substation would intersect the existing Plymouth – Parkers Lake 115 kV line and bring it in and out of the substation. The re-energized 69 kV line would run from Medina to Hollydale and then Hollydale to Pomerleau Lake. The Hollydale substation would become primarily served from the 69 kV line and effectively transfer the existing Hollydale load from Gleason Lake. This configuration provides flexibility for load serving in the Transmission Area of Concern by using the transmission system to serve the distribution system.

Additionally, if this configuration were to run out of load serving capabilities, the distribution load transfers would still be available to accommodate additional load growth. The 69 kV line was assumed to be operated normally closed, however a reverse power relay would be installed at Pomerleau Lake to disconnect the transformer if two sections of the Elm Creek to Parkers Lake 115 kV line were out of service and the Hollydale 69 kV line was the only source to the remaining 115 kV loads. Without the reverse power relay, the 69 kV lines serving Hollydale would need to be operated normally open or would overload under this condition. Figure 6.5 shows the Transmission Area of Concern at 230 MW, beyond the normal 210 MW threshold, with a no low voltage issues.

Figure 6.5: Contingency #2: Transmission Area of Concern at 230 MW

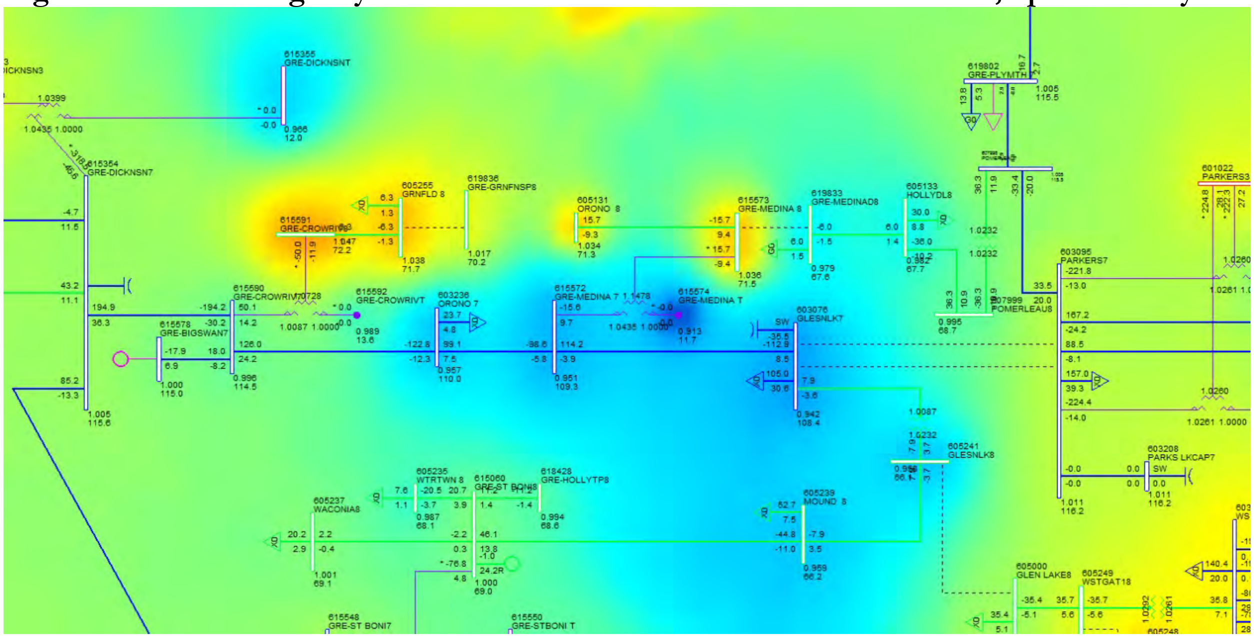


Note that the load that used to be only at Gleason Lake is now split between Hollydale and Gleason Lake. The biggest difference between this configuration and one with load transfers is that without any transfers, the system can easily handle load growth up to the normal 210 MW threshold.

Another potential way to operate this system is to open the 69 kV line at Hollydale looking towards Medina as a system adjustment once either Gleason Lake – Parkers Lake 115 kV line is out of service. This puts the Hollydale load on the Elm Creek – Parkers Lake 115 kV line and allows the Transmission Area of Concern to handle even more load under the critical contingency. Figure 6.6

shows the Transmission Area of Concern at 230 MW, with an open between Medina and Hollydale. The resulting configuration proves even more capable then having the 69 kV line closed through.

Figure 6.6: Contingency #2: Transmission Area of Concern at 230 MW, open at Hollydale



7.0: Overview of Alternatives Analyzed (timing and facilities).

All alternatives in this report solve the transmission and distribution needs. The three alternatives below were created using the components in Chapter 5 and Chapter 6. The names of each alternative and the components of each alternative are shown in Table 7.1.

Table 7.1: Overview of components of each alternative

Project	Distribution Voltage	Gleason Lake Cap	Gleason Lake - Parkers Lake Rebuild to Single Circuits	New Pomerleau Substation	Hollydale Expansion and Re-Energization of Hollydale – Pomerleau 69 kV	Parkers Lake Expansion on existing property	Parkers Lake Expansion on new property
Alternative A	34.5 kV	X	X	X		X	
Alternative B	34.5 kV	X	X			X	X
Alternative C	13.8 kV	X	X	X	X		

Common to Alternatives A, B, and C are the separation of the Parkers Lake – Gleason Lake 115 kV double circuit line into two separate circuits and installation of a transmission capacitor bank at Gleason Lake. Alternative C is the only alternative that re-energizes the existing Hollydale 69 kV line west of Hollydale and adds a small new extension of that line into a new Pomerleau Lake substation. In all alternatives, there is an initial transfer of load at Hollydale away from Gleason Lake. However as load grows, all alternatives except Alternative C require future transfers of distribution load away from the Gleason Lake substation to provide capacity for the transmission system.

The distribution capacity additions and transfer of load required by transmission is accomplished in different ways in the various plans. Common to all projects is the reinforcement of 13.8 kV feeders from Parkers Lake substation. In Alternative A, Pomerleau Lake is installed and 34.5 kV feeders are used to satisfy capacity needs and most load transfers. In Alternative B, Parkers Lake is expanded and 34.5 kV feeders are used in a similar fashion as Alternative A. Alternative C expands Hollydale substation and uses 13.8 kV feeders to satisfy capacity needs, with no load transfers required.

7.1: System Improvements to Address Distribution Needs.

The proposed distribution system improvements include new substation transformers and feeders in the Focused Study Area. This can be accomplished by three main methods, a substation located within the area such as Alternative C, an existing substation on the perimeter of the area such as Alternative B, or a new substation on the perimeter of the area such as Alternative A. To meet the existing system needs, either a voltage of 13.8 kV or 34. kV can be used to serve load. In each alternative, a combination of voltages were used to best utilize the existing system and proposed additions.

All alternatives were designed to meet both the required transmission needs as well as the identified distribution needs. In all alternatives, the transmission need is met by transferring load away from the Gleason Lake substation 34.5 kV transformer. However, in Alternatives A and B, the load is transferred to other distribution 34.5 kV facilities. In Alternative C, the load is transferred directly to the 69 kV transmission source at the Hollydale substation. Therefore, Alternatives A and B require additional capacity that is reserved for the Hollydale substation load and is not available to meet distribution system needs or supply load growth.

The distribution components of each alternative include new feeders and substation transformers as detailed in Chapter 8.0: of this report. These feeders will follow public right-of-way with standard construction of overhead lines unless required to be placed underground. Cost assumptions for this report assumed underground feeder construction as that will be the most conservative method for comparison of costs. The transformers installed are of standard capacity size and will be installed in either an expanded existing substation or a new substation.

While Distribution long range plans typically study the load growth over a 20 year period, we evaluated a 40 year forecast. Projecting the load out to 2056 on the eleven 13.8 kV feeders in the Focused Study Area, the load grows to 146 MW, the area contingency overload rises to 53 MW, and has a utilization of 118% on the existing system. If we install the proposed facilities in the plans we will have increased the area capacity so that in the year 2056 the utilization is reduced to 82% which equates to about a 12 MW area contingency overload. This capacity need would be met by adding additional substation transformer capacity and new feeders into the area. While all plans would provide the ability to add capacity to meet this need, Alternative C would give the most flexibility by providing expansion capabilities at Hollydale, Pomerleau Lake, and Parkers Lake substations to address additional load growth.

7.2: System Improvements to Address Transmission.

To meet the combined transmission and distribution need in the Transmission Area of Concern, Transmission Planning and Distribution Capacity Planning came up with three alternatives. All alternatives meet the needs in the area for 40 years under 1% growth. All alternatives require the installation of a capacitor bank at Gleason Lake and the rebuild of the existing Gleason Lake – Parkers Lake 115 kV double circuit into two separate circuits. Alternative A and Alternative B will each be coupled with moving load away from Gleason Lake to provide long-term distribution and transmission load serving capabilities. Moving load from Gleason Lake is achieved using 34.5 kV lines. These alternatives provide adequate system flexibility but require additional large investments if the area grows at 2% or higher load growth.

Alternative C is coupled with the creation of a new Pomerleau substation and re-energizing the existing Hollydale – Pomerleau 69 kV line, enabling the Hollydale substation to be served from this 69 kV line. By serving Hollydale from the 69 kV line, the Hollydale load is removed from Gleason Lake. This alternative provides the most system flexibility, least investment, and longest load serving capabilities.

Table 7.2 shows the total investment cost and project components of all three alternatives, assuming 1% load growth.

Table 7.2: Total investment cost and project components of the three alternatives under 1% growth scenario

1% Growth in Transmission Area of Concern									
	Distribution Voltage	Gleason Lake Cap	Gleason Lake - Parkers Lake Rebuild to Single Circuits	New Pomerleau Substation	Hollydale Expansion	Parkers Lake Expansion on existing property	Parkers Lake Expansion on new property	Gleason Lake Expansion on new property	Total
Alternative A	34.5 kV	X	X	X		X			$65.8M
Alternative B	34.5 kV	X	X			X	X		$68.8M
Alternative C	13.8 kV	X	X	X	X				$47.6M

This analysis also looked at the possibility of higher than expected load growth for the Transmission Area of Concern. Table 7.3 shows the total investment cost and project components of all three alternatives, assuming 2% load growth.

Table 7.3: Total investment cost and project components of the three alternatives under 2% growth scenario

2% Growth in Transmission Area of Concern									
	Distribution Voltage	Gleason Lake Cap	Gleason Lake - Parkers Lake Rebuild to Single Circuits	New Pomerleau Substation	Hollydale Expansion	Parkers Lake Expansion on existing property	Parkers Lake Expansion on new property	Gleason Lake Expansion on new property	Total
Alternative A	34.5 kV	X	X	X		X		X	$103.6M

Alternative B	34.5 kV	X	X			X	X	X	$106.6M
Alternative C	13.8 kV	X	X	X	X	X			$61.4M

If 2% growth does occur over the next 40 years, the investment costs of all alternatives except Alternative C reach $100 million. This means that if 2% growth occurs, Alternative C will cost roughly half as much as the next closest alternative.

Detailed maps of each alternative are located in Appendix A.

8.0: Comparison of Alternatives.

Alternatives A, B, and C are all designed to meet the distribution and transmission system needs for the next 40 years assuming 1% load growth. Each alternative achieves the same objective in a different way and all alternatives have pros and cons. A comparison of the benefits and shortcomings of each alternative is shown below. The plans for longer range (beyond 2038) facilities are conceptual at this time, and may change depending on how load in the area develops in the future.

Evaluation of Alternatives		Impacts	Performance

Plymouth Area Alternatives	**Alternative A**
	Construct 34.5 kV distribution lines from new Pomerleau Lake Substation to Hollydale Substation
		• 8 miles near-term (9 miles long-term) of new distribution line
		  o 1 mile where no lines currently exist
		  o 7 miles near-term (8 miles long-term) where there are already lines
		• 145 homes along new distribution line routes
		• 12 new pad-mounted transformers (approximately 9x11x10 feet) & up to 12 switching cabinets (5x6x7 feet)
		• New Pomerleau Lake substation site
			• Provides good solution for near-term (roughly 20 years).
			• Pomerleau Lake Substation makes future improvements to meet future needs east of I-494 less challenging and expensive.
			• Provides limited ability to efficiently increase load serving capacity long-term to serve additional electrical demand

Plymouth Area Alternatives	**Alternative B**
	Construct 34.5 kV distribution lines from Parkers Lake Substation to Hollydale Substation
		• 10 miles near-term (11 miles long-term) of new distribution line
		  o 0 miles where no lines currently exist
		  o 10 miles near-term (11 miles long-term) where there are already lines
		• 98 homes along new distribution line routes
		• 12 new pad-mounted transformers (approximately 9x11x10 feet) & up to 12 switching cabinets (5x6x7 feet)
		• Expansion of Parkers Lake Substation site would occur on privately-owned land (parking lot, drainage easement)
		• No new substation site
			• Provides adequate solution for near-term (roughly 20 years)
			• Additional improvements will be needed east of I-494 and will be more challenging and expensive without a new Pomerleau Lake Substation.
			• Does not provide ability to efficiently increase capacity if needed in the long-term to serve additional electrical demand.
			• A large amount of load would be served from Parkers Lake Substation which increases reliability risk.

Alternative C Re-energize existing 69 kV line east of Hollydale Substation and construct 13.8 kV distribution lines from Hollydale Substation & 0.7 miles of 69 kV line to connect existing line to new Pomerleau Lake Substation.	• 4 miles of new distribution line o 0 miles where no lines exist o 4 miles were there are already lines • 26 homes along new distribution line routes • 0.7 miles of new transmission line • No new pad-mounted transformers needed • Vegetation management required on unmaintained 69 kV line right-of-way east of Hollydale Substation (4 miles / approximately 63 residential lots) • New Pomerleau Lake Substation site	• Provides good solution for near-term (roughly 20 years). • Pomerleau Lake Substation makes additional improvement needs east of I-494 less challenging and expensive. • Provides ability to efficiently increase capacity if needed in the long-term to serve additional electrical demand.

8.1: Alternative A: Install new 34.5 kV source at Pomerleau Lake.

8.1.1: Overview

- Facilities and Timing:
    - 2018: Construct Pomerleau Lake substation; two 34.5 kV feeders at Pomerleau Lake; reinforce feeders at Parkers Lake; construct extension of one 13.8 kV feeder at Parkers Lake; install 40 MVAR capacitor at Gleason Lake; rebuild Gleason Lake – Parkers Lake 115/115 kV line as two separate lines;
    - 2040 and 2048: extend 34.5 kV feeders at Pomerleau Lake;
    - 2052: expand Parkers Lake substation; two 34.5 kV feeders at Parkers Lake.
- Total Additional Feeder Length: 8.5 miles near-term, 9.1 miles long-term
- Average Additional Feeder Length: 1.8 miles
- Distribution System Capacity Added under N-1 conditions: 70 MW
- Total Investment: $65.8 million (non-escalated)
- Net Present Value for 2016: $45.1 million

8.1.2: Distribution System Performance

Alternative A has long feeder circuits totaling approximately 8.5 miles. Longer feeder circuits consist of more equipment, have more elements that can fail, and have more exposure to external factors that increase the chance of feeder outages. Although the new feeders installed in Alternative A will have full life expectancy when they are installed, the longer feeder circuits will increase exposure to external elements, due to their length, that could ultimately negatively impact reliability. Additionally, no alternatives discussed in this study will impact reliability at the tap-level of the feeder circuit, as the feeder loads will be transferred to the new feeders at the mainline level. Continued work is expected to mitigate reliability concerns due to tap level failures. Overall, despite the full life expectancy of a new feeder circuit, longer feeder circuits will increase exposure and could potentially negatively impact reliability.

Alternative A does not perform as well as Alternative C since it installs additional substation transformer capacity at a substation farther from the identified load center in the Focused Study Area.

With respect to operability, Alternative A uses additional devices such as step-down transformers and switching cabinets, making Alternative A more vulnerable during overload and outage conditions. Alternative A also uses long express feeder circuits that require many more components to keep in running order and fully operational during all possible conditions.

With respect to future growth, Alternative A provides for future capacity additions at Pomerleau Lake with a potential third transformer. Alternative A also does not exhaust capacity at the Gleason Lake and Parkers Lake 13.8 kV substations. As a result, the Gleason Lake and Parkers Lake transformers could be replaced with larger units to serve additional load in the future.

8.1.3: Transmission System Performance

Alternative A includes the separation of the existing Gleason Lake – Parkers Lake 115 kV double circuit into two 115 kV lines. The line separation is combined with a Gleason Lake 115 kV capacitor bank to eliminate all of the critical contingencies in the Transmission Area of Concern for the near-term timeframe. These facilities are the first step in solving the transmission problem for the long-term.

Future load growth will exceed the transmission capabilities provided by these facilities and will then require load to be moved away from Gleason Lake. Requiring distribution to move load because of a transmission need is very unusual and is not sustainable for the long-term. Transferring load away from existing assets at Gleason Lake requires more assets to be installed to handle the transferred load. In an ideal situation, it is best to serve load in an area from multiple substations and spread out the load density to provide the most reliable service. Consolidating loads into fewer substations means that when a contingency occurs, there will be fewer ways to backup loads and bring customers' power back. The resulting condition is more customers out of power for longer periods of time.

Lastly, serving 2% load growth in Alternative A requires two direct 34.5 kV feeders from Parkers Lake to Gleason Lake and the expansion of Gleason Lake substation beyond land currently owned by Xcel Energy. This expansion and set of express 34.5 kV feeders is not a normal distribution planning solution, since these feeders would only be used to transfer load away from Gleason Lake substation for the benefit of the transmission system. If the load does grow at a faster than expected rate, and before these last facilities would go in service, the system would need to be re-evaluated to determine the best solution.

8.2: Alternative B: Expand Parkers Lake substation with new 34.5 kV source.

8.2.1: Overview

- Facilities and Timing:
  - 2018: expand Parkers Lake substation; two 34.5 kV feeders at Parkers Lake; reinforce 13.8 kV feeders at Parkers Lake; construct extension of one 13.8 kV feeder at

Parkers Lake; install 40 MVAR capacitor at Gleason Lake; rebuild Gleason Lake – Parkers Lake 115/115 kV line as two separate lines;
  - 2040 and 2048: extend 34.5 kV feeders at Parkers Lake;
  - 2052: expand Parkers Lake substation; two 34.5 kV feeders at Parkers Lake.

- Total Additional Feeder Length: 10.5 miles near-term, 11.0 miles long-term
- Average Additional Feeder Length: 2.2 miles
- Distribution System Capacity Added under N-1: 70 MW
- Total Investment: $68.8 million (non-escalated)
- Net Present Value for 2016: $41.7 million

8.2.2: Distribution System Performance

Alternative B has long feeder circuits totaling approximately 11 miles. Longer feeder circuits consist of more equipment, have more elements that can fail, and have more exposure to external factors that increase the chance of feeder outages. Although the new feeders installed in Alternative B will have full life expectancy when they are installed, the longer feeder circuits will have increase exposure to external elements that could ultimately negatively impact reliability. Additionally, no alternatives discussed in this study will impact reliability at the tap-level of the feeder circuit, as the feeder loads will be transferred to the new feeders at the mainline level. Continued work is expected to mitigate reliability concerns due to tap level failures. Overall, despite the full life expectancy of a new feeder circuit, longer feeder circuits will increase exposure and could potentially negatively impact reliability.

Alternative B does not perform as well as Alternative C since it installs additional substation transformer capacity at a substation farther from the identified load center in the Focused Study Area.

With respect to operability, Alternative B uses additional devices such as step-down transformers and switching cabinets, making Alternative B more vulnerable during overload and outage conditions. Alternative B also uses long express feeder circuits that require many more components to keep in running order and fully operational during all possible conditions.

With respect to future growth, Alternative B provides for less future capacity additions because no new substation is built and expansion capabilities at 34.5 kV have been used up at Parkers Lake. However, it does not exhaust capacity at the Gleason Lake and Parkers Lake 13.8 kV substations. As a result, the Gleason Lake and Parkers Lake transformers could be replaced with larger units to serve additional load in the future.

Alternative B requires installation of additional distribution facilities at the Parkers Lake Substation. Installing more distribution facilities at Parkers Lake involves an increased risk. It is not typical to have more than three distribution transformers at one distribution substation on the Northern States Power-Minnesota (“NSPM”) system. There is risk of “putting all the eggs in one basket” with this alternative. A common failure of all the transformers at the Parkers Lake Substation would put a large quantity of load in the area at risk. Though this should not be considered a primary driver of design, it should be considered. A common failure could be due to a tornado or other disasters that could require de-energization of the Parkers Lake Substation and put a large quantity of load at risk.

8.2.3: Transmission System Performance

Alternative B includes the separation of the existing Gleason Lake – Parkers Lake 115 kV double circuit into two 115 kV lines. The line separation is combined with a Gleason Lake 115 kV capacitor bank to eliminate all of the critical contingencies in the Transmission Area of Concern for the near-term timeframe. These facilities are relatively inexpensive and provide a great first step in solving the transmission problem for the long-term.

Future load growth will exceed the transmission capabilities provided by these facilities and will then require load to be moved away from Gleason Lake. Requiring distribution to move load because of a transmission need is very unusual and is not sustainable for the long-term. Transferring load away from existing assets at Gleason Lake requires more assets to be installed just to handle the transferred load. Also, expanding Parkers Lake's load serving capabilities puts more load at one location and the concern of placing "all your eggs in one basket" more pronounced. In an ideal situation, it is best to serve load in an area from multiple substations and spread out the load density to provide the most reliable service. Consolidating loads into fewer substations means that when a contingency occurs, there will be fewer ways to backup loads and bring customers' power back. The resulting condition is more customers out of power for longer periods of time.

Lastly, serving 2% load growth in Alternative B requires two direct 34.5 kV feeders from Parkers Lake to Gleason Lake and the expansion of Gleason Lake substation beyond land currently owned by Xcel Energy. This expansion and new set of 34.5 kV is beyond normal planning solutions. If the load does grow at a faster than expected, and before these last facilities would go in service, the system would need to be re-evaluated to determine the best solution.

8.3: Alternative C: Expand Hollydale substation, utilize existing transmission line corridors, construct Pomerleau Lake substation.

8.3.1: Overview

- Facilities and Timing:
  - 2018: rebuild Hollydale substation; three 13.8 kV feeders at Hollydale; construct Pomerleau Lake substation; construct extension of 69 kV line to Pomerleau Lake; re-energize Hollydale-Pomerleau Lake 69 kV line; reinforce feeders at Parkers Lake; construct extension of one 13.8 kV feeder at Parkers Lake; install 40 MVAR capacitor at Gleason Lake; rebuild Gleason Lake – Parkers Lake 115/115 kV line as two separate lines;
  - 2049: expand Hollydale.
- Total Additional Feeder Length: 4.1 miles
- Average Additional Feeder Length: 1.0 miles
- Distribution System Capacity Added under N-1: 56 MW
- Total Investment: $47.6 million (non-escalated)

- Net Present Value in 2016: $38.9 million

8.3.2: Distribution System Performance

Compared to Alternatives A and B, Alternative C best satisfies distribution planning criteria. With respect to system performance, the Alternative C installs additional substation transformer capacity at a substation nearest to the identified load center in the Focused Study Area. As a result, Alternative C has the shortest total miles of feeders at approximately 4 miles. Shorter feeder circuits consist of less equipment, have fewer elements that can fail, and have less exposure to external factors that increase the chance of feeder outages. In addition, shorter feeders have less electrical losses compared to longer feeders. The decreased exposure from shorter feeders in conjunction with the full life expectancy from new distribution feeders leads to the expectation that Alternative C will be more reliable than Alternatives A and B. However, Alternative C will not impact reliability at the tap-level of the feeder circuit, as the feeder loads will be transferred to the new feeders at the mainline level. Continued work is expected to mitigate reliability concerns due to tap level failures. Alternative C is capable of maintaining adequate voltage on feeder circuits.

Alternative C also has the best operability. Alternative C is an extension and reconfiguration of the existing distribution system and provides for a large number of standard options that could be quickly implemented under contingency conditions. Additionally, Alternative C does not require any step down transformers or switching cabinets.

With respect to future growth, the Alternative C provides the most possibilities of all the alternatives for future capacity additions. Alternative C does not exhaust capacity at the Gleason Lake and Parkers Lake substations. As a result, the Gleason Lake and Parkers Lake transformers could be replaced with larger units to serve additional load in the future. Alternative C also allows for additional distribution capacity to be added at Pomerleau Lake in the future as load grows in the area. In addition, the 69 kV transmission line into the Hollydale Substation would be able to source an additional new third transformer at this substation without adding additional transmission lines in the area.

Alternative C has a lower cost than the other alternatives in the near-term and significantly lower cost in the long-term because it uses many existing facilities.

8.3.3: Transmission System Performance

Alternative C includes the separation of the existing Gleason Lake – Parkers Lake 115 kV double circuit into two 115 kV lines. The line separation is combined with a Gleason Lake 115 kV capacitor bank to eliminate all of the critical contingencies in the Transmission Area of Concern for the near-term timeframe. These facilities are a good first step in solving the transmission problem for the long-term. Additionally, Alternative C includes the re-energization of the Hollydale – Pomerleau 69 kV line. This line provides load serving capabilities for the long-term as it takes the Hollydale load off of the Gleason Lake substation and onto the 69 kV line.

Alternative C utilizes many existing facilities and allows for the most system expandability of any alternative. For example, if a large spot load emerged in the area, Alternatives A and B may not be able to support the new load. However, Alternative C would have the available capacity to accommodate this load addition. Alternative C can handle the most load growth because it does not require the extra distribution load transfers that Alternatives A and B require. As a result, all of the distribution components in the other alternatives remain available if necessary.

Table 8.1 shows a comparison of Alternatives A, B, and C in regards to feeder improvements, distribution capacity, total investment, and net present value of each alternative. Based on these criteria and the performance criteria outlined above, Alternative C is the best performing alternative.

Table 8.1: Comparison of the three alternatives with respect to feeder improvements, distribution capacity, total investment cost, and net present value.

Project	Total Additional Feeder Length	Average Additional Feeder Length	Distribution System Capacity Added Under N-1	Total Investment	Net Present Value for 2016
Alternative A	9.1 mi	1.8 mi	70 MW	$65.8 M	$45.1 M
Alternative B	11.0 mi	2.2 mi	70 MW	$68.8 M	$41.7 M
Alternative C	4.1 mi	1.0 mi	56 MW[1]	$47.6 M	$38.9 M

[1] Alternative C could have a total of 126 MW of additional distribution system capacity under N-1 conditions by utilizing Pomerleau Lake substation for distribution.

8.4: Cost.

Table 8.2 shows the total investment cost and net present value for 2016 assuming load growth rates of 1% and 2%.

Table 8.2: Total Investment and Net Present Value Cost for the Three Alternatives, assuming 1% and 2% Load Growth

Project	Total Investment	Net Present Value for 2016	Total Investment	Net Present Value for 2016
	1% Growth		2% Growth	
Alternative A	$65.8 M	$45.1 M	$103.6 M	$46.7 M
Alternative B	$68.8 M	$41.7 M	$106.6 M	$43.3 M
Alternative C	$47.6 M	$38.9 M	$61.4 M	$39.5 M

Table 8.3 shows the near-term and long-term investment costs for each alternative, assuming 1% load growth.

Table 8.3: Total Near-term and Long-term Investment Cost for Each Alternative, assuming 1% Load Growth

Project	Near-term Investment	Long-term Investment
	1% Growth	
Alternative A	$50.7 M	$65.8 M
Alternative B	$46.2 M	$68.8 M
Alternative C	$44.6 M	$47.6 M

9.0: Recommended Alternative.

The best performing alternative from an engineering perspective for the Transmission Area of Concern and Focused Study Area is Alternative C, due to the system flexibility, lowest capital investment, and least amount of new infrastructure. Alternative A is the next best solution due to the system flexibility it provides over Alternative B. However, all three alternatives were designed to comparably meet the long-term load serving needs in the Transmission Area of Concern and Focused Study Area. Since all three alternatives are comparable solutions, input on non-engineering factors will be gathered during the permitting process that will help determine the best alternative to construct.

Appendix A: System Alternatives Maps

Figure A. 1: Map of Alternative A

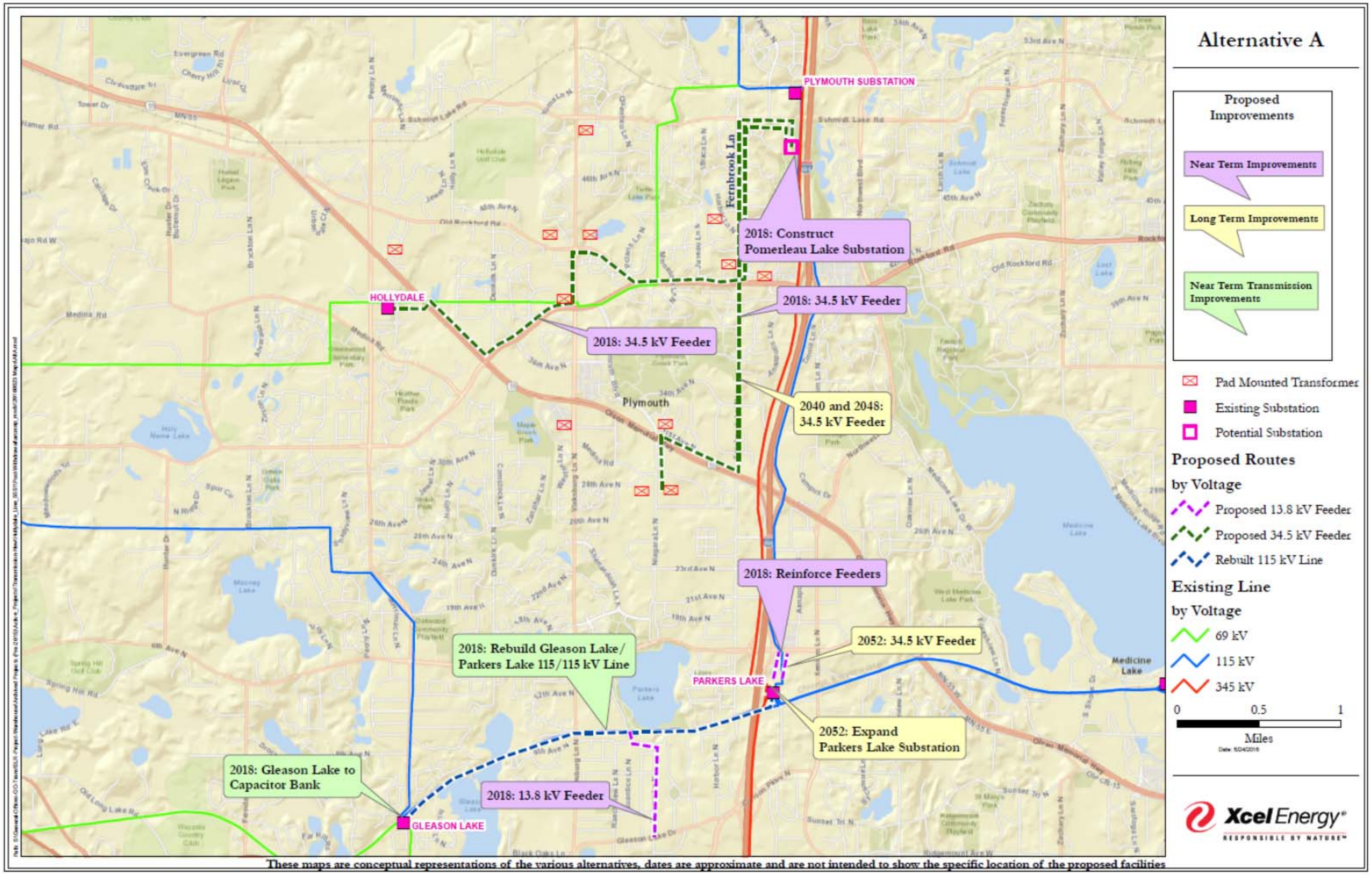


Figure A. 2: Map of Alternative B

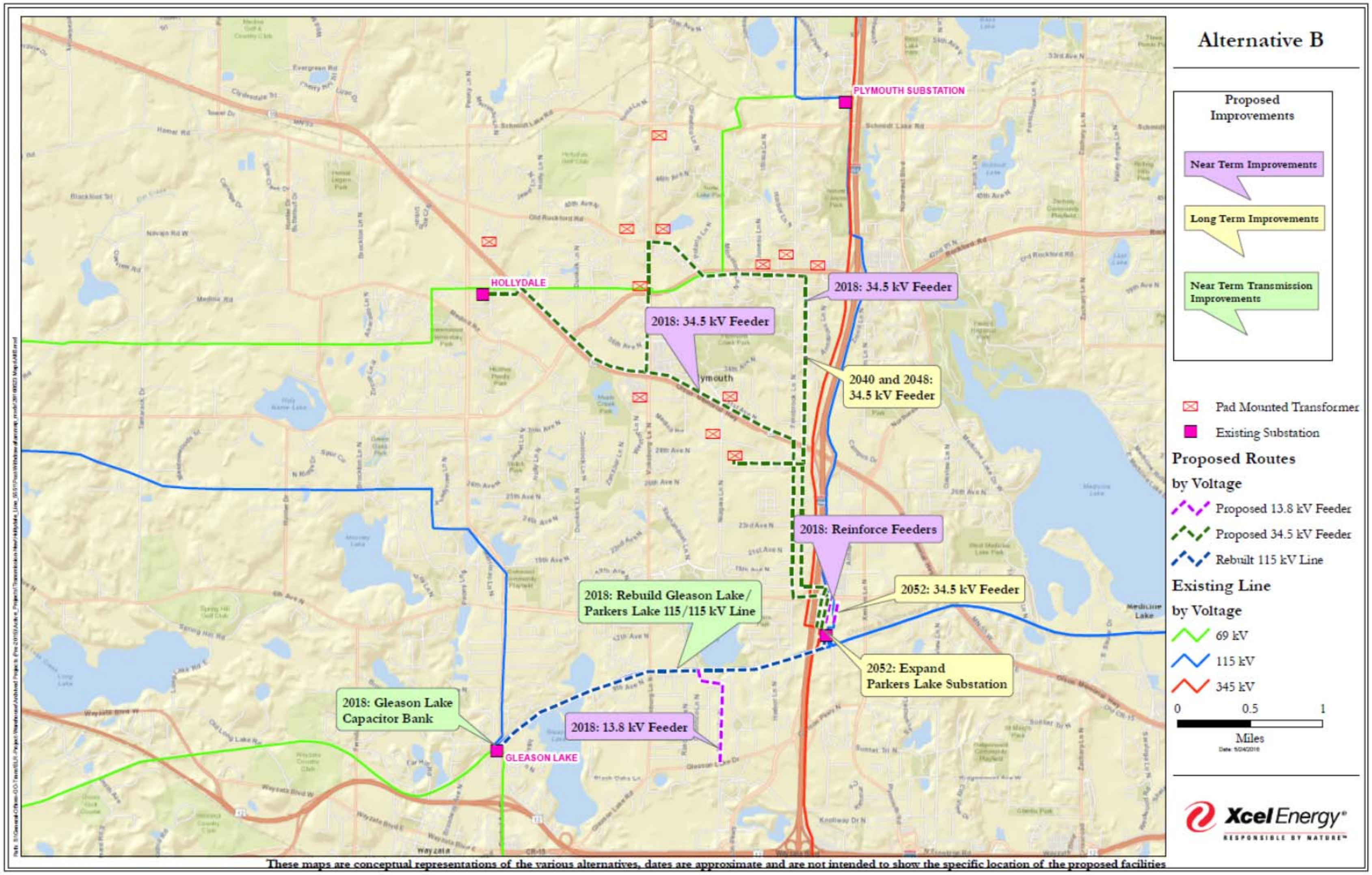
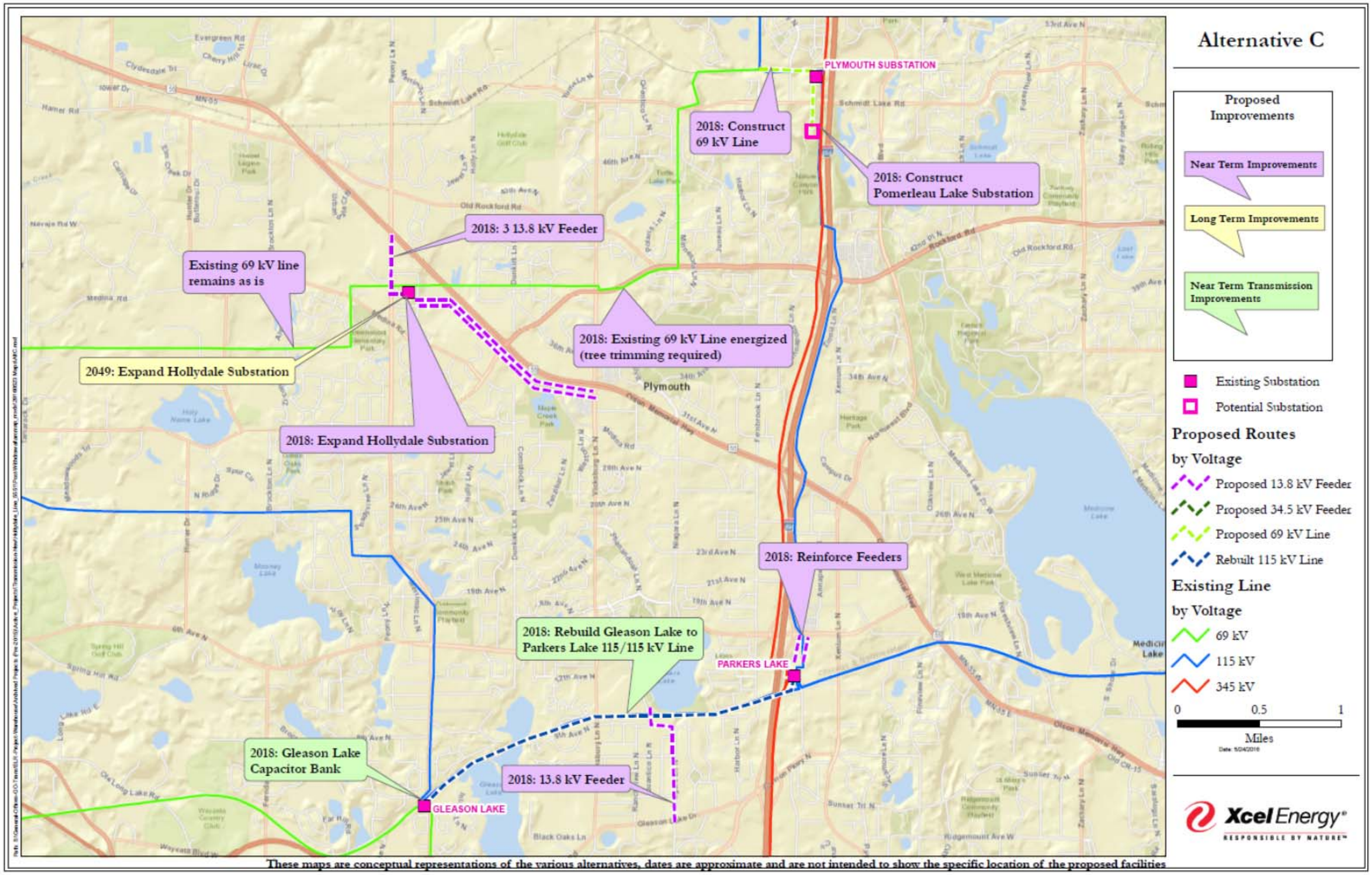


Figure A. 3: Map of Alternative C



Appendix B: Load Forecasts

Transmission Area of Concern
Forecasted Loads (MW)

1% Growth	2016	2017	2020	2025	2030	2035	2040	2045	2050
Gleason Lake	97.8	98.8	101.8	107.0	112.5	118.2	124.2	130.6	137.2
Medina	6.3	6.4	6.6	6.9	7.2	7.6	8.0	8.4	8.8
Mound	38.8	39.2	40.3	42.4	44.6	46.8	49.2	51.7	54.4
Orono	17.8	18.0	18.5	19.5	20.4	21.5	22.6	23.7	25.0
Greenfield	4.6	4.6	4.8	5.0	5.3	5.6	5.8	6.1	6.5
Total	165.3	166.9	172.0	180.8	190.0	199.7	209.9	220.6	231.8

2% Growth	2016	2017	2020	2025	2030	2035	2040	2045	2050
Gleason Lake	97.8	98.8	104.9	115.8	127.8	141.1	155.8	172.0	190.0
Medina	6.3	6.4	6.8	7.5	8.2	9.1	10.0	11.1	12.2
Mound	38.8	39.2	41.5	45.9	50.6	55.9	61.7	68.2	75.3
Orono	17.8	18.0	19.1	21.1	23.2	25.7	28.3	31.3	34.5
Greenfield	4.6	4.6	4.9	5.4	6.0	6.6	7.3	8.1	8.9
Total	165.3	166.9	177.2	195.6	216.0	238.4	263.3	290.7	320.9

Focused Study Area - Gleason Lake Sub Analysis 34.5 kV

Peak Forecast	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
GSL TR4			48.0	48.4	48.9	49.4	49.9	50.4	50.9	51.4	51.9	52.4	53.0	53.5	54.0	54.6	55.1	55.7	56.2	56.8	57.4	57.9	58.5
Conservative Forecast	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
GSL TR4	44.6	44.8	45.0	45.2	45.4	45.7	45.9	46.1	46.4	46.6	46.8	47.1	47.3	47.5	47.8	48.0	48.3	48.5	48.7	49.0	49.2	49.5	49.7

includes HOL load

Focused Study Area - Gleason Lake Sub Analysis 13.8 kV

Peak Forecast	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
GSL TR7			22.9	23.1	23.3	23.6	23.8	24.0	24.3	24.5	24.8	25.0	25.3	25.5	25.8	26.0	26.3	26.5	26.8	27.1	27.3	27.6	27.9
GSL TR8			31.5	31.8	32.2	32.5	32.8	33.1	33.5	33.8	34.1	34.5	34.8	35.2	35.5	35.9	36.2	36.6	37.0	37.3	37.7	38.1	38.5
TOTAL			54.4	54.9	55.5	56.0	56.6	57.2	57.7	58.3	58.9	59.5	60.1	60.7	61.3	61.9	62.5	63.1	63.8	64.4	65.1	65.7	66.4
Conservative Forecast	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
GSL TR7	19.1	19.2	19.3	19.4	19.5	19.6	19.7	19.8	19.9	20.0	20.1	20.2	20.3	20.4	20.5	20.6	20.7	20.8	20.9	21.0	21.1	21.2	21.3
GSL TR8	24.5	26.6	31.7	31.8	32.0	32.1	32.3	32.5	32.6	32.8	33.0	33.1	33.3	33.5	33.6	33.8	34.0	34.1	34.3	34.5	34.6	34.8	35.0
TOTAL	43.6	45.8	51.0	51.2	51.5	51.7	52.0	52.2	52.5	52.8	53.0	53.3	53.6	53.8	54.1	54.4	54.6	54.9	55.2	55.5	55.7	56.0	56.3

Focused Study Area - Feeder Analysis 13.8 kV and 34.5 kV

Peak Forecast	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
GSL341			18.1	18.3	18.4	18.6	18.8	19.0	19.2	19.4	19.6	19.8	20.0	20.2	20.4	20.6	20.8	21.0	21.2	21.4	21.6	21.8	22.1
GSL342			32.4	32.7	33.1	33.4	33.7	34.1	34.4	34.7	35.1	35.4	35.8	36.1	36.5	36.9	37.2	37.6	38.0	38.4	38.8	39.1	39.5
PKL062			6.8	6.9	7.0	7.0	7.1	7.2	7.3	7.3	7.4	7.5	7.5	7.6	7.7	7.8	7.9	7.9	8.0	8.1	8.2	8.3	8.3
PKL074			12.9	13.1	13.2	13.3	13.5	13.6	13.7	13.9	14.0	14.1	14.3	14.4	14.6	14.7	14.9	15.0	15.2	15.3	15.5	15.6	15.8
PKL075			9.4	9.5	9.6	9.7	9.8	9.9	10.0	10.1	10.2	10.3	10.4	10.5	10.6	10.7	10.9	11.0	11.1	11.2	11.3	11.4	11.5
PKL081			9.6	9.7	9.8	9.9	10.0	10.1	10.2	10.3	10.4	10.5	10.6	10.7	10.8	10.9	11.0	11.1	11.2	11.3	11.4	11.6	11.7
PKL083			9.2	9.3	9.4	9.5	9.6	9.7	9.8	9.9	9.9	10.0	10.1	10.3	10.4	10.5	10.6	10.7	10.8	10.9	11.0	11.1	11.2
PKL084			7.8	7.9	8.0	8.0	8.1	8.2	8.3	8.4	8.4	8.5	8.6	8.7	8.8	8.9	9.0	9.1	9.1	9.2	9.3	9.4	9.5
GSL061			6.9	7.0	7.1	7.1	7.2	7.3	7.4	7.4	7.5	7.6	7.7	7.7	7.8	7.9	8.0	8.0	8.1	8.2	8.3	8.4	8.5
GSL076			7.9	8.0	8.0	8.1	8.2	8.3	8.4	8.5	8.5	8.6	8.7	8.8	8.9	9.0	9.1	9.2	9.2	9.3	9.4	9.5	9.6
GSL079			7.7	7.8	7.8	7.9	8.0	8.1	8.2	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.8	8.9	9.0	9.1	9.2	9.3	9.4
TOTALS			128.7	130.0	131.3	132.6	134.0	135.3	136.7	138.0	139.4	140.8	142.2	143.6	145.1	146.5	148.0	149.5	151.0	152.5	154.0	155.5	157.1
Conservative Forecast	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
GSL341	17.7	17.8	17.9	18.0	18.1	18.2	18.3	18.4	18.4	18.5	18.6	18.7	18.8	18.9	19.0	19.1	19.2	19.3	19.4	19.5	19.6	19.7	19.8
GSL342	29.4	29.6	29.7	29.9	30.0	30.2	30.3	30.5	30.6	30.8	30.9	31.1	31.2	31.4	31.5	31.7	31.9	32.0	32.2	32.3	32.5	32.7	32.8
PKL062	6.4	6.4	6.5	6.5	6.5	6.6	6.6	6.6	6.7	6.7	6.7	6.8	6.8	6.8	6.9	6.9	6.9	7.0	7.0	7.0	7.1	7.1	7.2
PKL074	12.1	12.2	12.3	12.3	12.4	12.4	12.5	12.6	12.6	12.7	12.8	12.8	12.9	13.0	13.0	13.1	13.2	13.2	13.3	13.3	13.4	13.5	13.6
PKL075	8.9	9.0	9.0	9.1	9.1	9.1	9.2	9.2	9.3	9.3	9.4	9.4	9.5	9.5	9.6	9.6	9.7	9.7	9.8	9.8	9.9	9.9	10.0
PKL081	11.3	11.4	11.4	11.5	11.5	11.6	11.7	11.7	11.8	11.8	11.9	12.0	12.0	12.1	12.1	12.2	12.3	12.3	12.4	12.4	12.5	12.6	12.6
PKL083	9.4	9.5	9.5	9.6	9.6	9.7	9.7	9.8	9.8	9.9	9.9	10.0	10.0	10.1	10.1	10.2	10.2	10.3	10.3	10.4	10.4	10.5	10.5
PKL084	7.5	7.5	7.6	7.6	7.7	7.7	7.7	7.8	7.8	7.8	7.9	7.9	8.0	8.0	8.0	8.1	8.1	8.2	8.2	8.2	8.3	8.3	8.4
GSL061	4.3	4.3	4.3	4.3	4.4	4.4	4.4	4.4	4.4	4.5	4.5	4.5	4.5	4.6	4.6	4.6	4.6	4.7	4.7	4.7	4.7	4.7	4.8
GSL076	7.1	7.1	7.2	7.2	7.2	7.3	7.3	7.3	7.4	7.4	7.5	7.5	7.5	7.6	7.6	7.6	7.7	7.7	7.8	7.8	7.8	7.9	7.9
GSL079	6.8	6.9	6.9	6.9	7.0	7.0	7.1	7.1	7.1	7.2	7.2	7.2	7.3	7.3	7.3	7.4	7.4	7.5	7.5	7.5	7.6	7.6	7.6
TOTALS	121.1	121.7	122.3	122.9	123.5	124.1	124.8	125.4	126.0	126.6	127.3	127.9	128.5	129.2	129.8	130.5	131.1	131.8	132.5	133.1	133.8	134.4	135.1

Substation Transformer Historical Summer "Peak" Demand

MW															
Bank	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
GSL TR7	20.1	21.5	20.8	21.4	20.2	21.7	19.6	18.6	17.6	17.7	22.1	20.0	19.8	19.0	16.1
GSL TR8	23.5	27.0	24.1	25.7	27.0	28.0	24.3	23.1	21.9	24.3	26.7	25.8	26.1	24.5	25.3
TOTAL	43.6	48.5	44.9	47.1	47.2	49.6	43.9	41.7	39.6	42.1	48.8	45.8	45.8	43.6	41.4
KVA															
Bank	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
GSL TR7	20500	21950	21260	21850	20570	22120	20000	19000	18000	18100	22560	20450	20160	19420	16410
GSL TR8	24000	27500	24600	26190	27600	28540	24780	23580	22390	24820	27245	26310	26610	25050	25860
TOTAL	44500	49450	45860	48040	48170	50660	44780	42580	40390	42920	49805	46760	46770	44470	42270

MW															
Bank	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
GSL TR4	23.5	26.0	28.7	31.4	36.5	39.2	40.2	35.3	36.2	41.1	45.2	42.4	46.2	44.6	40.4
KVA															
Bank	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
GSL TR4	24000	26500	29310	32080	37200	40000	41000	36000	36910	41890	46110	43270	47170	45460	41270

Feeder Circuit Historical Summer "Peak" Demand

Megawatts (MW)															
Feeder	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
HOL061	2.6	6.0	5.9	5.6	6.1	6.2	8.0	7.5	7.4	6.7	8.1	7.3	7.1	6.4	6.8
HOL062	9.4	10.0	8.3	9.1	10.3	10.4	8.8	8.1	8.3	8.2	8.8	11.7	11.8	12.3	11.3
PKL062	11.3	11.4	8.6	8.3	8.3	6.4	6.1	6.7	6.6	7.0	6.5	6.7	6.6	6.4	6.2
PKL074	12.7	13.2	12.7	12.2	12.4	14.3	12.8	10.9	11.8	11.3	13.7	12.7	12.1	12.1	12.1
PKL075	7.5	9.5	9.3	7.6	8.3	9.7	9.4	8.8	8.3	9.2	9.7	9.3	9.1	8.9	9.5
PKL081	9.4	10.5	10.0	11.7	11.2	11.6	11.2	9.5	8.6	9.6	10.4	10.3	9.7	11.3	7.6
PKL083	9.6	10.7	9.5	8.8	8.6	9.5	8.6	8.6	8.9	9.3	7.8	9.5	10.0	9.4	7.3
PKL084	9.5	9.8	9.3	9.3	10.1	10.3	10.0	10.0	9.3	8.2	7.8	7.5	7.6	7.5	6.8
GSL061	9.8	8.5	8.0	7.8	8.3	8.4	6.4	5.8	5.7	3.8	4.9	6.8	5.2	4.3	3.8
GSL076	8.6	9.3	8.8	8.7	9.5	9.8	8.3	7.5	7.4	7.2	7.7	7.7	7.1	7.1	6.9
GSL079	7.4	7.7	8.7	8.8	8.0	8.7	8.2	6.8	7.2	6.4	7.3	7.6	6.6	6.8	6.6
GSL341	23.5	28.4	29.4	29.2	30.0	31.4	32.3	31.4	29.9	31.6	16.4	16.7	16.4	17.7	17.9
GSL342	0.0	0.0	0.0	2.9	6.1	8.5	9.1	9.7	11.3	11.7	29.4	28.8	32.0	29.4	25.1
TOTALS (MW)	109.4	119.0	114.2	115.1	120.9	128.4	122.4	115.6	114.8	115.4	121.6	123.6	122.5	121.1	109.6

KVA																
Feeder	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	
HOL061	2605	6116	6000	5700	6240	6300	8200	7700	7500	6886	8254	7458	7209	6513	6911	Included with GSL342 feeder load (GSL341 prior to 2011)
HOL062	9596	10242	8500	9270	10541	10600	8974	8303	8500	8402	8974	11958	12010	12505	11485	Included with GSL342 feeder load (GSL341 prior to 2011)
PKL062	11515	11590	8760	8450	8500	6494	6200	6861	6713	7113	6615	6870	6781	6538	6290	
PKL074	13000	13500	12927	12430	12684	14548	13073	11095	12007	11580	13971	12952	12333	12390	12306	
PKL075	7677	9700	9450	7707	8497	9911	9553	8950	8424	9407	9905	9468	9274	9098	9671	
PKL081	9637	10690	10193	11932	11447	11793	11459	9711	8813	9796	10658	10536	9941	11546	7707	
PKL083	9800	10938	9695	8950	8764	9724	8728	8788	9043	9468	7930	9711	10208	9637	7433	
PKL084	9695	10000	9447	9447	10342	10500	10184	10200	9447	8416	7951	7635	7805	7656	6936	
GSL061	10000	8701	8204	7955	8452	8576	6500	5900	5800	3850	4950	6961	5290	4360	3900	
GSL076	8810	9500	9000	8870	9646	10000	8500	7632	7600	7380	7860	7905	7250	7234	7035	
GSL079	7500	7856	8900	8950	8204	8850	8400	6911	7300	6530	7490	7707	6750	6986	6687	
GSL341	24000	28962	30000	29790	30640	32000	33000	32000	30500	32280	16750	17029	16760	18086	18272	
GSL342	0	0	0	3000	6215	8639	9323	9944	11500	11960	30000	29396	32629	30018	25606	
TOTALS	111634	121437	116576	117481	123391	131035	124920	117992	117147	117780	124080	126170	125021	123549	111843	excludes HOL061 and HOL062

Appendix C: Demand-Side Management

Appendix C – Demand Side Management Alternatives

Demand Side Management Alternatives

Demand Side Management (DSM) Alternatives have been reviewed in accordance with the May 12, 2014 Commission Order in Docket No. E-002/12-113.

The Company has had a long-standing commitment to DSM through our Conservation Improvement Program (CIP). CIP programs, including both energy efficiency and demand response, have been developed in accordance with regulations set forth by the Minnesota Department of Commerce, Division of Energy Resources (DER). In 2014, these programs provided a peak demand reduction of 114 MW and 481 GWh of energy savings[1]. Since 1992, these programs have contributed enough demand savings to prevent the need to build 11 medium sized power plants.

Our CIP portfolio includes voluntary programs in two categories: Energy Efficiency and Demand Response. Energy Efficiency programs provide an incentive to customers for installing efficient technologies such as compact fluorescent lighting or high efficiency air conditioning through a rebate. These programs help reduce overall system growth and reduce the need to invest in additional generation resources. Demand Response programs are designed to provide immediate load reduction during times of high system load by providing customers an incentive to curtail their usage. Examples of these programs include our Saver's Switch® and Energy Rate Savings programs.

1. Energy Efficiency Impact

There has been strong participation in energy efficiency programs by customers within the affected area. Over the past five years nearly 5,200 separate rebates have been awarded within the Hollydale affected area, resulting in peak load reductions of 9.2 MW. The majority of these have been for residential efficiency measures given that the affected area is a predominantly residential customer base. Programs customers commonly take advantage of include; air conditioning replacement, lighting efficiency, home energy audits, refrigerator recycling, and cooling efficiency to name a few. New programs such as the Smart Thermostat pilot are also seeing adoption within the area. Table A below reflects the impact and participation for the last five years:

Table A: Energy Efficiency Participation and Impact

Year	Participants	Peak kW Reduction
2011	748	1,848
2012	752	1,534
2013	1,071	1,526
2014	1,330	2,124
2015	1,280	2,183
Total	**5,181**	**9,215**

[1] As filed on April 1, 2015, Docket No. E,G002/CIP-12-447.07

Efficiency programs have already helped mitigate constraints within the affected area by reducing peak demand. Unfortunately these efforts are not enough to solve the existing 2016 Distribution Substation Transformer Need of 14 MW outlined in section 4.1.4 of this report, nor the ~12 MW of Transmission Need identified in section 4.2.2. Even with increased marketing efforts it would not be feasible to meet these needs through efficiency programs. The benefit efficiency programs bring to the area is largely in controlling and reducing future load growth. This has been reflected in the "Conservative Growth Forecast" presented in section 4.1.2.

2. Demand Response (DR) Impact

Unlike Energy Efficiency programs which create a permanent reduction in load, demand response programs are designed to reduce load at specific times; traditionally when the electric system is at peak. These programs provide customers incentive to curtail load during certain hours of these critical days. The programs are voluntary and in most cases customers may cancel their enrollment at any time.

To date, the Company has utilized demand resources almost exclusively in situations when there is a system wide constraint. Demand Response programs were not originally designed to be dispatched for localized issues such as those occurring within the affected area. It would take system modifications and investments to use these resources for localized emergencies.

There are two programs already offered within the affected area are the Saver's Switch program and the Electric Rate Savings program. Through Saver's Switch (SS) the Company can remotely control central air conditioning loads using a load control switch installed at the customer's site. The Electric Rate Savings (ERS) program is designed for larger commercial and industrial customers. Participants are required to reduce load to a pre-determined level, with the minimum load reduction being at least 50 kW. Both the SS and ERS programs offer customers incentives on their electric bill for their participation. Existing participation rates are relatively high, with over 30% of the customer base enrolled in these programs (Reference Table B).

Table B: Demand Response Program Participation

Customer Type	Customer Count	DR Program Participation	Participation %
Residential	22,872	8,286	36%
Commercial	2,808	224	8%
Industrial	262	59	23%
Total	25,942	8,569	33%

Allowing that the necessary system modifications and investments were made these programs could provide approximately 3.8 MW of load relief to the Distribution constrained areas and 11.7 MW to the Transmission area. Though substantial, these load reductions do not meet the need in the area. The Company also looked at remaining demand response potential in the area and identified approximately 2 MW of additional DR resources, largely by increasing participation in the Saver's Switch program. Even including this additional potential, DR is unable to address the Distribution and Transmission needs (see table C). This is partly a result of the distribution of demand response resources. Some are located on feeders which could address the Transmission need, others on feeders addressing the Distribution need and a few on feeders which overlap the Transmission and Distribution areas. The conclusion is that even assuming DR programs were expanded to every eligible customer within the area the programs would not meet the Transmission and Distribution needs identified in 2016.

Table C: Demand Response Potential by Need within Affected Area

Need Addressed	Existing DR (MW)	Additional Potential (MW)	2016 MW Required	Remaining Shortfall
Distribution	3.8	0.4	14	10.2
Transmission	11.7	0.8	12	0.6

2. DSM Impact on Hollydale

Demand response and energy efficiency have impacted the affected area, helping to reduce overall load growth over the past ten years. However, the immediate needs identified within the affected area surpass the relief DSM can immediately bring to the system.

The Company continues to evaluate whether any alternative, non-traditional, CIP programs could be developed to address the particular transmission and distribution issues within this area and will continue to update the Commission on the results of further evaluation. In the meantime the Company will continue to market its continually evolving portfolio of conservation and demand response programs to the affected area.

Appendix D: Cost Estimates

Appendix D - Cost Estimates

Alternative A: Facilities and Costs
34.5 kV at Pomerleau Lake

Project	ISD Year	Location	Project Scope (excludes Permitting Costs)	SUB Costs
Alternative A	2018	Transmission	Gleason Lake - Parkers Lake Dbl Ckt rebuild to single circuits (line 1)	$50,729,000
			Gleason Lake - Parkers Lake Dbl Ckt rebuild to single circuits (line 2)	
			Replace Distribution underbuild on GSL-PKL line	
	2018	Gleason Lake	115 kV capacitor bank	
	2018	Parkers Lake	Reinforce Feeder Exits	
	2018	Hollydale	Substation improvements	
	2018	Pomerleau Lake	Land	
			GRE Xmsn In/Out	
			Install New Sub & 2- 115/34.5kV 70MVA TRs	
			2- Distribution feeders	
	2040	Pomerleau Lake	Distribution feeder reconfigure	$ -
	2048	Pomerleau Lake	Distribution feeder reconfigure	$ 300,000
	2052	Parkers Lake	Install 2- 115/34.5kV 70MVA TRs	$14,800,000
			2- Distribution feeders	
2.0% Growth	2060	PKL to GSL feeder	2- Distribution feeders	$15,800,000
	2060	Gleason Lake	Install 2- 34.5/13.8kV 28MVA TRs	$22,000,000

Total (1% Growth)	$ 65,829,000
Near Term	$ 50,729,000
Far Term	$ 15,100,000
2% Growth Long Term	$ 37,800,000

Alternative B: Facilities and Costs
34.5 kV at Parkers Lake

Project	ISD Year	Location	Project Scope (excludes Permitting Costs)	SUB Costs
Alternative B	2018	Transmission	Gleason Lake - Parkers Lake Dbl Ckt rebuild to single circuits (line 1)	$46,179,000
			Gleason Lake - Parkers Lake Dbl Ckt rebuild to single circuits (line 2)	
			Replace Distribution underbuild on GSL-PKL line	
	2018	Gleason Lake	115 kV capacitor bank	
	2018	Parkers Lake	Reinforce feeder exits	
	2018	Hollydale	Substation improvements	
	2018	Parkers Lake	Install 2- 115/34.5kV 70MVA TRs	
			2- Distribution feeders	
	2040	Parkers Lake	Distribution feeder reconfigure	$ -
	2048	Parkers Lake	Distribution feeder reconfigure	$ 300,000
	2052	Parkers Lake	Install 2- 115/34.5kV 70MVA TRs	$22,300,000
			Land	
			2- Distribution feeders	
2.0% Growth	2060	PKL to GSL feeder	2- Distribution feeders	$15,800,000
	2060	Gleason Lake	Install 2- 34.5/13.8kV 28MVA TRs	$22,000,000

Total (1% Growth)	$68,779,000
Near Term	$46,179,000
Far Term	$22,600,000
2% Growth Long Term	$ 37,800,000

Alternative C: Facilities and Costs
69 kV line to Hollydale

Project	ISD Year	Location	Project Scope (excludes Permitting Costs)	SUB Costs
Alternative C	2018	Transmission	Gleason Lake - Parkers Lake Dbl Ckt rebuild to single circuits (line 1)	$44,624,000
			Gleason Lake - Parkers Lake Dbl Ckt rebuild to single circuits (line 2)	
			Replace Distribution underbuild on GSL-PKL line	
	2018	Gleason Lake	115 kV capacitor bank	
	2018	Parkers Lake	Reinforce feeder exits	
	2018	Hollydale	Substation improvements	
			Install 2- 28MVA 69/13.8kV TRs	
			3- Distribution feeders	
	2018	Pomerleau Lake	GRE Xmsn in/out	
			Land	
			Install NSP Sub & 1- 112MVA 115/69kV TR	
	2018	T line 69 kV	Medina-Hollydale-Pomerleau Lake 69 kV purchase, trim trees	
	2049	Hollydale	Install 1- 28MVA 69/13.8kV TR	$ 3,000,000
2.0% Growth	2060	Parkers Lake	Install 2- 115/34.5kV 70MVA TRs	$13,800,000
			2- Distribution feeders	

Total (1% Growth)	$ 47,624,000
Near Term	$ 44,624,000
Long Term	$ 3,000,000
2% Growth Long Term	$ 13,800,000

CERTIFICATE OF SERVICE

I, Carl Cronin, hereby certify that I have this day served copies or summaries of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States Mail at Minneapolis, Minnesota

xx electronic filing

Docket No. E999/CI-15-556

Dated this 21st day of June 2017

/s/

____

Carl Cronin
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Allen	michael.allen@allenergysolar.com	All Energy Solar	721 W 26th st Suite 211 Minneapolis, Minnesota 55405	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Ellen	Anderson	ellena@umn.edu	325 Learning and Environmental Sciences	154 Buford Ave St. Paul, MN 55155	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Donna	Attanasio	dattanasio@law.gwu.edu	George Washington University	2000 H Street NW Washington, DC 20052	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
John	Bailey	bailey@ilsr.org	Institute For Local Self-Reliance	1313 5th St SE Ste 303 Minneapolis, MN 55414	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Kenneth	Baker	Kenneth.Baker@walmart.com	Wal-Mart Stores, Inc.	2001 SE 10th St. Bentonville, AR 72716-5530	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Sara	Baldwin Auck	sarab@irecusa.org	Interstate Renewable Energy Council, Inc.	PO Box 1156 Latham, NY 12110	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
James J.	Bertrand	james.bertrand@stinson.com	Stinson Leonard Street LLP	150 South Fifth Street, Suite 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Derek	Bertsch	derek.bertsch@mrenergy.com	Missouri River Energy Services	3724 West Avera Drive PO Box 88920 Sioux Falls, SD 57109-8920	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
William	Black	bblack@mmua.org	MMUA	Suite 400 3025 Harbor Lane North Plymouth, MN 554475142	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Kenneth	Bradley	kbradley1965@gmail.com		2837 Emerson Ave S Apt CW112 Minneapolis, MN 55408	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Sydney R.	Briggs	sbriggs@swce.coop	Steele-Waseca Cooperative Electric	2411 W. Bridge St PO Box 485 Owatonna, MN 55060-0485	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Mark B.	Bring	mbring@otpco.com	Otter Tail Power Company	215 South Cascade Street PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Tony	Brunello	BADEMAIL-tbrunello@greentechleadership.org	Greentech Leadership Group	426 17th St Ste 700 Oakland, CA 94612-2850	Paper Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	200 S 6th St Ste 4000 Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Michael J.	Bull	mbull@mncee.org	Center for Energy and Environment	212 Third Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Jessica	Burdette	jessica.burdette@state.mn.us	Department of Commerce	85 7th Place East Suite 500 St. Paul, MN 55101	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Jason	Burwen	j.burwen@energystorage.org	Energy Storage Association	1155 15th St NW, Ste 500 Washington, DC 20005	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Joel	Cannon	jcannon@tenksolar.com	Tenk Solar, Inc.	9549 Penn Avenue S Bloomington, MN 55431	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Douglas M.	Carnival	dmc@mcgrannshea.com	McGrann Shea Carnival Straughn & Lamb	N/A	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.	12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Kenneth A.	Colburn	kcolburn@symbioticstrategies.com	Symbiotic Strategies, LLC	26 Winton Road Meredith, NH 32535413	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Carl	Cronin	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Arthur	Crowell	Crowell.arthur@yahoo.com	A Work of Art Solar	14333 Orchard Rd. Minnetonka, MN 55345	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Leigh	Currie	lcurrie@mncenter.org	Minnesota Center for Environmental Advocacy	26 E. Exchange St., Suite 206 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
David	Dahlberg	davedahlberg@nweco.com	Northwestern Wisconsin Electric Company	P.O. Box 9 104 South Pine Street Grantsburg, WI 548400009	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, Fifth Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Curt	Dieren	curt.dieren@dgr.com	L&O Power Cooperative	1302 S Union St Rock Rapids, IA 51246	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Ian	Dobson	Residential.Utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Brian	Draxten	bhdraxten@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380498	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Mike	Eggl	meggl@bepc.com	Basin Electric Power Cooperative	1717 East Interstate Avenue Bismarck, ND 58503	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kristen	Eide Tollefson	N/A	R-CURE	28477 N Lake Ave Frontenac, MN 55026-1044	Paper Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Bob	Eleff	bob.eleff@house.mn	Regulated Industries Cmte	100 Rev Dr Martin Luther King Jr Blvd Room 600 St. Paul, MN 55155	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Betsy	Engelking	betsy@geronimoenergy.com	Geronimo Energy	7650 Edinborough Way Suite 725 Edina, MN 55435	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Oncu	Er	oncu.er@avantenergy.com	Avant Energy, Agent for MMPA	220 S. Sixth St. Ste. 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
James C.	Erickson	jericksonkbc@gmail.com	Kelly Bay Consulting	17 Quechee St Superior, WI 54880-4421	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	1313 5th St SE #303 Minneapolis, MN 55414	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Emma	Fazio	emma.fazio@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
John	Fernandes	john.fernandes@res-americas.com	RES	11101 W. 120th Ave Suite 400 Broomfield, CO 80021	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Nathan	Franzen	nathan@geronimoenergy.com	Geronimo Energy	7650 Edinborough Way Suite 725 Edina, MN 55435	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Amy	Fredregill	Amy.S.Fredregill@xcelenergy.com	Xcel Energy	414 Nicollet Mall Minneapolis, MN 55401	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
John	Fuller	john.fuller@senate.mn	MN Senate	75 Rev Dr Martin Luther King Jr Blvd Room G-17 St. Paul, MN 55155	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Karen	Gados	karen@mysunshare.com	SunShare, LLC	1441 18th Street Suite 400 Denver, CO 80202	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Hal	Galvin	halgalvin@comcast.net	Provectus Energy Development llc	1936 Kenwood Parkway Minneapolis, MN 55405	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Allen	Gleckner	gleckner@fresh-energy.org	Fresh Energy	408 St. Peter Street Ste 220 Saint Paul, Minnesota 55102	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Bryan	Gower	bgower@apx.com	APX, Inc.	N/A	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Timothy	Gulden	info@winonarenewableenergy.com	Winona Renewable Energy, LLC	1449 Ridgewood Dr Winona, MN 55987	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Tony	Hainault	anthony.hainault@co.hennepin.mn.us	Hennepin County DES	701 4th Ave S Ste 700 Minneapolis, MN 55415-1842	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Jim	Hawley	jim.hawley@deweysquare.com	Mission:data Coalition	1020 16th Street, Suite 20 Sacramento, CA 95814	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Todd	Headlee	theadlee@dvigridsolutions.com	Dominion Voltage, Inc.	701 E. Cary Street Richmond, VA 23219	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Duane	Hebert	duane.hebert@novelenergy.biz	Novel Energy Solutions	1628 2nd Ave SE Rochester, MN 55904	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
John	Helmers	helmers.john@co.olmsted.mn.us	Olmsted County Waste to Energy	2122 Campus Drive SE Rochester, MN 55904-4744	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Jared	Hendricks	hendricksj@owatonnautilities.com	Owatonna Public Utilities	PO Box 800 208 S Walnut Ave Owatonna, MN 55060-2940	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Shane	Henriksen	shane.henriksen@enbridge.com	Enbridge Energy Company, Inc.	1409 Hammond Ave FL 2 Superior, WI 54880	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Paul	Hernandez	Paul.Hernandez@energycenter.org	Center for Sustainable Energy	426 17th Street, Suite 700 Oakland, CA 94612	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Michael	Hoppe	il23@mtn.org	Local Union 23, I.B.E.W.	932 Payne Avenue St. Paul, MN 55130	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Jim	Horan	Jim@MREA.org	Minnesota Rural Electric Association	11640 73rd Ave N Maple Grove, MN 55369	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Jan	Hubbard	jan.hubbard@comcast.net		7730 Mississippi Lane Brooklyn Park, MN 55444	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Casey	Jacobson	cjacobson@bepc.com	Basin Electric Power Cooperative	1717 East Interstate Avenue Bismarck, ND 58501	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
John S.	Jaffray	jjaffray@jjrpower.com	JJR Power	350 Highway 7 Suite 236 Excelsior, MN 55331	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2265 Roswell Road Suite 100 Marietta, GA 30062	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Nate	Jones	njones@hcpd.com	Heartland Consumers Power	PO Box 248 Madison, SD 57042	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Michael	Kampmeyer	mkampmeyer@a-e-group.com	AEG Group, LLC	260 Salem Church Road Sunfish Lake, Minnesota 55118	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Mark J.	Kaufman	mkaufman@ibewlocal949.org	IBEW Local Union 949	12908 Nicollet Avenue South Burnsville, MN 55337	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
John	Kearney	jmkearney@MnSEIA.org	MnSEIA	2512 33rd Ave S Minneapolis, MN 55406	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Jennifer	Kefer	jennifer@dgardiner.com	Alliance for Industrial Efficiency	David Gardiner & Associates, LLC 2609 11th St N Arlington, VA 22201-2825	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Julie	Ketchum	N/A	Waste Management	20520 Keokuk Ave Ste 200 Lakeville, MN 55044	Paper Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Hudson	Kingston	hkingston@mncenter.org	MN Center for Environmental Advocacy	26 East Exchange Street, Suite 206 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Brad	Klein	bklein@elpc.org	Environmental Law & Policy Center	35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago, IL 60601	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Madeleine	Klein	mklein@socoreenergy.com	SoCore Energy	225 W Hubbard Street Suite 200 Chicago, IL 60654	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
John	Kluempke	BADEMAIL-jwkluempke@winlectric.com	Elk River Winlectric	12777 Meadowvale Rd Elk River, MN 55330	Paper Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Brian	Krambeer	bkrambeer@tec.coop	Tri-County Electric Cooperative	PO Box 626 31110 Cooperative Way Rushford, MN 55971	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Jon	Kramer	sundialjon@gmail.com	Sundial Solar	3209 W 76th St Edina, MN 55435	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Michael	Krause	michaelkrause61@yahoo.com	Kandiyo Consulting, LLC	433 S 7th Street Suite 2025 Minneapolis, Minnesota 55415	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Michael	Krikava	mkrikava@briggs.com	Briggs And Morgan, P.A.	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Matthew	Lacey	Mlacey@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Douglas	Larson	dlarson@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Dean	Leischow	dean@sunriseenergyventures.com	Sunrise Energy Ventures	601 Carlson Parkway, Suite 1050 Minneapolis, MN 55305	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Benjamin	Lowe	ben.lowe@alevo.com	Alevo USA Inc.	2321 Concord Parkway South Concord, North Carolina 28027	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Susan	Ludwig	sludwig@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Samuel	Mason	smason@beltramielectric.com	Beltrami Electric Cooperative, Inc.	4111 Technology Dr. NW PO Box 488 Bemidji, MN 56619-0488	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Erica	McConnell	mcconnell@smwlaw.com	Shute, Mihaly & Weinberger LLP	396 Hayes St San Francisco, California 94102-4421	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Dave	McNary	David.McNary@hennepin.us	Hennepin County DES	701 Fourth Ave S Ste 700 Minneapolis, MN 55415-1842	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
John	McWilliams	jmm@dairynet.com	Dairyland Power Cooperative	3200 East Ave SPO Box 817 La Crosse, WI 54601-7227	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Thomas	Melone	Thomas.Melone@AllcoUS.com	Minnesota Go Solar LLC	222 South 9th Street Suite 1600 Minneapolis, Minnesota 55120	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Herbert	Minke	hminke@allete.com	Minnesota Power	30 W Superior St Duluth, MN 55802	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Dalene	Monsebroten	dalene@mncable.net	Northern Municipal Power Agency	123 2nd St W Thief River Falls, MN 56701	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Martin	Morud	mmorud@trunorthsolar.com	Tru North Solar	5115 45th Ave S Minneapolis, MN 55417	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Michael	Murray	mmurray@missiondata.org	Mission:Data Coalition	1020 16th St Ste 20 Sacramento, CA 95814	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Ron	Nelson	ron.nelson@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street Saint Paul, Minnesota 55101	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Ben	Nelson	benn@cmpasgroup.org	CMMPA	459 South Grove Street Blue Earth, MN 56013	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute	2801 21ST AVE S STE 220 Minneapolis, MN 55407-1229	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	O'Brien	david.obrien@navigant.com	Navigant Consulting	77 South Bedford St Ste 400 Burlington, MA 01803	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Jeff	O'Neill	jeff.oneill@ci.monticello.mn.us	City of Monticello	505 Walnut Street Suite 1 Monticelllo, Minnesota 55362	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Russell	Olson	rolson@hcpd.com	Heartland Consumers Power District	PO Box 248 Madison, SD 570420248	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Dan	Patry	dpatry@sunedison.com	SunEdison	600 Clipper Drive Belmont, CA 94002	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Jeffrey C	Paulson	jeff.jcplaw@comcast.net	Paulson Law Office, Ltd.	4445 W 77th Street Suite 224 Edina, MN 55435	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Mary Beth	Peranteau	mperanteau@wheelerlaw.com	Wheeler Van Sickle & Anderson SC	44 E. Mifflin Street, 10th Floor Madison, WI 53703	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Hannah	Polikov	hpolikov@aee.net	Advanced Energy Economy Institute	1000 Vermont Ave, Third Floor Washington, DC 20005	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
David G.	Prazak	dprazak@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Gayle	Prest	gayle.prest@minneapolismn.gov	City of Mpls Sustainability	350 South 5th St, #315 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Gregory	Randa	granda@lakecountrypower.com	Lake Country Power	2810 Elida Drive Grand Rapids, MN 55744	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Mark	Rathbun	mrathbun@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Michael	Reinertson	michael.reinertson@avantenergy.com	Avant Energy	220 S. Sixth St. Ste 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
John C.	Reinhardt		Laura A. Reinhardt	3552 26Th Avenue South Minneapolis, MN 55406	Paper Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Craig	Rustad	crustad@minnkota.com	Minnkota Power	1822 Mill Road PO Box 13200 Grand Forks, ND 582083200	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Robert K.	Sahr	bsahr@eastriver.coop	East River Electric Power Cooperative	P.O. Box 227 Madison, SD 57042	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Thomas	Scharff	thomas.scharff@versoco.com	Verso Corp	600 High Street Wisconsin Rapids, WI 54495	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

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Larry L.	Schedin	Larry@LLSResources.com	LLS Resources, LLC	332 Minnesota St, Ste W1390 St. Paul, MN 55101	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Christopher	Schoenherr	cp.schoenherr@smmpa.org	SMMPA	500 First Ave SW Rochester, MN 55902-3303	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Dean	Sedgwick	N/A	Itasca Power Company	PO Box 457 Bigfork, MN 56628-0457	Paper Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Maria	Seidler	maria.seidler@dom.com	Dominion Energy Technology	120 Tredegar Street Richmond, Virginia 23219	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
William	Seuffert	Will.Seuffert@state.mn.us		75 Rev Martin Luther King Jr Blvd 130 State Capitol St. Paul, MN 55155	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
David	Shaffer	DShaffer@MnSEIA.org	Minnesota Solar Energy Industries Project	1005 Fairmount Ave Saint Paul, MN 55105	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Patricia	Sharkey	psharkey@environmentallawcounsel.com	Midwest Cogeneration Association.	180 N. LaSalle Street Suite 3700 Chicago, Illinois 60601	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Bria	Shea	bria.e.shea@xcelenergy.com	Xcel Energy	414 Nicollet Mall Minneapolis, MN 55401	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Doug	Shoemaker	dougs@mnRenewables.org	MRES	2928 5th Ave S Minneapolis, MN 55408	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Mrg	Simon	mrgsimon@mrenergy.com	Missouri River Energy Services	3724 W. Avera Drive P.O. Box 88920 Sioux Falls, SD 571098920	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Anne	Smart	anne.smart@chargepoint.com	ChargePoint, Inc.	254 E Hacienda Ave Campbell, CA 95008	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Ken	Smith	ken.smith@ever-greenenergy.com	Ever Green Energy	1350 Landmark Towers 345 St. Peter St St. Paul, MN 55102	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Joshua	Smith	joshua.smith@sierraclub.org		85 Second St FL 2 San Francisco, California 94105	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Beth H.	Soholt	bsoholt@windonthewires.org	Wind on the Wires	570 Asbury Street Suite 201 St. Paul, MN 55104	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Sky	Stanfield	stanfield@smwlaw.com	Shute, Mihaly & Weinberger	396 Hayes Street San Francisco, CA 94102	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Tom	Stanton	tstanton@nrri.org	NRRI	1080 Carmack Road Columbus, OH 43210	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Byron E.	Starns	byron.starns@stinson.com	Stinson Leonard Street LLP	150 South 5th Street Suite 2300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
James M.	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	470 U.S. Bank Plaza 200 South Sixth Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Eric	Swanson	eswanson@winthrop.com	Winthrop Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Thomas P.	Sweeney III	tom.sweeney@easycleanenergy.com	Clean Energy Collective	P O Box 1828 Boulder, CO 80306-1828	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Steve	Thompson	stevet@cmpasgroup.org	Central Minnesota Municipal Power Agency	459 S Grove St Blue Earth, MN 56013-2629	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD	4445 W 77th Street Suite 224 Edina, MN 55435	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Lise	Trudeau	lise.trudeau@state.mn.us	Department of Commerce	85 7th Place East Suite 500 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Karen	Turnboom	karen.turnboom@versoco.com	Verso Corporation	100 Central Avenue Duluth, MN 55807	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Roger	Warehime	warehimer@owatonnautilities.com	Owatonna Public Utilities	208 South WalnutPO Box 800 Owatonna, MN 55060	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Jenna	Warmuth	jwarmuth@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802-2093	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Paul	White	paul.white@prcwind.com	Project Resources Corp./Tamarac Line LLC/Ridgewind	618 2nd Ave SE Minneapolis, MN 55414	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Jason	Willett	jason.willett@metc.state.mn.us	Metropolitan Council	390 Robert St N Saint Paul, MN 55101-1805	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Cam	Winton	cwinton@mnchamber.com	Minnesota Chamber of Commerce	400 Robert Street North Suite 1500 St. Paul, Minnesota 55101	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Daniel P	Wolf	dan.wolf@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Thomas J.	Zaremba	TZaremba@wheelerlaw.com	WHEELER, VAN SICKLE & ANDERSON	44 E. Mifflin Street, 10th Floor Madison, WI 53703	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List
Christopher	Zibart	czibart@atcllc.com	American Transmission Company LLC	W234 N2000 Ridgeview Pkwy Court Waukesha, WI 53188-1022	Electronic Service	No	OFF_SL_15-556_OFF_SL_15-556_Official Service List