



2016 WIND INTEGRATION STUDY

January 5, 2016

Operations and Planning Engineering



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EXECUTIVE SUMMARY

1.1 OVERVIEW

The Southwest Power Pool (SPP) in 2009 conducted a Wind Integration Study, which forecasted a significant increase of installed wind capacity in the region. As a result, SPP implemented a number of recommendations from the study to ensure continued reliable operation of the power grid. With the 2014 launch of the SPP Integrated Marketplace, the 2015 addition of the Integrated System as an SPP member and additional wind capacity currently in queue, SPP conducted a new Wind Integration Study in 2015 to determine the operational and reliability impacts of integrating increased wind generation into the SPP transmission system. The study required detailed engineering analysis and significant effort to interpret the study results and findings. The study assessed the reliability impacts associated with additional wind generation resources installed within the SPP operating area.

1.2 STUDY APPROACH

The study was performed for the year 2016 with the assumption that SPP operates the additional wind resources included within the Integrated Systems region. Three wind penetration levels were studied and each was compared to the current system conditions (Base Case, with approximately % wind penetration). The three penetration levels were 30%, 45%, and 60% wind penetration as a percentage of internal SPP load (30% Case, 45% Case, and 60% Case, respectively).

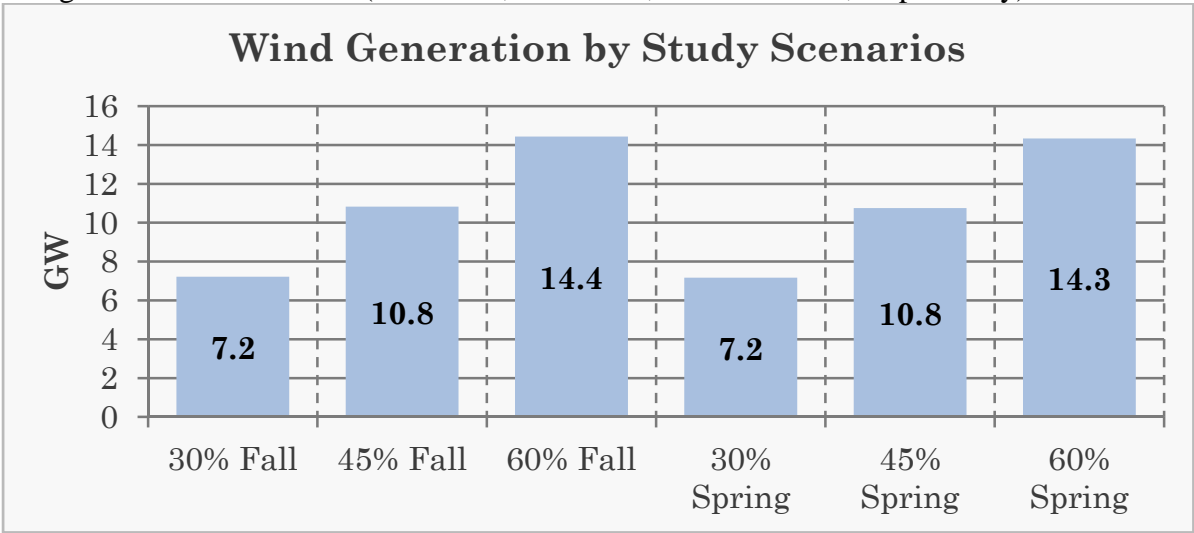


Figure 1.1: Wind Generation in each studied scenario

The goal of the study was to identify challenges for integrating higher levels of wind penetration into the SPP transmission system and to make recommendations for areas that need to be improved to operate at those levels. The study was a reliability-based study between operations and planning with limited focus on economics. The study did not attempt to identify analytical cost comparison between building transmission upgrades and curtailing wind. The study assessed overall system impacts and potential reliability system impacts as wind penetration increases. The Wind Integration Study utilized and assessed results from existing Integrated Transmission Plan (ITP) studies, installed conceptual transmission and voltage components for mitigation of constrained elements. The study discovered potential solutions and made recommendations to support reliability and

maintain system integrity as wind penetration levels increase. The Wind Integration Study performed a steady state N-1 thermal and voltage analysis, which assessed transmission impacts. The area regions defined in the study are Woodward, West Kansas, East and Central Kansas, Texas Panhandle South and New Mexico (SPS Region), and Nebraska North. The study applied historical operations day planned outages to the model to simulate and create a more accurate model. The Wind Integration Study also performed simulations and analysis with no outages applied in the models and compared results between simulations. This analysis identified outage impacting constraints and also provided insight into areas of the system where identified ITP projects should be expedited. The Wind Integration Study performed a redispatch analysis to assess potential curtailments and a voltage stability analysis to assess the potential for voltage collapse. The Electric Power Research Institute (EPRI) performed an analysis for the SPP area using the EPRI developed Inflexion tool, which assessed ramping, variability, and generator flexibility.

1.3 MAJOR FINDINGS

SPP wind generation resources are primarily located in the southwestern and north central portions of the SPP footprint. Wind energy has grown over the last several years as additional bulk transmission has been added to the footprint and represented approximately 14% of total system capacity at the end of 2015. Wind development is expected to expand to higher levels based on the generation interconnection requests in the queue. This study determined that additional operational procedures need to be considered to reliably operate above the currently installed maximum wind capability. Recommendations in the following section outline specific tasks that, if implemented, would enable the SPP transmission system to reliably handle up to the 60% wind penetration levels studied.

- Steady-state thermal and voltage analysis confirmed the need for approved ITP projects and discovered additional transmission needs beyond what is approved in the ITP process. In some cases the approved ITP projects should be expedited and placed in-service sooner than the projects' scheduled in-service date. The steady-state analysis also found that Nebraska north into the Integrated System did not experience major congestion related to wind integration. The analysis did indicate high voltage conditions between Nebraska and the Integrated System, which was mitigated by switching existing capacitor banks.
- Voltage stability analysis showed that renewable penetration levels are approaching current limits. Uncertainty in knowledge of operations and planning model variables warrants criteria for real and reactive power margins and incentive to supply Dynamic Reactive Reserves to extend voltage collapse beyond thermal and voltage criteria limiting conditions.
- Ramping analysis examined the impact of wind on system ramping requirements and the ability of the system to meet the ramping needs. By studying one year of data (March 2014-Feb 2015), it was shown that wind does have an impact on overall system ramping, albeit at a relatively small level. Ramp lengths from 5 minutes up to 12 hours were all shown to increase due to wind, with longer intervals seeing a larger impact. While the largest ramps show a minor increase, the time periods during which large ramping occurs becomes less predictable, and the net load (load minus wind) has become slightly more variable due to the presence of wind. Studying the actual hourly dispatch of the system, SPP appears to have sufficient ramping capability for the near term. However, ramping issues should be monitored – the study here provides a useful base against which future changes can be measured. As wind increases, the system may require new operational capabilities, either by

developing new ancillary services products to manage within-hour ramping, or new situational awareness tools for inter-hour ramping. It was also shown that the ability to dispatch variable energy resources can reduce the largest short-term net load ramps, particularly in the case of over generation issues.

- Redispatch analysis found that all N-1 constraints were able to be successfully resolved with re-dispatch of the existing dispatchable generation, with very heavy curtailments of wind farms at the higher penetration cases. However, the heavy curtailments result in thousands of MWs from low variable cost generation being left on the table due to significant transmission constraints. Allowing Non Dispatchable Variable Energy Resources (NDVER) to participate as dispatchable resources led to a reduction of wind curtailments in high wind penetration scenarios. This lowered the overall production costs as the load was served from a high penetration of wind power, lower shadow prices on constraints, and less extreme pricing during congestion as the Security Constrained Economic Dispatch (SCED) was allowed to redispatch the previously NDVER generation closer to the constraint, rather than curtailing larger amounts of generation located further away from the constraint.
- Outage analysis demonstrated that without transmission outages applied, significant overloads were still observed on multiple facilities. Several of the remaining overloaded facilities do not have upgrades approved that will provide relief. Additionally, the overloads that existed only during outage conditions in the studies demonstrated the value of planned transmission upgrades and a potential need to expedite those projects.

1.4 RECOMMENDATIONS

The Wind Integration Study performed an assessment and identified areas to enhance reliability and provide additional grid flexibility. The listed recommendations would increase transmission reliability and provide additional reliability capabilities as additional renewable capacity is installed throughout the SPP region.

Assess Voltage reactive support capabilities for existing wind farms and recommend enhanced operations tools for Dynamic Reactive Reserves and develop criteria requirements for real-time operations.

1. Evaluate and recommend real-time operations tools to calculate and monitor real-time voltage stability limits using an applicable real-time software suite
2. Provide additional flexibility to the Reliability Coordinator for NDVER redispatch.
3. Develop additional planning criteria to enhance analysis requirements for incorporating a more robust scenario development.

Accelerate ITP projects

4. Evaluate the bulk electric system impacts with the addition of Solar PV in combination with wind.
5. Perform an additional evaluation of PMU applications to provide real-time situational awareness.

GLOSSARY

2.1 GLOSSARY TERMS

Asset Owner

An owner of any combination of: (1) registered physical assets (Resource, load, Import Interchange Transaction, Export Interchange Transaction, Through Interchange Transaction), (2) Transmission Congestion Rights or (3) any combination of financial assets (Virtual Energy Offer, Virtual Energy Bid, Bilateral Settlement Schedules) within the SPP Balancing Authority Area.

Balancing Authority

As defined in the SPP Tariff.

Balancing Authority Area

As defined in the SPP Tariff. As defined in Attachment AE of the SPP Tariff.

Bulk Electric System (BES)

All Transmission Elements operated at 100 kV or higher. This does not include facilities used in the local distribution of electric energy. Inclusions and exclusions apply.¹

Central Prevailing Time (CPT)

Clock time for the season of a year, i.e. Central Standard Time and Central Daylight Time.

Common Bus

A single bus to which two or more Resources that are owned by the same Asset Owner are connected in an electrically equivalent manner where such Resources may be treated as interchangeable for certain compliance monitoring purposes.

Congestion Management Event (CME)

An event during which constraints are activated in RTBM in order to re-dispatch the system to reduce the impact of SPP Market Flow on a Coordinated Flowgate or Reciprocal Coordinated Flowgate or in order to redispatch the system to remove projected limit violation on flowgates other than a Coordinated Flowgate or Reciprocal Coordinated Flowgate. This event may entail a parallel issuance of TLR.

Contingency Reserve

As defined in the SPP Tariff.

Day-Ahead

The time period starting at 0001 and ending at 2400 on the day prior to the Operating Day.

¹ [NERC, Bulk Electric System Definition Reference Document](#), version 2, April 2014, page 3.

Day-Ahead Market (DA Market)

The financially binding market for Energy and Operating Reserve that is conducted on the day prior to the Operating Day.

Day-Ahead Reliability Unit Commitment (Day-Ahead RUC)

The process performed by SPP following the close of the DA Market and prior to the Operating day to assess resource and operating reserve adequacy for the Operating Day, commit and/or de-commit Resources as necessary, and communicate commitment or de-commitment of Resources to the appropriate Market Participants as necessary.

De-Commit Time

The time specified by SPP or a local Transmission Operator in a de-commit order at which a Resource should begin de-synchronization procedures.

Designated Resource

As defined in the SPP Tariff.

Desired Dispatch

A MW value calculated from a Resource's RTBM Energy Offer Curve that represents the point at which the Resource's incremental Energy offer first exceeds the Resource's RTBM LMP.

Dispatch Instruction (DI)

The communicated Resource target energy MW output level at the end of the Dispatch Interval.

Dispatch Status

A parameter submitted as part of a Resource Offer that specifies the option under which the Resource is to be dispatched once the Resource has been committed and becomes a Synchronized Resource.

Dispatchable Demand Response Resource

A controllable load, including behind-the-meter generation, that is a Dispatchable Resource that can reduce the withdrawal of Energy from the transmission grid when directed by SPP.

Dispatchable Resource

A Resource for which an Energy Offer Curve has been submitted and that is available for dispatch by SPP on a Dispatch Interval basis.

Dispatchable Variable Energy Resource (DVER) A Variable Energy Resource that is capable of being incrementally dispatched down by the Transmission Provider.

Dynamic reactive reserves (DRR)

Reactive reserves that can be used to rapidly respond to system voltage deviations. SVCs, SC, and synchronous generators provide dynamic reactive reserves.

Dynamic Security Assessment Software (DSATools)

A suite of state-of-the-art power system analysis tools and provides the capabilities for a comprehensive system security assessment, including all forms of stability.

Electric Industry Registry (EIR)

The Electric Industry Registry serves as a central repository of information that is required for commercial interactions.

Emergency

As defined as Emergency Condition in the SPP Tariff.

Energy

An amount of electricity that is Bid or Offered, produced, purchased, consumed, sold or transmitted over a period of time, which is measured or calculated in megawatt hours (MWh).

Energy and Operating Reserve Markets

The Day-Ahead Market and Real-Time Balancing Market.

Energy Management System (EMS)

The software system used by SPP for the real-time acquisition of operating data and operations.

Export Interchange Transaction

A Market Participant schedule for exporting Energy out of the SPP Balancing Authority Area.

Import Interchange Transaction

A Market Participant schedule for importing Energy into the SPP Balancing Authority Area.

Interchange Transaction

Any Energy transaction that is crossing the boundary of the SPP Balancing Authority Area and requires checkout with one or more external Balancing Authority Areas. This includes any Import Interchange Transaction, Export Interchange Transaction and/or Through Interchange Transaction.

Intra-Day Reliability Unit Commitment (IDRUC)

The process performed by SPP following the completion of the DA RUC and throughout the Operating day to assess Resource and Operating Reserve adequacy for the Operating Day, commit and/or de-commit Resources as necessary, and communicate commitment or de-commitment of Resources to the appropriate Market Participants as necessary.

Jointly Owned Resource (JOU)

A Resource that is owned by more than one Asset Owner.

Load Serving Entity (LSE)

As defined in Attachment AE of the Tariff.

Local Emergency Condition (LEC)

As defined in the SPP Tariff

Local Reliability Issue (LRI)

As defined in the SPP Tariff.

Locational Marginal Price (LMP)

The market clearing price for Energy at a given Price Node which is equivalent to the marginal cost of serving demand at the Price Node while meeting SPP Operating Reserve requirements.

Long-Term Congestion Right (LTCR)

As defined in Attachment AE of the Tariff.

Manual Dispatch Instruction

A dispatch instruction created outside of the normal RTBM SCED Dispatch Instruction solution to address a system reliability condition that could not be resolved by the RTBM SCED.

Market Clearing Price (MCP)

The price used for settlements of an Operating Reserve product in each Reserve Zone. A separate price is calculated for Regulation-Up Service, Expected Regulation-Up Mileage, Regulation-Down Service, Expected Regulation-Down Mileage, Spinning Reserve and Supplemental Reserve.

Market Flow

The impact on transmission system flowgate flows resulting from an operational entity's Resources serving market load within a defined market footprint.

Market Participant (MP)

As defined in the SPP Tariff.

Megawatt (MW)

A measurement unit of the instantaneous demand for energy.

Mid-Term Load Forecast

A Settlement Area Load forecast developed by SPP on a rolling hourly basis for the next seven days for input into Reliability Unit Commitment.

Net Actual Interchange

The algebraic sum of all metered interchange over all interconnections between two physically adjacent Balancing Authority Areas.

Net Benefits Test

As defined in the SPP Tariff.

Net Scheduled Interchange

The algebraic sum of all Interchange Transactions between Balancing Authorities for a given period or instant in time.

Non-Dispatchable Variable Energy Resource (NDVER)

A Variable Energy Resource that is not capable of being incrementally dispatched down by the Transmission Provider.

Offer

A commitment to sell (i) a quantity of Energy at a specific minimum price such as a Resource Offer, a Virtual Energy Offer and/or an Import Interchange Transaction Offer, or (ii) a quantity of Transmission Congestion Rights at a specific minimum price, where such quantities may be submitted in 0.1 MW increments.

Operating Day

A daily period beginning at midnight.

Operating Hour

A 60-minute period of time during the Operating Day corresponding to a clock hour typically expressed as hour-ending.

Operating Reserve

Resource capacity held in reserve for Resource contingencies and NERC control performance compliance which includes the following products: Regulation-Up Service, Regulation-Down Service, Spinning Reserve and Supplemental Reserve.

Operating Reserve Only Resource

A Resource that cannot be cleared or dispatched for Energy that is qualified to provide any or all of the Operating Reserve products: Regulation-Up, Regulation-Down, Spinning Reserve, or Supplemental Reserve.

Parallel Flow

Flow on the Transmission System not scheduled with SPP caused by entities external to the SPP Market Footprint. (Also known as loop flow.)

Power Transfer Distribution Factor (PTDF)

The percentage of power transfer flowing through a facility or set of facilities (flowgate) for a particular transfer when there are no contingencies.

Quick-Start Resource

A Resource that can be started, synchronized and inject Energy within ten minutes of SPP notification.

Ramp-Rate-Down

A curve specifying MW/minute ramp rates applicable between Resource operating ranges that is used to dispatch Resources in the down direction.

Ramp-Rate-Up

A curve specifying MW/minute ramp rates applicable between Resource operating ranges that is used to dispatch Resources in the up direction.

Real-Time

The continuous time period during which the RTBM is operated.

Real-Time Balancing Market (RTBM)

The market operated by SPP continuously in real-time to balance the system through deployment of Energy and to clear Regulation-Up, Regulation-Down, Spinning Reserve and Supplemental Reserve.

Reference Bus

The location on the SPP Transmission System relative to which all mathematical quantities, including shift factors and penalty factors relating to physical operation, will be calculated.

Regulation Deployment

The utilization of Regulation-Up Service and/or Regulation-Down Service through Automatic Generation Control (AGC) equipment to automatically and continuously adjust Resource output to balance the SPP Balancing Authority Area in accordance with NERC control performance criteria.

Regulation-Down

As defined in the SPP Tariff.

Regulation Ramp Rate

A curve specifying MW/minute ramp rates that are used to determine a Resource's maximum Regulation-Up Service and/or Regulation-Down Service quantities.

Regulation Response Time

The maximum amount of time allowed for a Resource to move its output from zero Regulation Deployment to the full amount of Regulation-Up cleared or to move from zero Regulation Deployment to the full amount of Regulation-Down cleared.

Regulation-Up

As defined in the SPP Tariff.

Reported Load

As defined in the SPP Tariff.

Reserved Capacity

The reservation MW between a specified source and sink associated with SPP Transmission Service.

Reserve Sharing Event (RSE)

A request for assistance to deploy Contingency Reserve by any Reserve Sharing Group (RSG) member following the sudden loss of a Resource.

Reserve Sharing Group (RSG)

As defined in the SPP Tariff.

Reserve Shutdown

An SPP approved Resource shutdown that is requested by a Market Participant for the purposes of making the Resource unavailable for SPP commitment and dispatch due to reasons other than to perform maintenance or to repair equipment.

Reserve Zone (RZ)

A zone containing a specific group of Price Nodes for which a minimum and maximum Operating Reserve requirement is established.

Resource

As defined in the SPP Tariff.

Resource Offer For a Resource, the combination of its Start-Up Offer, No-Load Offer, Energy Offer Curve, Regulation-Up Service Offer, Regulation-Down Service Offer, Spinning Reserve Offer and Supplemental Reserve Offer.

Reliability Unit Commitment (RUC)

The process performed by SPP to assess resource and operating reserve adequacy for the Operating Day, commit and/or de-commit resource as necessary, and communicate commitment or de-commitment of Resources to the appropriate Market Participants as necessary.

Security Constrained Economic Dispatch (SCED)

An algorithm capable of clearing, dispatching, and pricing Energy and Operating Reserve on a co-optimized basis that minimizes overall cost while enforcing multiple security constraints.

Security Constrained Unit Commitment (SCUC)

An algorithm capable of committing Resources to supply Energy and/or Operating Reserve on a co-optimized basis that minimizes capacity costs while enforcing multiple security constraints.

Short-Term Load Forecast (STLF)

A Settlement Area Load forecast developed by SPP on a rolling 5-minute basis for the next 120 Dispatch Intervals for input into the Real-Time Balancing Market.

Spinning Reserve

As defined in the SPP Tariff.

SPP Forecast Area

A geographic area within the SPP BA defined by SPP based upon historical operating experience for the purposes of developing load forecasts.

SPP Integrated Marketplace

The Energy and Operating Reserve Markets and the Transmission Congestion Rights Markets.

SPP Region

As defined in the SPP Tariff.

State Estimator

The computer software used to estimate the properties of the electric system based on a sample of system measurements based on current system conditions.

Static VAR compensator (SVC)

VAR sources that are composed of shunt reactors and shunt capacitors. High Speed electronic switching equipment (thyristor switches) are used to adjust the amount of reactors or capacitors in-service at any one time. In an SVC there are no rotating parts every element is static.²

Synchronous condenser (SC)

A synchronous motor that produces only reactive power.

Synchronized Resource

A Resource that is electrically connected to the grid as evidenced by the closing of the Resource circuit breaker.

System Intact (SI)

Power flow BES model with all normally in-service components on or energized.

Through Interchange Transaction

A Market Participant schedule submitted between two External Interfaces for use in the DA Market or RTBM for moving Energy through the SPP Balancing Authority Area.

Transmission Loading Relief (TLR)

The NERC prescribed method for relieving congestion on Coordinated Flowgates and Reciprocal Coordinated Flowgates through reductions in tagged flow and Market Flow associated with these flowgates.

Variable Energy Resource (VER)

A device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

² Electric Power Research Institute, "EPRI Power system Dynamics Tutorial", EPRI, Palo Alto, CA. 2009. 1016042, available at www.epri.com, Section 5.6.4, pages 5-57 and 5-58.

Voltage Collapse

Voltage Collapse is a Process in which a voltage unstable system experiences an uncontrolled reduction in system voltage.³

Voltage Stability

Voltage stability is the ability of a power system to maintain adequate voltage magnitudes. When the load connected to a voltage stable system is increased, the power delivered to that load also increases. In a voltage stable system both power and voltage are controllable. In a voltage unstable system the system operators have lost control of both voltage magnitude and power transfer.⁴

Voltage Security Analysis (VSA)

Powerflow based steady-state assessment to determine the voltage stability for generation to generation real power transfers while maintaining constant loads under different powerflow initial conditions, i.e. no outages, multiple outages.

Voltage Security Assessment Tool (VSAT)

Powertech Labs, Inc., DSATools, VSAT is a highly automated analysis tool designed for a comprehensive voltage security assessment using powerflow-based steady-state methods.⁵

Wind Integration Study (WIS)

A SPP system study that evaluates the impact of wind penetration and identifies system breakpoints.

³ Ibid, 2, Section 6.2.2, page 6-2.

⁴ Electric Power Research Institute, “EPRI Power system Dynamics Tutorial”, EPRI, Palo Alto, CA. 2009. 1016042, available at www.epri.com, Section 6.2.2, page 6-1.

⁵ Powertech Labs, Inc., Dynamic Security Assessment Software (DSATools), [Voltage Security Assessment Tool \(VSAT\)](#).

INTRODUCTION

3.1 BACKGROUND AND OBJECTIVES OF THE STUDY

The Southwest Power Pool (SPP) in 2015 began conducting a study to determine the operational and reliability impacts of integrating wind generation into the SPP transmission system. The study required detailed engineering analysis and significant effort to interpret the study results and findings. The study assessed the reliability impacts associated with additional wind generation resources installed within the SPP operating area. The study objectives were to identify system transmission and Voltage break points and perform ramping, re-dispatch, and outage analysis within the SPP transmission system through increasing wind penetration levels.

TRANSMISSION IMPACT STUDY

- Steady-state thermal and voltage analysis
- Voltage stability analysis
- Ramping analysis
- Re-dispatch analysis
- Outage analysis

3.2 THE SOUTHWEST POWER POOL

SPP was founded in 1941 with 11 members and after WWII the members companies continue the realized benefits of regional coordination. In 1968 SPP became a NERC regional council and SPP continued to reach a number of milestones as the organization progressed through history. SPP implemented telecommunication networks in 1980; in 1991 SPP implemented the reserve sharing group then implemented reliability coordination in 1997, and tariff administration in 1998. The SPP's most recent achievement occurred in 2014 with the launch of the Integrated Market Place. SPP is a Regional Transmission Organization (RTO) approved by the Federal Energy Regulatory Commission (FERC). As an RTO, SPP ensures the reliability of the transmission system and transmission infrastructure. SPP also, provides competitive wholesale pricing of electricity.

3.3 KEY CHALLENGES OF WIND INTEGRATION

SPP has already experienced real-time wind penetration levels of almost 40%. This is projected to significantly increase in the next couple of years. At these high levels of wind penetration, SPP operations must ensure that it is prepared for changes that occur in generation output. SPP currently has a combination of Non-Dispatchable and Dispatchable Variable Energy Resources (NDVER/DVER) installed within the SPP footprint. By maintaining a fleet of NDVERS, it limits available ancillary service capacity and requires thermal resources and DVERs to provide available capacity for ancillary services.

3.4 STUDY PROCESS

The 2015 Wind Integration Study had multiple sensitivities and followed the process shown below for reliability assessment portion of the study.

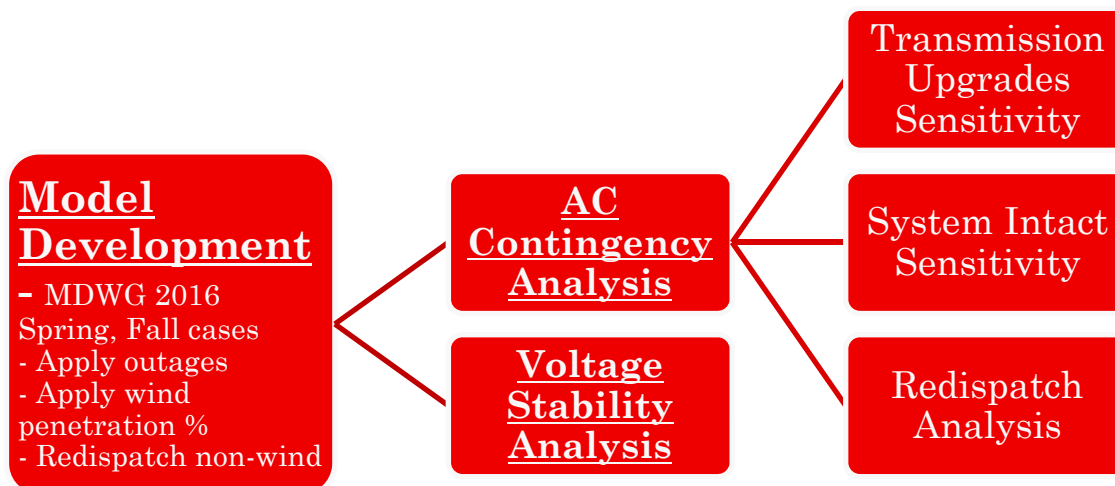


Figure 3.1: Process flow for Analysis of Wind Integration Study

The Ramping Analysis stage of the study was carried out separately by EPRI, using the data supplied by SPP.

SPP MODEL DEVELOPMENT

4.1 STEADY STATE MODELING

The topology used for the Wind Integration Study was developed through the Model Development Working Group (MDWG) which is responsible for maintenance of an annual series of transmission planning models (power flow and short circuit models and associated stability database) which represent the current and planned electric network of the Southwest Power Pool. It is also responsible for providing NERC with data that supports the models developed by the Multiregional Modeling Working Group (MMWG) and the System Dynamics Database Working (SDDWG). An SPP MDWG Model Development Procedure Manual is publically posted on spp.org.

The desired base models for the Wind Integration Study analysis consisted of a 2016 Spring and a 2016 Fall topology with Light load conditions and historical operations transmission and generation outages applied. A total of six models were built with wind dispatched at 30%, 45%, and 60% of SPP load. There wasn't enough wind in the MDWG models to dispatch to 60% of the SPP 2016 Light load. Wind generation from the SPP Generator Interconnection Queue that is on-schedule and has a fully executed Interconnection Agreement was added to the 60% Wind Integration Study models. This resulted in about 2.9GW of additional wind capacity.

The 2015 Series MDWG models were used to develop the Wind Integration Study models. Since the MDWG Light load powerflow models have the same topology as the spring models, the 2016 Light load MDWG model was used to develop the 2016 Spring Wind Integration Study model. The SPP load levels from the 2016 MDWG Light model were applied to the 2016 MDWG Fall model to develop the 2016 Fall Wind Integration Study model. Historical transmission and generation outages were applied and the difference in historical outages between the Fall and Spring did cause the light load level in the Fall to be slightly different than the Spring.

TARA PowerGem was used to dispatch the models by applying a Security Constrained Dispatch (SCED) treating SPP as a Consolidated Balancing Authority. The economic data from the 2015 ITP10 was utilized to perform the SCED. The SPP portion of the NERC Book of Flowgates was used initially to constrain the SCED dispatch. Any overload or voltage issue resulting from the dispatch was evaluated during the analysis of each Wind Integration Study model. Manual adjustments were made based on engineering judgment to address base case overloads and voltage less than .95 per unit. This included adjusting transformer tap settings, cap banks, reactors and minor dispatch changes. There were a few base case overloads and low voltage instances remaining in the 60% Wind Integration Study models. SVCs were also added to the 60% Wind Integration Study models to address solving issues due to voltage collapse. The SVCs were added at Washita 138kV (WFEC), Spearville 345kV (SUNC), and Thistle 345kV (SUNC).

The load level for SPP in the Wind Integration Study Spring models is about 23.9GW and in the Fall is about 24GW. A summary of generation output by fuel type is provided below for each Wind Integration Study model. The average wind capacity factors of the wind dispatched is about:

- 30% WIS models – 80% Capacity Factor
- 45% WIS models – 87% Capacity Factor
- 60% WIS models – 93% Capacity Factor

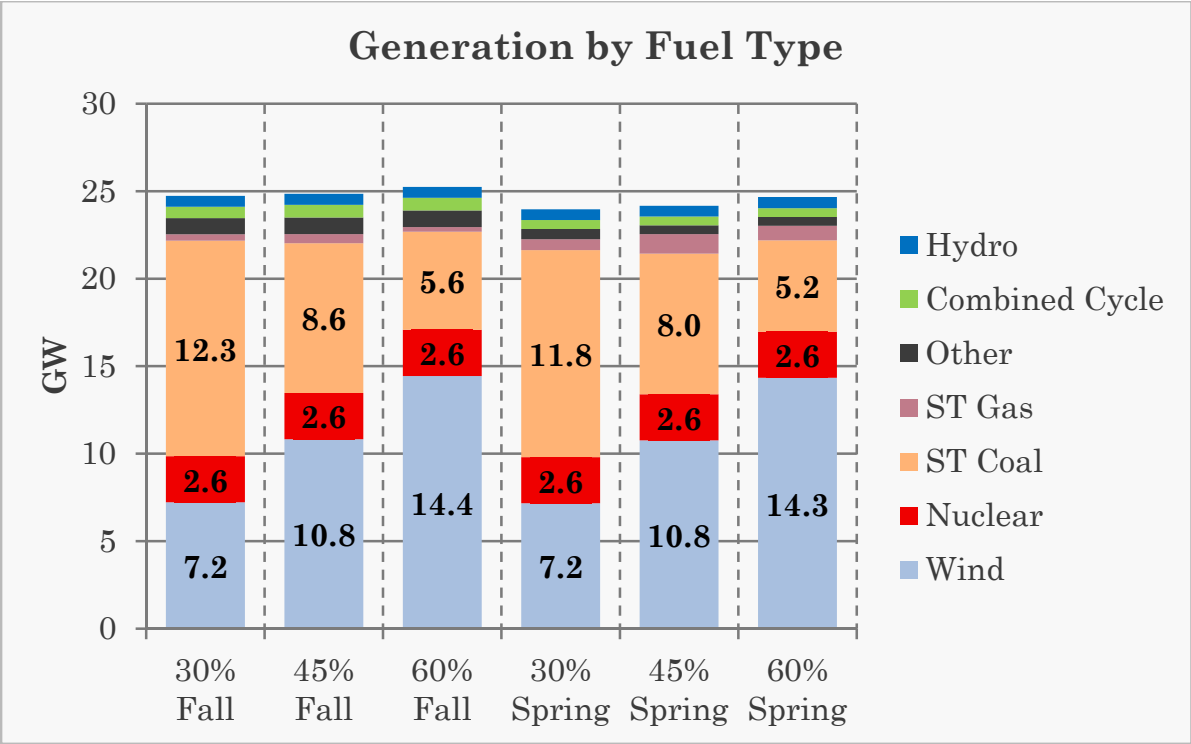


Figure 4.1.1: Generation breakdown by case, fuel type

There was some variation in dispatch across the scenarios, primarily due to seasonal outages and transmission losses. Losses increased substantially across the system as the wind penetration increased. Some of this was driven by higher transfer flows from the west to the east.

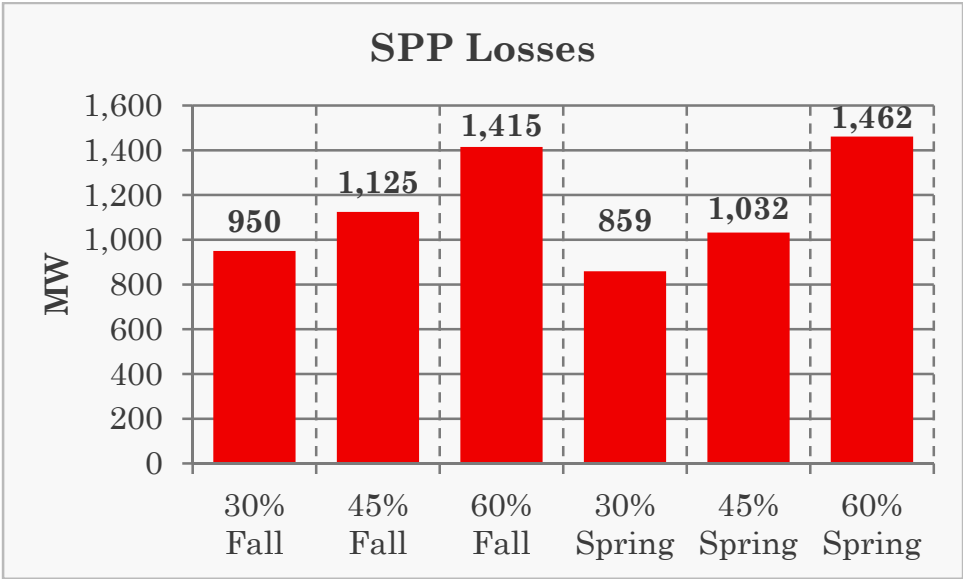


Figure 4.1.2: System MW losses by scenario

SPP TRANSMISSION IMPACTS AND WIND INTEGRATION

5.1 OVERVIEW OF POWER FLOW CASES 30%, 45%, 60%

The six cases (two seasons, three penetration levels) were analyzed with AC Contingency Analysis to determine the expected overloads to be mitigated during the high wind penetration in the footprint. Overloads occurred primarily in four regions:

- Woodward/NW Oklahoma
- SPS and Texas Panhandle
- West Kansas
- East and Central Kansas

The analysis identified several active or approved upgrades that provided relief for many of the constraints found in the contingency analysis.

- Woodward – Tatonga – Mathewson – Cimarron 345kV (Project 30364)
- Woodward – Windfarm 138kV (Project 757)
- Cimarron – Draper 345kV (Project 30843)
- Potter County – Tolk 345kV (Project 30404)
- Sundown – Amoco 230kV (Project 30711)
- Canyon East – Canyon West 115kV (Project 30509)
- Canyon West – Dawn 115kV (Project 30817)
- Terry County – Wolfforth 115kV (Project 30660)
- Carlisle – Doud 115kV (Project 30758)
- Highland – Pantex South – Pantex North – Martin 115kV (Project 30842)
- Mingo – Post Rock 345kV (Project 30391)
- Spearville – Great Bend – Circle – Reno 345kV (Project 30393)
- Buckner – Spearville 345kV (Project 30916)
- Elm Creek – Summit 345kV (Project 30367)
- Wolf Creek – Neosho 345kV (Project 30605)
- Harper – Milan Tap 138kV (Project 30500)
- Milan Tap – Clearwater 138kV (Project 30736)

Additionally, after the upgrades listed above were applied to the cases, post-contingent overloads still existed for the following monitored elements without corresponding upgrades available:

- Highland Tap – Asarco – Nichols 115kV
- Randall – Canyon East 115kV
- Eddy 230/115kV transformer #2
- Smoky Hills – Summit 230kV
- Buckner – Holcomb 345kV
- Phillipsburg – Smith Center 115kV
- Crooked Creek – Cudahy – Kismet – Cimarron River Tap 115kV
- Shooting Star – Greenburg – Sun City – Medicine Lodge 115kV
- Clearwater – Gill 138kV
- Swissvale – West Gardner 345kV

- Butler – Altoona 138kV
- Tecumseh Hill – Stull Tap – Mockingbird 115kV
- Marshall – Smittyville – Baileyville – Seneca 115kV
- Neosho – Riverton 161kV
- Elk City – Clinton Junction 138kV
- Tupelo – Tupelo Tap – Lula 138kV

The following maps provide an overview of the geographic location of wind generating facilities. The 30 and 45 percent wind penetration power flow cases were able to utilize existing facilities to achieve the target penetration levels. The 60 percent wind penetration power flow case required additional installed capacity, and utilized the SPP generation interconnection queue to achieve the target.

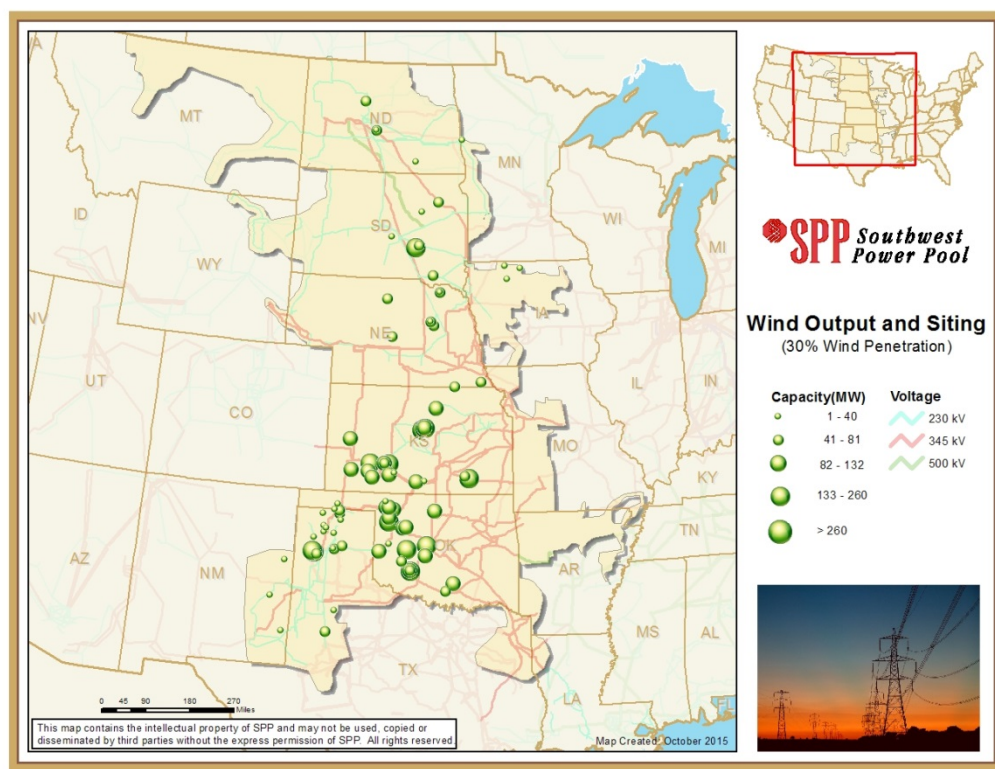


Figure 5.1.1: 30% Wind Penetration Wind Output and Siting.

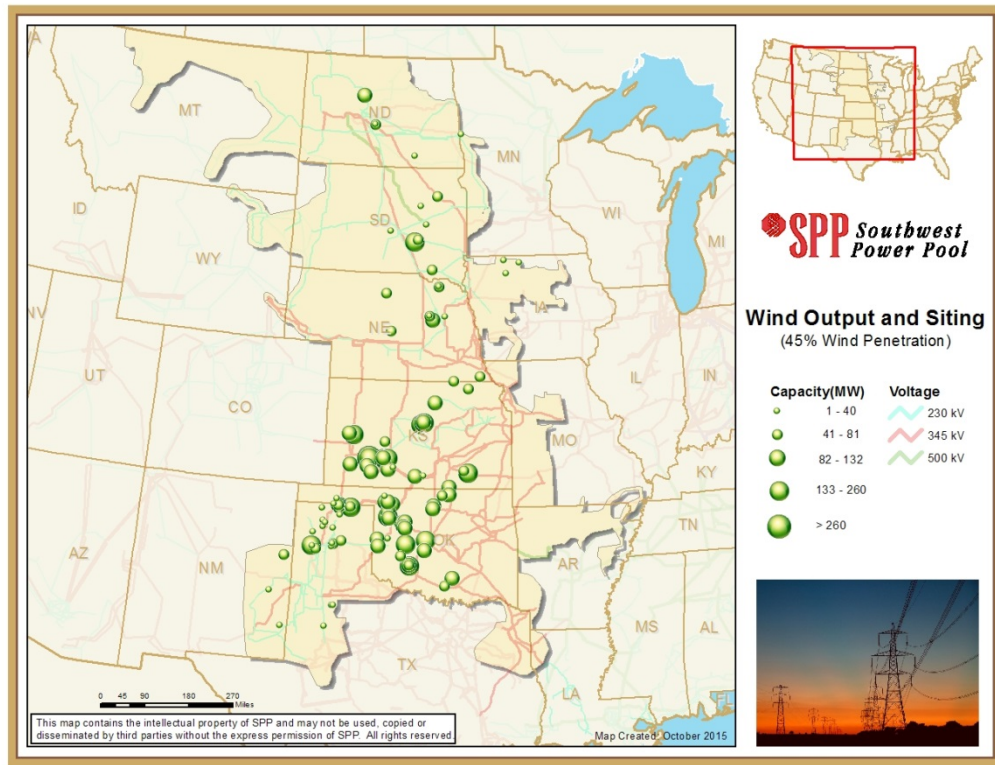


Figure 5.1.2: 45% Wind Penetration Wind Output and Siting.

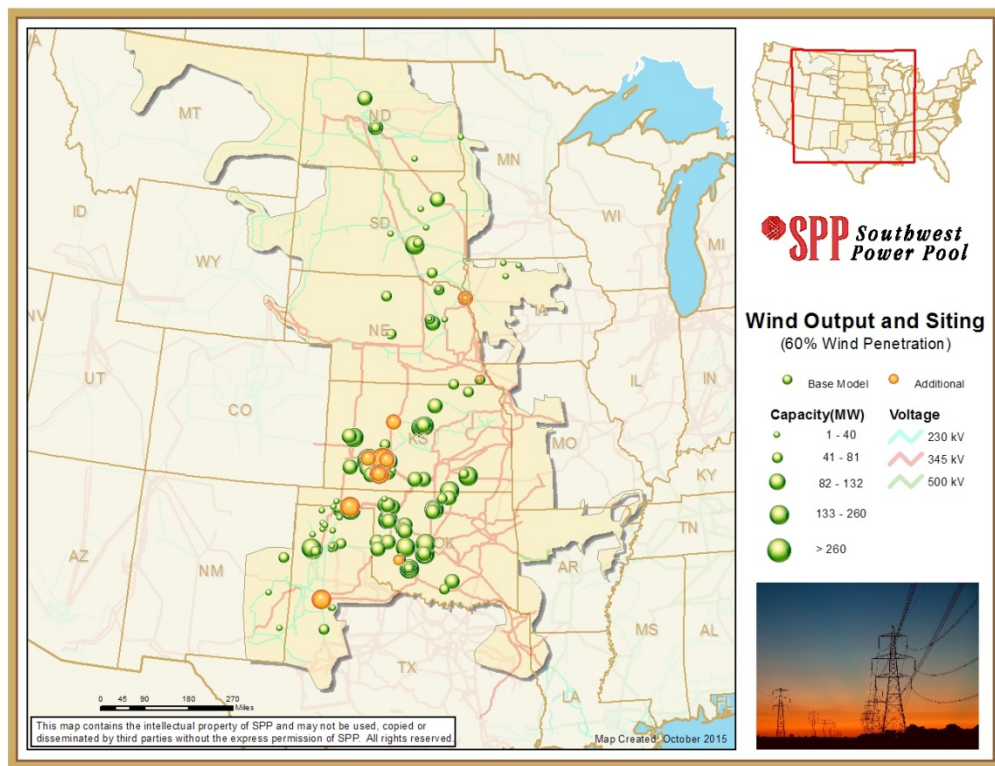


Figure 5.1.3: 60% Wind Penetration Wind Output and Siting.

5.2 WOODWARD AREA ANALYSIS

The study results showed that high wind penetration on the SPP footprint caused heavy West to East flows in the Woodward area. The overloads identified in the 30% wind penetration models were relieved by re-dispatching local non-renewable resources. The 45% and 60% wind penetration cases did require additional transmission to address overload and voltage issues.

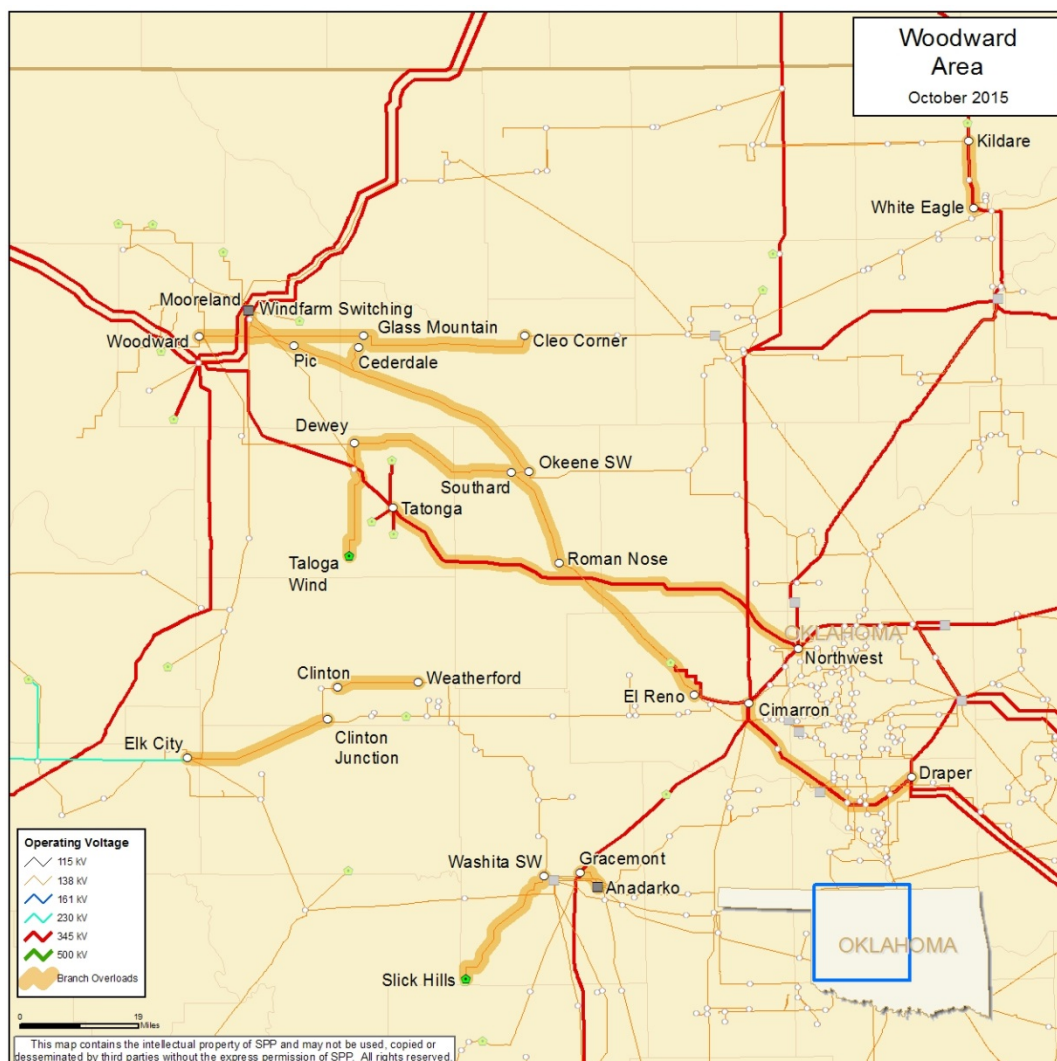


Figure 5.2.1: Most limiting overloaded elements in all cases.

The loss of any section of the Woodward-Tatonga-Northwest 345kV section causes several overloads and voltages issues on the surrounding 138kV system. The Tatonga-Northwest 345kV line was base case overloaded 60% penetration model. There are a couple projects in SPP's ITP10 that address these issues. The ITP10 PID 30364 project includes tapping the existing circuit from Tatonga – Northwest 345kV at the Mathewson 345kV station and building a second circuit from Woodward – Tatonga – Mathewson 345kV. The project also includes building a second circuit from Mathewson – Cimarron 345kV. The entire project is currently expected to be in-service in 2021.

Cimarron – Draper 345kV also overloads in the 60% penetration model for the loss of either Northwest-Cimarron 345kV or Oklaunion-Lawton Eastside 345kV. The ITP10 PID 30843 project

will address this issue. The project will upgrade the terminal equipment on the Cimarron-Draper 345kV line from 717MVA to 1195MVA. Currently this project is expected to be in-service in 2019.

Woodward-FPL_SWITCH 138kV is base case overloaded in the 60% model. The Woodward-Tatonga-Northwest 345kV project does provide significant flow reduction on Woodward-FPL_SWITCH 138kV path, but not enough to relieve the overload in the 60% model. The ITP10 PID 757 project will reconductor the line increasing the rating from 153MVA to 485MVA. FPL_SWITCH – Mooreland 138kV is a .18 mile long line and is currently rated at 287MVA which is higher than Woodward-FPL_SWITCH. The line isn't base case overloaded in the 60% model, but several contingencies cause it to overload. Reconductoring the line to 485MVA would address this overload as well, but that is not currently in the ITP10.

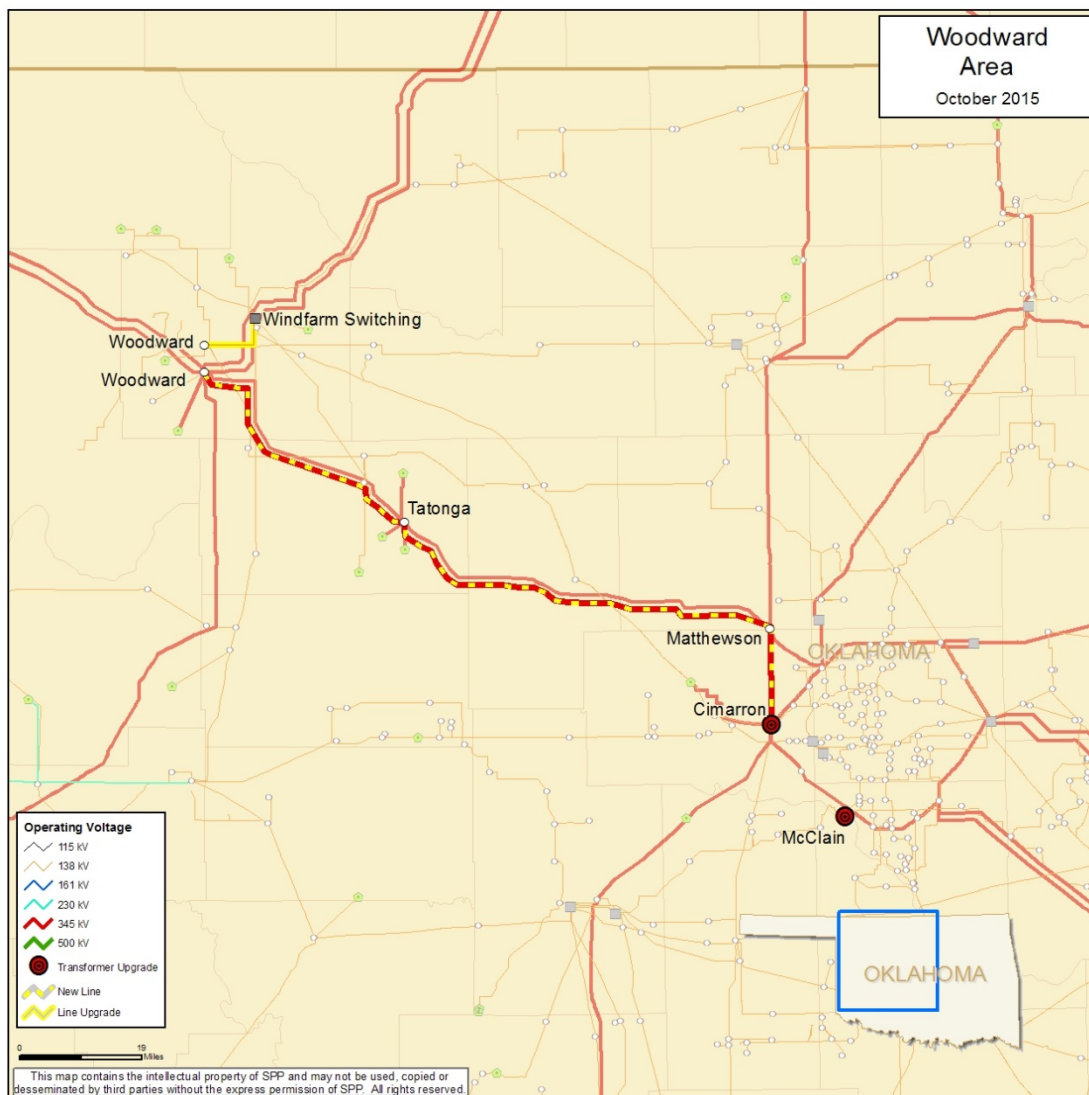


Figure 5.2.2: Woodward Area Solutions.

A couple of Spring outages were observed to impact the flows in the Woodward area during high wind penetration, and the outages were restored to help mitigate overloads. These outages are shown below:

- Hobart Junction – Carnegie 138kV

- Post Rock – Axtell 345kV

5.3 WEST KANSAS AREA ANALYSIS

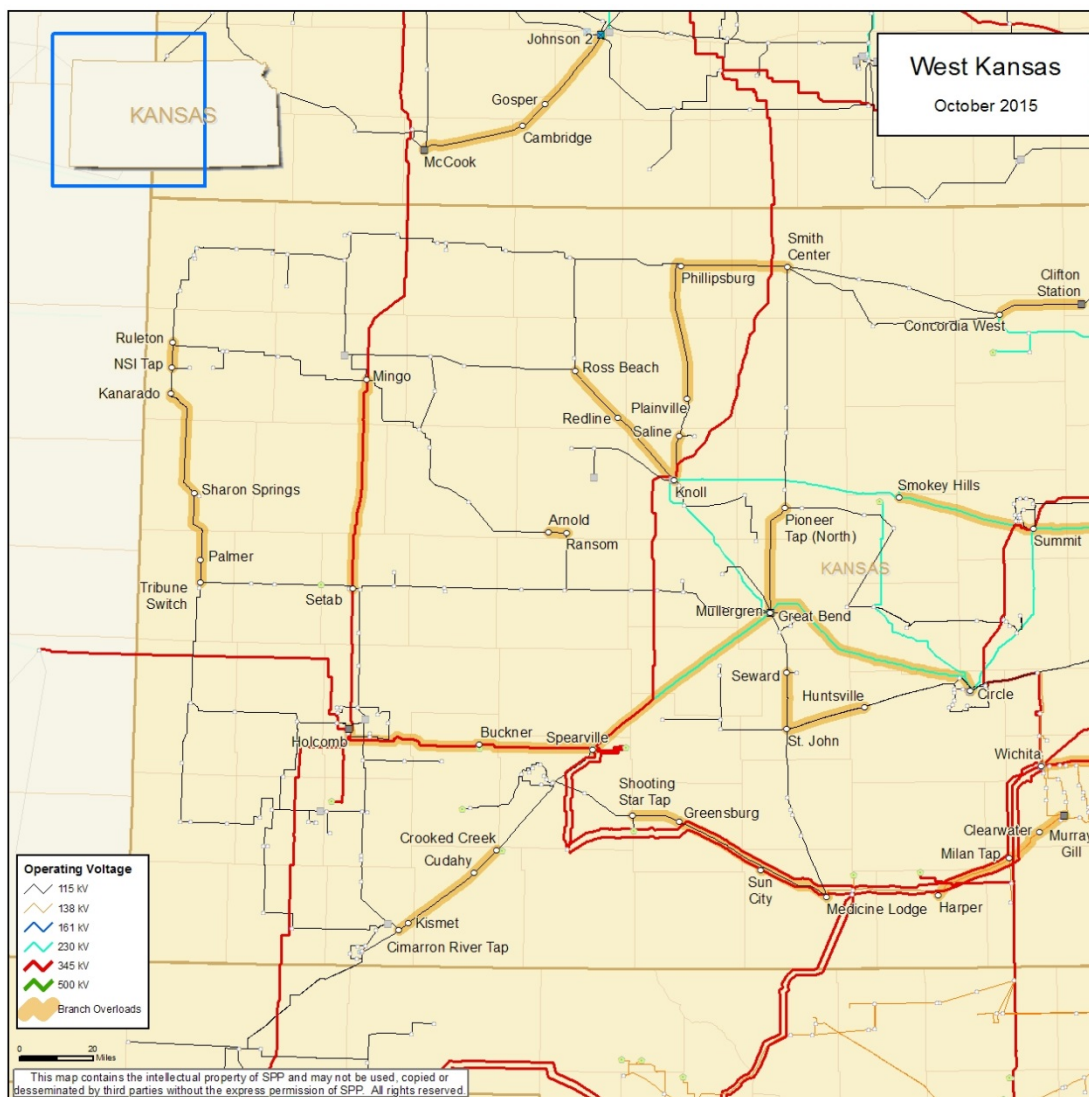


Figure 5.3.1: Most limiting overloaded elements in all cases.

Mingo – Setab 345 kV FTLO Northwest – Tatonga 345 kV.

Mingo – Setab 345 kV becomes overloaded upon contingency of the Northwest – Tatonga 345 kV line. The contingency cuts off the increased north to south flow into Oklahoma, forcing flow north into west Kansas. The Axtell – Post Rock 345 kV outage also aggravates the situation. ITP10 upgrades including the double circuiting of Woodward – Tatonga 345 kV (ID 50420) and the new Tatonga – Mathewson 345 kV line (ID 50421) relieve this contingency. Also, the proposed ITP20 project Mingo – Post Rock 345 kV line (ID 50474) alleviates this contingency.

Great Bend – Spearville 230 kV FTLO Post Rock – Spearville 345 kV

Great Bend – Spearville 230 kV becomes overloaded upon contingency of the Post Rock – Spearville 345 kV line. The Axtell – Post Rock 345 kV outage pushes Kansas to Nebraska flow further east, overloading the 230 kV system around Great Bend and Circle. The ITP20 proposed

projects Spearville – Great Bend 345 kV (ID 50476) and Great Bend – Circle 345 kV (ID 50477) helps move the increased flow across a scarce 345 kV area and relieves this contingency.

Holcomb – Buckner 345 kV FTLO Spearville – Buckner 345 kV

Spearville – Buckner 345 kV FLTO Holcomb – Buckner 345 kV

Due to the increased wind output at Buckner, when either side of this 345 kV bus is tripped, the other side overloads, proving an outlet issue. Initial analysis showed that an upgrade on both the Holcomb – Buckner 345 kV and Buckner – Spearville 345 kV were necessary, but the rated maximum output and current output in the models were above the maximum we have seen in real time. After adjusting the output, Buckner – Spearville 345 kV was the only upgrade necessary, which is already a Regional Reliability project (ID 51209).

Arnold – Ransom 115 kV FTLO Mingo – Setab 345 kV

Arnold – Ransom 115 kV becomes overloaded upon contingency of Mingo – Setab 345 kV. This contingency cuts off the south to north flow trying to make its way onto the Mingo – Red Willow 345 kV line and into Nebraska. To get to the Mingo – Red Willow 345 kV line, the flow drops down to the 115 kV system, overloading Arnold – Ransom 115 kV along with Tribune Swith – Palmer – Sharon Springs – Midwest Pump – Kanarado 115 kV and NSI Tap – Ruleton 115 kV. Two possibilities alleviate this contingency: reconductoring this low 115 kV area, or the proposed ITP20 project Mingo – Post Rock 345 kV line (ID 50474).

Phillipsburg – Smith Center 115 kV FTLO Mingo – Red Willow 345 kV

Phillipsburg – Smith Center 115 kV becomes overloaded upon the contingency of Mingo – Red Willow 345 kV. This contingency cuts off south to north flow from west Kansas to Nebraska, which is further aggravated due to the outage of Atxtell – Post Rock 345 kV. The flow drops down onto the 115 kV system and heads east, overloading Phillipsburg – Smith Center 115 kV. This line needs to be reconducted.

Harper – Milan Tap 138 kV FTLO Wichita – Thistle 345 kV

Harper – Milan Tap 138 kV becomes overloaded upon the contingency of Wichita – Thistle 345 kV. This contingency pushes MWs down onto the low rated 138 kV system between Flat Ridge and Gill. Along with Harper – Milan Tap 138 kV, Milan Tap – Clearwater – Gill 138 kV overload as well. Reconductoring is necessary on these lines. Harper – Milan Tap 138 kV is an ITP10 project (ID 50439) and Milan Tap – Clearwater 138 kV is a Regional Reliability project (ID 50832). Clearwater – Gill 138 kV would need to be included.

Seward – St. John 115 kV FTLO Circle – Great Bend 230 kV

Seward – St. John 115 kV becomes overloaded upon the contingency of Circle – Great Bend 230 kV. This overload is aggravated by the Pioneer Tap 115 kV bus outage, which pushes MW flow south instead of continuing north. Placing the bus and three transmission lines back in service alleviates the overload. A reconfiguration does relieve this overload: opening St. John – Huntsville 115 kV. However, HEC – Huntsville – St. John – Seward 115 kV should be reconducted.

Great Bend – Pioneer Tap 115 kV FTLO Circle – Great Bend 230 kV

Great Bend – Pioneer Tap 115 kV becomes overloaded upon the contingency of Circle – Great Bend 230 kV. This contingency pushes flow north, overloading the monitored element. A reconfiguration does relieve this overload: opening Smith – Covert 115 kV. However, Great Bend – Pioneer Tap 115 kV should be reconducted.

Greensburg - Sun City 15 kV FTLO Spearville – North Fort Dodge 115 kV

Shooting Star Tap - Greensburg – Sun City 115 kV become overloaded upon the contingency of Spearville – North Fort Dodge 115 kV. The Spearville 345/115 kV transformer outage aggravates this overload. Increased wind flow on the surrounding 115 kV system can't travel north to Spearville, causing an outlet issue east of Shooting Star. Reconductoring this low rated 115 kV area is recommended to mitigate this overload.

Crooked Creek – Cuday 115 kV FTLO Spearville – North Fort Dodge 115 kV

Crooked Creek – Cuday – Kismet – Cimarron River Tap 115 kV become overloaded upon the contingency of Spearville – North Fort Dodge 115 kV. The Spearville 345/115 kV transformer outage aggravates this overload. Increased wind flow on the surrounding 115 kV system can't travel north to Spearville, causing an outlet issue west of Ensign Wind. A RAS in this area relieves the area in real time and will still be in effect.

5.4 EAST AND CENTRAL KANSAS AREA ANALYSIS

Similar to the previous two areas, the east and central Kansas region experienced heavier west→east flows as the level of wind penetration increased. While there were still several wind farms in the area, much of the loading in the easternmost portion Kansas area was due to the lack of generation in the east. There was low generation on the eastern side of the footprint because many of the fossil fuel units near the large load pockets (Kansas City, SW Missouri, Wichita, etc) had been shut down or dispatched to minimum to allow for the increased wind in the cases. This created the heavy west→east flows that spanned across the entire state of Kansas. The few areas in east Kansas with nearby wind farms did experience overloads as well. The outage of Post Rock – Axtell 345kV in the spring had a large impact on those cases.

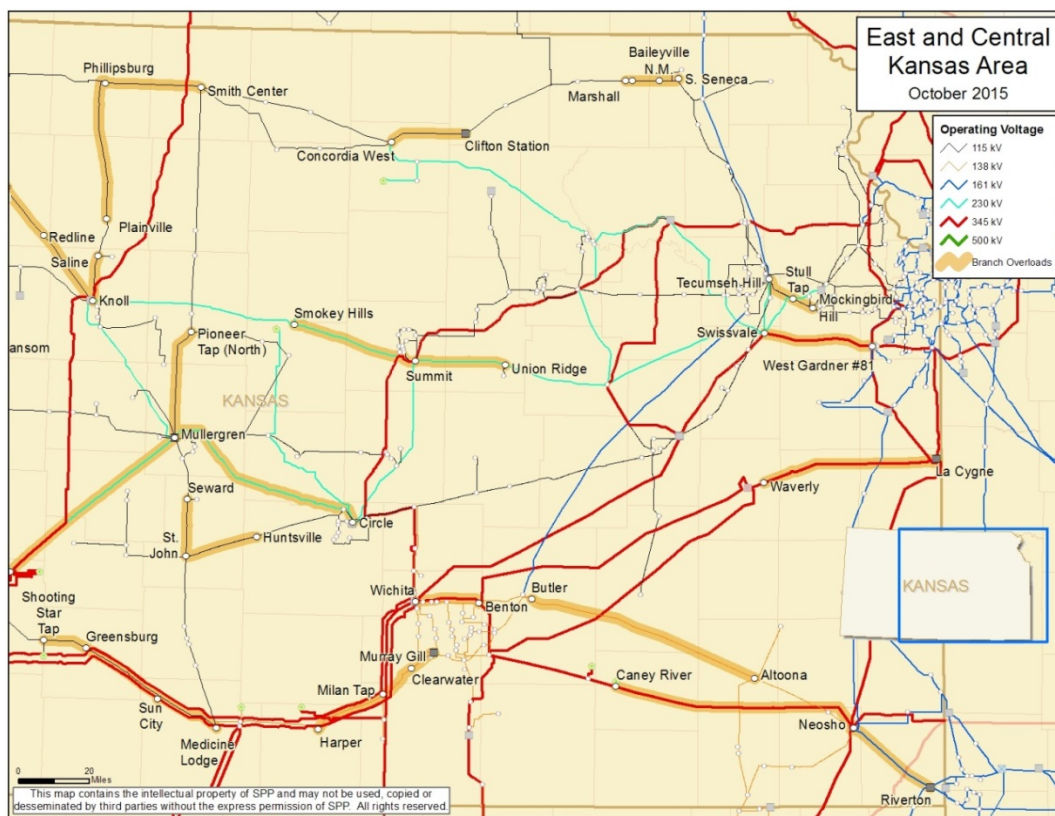


Figure 5.4.1: Most limiting overloaded elements in all cases

Several lines in the region were overloaded in the 60% base cases and could not be relieved with further redispatch without reducing the wind farms in west (while still maintaining the BA generation/load balance). The lines were

- Smoky Hills – Summit 230kV
- Clearwater – Milan Tap 138kV
- Milan Tap – Harper 138kV
- Butler – Altoona 138kV

Smoky Hills – Summit 230kV

This line was loaded in the 45% cases and very highly loaded in the 60% cases, due to multiple contingencies: Great Bend – Circle 230kV, Red Willow Mingo 345kV, Axtell – Post Rock 345kV. SMOSUMMULCIR is a permanent flowgate that already exists for one of these constraints. The loading was caused by the very heavy west→east flows across Kansas, with several large wind farms only a few stations away from this line. The Axtell – Post Rock 345kV outage in the spring cases did change some of the more limiting contingencies and increased some loading, but there were still heavy N-1 overloads without the outage. Other constraints overloading in the same area (though at lower total loading percentage) were

- Great Bend – Circle 230kV ftlo Smoky Hills Summit 230kV
- Summit – Union Ridge 230kV ftlo Summit – Jeffrey 345kV
- Circle 230/115kV transformer ftlo of Circle – E McPherson 230kV
- St John – Huntsville – Ark Valley Jct 115kV ftlo Great Bend – Circle 230kV

The ITP20 project Spearville – Great Bend – Circle – Reno 345kV provided some relief for these overloads. However, even after this ITP20 project was modeled, Smoky Hills – Summit 230kV was still among the N-1 overloads in the Spring and Fall 60% penetration cases.

Harper - Milan Tap – Clearwater – Gill 138kV ftlo Wichita Thistle 345kV (ckt 1 or 2)

This constraint was loaded in the 45% cases and much more heavily loaded in the 60% cases. Loading was again driven by the very heavy west→east flows on the system on top of the additional flows needed to serve the Wichita load. The Milan – Clearwater 138kV line is the monitored element for two permanent flowgates (#5486, #5532). The Spearville – Great Bend – Circle 345kV project did not provide full relief of these constraints. The existing projects (30500, 30736) to rebuild the Harper – Milan Tap – Clearwater 138kV path provided the necessary relief for those two lines. There were still N-1 overloads in the Spring and Fall 60% cases on the Clearwater – Gill 138kV line after the application of the planned upgrades. No upgrades are currently active for the Clearwater – Gill 138kV line.

Marshall – Smittyville 115kV ftlo Elm Creek – N Manhattan 230kV

There were heavy overloads on this line and other constraints with the same contingency present in the 45% and 60% penetration cases. Major contributors to the high loading were the high output from nearby wind farms and the heavy west→east transfers across the state of Kansas. Additional overloaded elements for the Elm Creek – N Manhattan 230kV contingency were

- Clifton – Concordia 115kV
- Smittyville – Baileyville 115kV
- Baileyville – Seneca 115kV

The Elm Creek – Summit 345kV project (Project 30367) provided relief for the Elm Creek – N Manhattan 230kV contingency, so it is recommended to expedite this project if possible. After

the upgrade was applied, the Marshall – Seneca 115kV path still experienced overloads for the loss of the Steele City – Harbine 115kV contingency. No other active projects were found to provide relief for the constraint Marshall – Smittyville 115kV for the loss of Steele City – Harbine 115kV.

Swissvale – W Gardner 345kV ftlo Waverly Lacygne 345kV

This was one of multiple overloads in the west→east corridor of the eastern Kansas area and loading was limited to the 60% penetration cases. The primary driver for this overload was the higher load in Kansas City and Missouri and the lack of nearby generation to serve that load, due to those fossil fuel units being dispatched down or shut down to accommodate the high wind penetration on the system. Several nearby wind farms and the base load nuclear generation also contributed to the loading. There were additional overloads on the Caney River – Neosho 345kV and Butler – Altoona 138kV lines for this same contingency. The ITP20 project Wolf Creek – Neosho 345kV (Project 30605) was used to provide much of the relief in the area. After the application of transmission upgrades (including the Wolf Creek – Neosho 345kV line), Swissvale – W Gardner overloads were relieved in the Fall scenarios, but still existed in the Spring cases due to an outage on a nearby 230kV line.

Butler – Altoona 138kV ftlo Caney River – Neosho 345kV

The Butler – Altoona 138kV line was highly loaded in the 45% and 60% cases for this and other 345kV contingencies in the area. The primary driver for the congestion was similar to the Swissvale – W Gardner constraints, with low generation in the east and high nearby wind farm output contributing to the west→east flows. The ITP 20 project Wolf Creek – Neosho 345kV was utilized to provide some relief, but it did not relieve all N-1 overloads for this line. No other active upgrades were found to relieve the N-1 loading on this path.

Neosho – Riverton 161kV

This constraint showed light loading in the spring 60% case for the loss of either the Neosho – Blackberry 345kV line or Asbury – Litchfield 161kV line. Both of these constraints exist as permanent flowgates (#5375, #5452 respectively). The loading is primarily driven by high output from nearby wind farms and a lack of generation in the NW Arkansas and SW Missouri area. Constraints for this line existed in multiple cases, loading more heavily in the 60% penetration cases. No active upgrades were found for this facility.

The following constraints were not mitigated with separate transmission upgrades in the studies:

- Wichita – Benton 345kV ftlo Tatonga – Northwest 345kV
 - This would be fixed by the ITP10 project for the Woodward – Tatonga – Mathewson 345kV circuit, identified in the Woodward area analysis.
- Tecumseh Hill – Stull Tap 115kV ftlo Hoyt – Stranger 345kV
 - This constraint only loaded up heavily in the Spring 60% case and was due primarily to a 230kV outage in the region. Restoring the outage relieved the constraint entirely, and there was a reconfiguration option that provided a majority of the relief without restoring the outage.

The total transmission projects added to these regions to accommodate the 60% wind penetration cases (with no curtailments) are shown on the map below.

- ITP20 Wolf Creek – Neosho 345kV (Project 30605)
- ITP10 Elm Creek – Summit 345kV (Project 30367)

- ITP20 Spearville – Great Bend – Circle – Reno 345kV (Project 30393)
- Harper – Milan – Clearwater – Gill 138kV rebuild (Projects 30500, 30736)

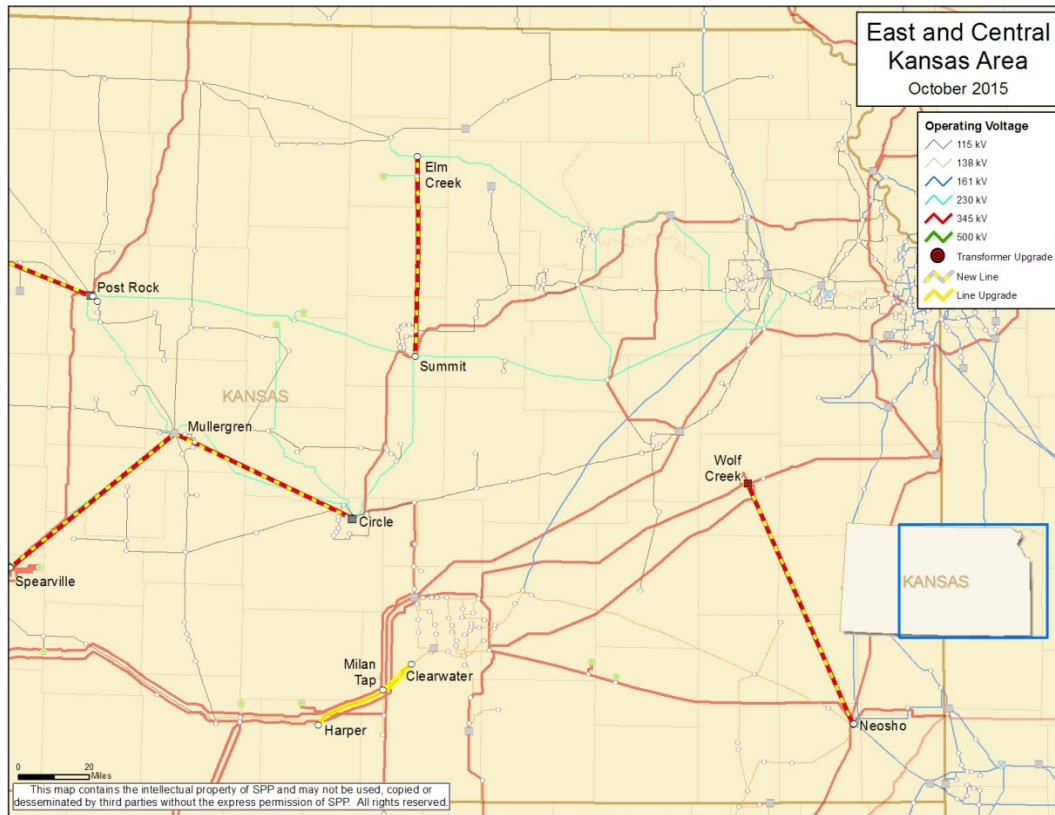


Figure 5.4.2: Upgrades utilized to relieve loading.

5.5 SPS AREA ANALYSIS

The SPS region outlines the area between the Texas and Oklahoma pan handle south into New Mexico. The Wind Integration Study identified seven thermal constraints, which were mitigated through additional transmission upgrades, and utilizing generation redispatch.

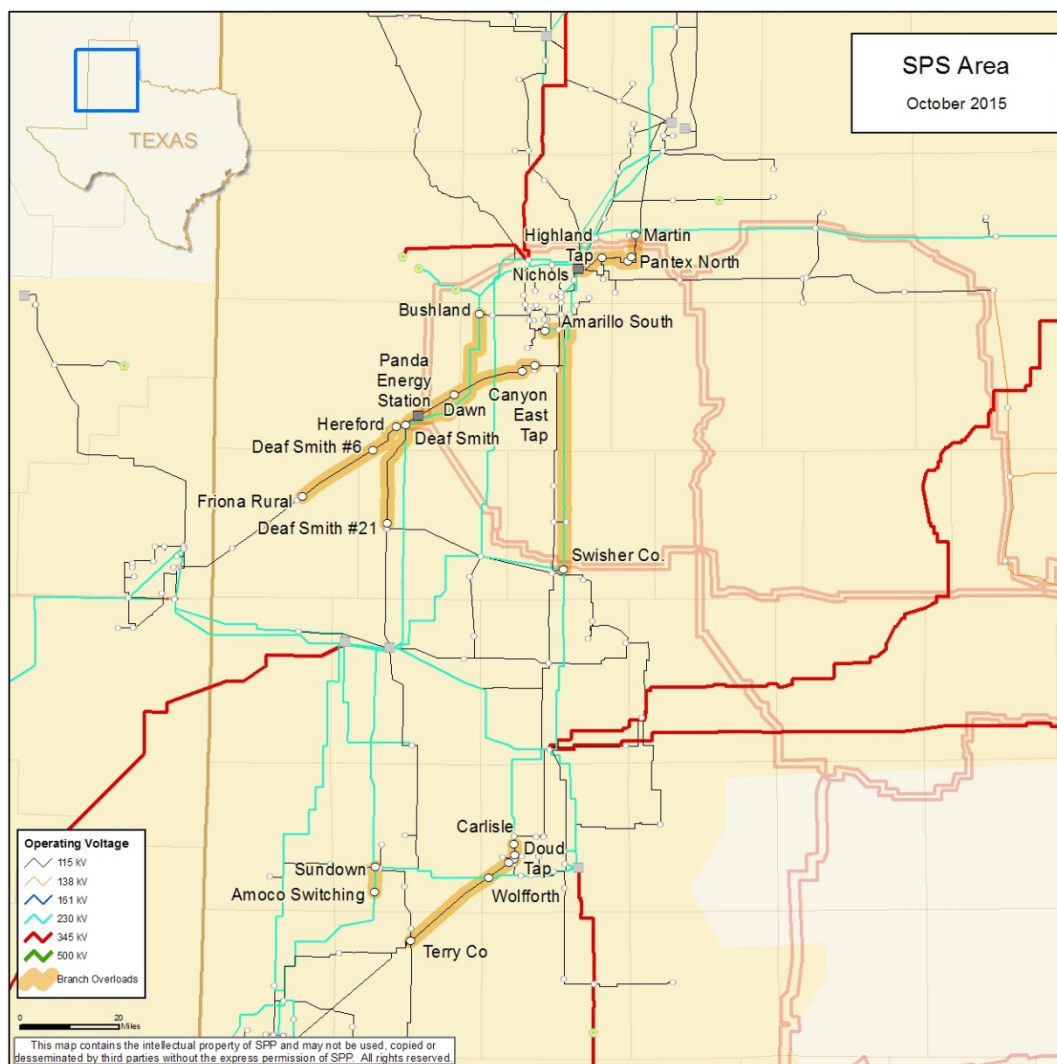


Figure 5.5.1: Most limiting overloaded elements in all cases.

Highland – Pantex South 115 kV FTLO Hutchinson – Martin 115 kV

Highland – Pantex South 115 kV becomes overloaded upon contingency of the Hutchinson – Martin 115 kV line. The contingency creates a radial outlet configuration that requires a reduction of wind generation located along the radial line to remain within tolerance of the MVA line limits. The Wind Integration Study discovered under normal operating conditions and controlling to N-1 limits the wind farm would be required to operate at 69.4% of its total available capacity. The Wind Integration Study upgraded the conductor MVA ratings to 175 MVA for Martin – Pantex North 115 kV, Pantex North – Pantex South 115 kV, Pantex South – Highland 115 kV, and Highland – Asarco 115 kV. This mitigated the identified overloads to allow for maximum output without curtailment.

Canyon West – Canyon East 115 kV FTLO Bushland – Deaf Smith 230 kV

Canyon West – Canyon East 115 kV will overload upon contingency of the Bushland – Deaf Smith 230kV line. The ITP 10 identified a project to re build the existing 115kV line from Canyon West – Dawn – Panda – Deaf Smith, the Wind Integration Study evaluated the ITP 10 project and determined that the rebuild would need to extend from Canyon West – Canyon East – Randall. The Wind Integration study also indicates that under contingency with the ITP 10 line rebuilds Amarillo

– Swisher 230 kV would experience heavy loading, which would create redispatch conditions. The wind integration study found an additional option to mitigate transmission loading and the redispatch of wind generation north of Potter County. The Wind Integration Study recommends building a new transmission line between Potter County and Tolk. The multiple area constraints were mitigated by installing a new 345kV line between Potter Co and Tolk, and installing a 345kV bus with a 345/230kV transformer at Bushland. The installation of this new line provided stability to the SPS region while supporting the voltage and thermal related issues with wind generation north of Potter County producing at 100% capacity under contingency.

Sundown – Amoco 230kV FTLO Tolk West – Yoakum 230kV

Sundown – Amoco 230kV will overload upon contingency of the Tolk West – Yoakum 230kV line. The ITP near term has an approved project scheduled to replace the Sundown and Amoco wave traps by 4/1/2020. The Wind Integration Study recommends adjusting the scheduled project need date for the ITPNT project. The Wind Integration Study tested a mitigation solution by installing a new 345kV line between Potter Co and Tolk, and installing a 345kV bus with a 345/230kV transformer at Bushland. The installation of the 345kV allows for a reduction of generation in South SPS, which will increase southern imports of wind generation. This solution will provide stability to the SPS region and support the voltage and thermal related issues while wind generating north of Potter County at 100% capacity under contingency.

Carlisle – Doud 115kV FTLO Lubbock – Wolfforth 230kV

Carlisle – Doud 115kV will overload upon contingency of the Lubbock – Wolfforth 230kV line. The Wind Integration Study found that building a new 230kV line between Carlisle – Wolfforth would decrease the loading. The 230kV line would complete a loop with the existing 230kV lines. “Carlisle-Wolfforth-Lubbock-Jones-Tuco-Carlisle 230kV” Completing the 230kV loop would provide reliability support and reduce congestion in the area. The Wind Integration Study also assessed the increasing the MVA limit on the 115kV lines to 180 MVA between Carlisle and Wolfforth to mitigate post contingent loading.

Wolfforth – Terry County 115kV FTLO Sundown – Wolfforth 230kV

Wolfforth – Terry County 115kV will overload upon contingency of the Sundown – Wolfforth 230kV line. The Wind Integration Study found similarities with this constraint and Carlisle – Doud 115kV FTLO Lubbock – Wolfforth 230kV. Increasing the MVA limits between Carlisle and Wolfforth will not mitigate the Wolfforth – Terry County 115kV section, but installing a new 230kV line between Carlisle – Wolfforth would mitigate the issue. The 230kV line would complete a loop with the existing 230kV lines “Carlisle-Wolfforth-Lubbock-Jones-Tuco-Carlisle 230kV”. Completing the 230kV loop would provide reliability support and reduce congestion in the area.

Eddy North 230/115 kV FTLO Eddy North – Eddy South 230 kV

Eddy North 230/115 kV transformer will overload upon contingency of the North – Eddy South 230 kV line. With heavy north to south flow this contingency creates a situation that separates the Eddy South transformer from the flow on the 230kV system and causes the Eddy North transformer to receive the majority power flow between the north and south transformers, which creates an overload situation for the Eddy North transformer. The Wind Integration Study attempted to reconfigure the Eddy North transformer and as a result caused voltage collapse conditions. To resolve the voltage collapse SVCs were installed at Seminole 230kV and Potash Junction 230kV. The SVCs allowed the model to solve under contingency while reconfiguring, which stabilized the system voltage. Although the voltage stabilized, thermal overloads were created on 230kV line

Yoakum – Hobbs, and the SVCs at Seminole produced 142 MVARs while Potash Junction produced 148 MVARs. Redispatch would be required without new transmission to maintain system reliability for this constraint. The Wind Integration Study recommends additional reactive devices installed at Potash Junction and Seminole for system reliability.

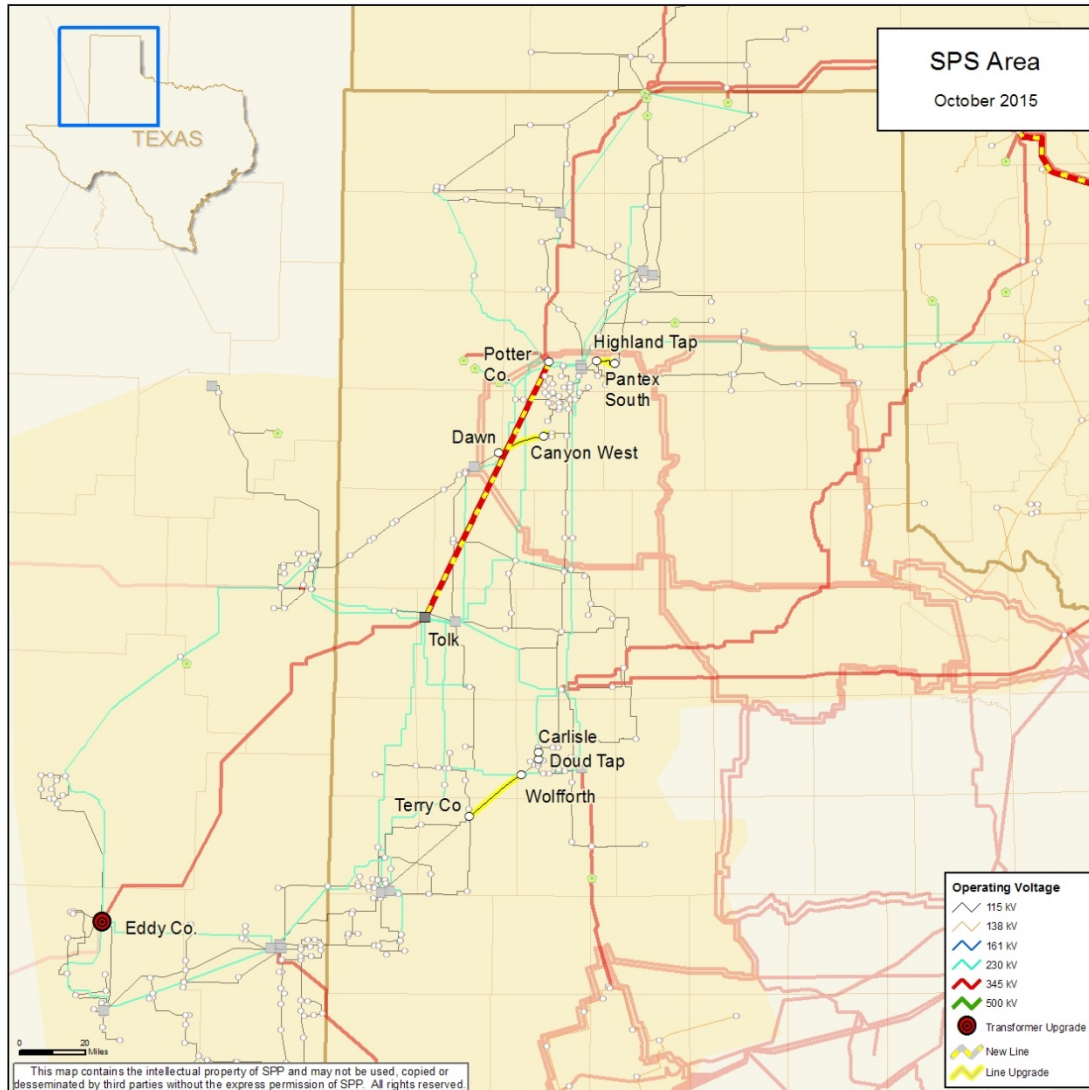


Figure 5.5.2: Upgrade solutions utilized to mitigate overloads.

5.6 NEBRASKA NORTH AREA ANALYSIS

Nebraska north experience high voltage conditions that were mitigated through capacitor switching, and there was only one branch overload found in the region north of Kansas: overloads on the Red Willow 345/115kV transformer and the McCook – Johnson Lake 115kV lines for the loss of Red Willow – Gentleman 345kV in the Spring 60% penetration case. Due to a pre-existing reconfiguration and the high impact of the Spring outage for Axtell – Post Rock on these constraints, no upgrades were used to mitigate this constraint.

5.7 REDISPATCH ANALYSIS

Analysis was done to determine the feasibility of redispatching around the constraints with the inclusion of wind curtailments in the redispatch. The base cases had been modeled so that no wind was curtailed (in order to maintain the 30%, 45%, 60% penetration levels) while the remaining conventional generation had been redispatched as much as possible to relieve the existing constraints. There were two primary goals of the redispatch analysis:

- 1) Determine if all N-1 and base case constraints could be resolved if the redispatch included curtailment of DVERs
- 2) Model all wind farms as DVERs and determine if all N-1 and base case constraints could be resolved if the redispatch included curtailment of DVERs (NDVER Conversion sensitivity)

Methodology

PowerGem TARA was used to perform the redispatch, as had been done on the base cases. The redispatch was based on a Security Constrained Economic Dispatch (SCED). No additional generation was committed or decommitted to resolve constraints. For each season/penetration level, two cases were created:

- The base case for that season/penetration level (30% Fall for instance), where all existing DVERs in the case were allowed to participate in the redispatch.
- The “B” case for that season/penetration level (30% Fall B for instance), where all existing DVERs and NDVERs were allowed to participate in the redispatch. This would simulate the impacts for converting all NDVER wind farms to DVERs.

All wind farms were given the same offer prices, equivalent to $-\$34/\text{MWhr}$, based on estimated Production Tax Credit incentives. The wind farms were not allowed to be dispatched up from their initial output; the initial output in the cases were assumed to be the maximum, unconstrained capability of the resource. Since these cases were snapshot cases, there were no ramp considerations. For constraints, the highest loaded N-1 constraints identified in the contingency analysis were used as inputs for the SCED solution to dispatch around.

Results

The results of the redispatch are summarized in the charts below. All cases were successfully solved with the SCED solution. There was very little wind generation curtailed in the 30% penetration cases. The 45% and 60% penetration cases indicated much higher wind curtailments, even up to 5,006 MW for the 60% Spring case, which corresponded to approximately 35% of the available wind power and 20% of the BA load.

The top six most frequently binding constraints in all scenarios were

- All 12 scenarios – WDWFPLTATNOW (flowgate #5563)
- 11 scenarios – Randall – Canyon E 115kV ftlo Bushland – Deaf Smith 230kV (similar to flowgate #5371 OSGCANBUSDEA)
- 7 scenarios – SUNAMOTOLYOA (flowgate #5548)
- 4 scenarios
 - CARLPDLUBWOL (flowgate #5056)
 - Crooked Creek – Cudahy 115kV ftlo N Ft Dodge – Spearville 115kV
 - Marshall – Smittyville 115kV ftlo Elm Creek – N Manhattan 230kV

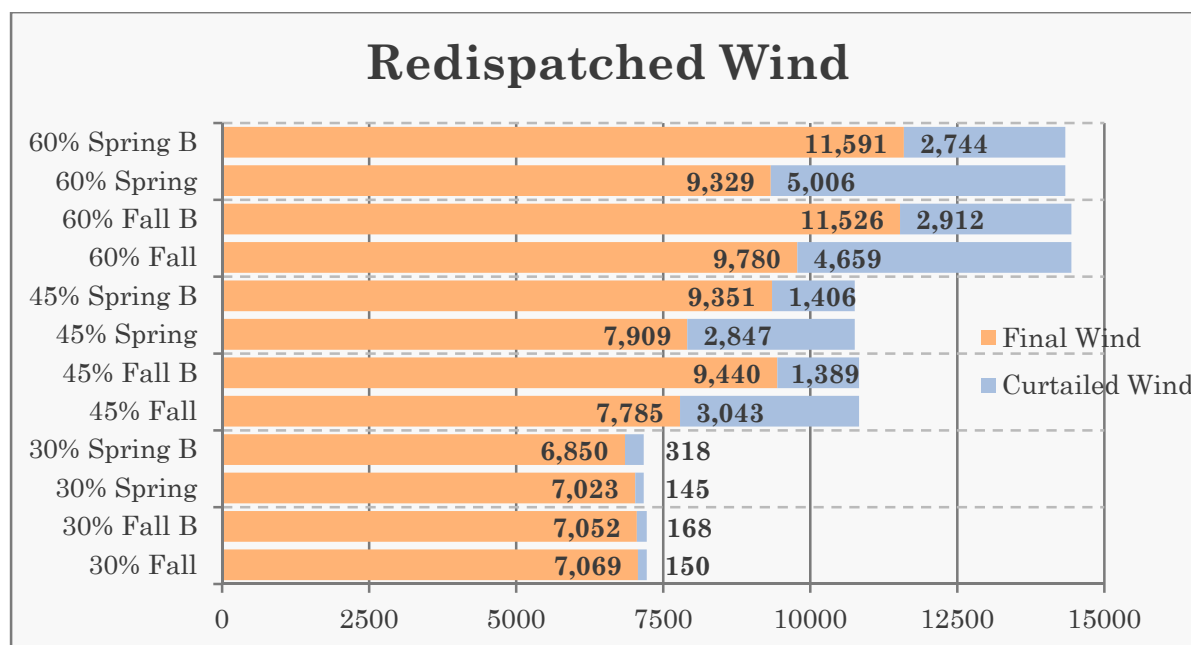


Figure 5.7.1: Initial and final wind for redispatch scenarios

The NDVER conversion scenarios (B cases) showed a considerable reduction in wind curtailments. As an example, to solve the N-1 constraints for the 60% Spring case:

- 5,006 MW of wind was curtailed using only existing and future DVERs
- 2,744 MW of wind was curtailed when all wind farms were dispatched as DVERs (including existing registered NDVERs)
 - This included 1,938 MW of existing DVER curtailments and
 - 806 MW of “converted DVER” curtailments (currently registered as NDVERs)

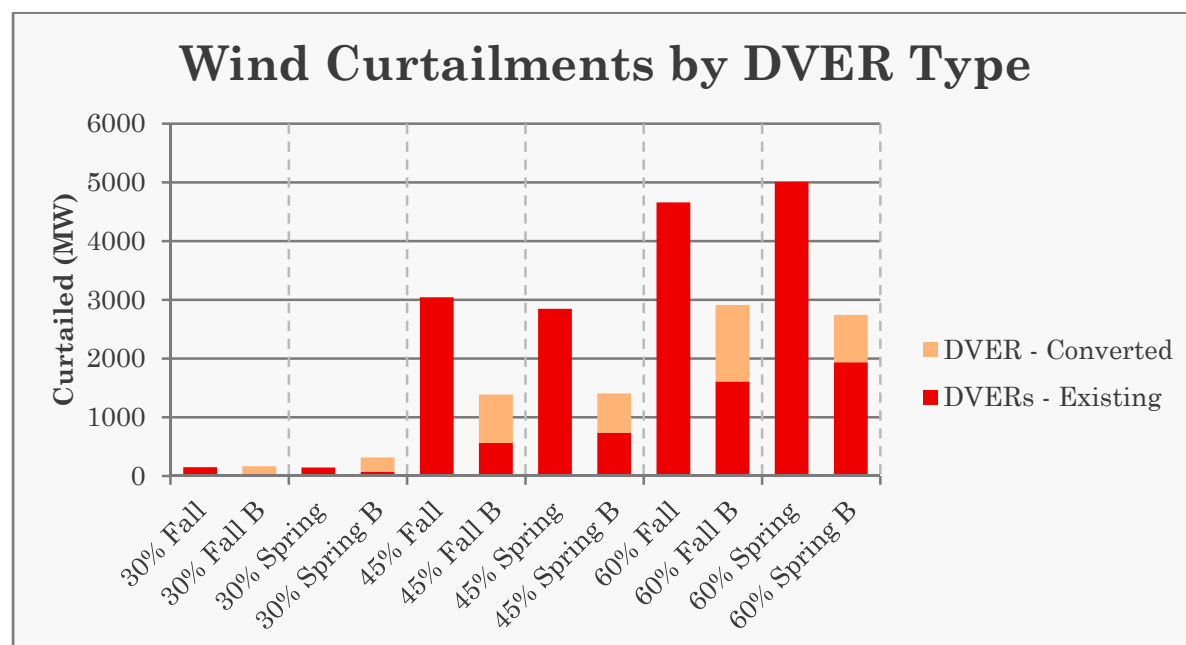


Figure 5.7.2: Wind curtailment breakdown for redispatch scenarios

Most of the redispatched conventional generation was coal generation being dispatched up to balance the curtailed MW of wind farms. This was mostly due to the majority of dispatchable non-wind generation being coal units for these light load cases as well as the lower cost of those resources. There was also some fossil fuel generation (primarily gas/steam) that was dispatched down in some of the SCED solutions. These resources had typically been dispatched up in the base cases to support the multiple transmission constraints that had been showing up with the high wind penetration. As the wind was curtailed in the SCED solution, these gas/steam units were allowed to reduce output as the constraint was no longer highly loaded.

It is also important to note that the wind curtailments and reduction in high west→east flows caused a reduction in losses of several hundred MWs for the 45% and 60% scenarios. The incremented conventional generation was actually several hundred MWs less than the curtailed wind generation in those scenarios, because transfers across the system were reduced.

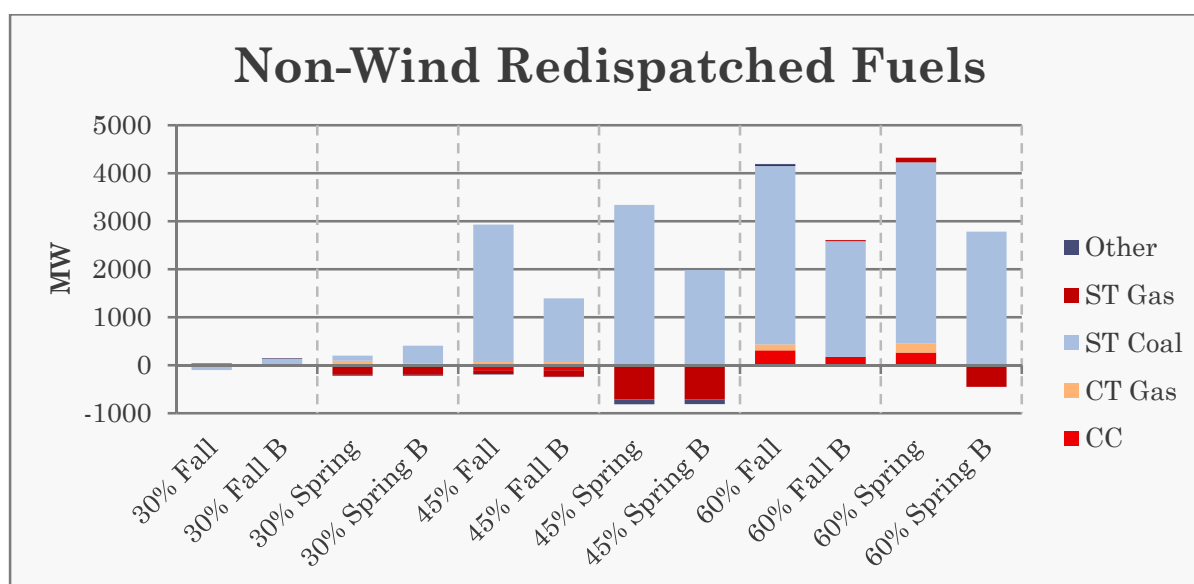


Figure 5.7.3: Redispatch of non-wind generation

Due to the curtailments, the final wind penetration in the redispatched cases was significantly lower than the initial input wind penetration.

- “45%” wind penetration cases were reduced to
 - ~33% wind penetration in redispatch base case
 - ~39% wind penetration in redispatch NDVER conversion case
- “60%” wind penetration cases were reduced to
 - ~40% wind penetration in redispatch base case
 - ~48% wind penetration in redispatch NDVER conversion case

Shadow prices on constraints were very high on some of the higher wind penetration scenarios. As would be expected, for each season/penetration level, the NDVER conversion scenario had lower average shadow prices on the binding constraints. This is because the SCED solution had more resources available to dispatch, and in many cases, the converted NDVERs were very near the site of the congestion. Without the NDVER conversion, the SCED solution was forced to use resources further away (lower GSFs) to mitigate the constraint. One outlier was the 45% Fall case, which had the highest average shadow price. This was due to the case only having one binding constraint

(WDFWPLTATNOW), which had a very large shadow price. All other cases had at least three binding constraints. Note that the standard Violation Relaxation Limit blocks of \$500/MWhr, \$750/MWhr, etc used in RTBM were not applied here, in order to guarantee a solution to 100% loading.

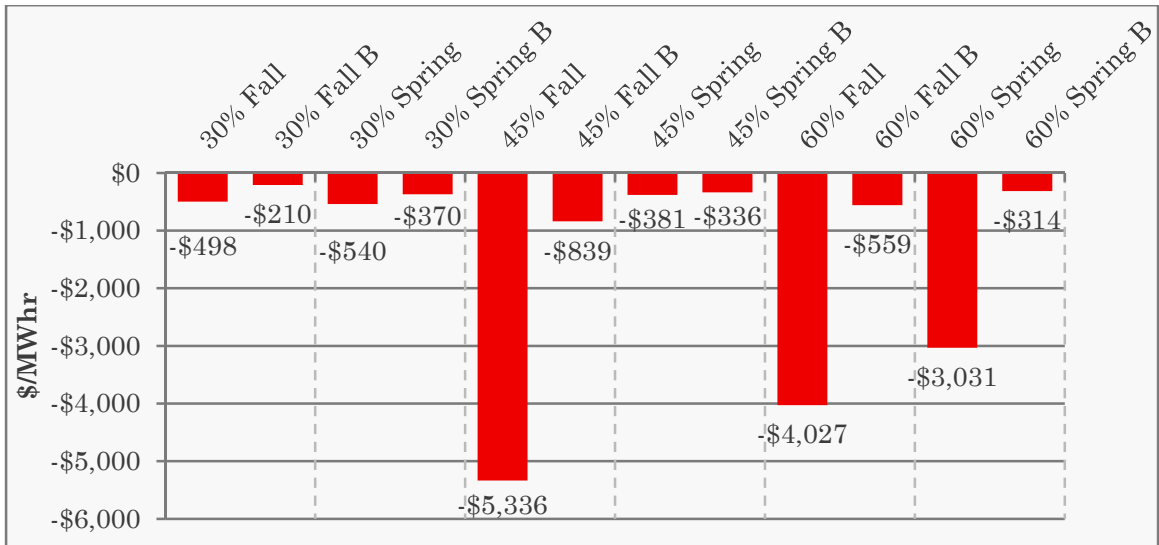


Figure 5.7.4: Average shadow price of binding constraints

Conclusion

All N-1 constraints were able to be successfully resolved with redispatch of the existing dispatchable generation, with very heavy curtailments of wind farms at the higher penetration cases. However, the heavy curtailments result in thousands of MWs from low variable cost generation being left on the table due to significant transmission constraints. Additionally, several constraints were identified to be binding in the SCED solutions and may be investigated as potential flowgates.

The NDVER conversion sensitivity highlighted several potential issues. Allowing NDVERs to participate as dispatchable resources led to

- a reduction of up to 2,300 MW of regained wind from curtailments (~10% of load) in high wind penetration scenarios,
- lower overall production costs as the load was served from a high penetration of wind power (\$0 fuel cost),
- lower shadow prices on constraints and less extreme pricing during congestion as the SCED was allowed to redispatch the previously NDVER generation closer to the constraint, rather than curtailing larger amounts of generation located further away from the constraint.

5.8 OUTAGE ANALYSIS

The original base cases included historical outages from an actual operating day, and for the outage analysis the historical outages included in the base cases were returned to service. This analysis created two sets of base cases; one with outages (N-X) and a second set without outages (N-0). The N-0 set of base cases mirrors traditional planning models and the N-X set of base cases mirrors operational models. An AC contingency analysis was executed for all six scenarios of the new N-0 cases and compared to the existing N-X results. The following list of monitored elements were impacted by outages, as they were identified in the N-X AC contingency analysis, but were not identified in the N-0 AC contingency analysis.

- Tupelo – Tupelo Tap – Lula 138kV
- Clinton – Weatherford 138kV
- Taloga – Dewey – Southard 138kV
- Cimarron – Draper 345kV
- Gracemont – Anadarko 138kV
- Pic – Cedardale – Okeene 138kV
- Knoll 230/115kV transformer
- Knoll – Redline – Beach 115kV
- Knoll – Saline 115kV
- Seward – St John – St John 115kV
- Huntsville – Ark Valley Jct 115kV
- Tribune Switch – Palmer – Sharon Springs – WTCLF Tap – Kanarado 115kV
- NSI Tap – Ruleton 115kV
- Ransom – Arnold 115kV
- Mingo – Setab 345kV
- Caney River – Neosho 345kV
- Benton – Wichita 345kV
- Waverly – Lacygne 345kV
- Circle – Great Bend 230kV
- Circle 230/115kV transformer
- Summit – Union Ridge 230kV
- Tecumseh – Stull Tap – Mockingbird 115kV
- Crooked Creek – Cudahy – Kismet – Cimarron River Tap 115kV
- Shooting Star – Greenburg – Sun City – Medicine Lodge 115kV
- Plainville – Phillipsburg – Smith Center 115kV
- Red Willow 345/115kV transformer
- McCook – Cambridge – Gosper – Johnson Lake 115kV

WIND INTEGRATION AND SPP VOLTAGE STABILITY ANALYSIS

6.1 OVERVIEW OF VOLTAGE STABILITY

Nominal load is the active power the customer load will draw if it is operated at its nominal voltage and frequency. The actual load may be different than the nominal load. Voltage Stability is the ability of a power system to maintain voltage so that when the system nominal load is increased the MW transferred to that load will increase.⁶

When MW is transferred across a radial power system a curve can be created that relates the voltage at the receiving end of the system (V_R) to the MW transferred across the system. Figure 6.1.1 contains an example of this type of curve (called a power versus voltage curve or P-V curve). Note from this curve that as the MW transfer increases across the system, the voltage at the receiving bus (V_R) slowly decreases.

Eventually a point is reached (the “knee” of the P-V curve) where any further increase in MW transfer will lead to a rapid decrease in voltage. The knee of the P-V curve is the boundary between voltage stability and voltage instability. The voltage and MW transfer levels at the knee of the curve are called the “critical” values. For example, in Figure 6.1.1, the critical voltage is 70% of nominal and the critical MW transfer is 3000 MW.

Once the critical values are exceeded the system has entered a condition of voltage instability. The system voltage could collapse at any time. When voltage is unstable system operators have lost control of power transfer and voltage magnitude.⁷

⁶ Electric Power Research Institute, “EPRI Power system Dynamics Tutorial”, EPRI, Palo Alto, CA. 2009. 1016042, available at www.epri.com, Section 6.9.2, page 6-41.

⁷ Ibid, 6, Section 6.4.3, pages 6-6 through 6-7.

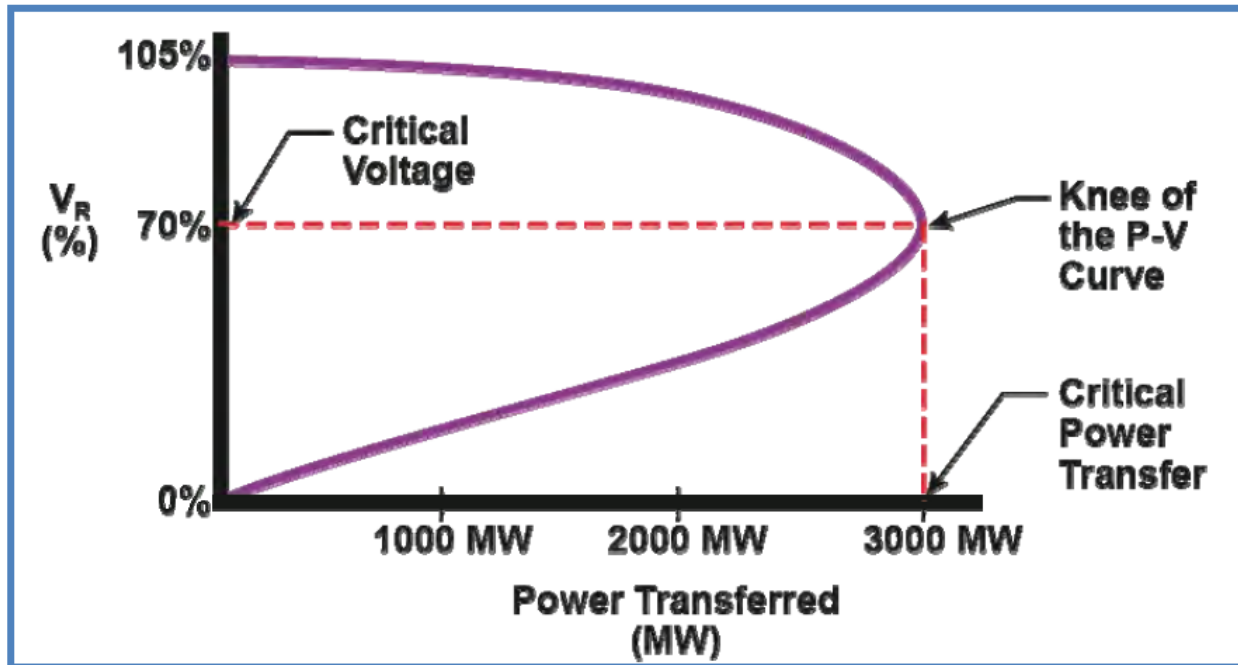


Figure 6.1.1: Sample P-V Curve

Assume the power system whose P-V curve is shown in Figure 6.1.2 is initially operating at an active power transfer of 2000 MW. From the curve the receiving bus voltage will be approximately 100% of nominal at this transfer level. Assume further that the system load (the nominal load) starts to grow. MW transfer grows with the increasing nominal system load. Eventually the MW transfer grows to 3000 MW.

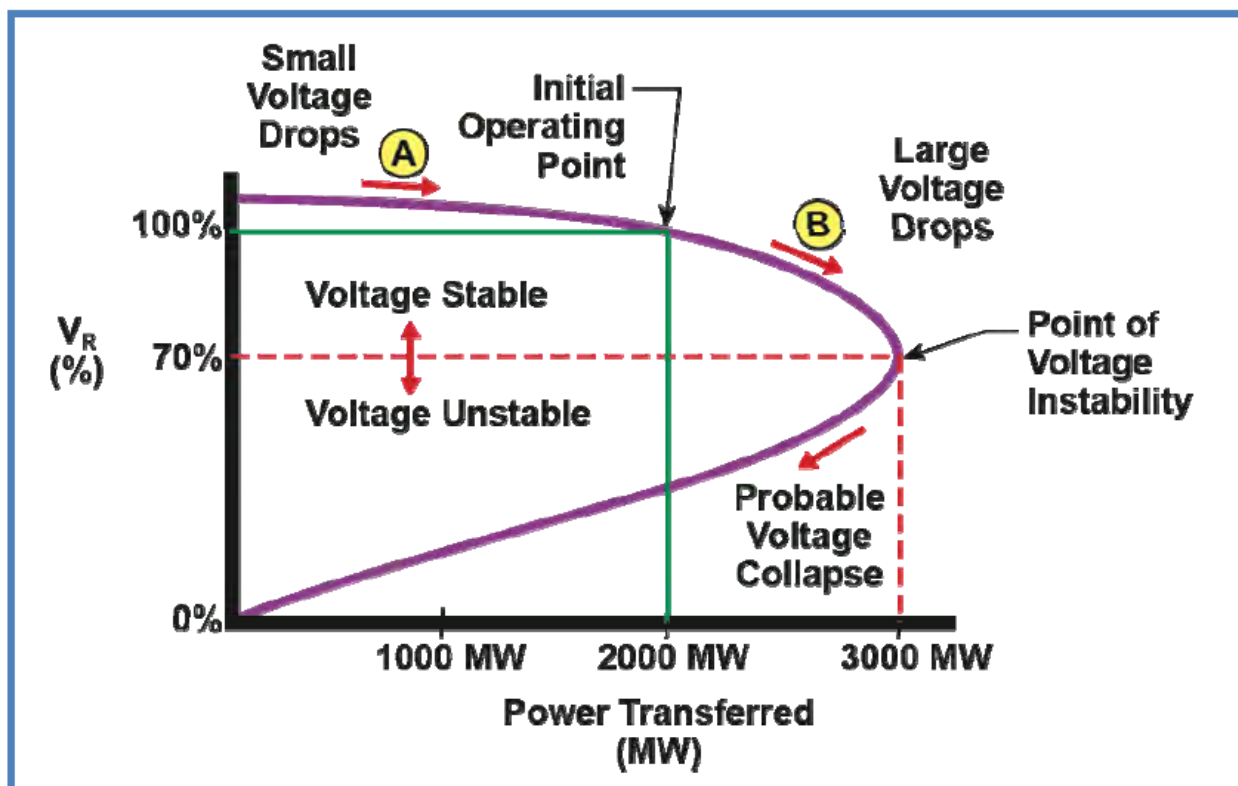


Figure 6.1.2: P-V Curve Illustration of Voltage Collapse

The system is now on the brink of voltage instability. If the nominal load were to grow any larger, the MW transferred to the load would actually begin to digress. Once the MW transfer exceeds the critical value the system is voltage unstable and the voltage collapse could occur at any time.⁸ See Appendix 1⁹ for a more detailed example of AC power transmission and the steady-state voltage stability limits.

Transmission outages reduce the current operating network point of voltage instability, refer to the post-disturbance curve in Figure 6.1.3.¹⁰

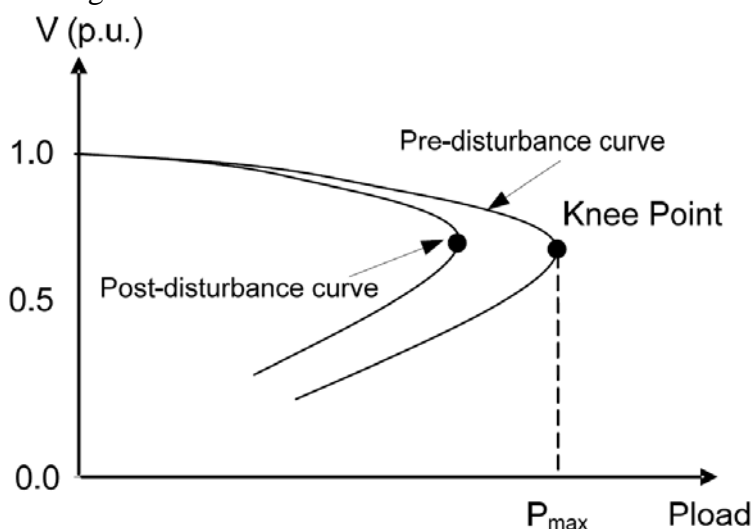


Figure 6.1.3: Maximum Power transfer reduction due to network outage (post-disturbance)⁴

The WIS voltage stability analysis (VSA) is performed by increasing generation power transfers on the Bulk Electric System (BES) to the point of voltage collapse. The renewable source generation is increased while the study thermal generation is reduced until source generation is at full capacity, sink generation is at zero MW, or voltage collapse occurs. Load remains constant during the power transfers. The study determines the voltage stability limit for the base case models and the top Four (4) most limiting single SPP 345 kV transmission and transformer outages.

The next section provides an overview of the voltage stability analysis assumptions, analysis, and results.

6.2 VOLTAGE STABILITY ANALYSIS

The VSA was performed using the Powertech Labs, Inc., Dynamic Security Assessment Software, Voltage Security Assessment Tool (VSAT)⁵. The VSA uses the steady state Spring and Fall 2016

⁸ Electric Power Research Institute, “EPRI Power system Dynamics Tutorial”, EPRI, Palo Alto, CA. 2009. 1016042, available at www.epri.com, Section 6.4.3, pages 6-6 through 6-7.

⁹ [Open Electrical: AC Power Transmission](#)

¹⁰ [Decision Tree Based Online Voltage Security Assessment Using PMU Measurements](#), Vijay Vitall, PSERC Seminar, January 27, 2009, Arizona State University, slide 26.

powerflow base case models. The base case models reflect renewable generation penetration levels at 30%, 45%, and 60% respectively. The base case models also include operations selected generation and transmission outages. A set of models called system intact (SI) was developed that returned operational transmission outages to service. The base case and system intact models were stressed with source to sink real power (MW) transfers to determine the point of voltage collapse. The initial transfer source (renewable) and sink (thermal) generation that participate in the VSA are in Figures 6.2.1 through 6.2.6.

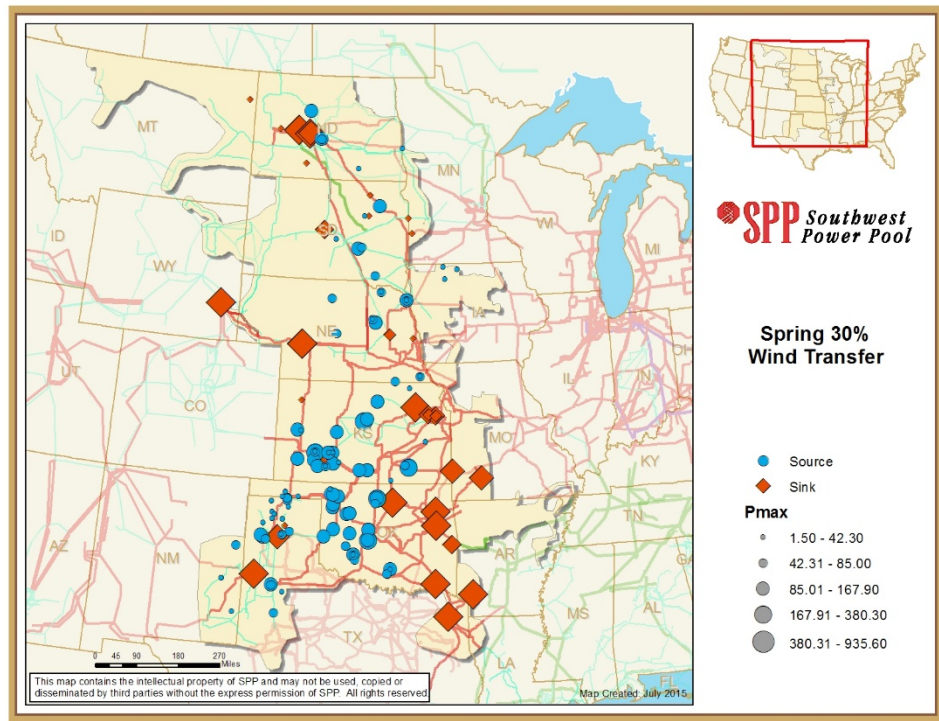


Figure 6.2.1: Spring 30% renewable penetration model VSA transfer source and sink generation

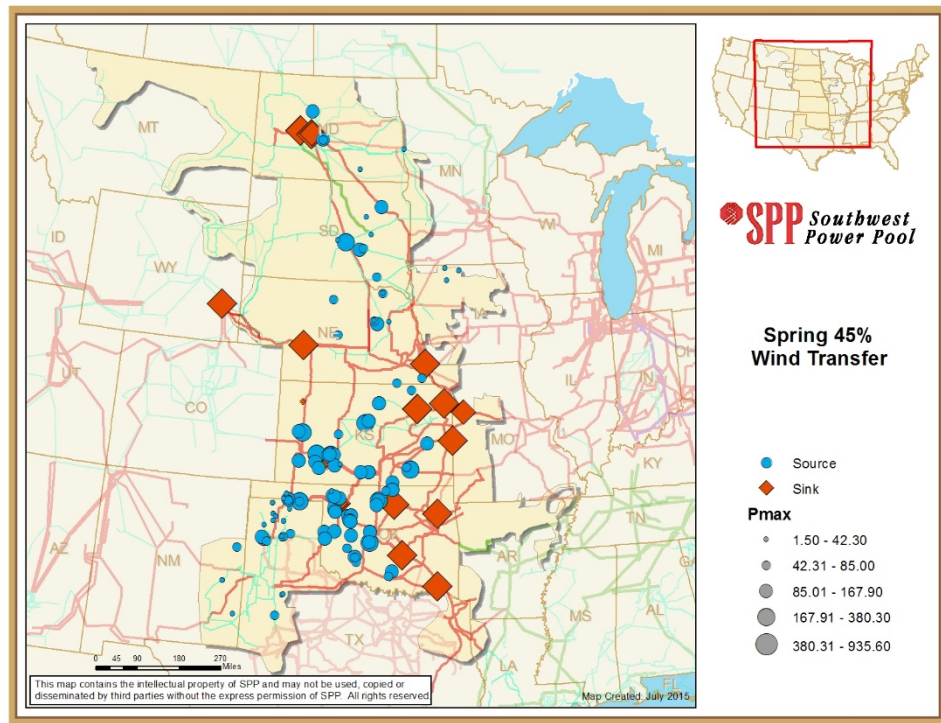


Figure 6.2.2: Spring 45% renewable penetration model VSA transfer source and sink generation

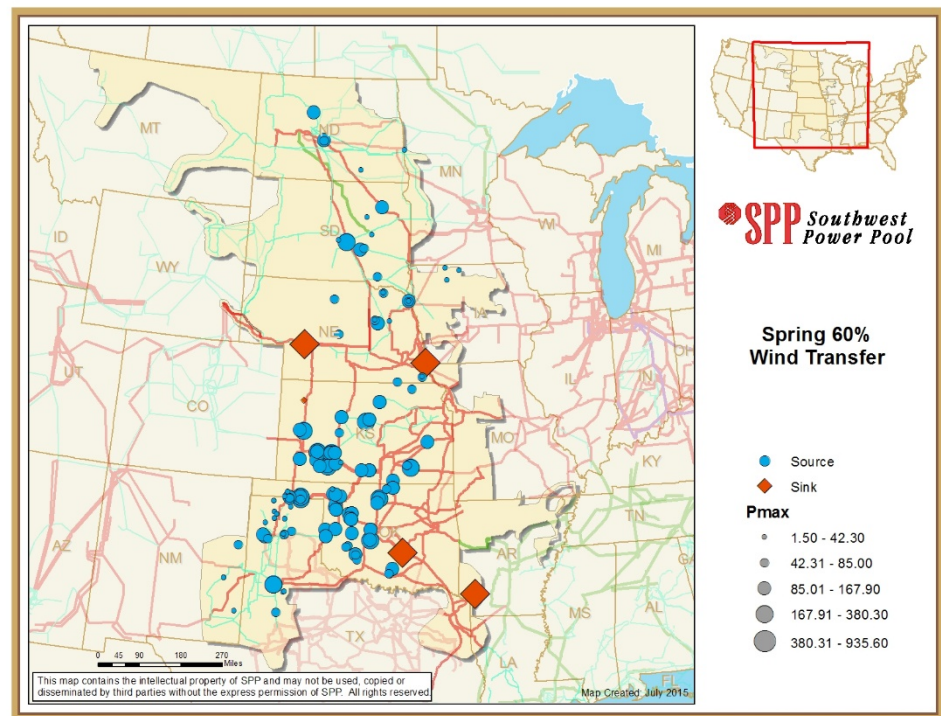


Figure 6.2.3: Spring 60% renewable penetration model VSA transfer source and sink generation

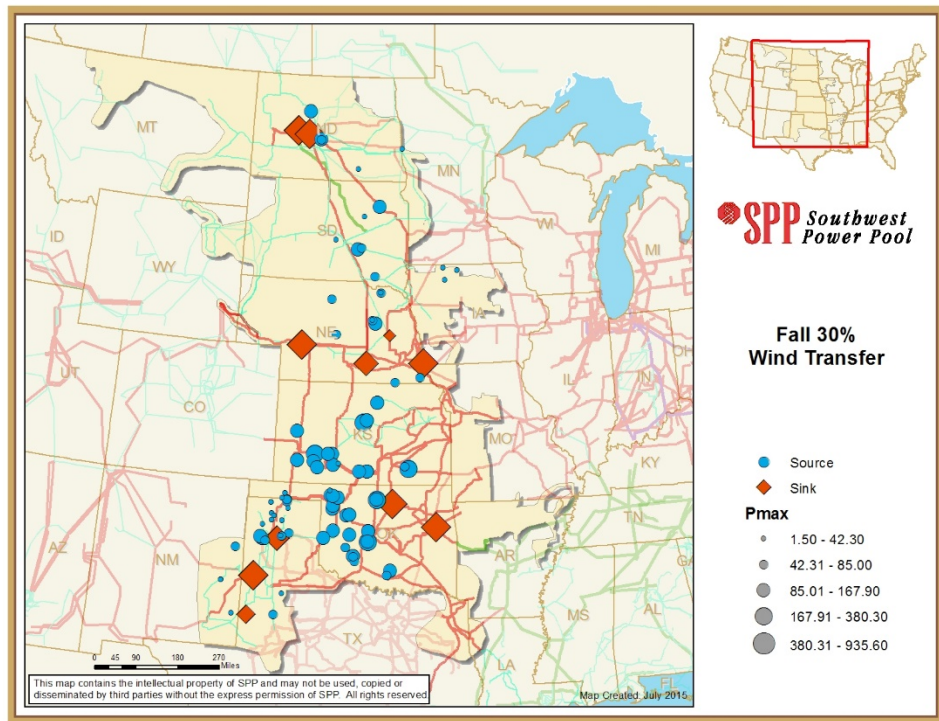


Figure 6.2.4: Fall 30% renewable penetration model VSA transfer source and sink generation

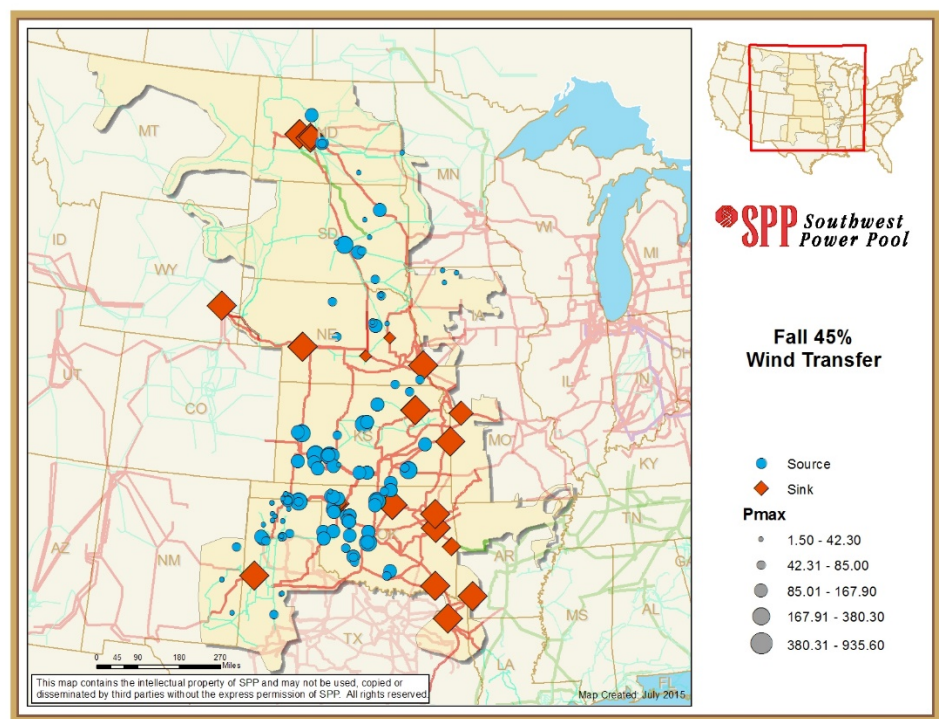


Figure 6.2.5: Fall 45% renewable penetration model VSA transfer source and sink generation

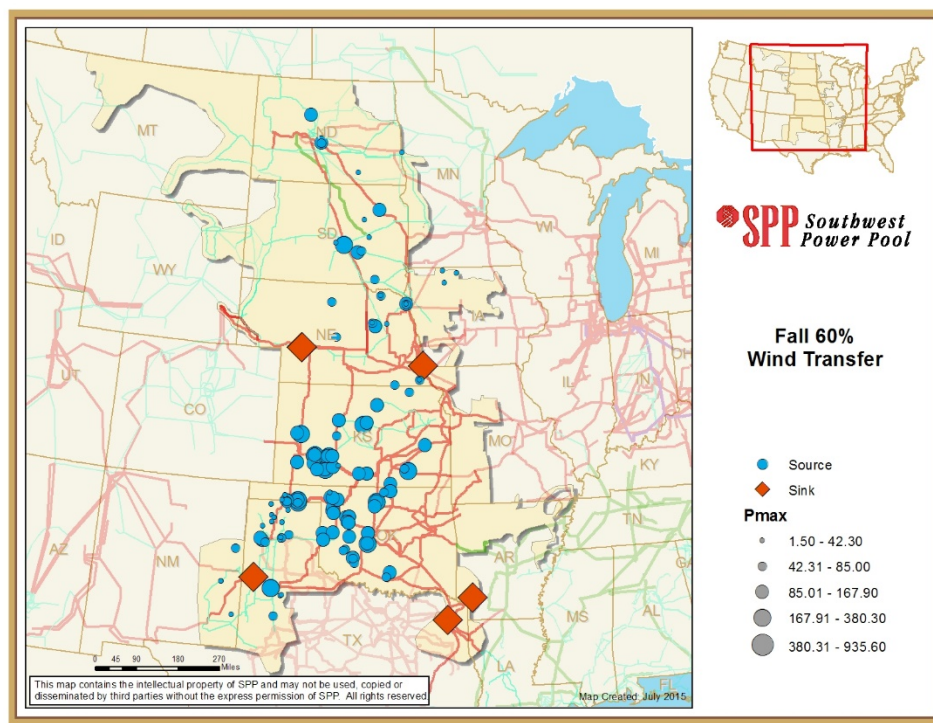


Figure 6.2.6: Fall 60% renewable penetration model VSA transfer source and sink generation

The base case and system intact models were also stressed with source to sink transfers for SPP 345 kV Grid single contingency transmission line and transformer outages. The 60% models maximum study transfer was to the point where participating sink generation reached 0 MW, while maintaining reactive output or support (MVAR). Voltages below 0.90 PU and loadings of transmission lines and transformers is ignored.

The following conditions were imposed on the transfer analysis:

- switchable shunts (capacitors and reactors) were locked
- generation reactive power (MVAR) limits
- enabled voltage controlling autotransformer taps
- enabled Static VAR Compensator (SVC) continuous switch shunts

The scenarios that exhibited voltage collapse were reanalyzed by placing reactive power source(s) on strategic Grid locations to extend the transfer. Examples of reactive power sources are capacitor banks, synchronous condensers (SC), and static VAR compensator (SVC).

A synchronous condenser is very similar to a synchronous generator with the exception that it is not capable of producing any sustained active power (MW). SCs produce /absorb reactive power. SCs do not need a prime mover as they are operated as a synchronous motor. The power system supplies the MW to turn the rotor. An excitation system is used to control the amount of MVAR produced or

absorbed by the synchronous condenser. SCs are an expensive source of reactive power and are seldom used in modern power system.¹¹

A static var compensator (SVC) is similar to a synchronous condenser in that it is also used to supply or absorb reactive power. However, in an SVC there are no rotating parts, every element is static. SVCs are composed of shunt reactors and shunt capacitors. High Speed electronic switching equipment (thyristor switches) are used to adjust the amount of reactors or capacitors in-service at any one time. SVCs have the equivalent of automatic voltage regulator systems to set and maintain a target voltage level.¹²

Dynamic reactive reserves (DRR) are reactive reserves that can be used to rapidly respond to system voltage deviations. In this context rapidly could means responding within a few cycles to a few seconds dependent on the particular power system. Manual reactive reserves are spare MVAR which take too long to place in-service. The majority of the time manual reactive reserves require operator action to utilize. From a system operations perspective maintaining an adequate level of dynamic reactive reserves is the key. Every transmission operating company must examine their reactive supply needs for both normal and disturbance conditions and then ensure they have enough spare dynamic MVAR to respond to support system voltages.¹³ SVCs, SC, and synchronous generators provide dynamic reactive reserves.

The analysis captured the reactive support supplied by the sink renewable generation, source thermal synchronous generation, and voltage supporting **Dynamic Reactive Reserves (DRR)** required to maintain the maximum transfer to voltage collapse. The VSA uses SVCs to provide DRR. The selection of SVCs is for simulation purposes only. Figure 6.2.7 shows study SVC locations.

¹¹ Electric Power Research Institute, “EPRI Power system Dynamics Tutorial”, EPRI, Palo Alto, CA. 2009. 1016042, available at www.epri.com, Section 5.6.3, page 5-57.

¹² Ibid, 11, Section 5.6.4, pages 5-57 and 5-58.

¹³ Ibid, 11, Section 5.7.4, page 5-63.

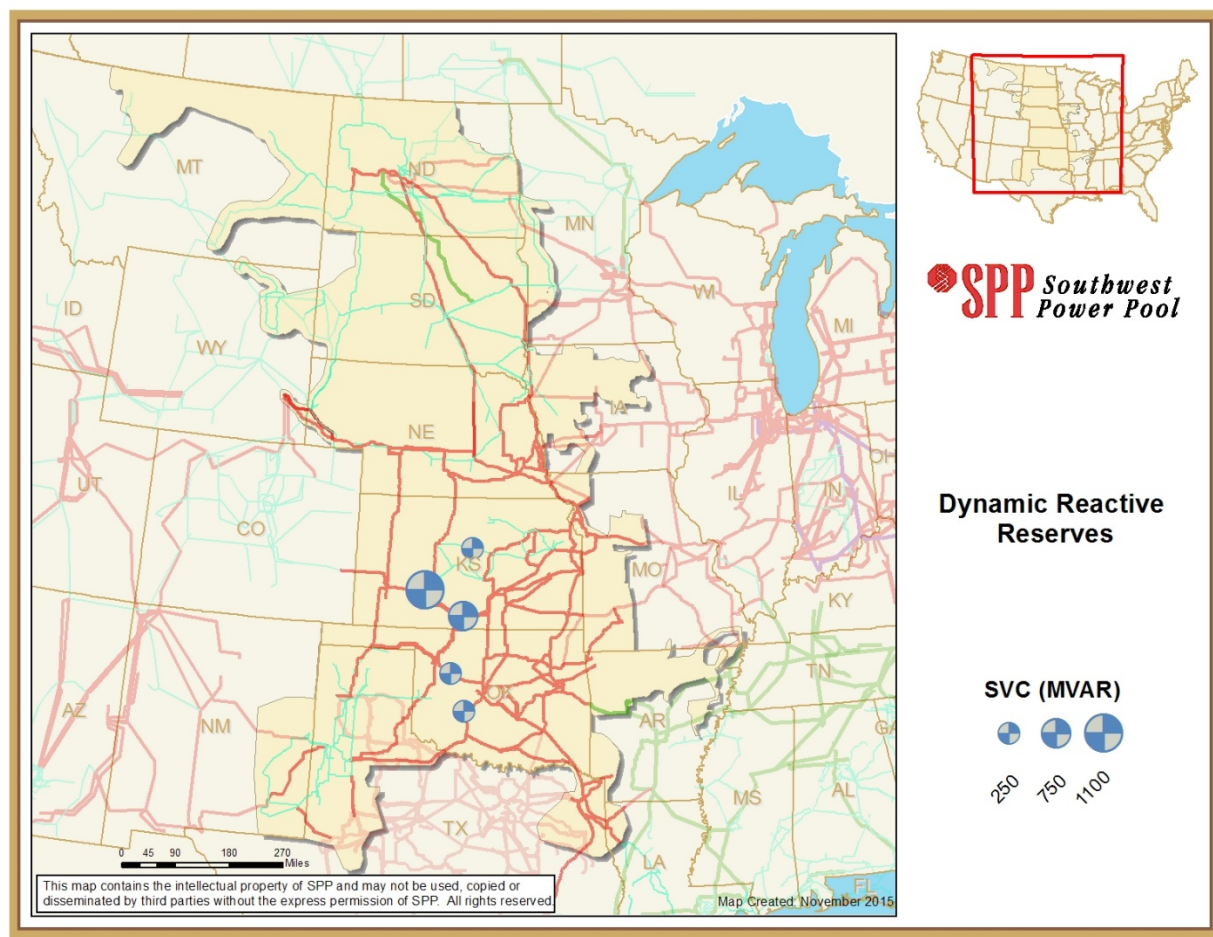


Figure 6.2.7: Dynamic Reactive Reserve - SVC locations

6.2.1 VSA Base case transfers

The Spring and Fall 30%, 45%, and 60% renewable generation initial MWs is in Table 6.2.1.1. The 30% renewable generation plus models turn on additional renewable generation that allow the model to transfer MW up to the 45% base model levels. Similarly, the 45% renewable generation plus models turn on additional renewable generation that allow the model to transfer MW to the 60% base model levels.

| Renewable Penetration | Transfer Start (MW) | |
|-----------------------|---------------------|--------|
| | Spring | Fall |
| 30% | 7,100 | 7,200 |
| 30% plus* | 9,200 | 9,200 |
| 45% | 10,700 | 10,800 |
| 45% plus* | 12,600 | 12,400 |
| 60% | 14,300 | 14,400 |

*Scale additional renewable resource MW.

Table 6.2.1.1: Initial renewable source MW

Operation Base Case (Spring)

The spring 30% renewable generation is able to transfer 10,700 MW without voltage collapse, Figure 6.2.1.1.

The spring 45% renewable penetration scenario showed voltage collapse for a transfer of 1,000 MW, renewable generation at 11,700 MW, Figure 6.2.1.2. Adding 2,000 MVAR of SVC⁽²⁾ allowed the renewable generation to go up to 14,300 MW, a 3,600 MW transfer without voltage collapse. Table 6.2.1.2 shows SVC locations used in the VSA to maximize renewable resource transfers.

| SVC Scenario | Location |
|-------------------------|---|
| (1) | Washita, Spearville, Thistle |
| (2) | Washita, Spearville, Thistle, Tatonga |
| (3) | Washita, Spearville, Thistle, Tatonga, Smokey Hills |

Table 6.2.1.2: Initial renewable source MW

The spring 60% renewable penetration scenario shows voltage collapse for a transfer of 900 MW with 2,000 MVAR of SVC⁽²⁾, at 15,300 MW, Figure 6.2.1.3. The spring 60% renewable penetration scenario is voltage stable for a transfer of 1,100 MW with 2,100 MVAR of SVC⁽³⁾. At this operating condition the renewable generation reached 15,400 MW, real power maximum output.

The transfer of renewable resource generation to thermal sink generation requires reactive support. The reactive support is supplied in part by the renewable resources, participating thermal sink generation, other online generation, capacitors, and SVCs. The total amount of Source, Sink, and SVC reactive power to support the renewable generation to thermal generation transfer for the base cases and contingency models is shown on ***Table 6.2.3***

The addition of reactive resources (example SVCs) will be required to support renewable penetrations above the 45% level. System redispatch of thermal units is required at each increment of additional renewable resource power injection to minimize system losses and the addition of reactive source MVAR. As sink units are brought to minimum power (MW) their reactive support will be critical to maintain the renewable penetration power levels. When thermal units are brought off line during renewable penetration greater than 45% it is crucial to ensure that the reactive support displaced by these units is supplied by other reactive resources.

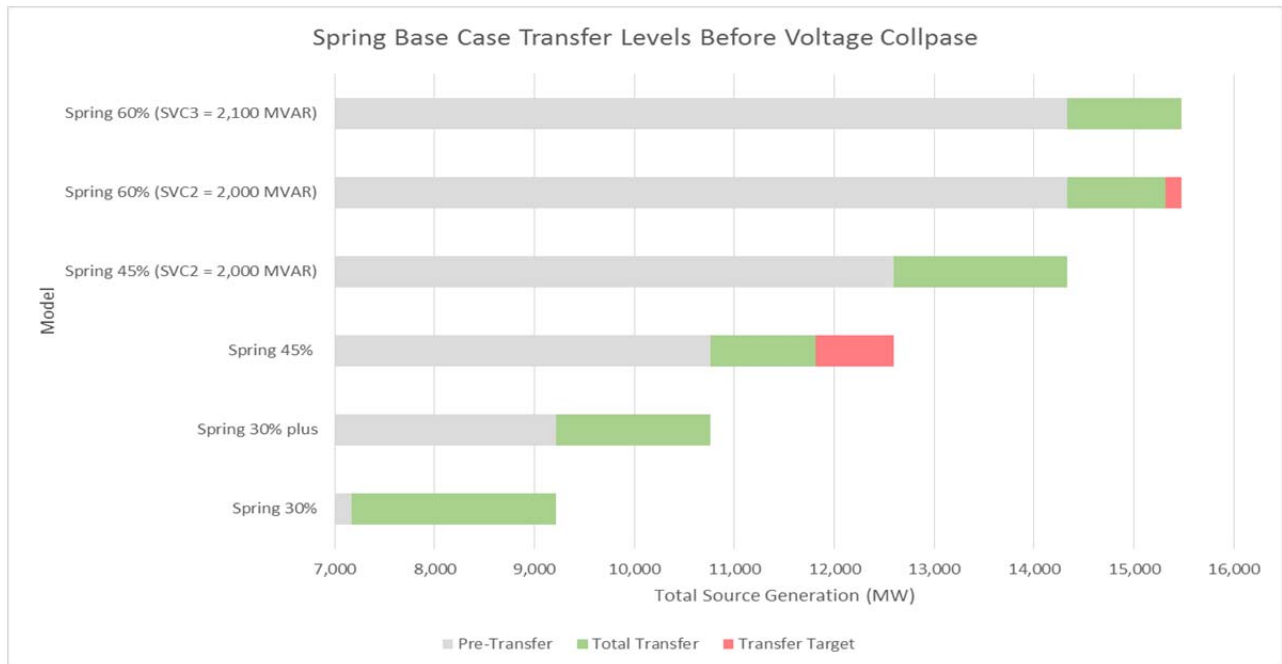


Figure 6.2.1.1: Spring base case transfer limits to voltage collapse (includes operation outages)

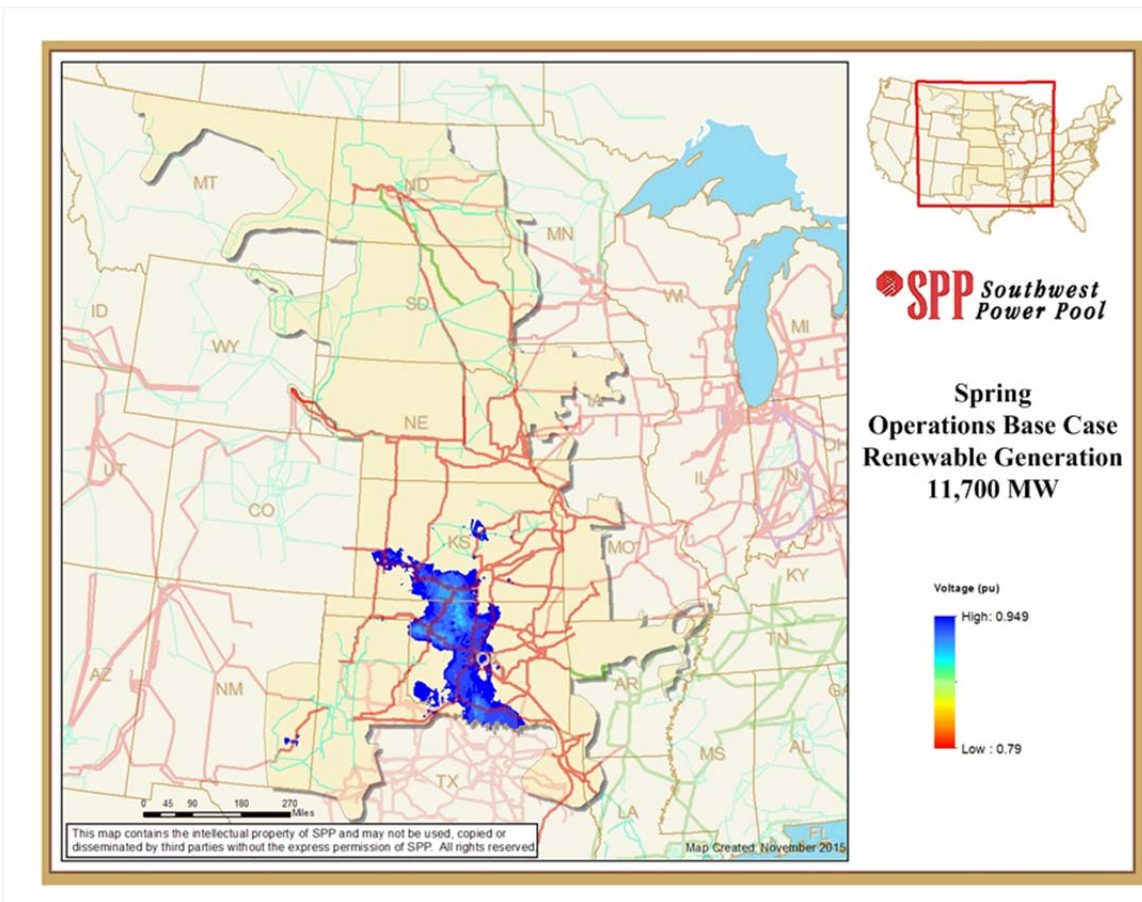


Figure 6.2.1.2: Spring 45% plus 1,000 MW renewable generation - Voltage Contour

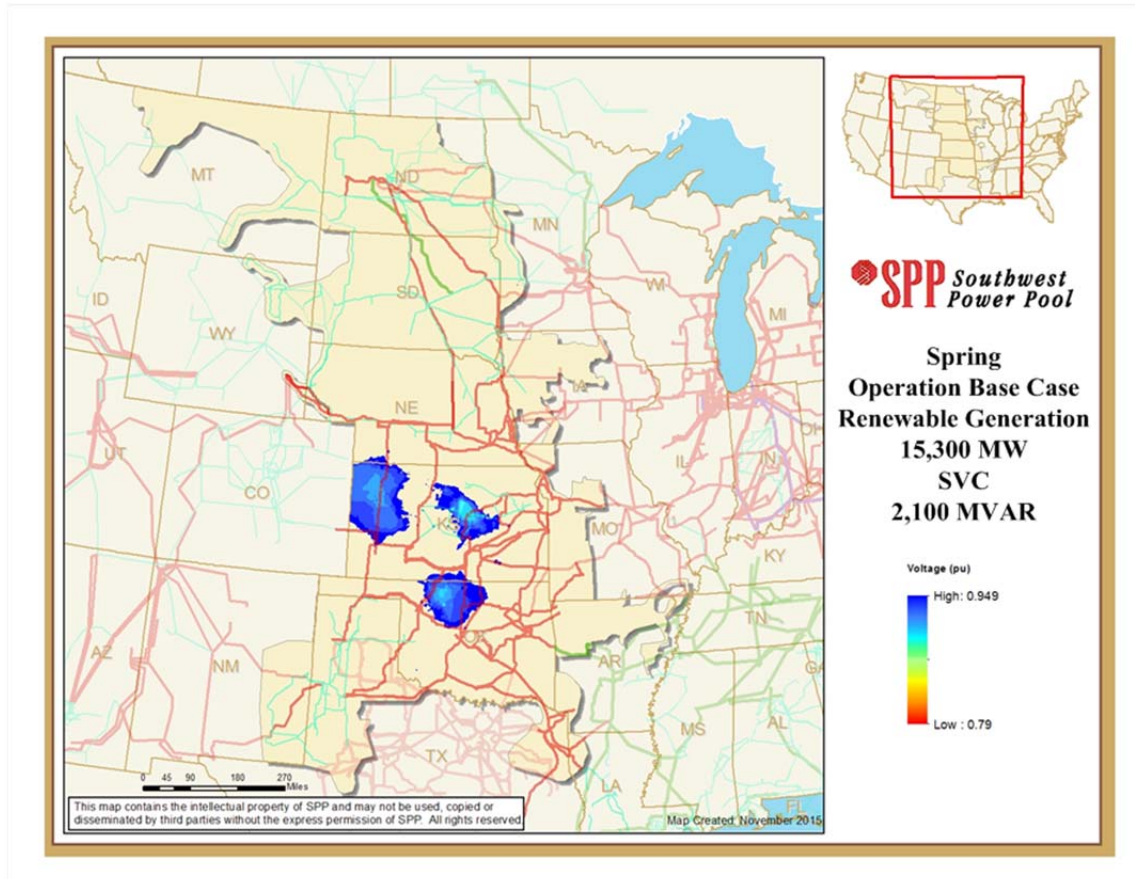


Figure 6.2.1.3: Spring 60% Penetration plus 1,200 MW with SVC² - Voltage Contour

System Intact (Spring)

The system intact Spring 30% renewable penetration base case is voltage stable for the transfer of 3,600 MW, the 45% renewable penetration generation of 10,700 MW, Figure 6.2.1.4.

The system intact Spring 45% renewable penetration base case showed voltage collapse for an incremental transfer of 2,400 MW, when the source generation is at 13,100 MW, Figure 6.2.1.5. The source generation could go to the 60% penetration target of 14,300 MW with 1,300 MVAR of SVC without voltage collapse.

The spring 60% system intact renewable penetration scenario required 1,400 MVAR of SVC to support 1,100 MW of transfer to thermal sink generation, Figure 6.2.1.4. The maximum study transfer was stopped when the source generation was scaled to real power maximum, 15,400 MW.

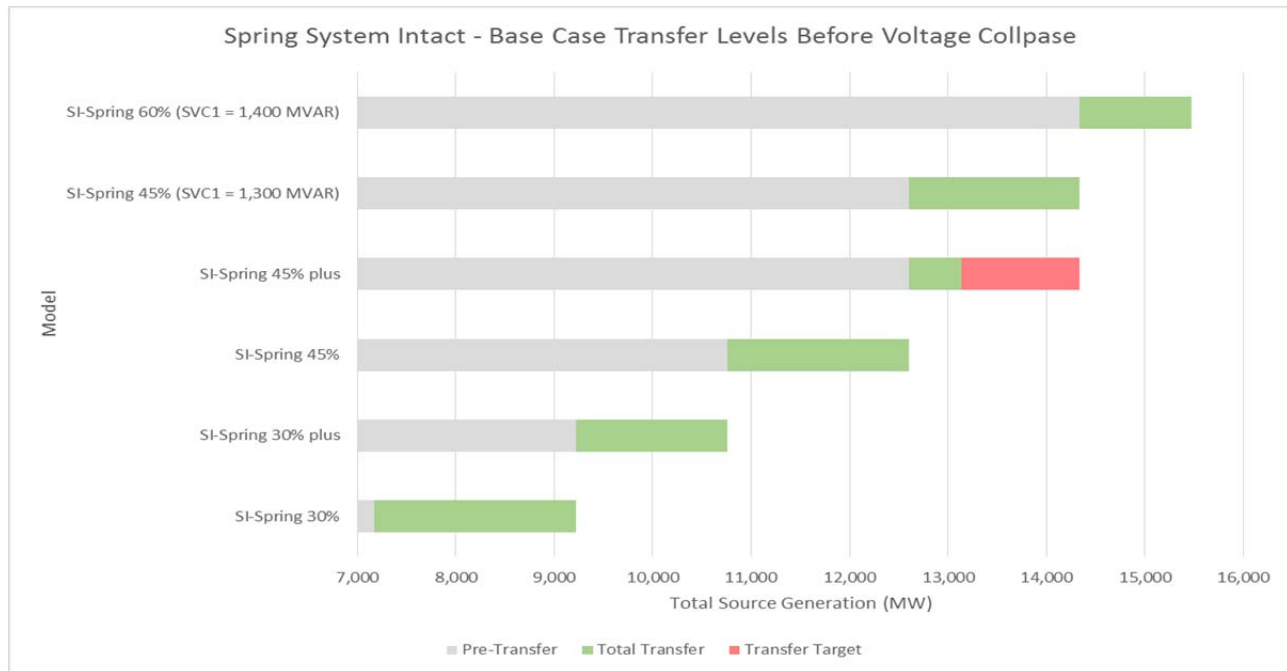


Figure 6.2.1.4: Spring System Intact transfer limits to Voltage Collapse (Operation outages in-service)

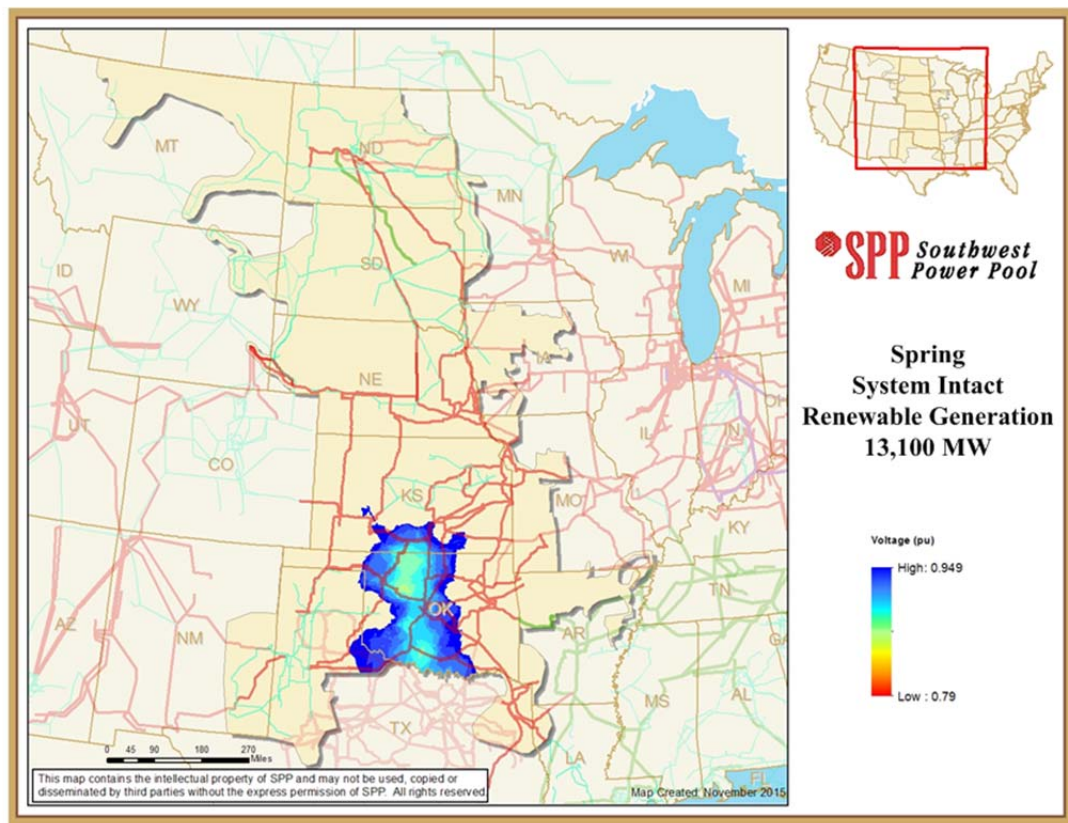


Figure 6.2.1.5: Spring System Intact 45% Penetration plus 2,400 MW - Voltage Contour

Operation Base Case v System Intact Summary (Spring)

The Spring 45% system intact model can support 1,400 MW more renewable generation than the base case before voltage collapse, Table 6.2.1.3. The spring 45% system intact model requires 700 MVAR less reactive SVC support to scale renewable generation to the spring 60% level. The spring 60% system intact model transfers 100 MW more source generation than the base case while requiring up to 700 MVAR less reactive SVC support.

| Model | Delta Transfer (MW) | Transfer Support SVC (MVAR) | Final Transfer State |
|-------------------------------|----------------------------|------------------------------------|-----------------------------|
| Spring 30% | 0 | 0 | Stable |
| Spring 45% | 1,400 | 0 | Voltage Collapse |
| Spring 45% + SVC | 0 | -700 | Stable |
| Spring 60% + SVC ³ | 0 | -700 | Stable |
| Spring 60% + SVC ² | 100 | -700 | Voltage Collapse |

Table 6.2.1.3: Spring system intact compared to base case (operations outages)

Operation Base Case (Fall)

The Fall 30% renewable penetration base case (includes operational outages) is voltage stable for the transfer of 3,600 MW, the 45% renewable penetration generation of 10,800 MW, Figure 6.2.1.6.

The Fall 45% base case exhibited voltage collapse for a transfer of 2,200 MW, Figure 6.2.1.6. The renewable generation is 13,000 MW. The voltage contour for this scenario is in Figure 6.2.1.7. The addition of 1,700 MVAR SVC⁽¹⁾ allowed the base case to transfer up to the 60% renewable penetration generation of 14,400 MW without voltage collapse.

The Fall 60% renewable generation base case could transfer 1,000 MW with 1,500 MVAR SVC⁽¹⁾, the Fall 60% renewable generation maximum study transfer target of 15,400 MW where all source generation is at maximum real power output.

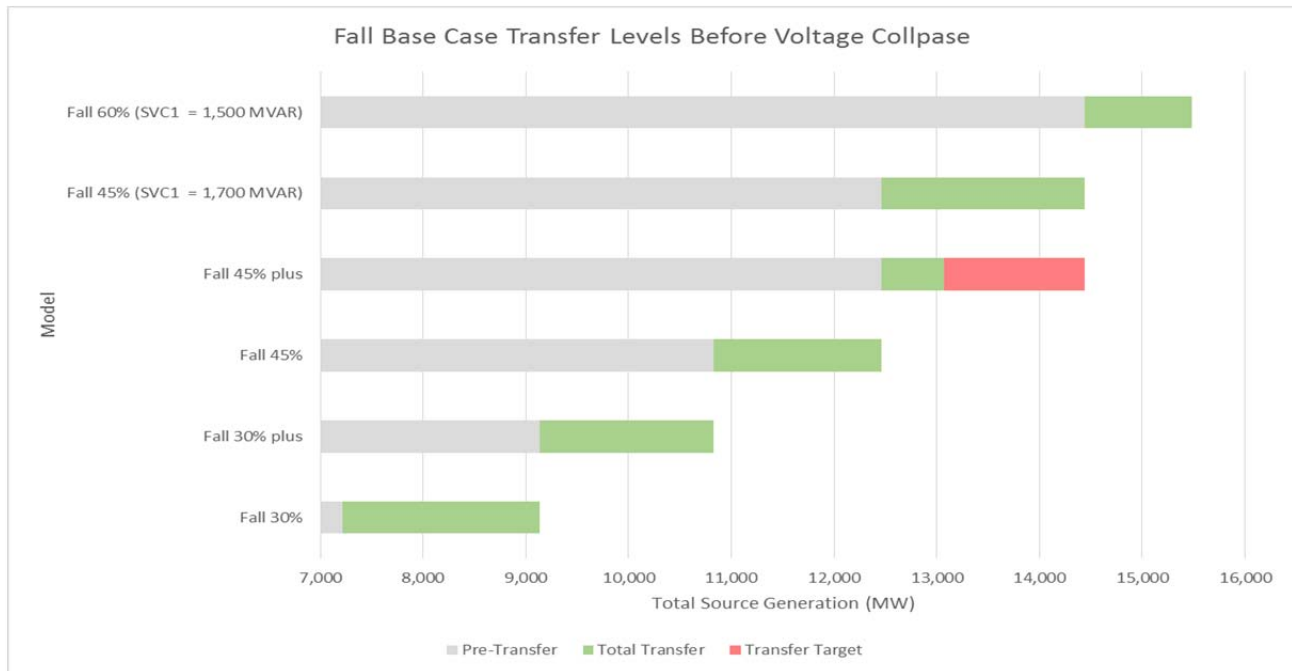


Figure 6.2.1.6: Fall base case transfer limits to voltage collapse (includes operation outages)

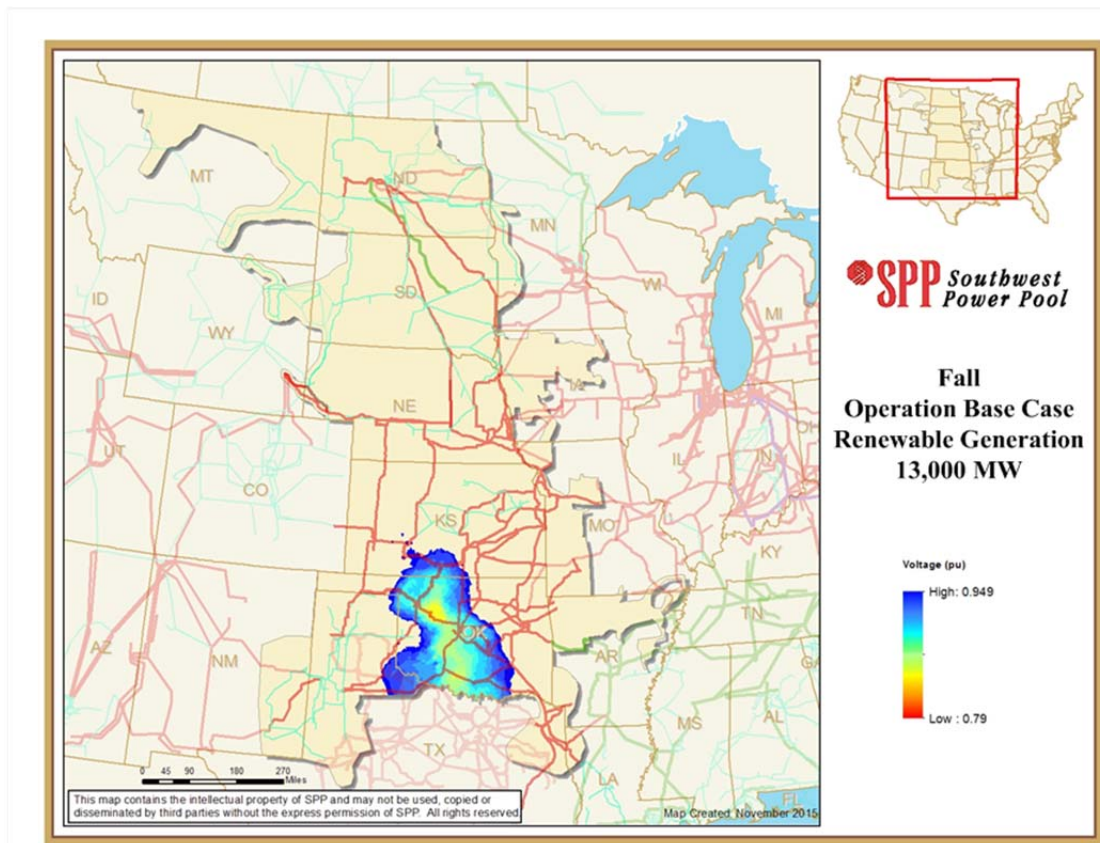


Figure 6.2.1.7: Fall 45% Penetration plus 2,200 MW - Voltage Contour

System Intact (Fall)

The system intact Fall 30% renewable penetration case (operational outages in service) is voltage stable for the transfer of 3,600 MW, the 45% renewable penetration generation of 10,800 MW, Figure 6.2.1.8.

The Fall 45% renewable generation exhibited voltage collapse for a transfer of 2,300 MW. The renewable generation is 13,100 MW. The voltage contour for this scenario is in Figure 6.2.1.9. The addition of 1,400 MVAR SVC⁽¹⁾ allowed the base case to transfer up to the 60% renewable penetration generation of 14,400 MW without voltage collapse.

The Fall 60% renewable generation base case could transfer 1,000 MW with 1,500 MVAR SVC⁽¹⁾, the Fall 60% renewable generation maximum study transfer target of 15,400 MW where all source generation is at maximum real power output.

- The 60% model requires less reactive support than the 45% plus model for the following reasons:
- the 60% model starts from a SPP CBA dispatch which takes into account transmission losses for the initial renewable penetration of 14,400 MW and
 - the 45% model starts scaling selected renewable resources from 10,800 MW and participating sink generation without dispatch for losses.

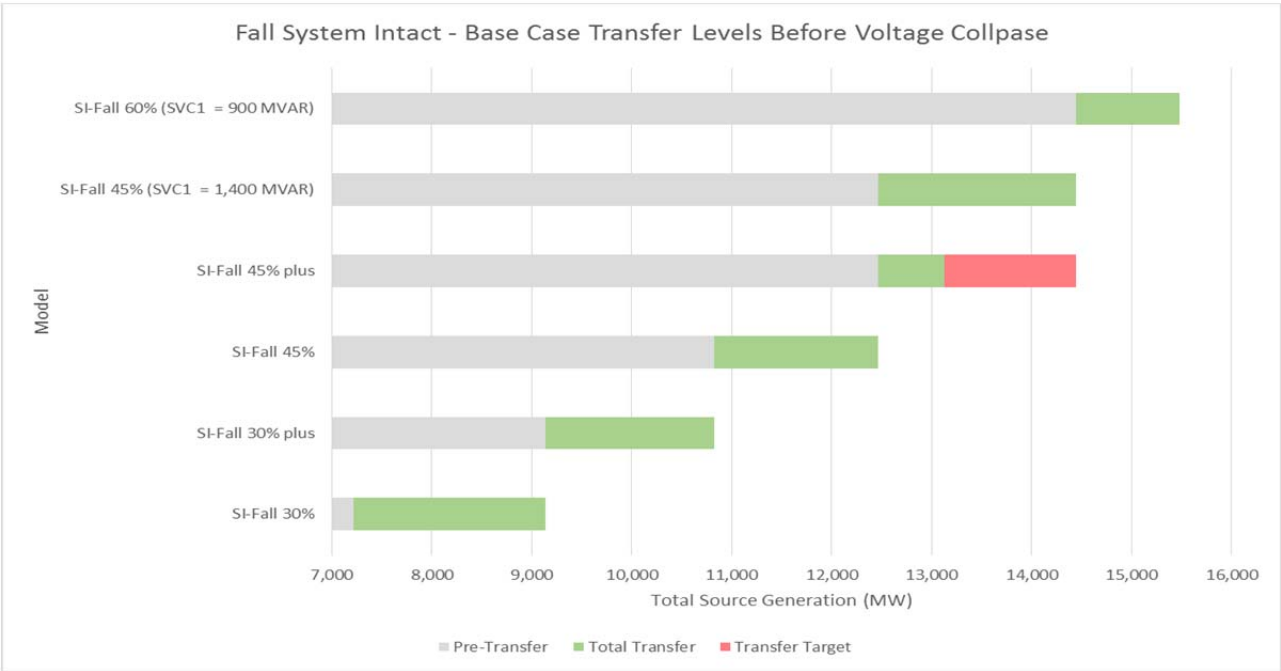


Figure 6.2.1.8: Fall system intact transfer limits to voltage collapse (includes operation outages)

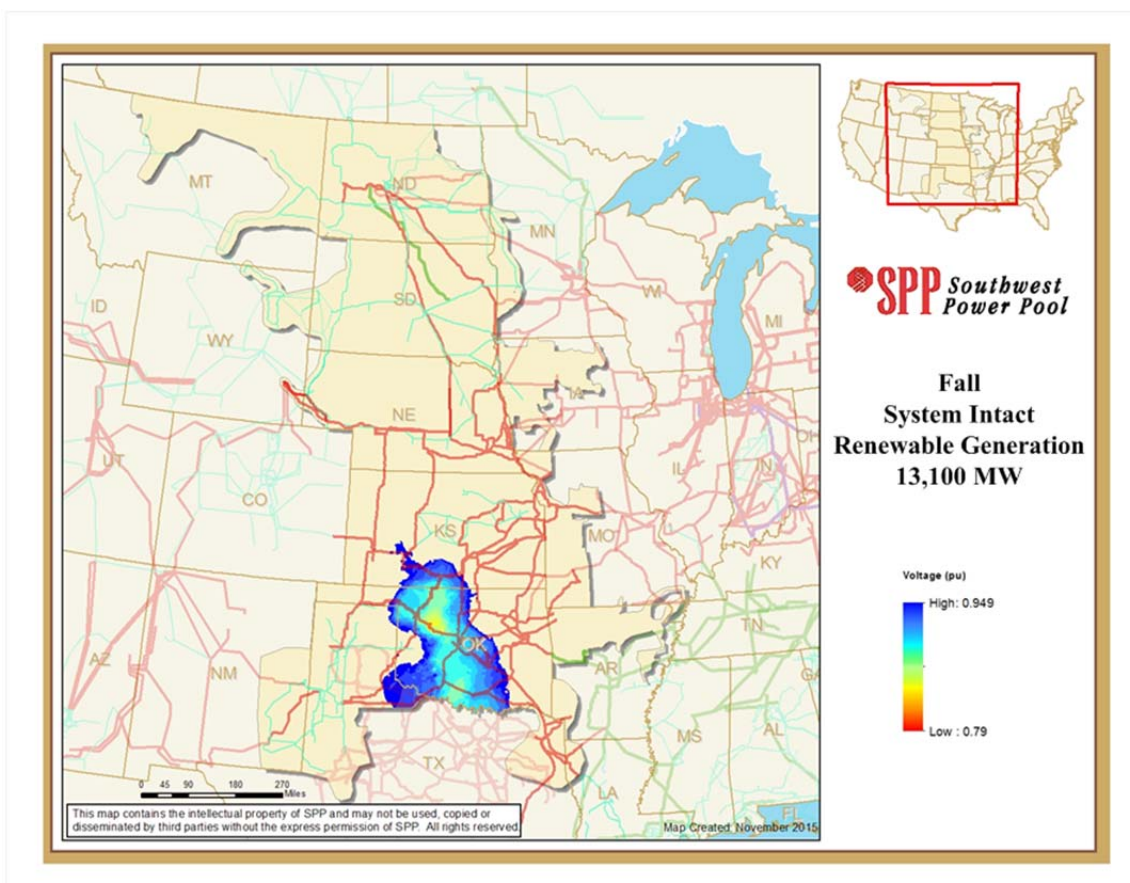


Figure 6.2.1.9: Fall System Intact 45% Penetration plus 2,300 MW - Voltage Contour

Operation Base Case v System Intact Summary (Fall)

The Fall 45% system intact (operational outages in-service) model provides an additional 100 MW of transfer capability before voltage collapse. The Fall 45% system intact requires 300 MVAR less SVC to transfer renewable generation up to 60% penetration without voltage collapse.

The Fall 60% model required 600 MVAR less SVC to support the maximum study renewable transfer.

6.2.2 VSA Event 1 through 5 (Spring)

The VSA tested over 267 (345 kV) transmission line events (outages) and 210 (345 kV) transformer events. The most limiting events occurred in the Spring models, Figure 6.2.2.1.

| Event | Contingency | Voltage (kV) |
|-------|----------------------|--------------|
| 1 | Northwest to Totonga | 345 |
| 2 | Holcomb to Buckner | 345 |
| 3 | Mingo to Setab | 345 |
| 4 | Mingo to Red Willow | 345 |
| 5 | Waverly to Lacygne | 345 |

Table 6.2.2.1: Most limiting 345 kV events

6.2.2.1 Event 1: Northwest to Totonga 345 kV line outage, Figure 6.2.2.1.1

The Spring 30% operation model with event 1 has voltage collapse (VC) for a renewable generation transfer of 3,600 MW, renewable generation of 10,700 MW. The voltage contour is in Figure 6.2.2.1.2.

The Spring 45% operation outage case with event 1 has voltage collapse, no transfer capability. The addition of 1,700 MVAR SVC² extended the voltage collapse point to 13,300 MW, a 2,600 MW transfer.

The Spring 60% operation outage case with event 1 has 0 MW transfer capability due to voltage collapse.

The Spring 45% system intact model with event 1 has voltage collapse at a renewable generation level of 11,200 MW, a 500 MW transfer. The voltage contour for this scenario is in Figure 6.2.2.1.3. The addition of 1,400 MVAR of SVC¹ extended the voltage collapse point to 13,700 MW.

The Spring 60% system intact model with event 1 with 1,800 MVAR SVC¹ can only transfer 500 MW of renewable generation, 14,800 MW, the point of voltage collapse.

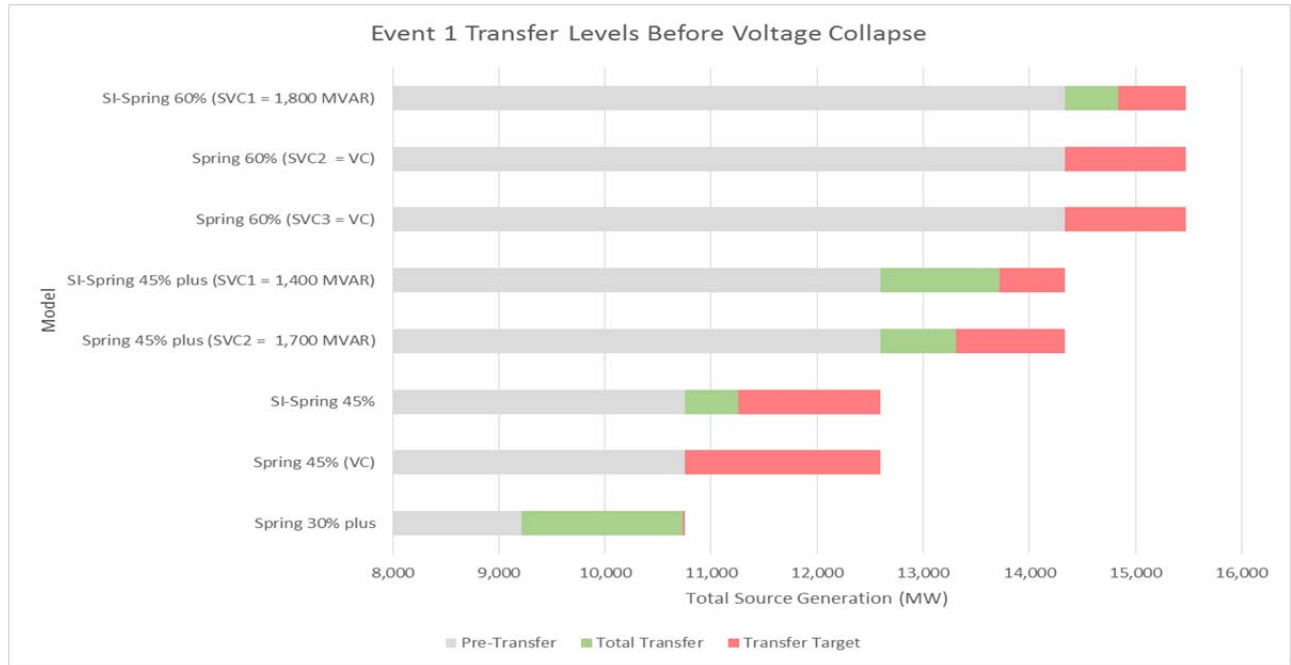


Figure 6.2.2.1.1: Spring Event 1 Northwest to Tatonga 345kV outage transfers to voltage collapse

SVC¹ locations are Washita, Spearville, Thistle.
SVC² locations are Washita, Spearville, Thistle, Tatonga.
SVC³ locations are Washita, Spearville, Thistle, Tatonga, Smokey Hills.
(VC) Voltage Collapse

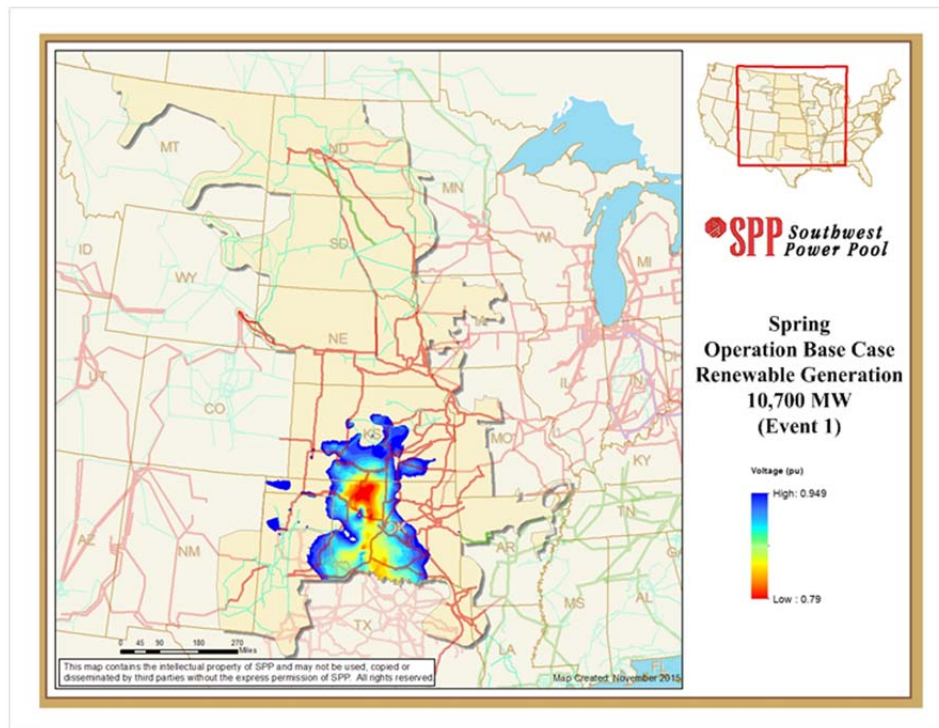


Figure 6.2.2.1.2: Spring 30% Penetration Event 1 plus 3,600 MW - Voltage Contour

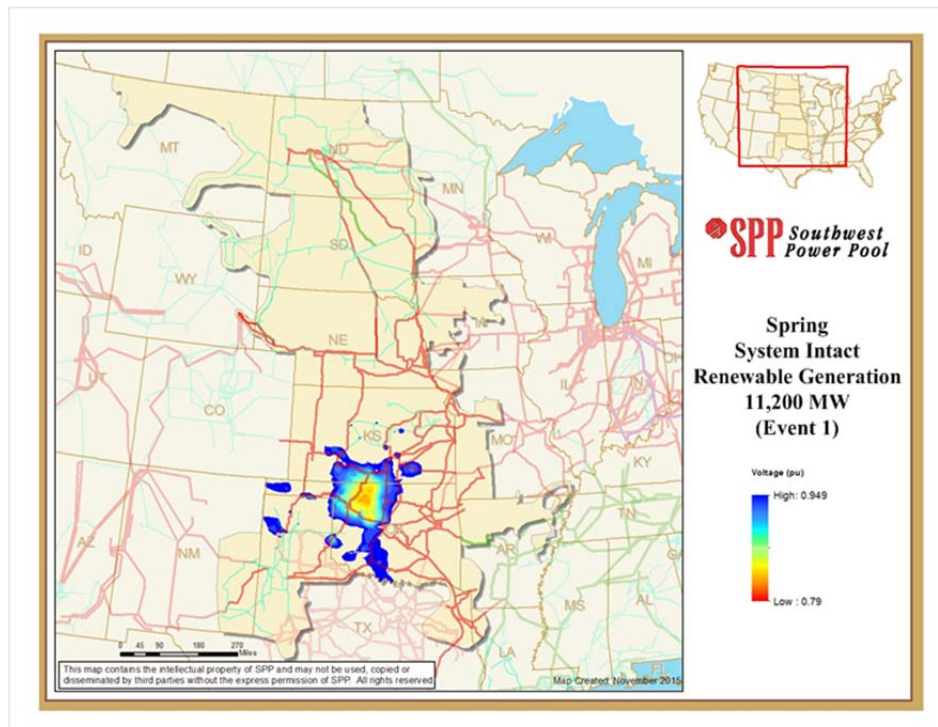


Figure 6.2.2.1.3: Spring System Intact 45% Penetration plus 500 MW - Voltage Contour

The operation models have 500 MW of less renewable generation capability than the system intact models and require 300 MVAR of additional SVC, Table 6.2.2.1.

| Model | Delta Transfer (MW) | Transfer Support SVC (MVAR) | Final Transfer State |
|------------------|---------------------|-----------------------------|----------------------|
| Spring 45% | 500 | 0 | Voltage Collapse |
| Spring 45% + SVC | 400 | -300 | Voltage Collapse |
| Spring 60% + SVC | 500* | 100 | Voltage Collapse |

Table 6.2.2.1: Spring system intact compared to operation outage model with event 1

Event 1 is the most limiting 345 kV outage in the Fall operations outage and system intact models. The Fall 45% renewable generation exhibits voltage collapse at 10,900 MW for events 1.

6.2.2.2 Event 2: Holcomb to Buckner 345 kV line outage, Figure 6.2.2.2.1

The Spring 45% system intact model with event 2 has voltage collapse at 11,700 MW of renewable generation. 1,500 MVAR SVC extends the renewable generation to 14,300 MW.

The Spring 45% operations outage model with event 2 has voltage collapse at a renewable generation of 11,200 MW. 2,100 MVAR of SVC allowed stable operation to 14,300 MW, the 60% renewable penetration level.

The Spring 60% system intact model with event 2 and 1,700 MVAR of SVC reactive support extend renewable generation to 15,400 MW, the maximum study transfer without voltage collapse.

The Spring 60% operation model with event 2 and 2,200 MVAR of SVC exhibits voltage collapse at 15,100 MW of renewable generation. 2,400 MVAR of SVC³ reactive support extends the renewable generation voltage collapse point to 15,400 MW.

The 45% renewable penetration operation outage model has 500 MW of less renewable generation capability than the system intact model and requires 700 MVAR of additional SVC to host the Spring 60% renewable generation level, Table 6.2.2.2.

The 60% renewable penetration operation model has 100 MW of less renewable generation capability than the system intact model and requires 800 MVAR of additional SVC to host the Spring 60% renewable penetration generation level point of voltage collapse.

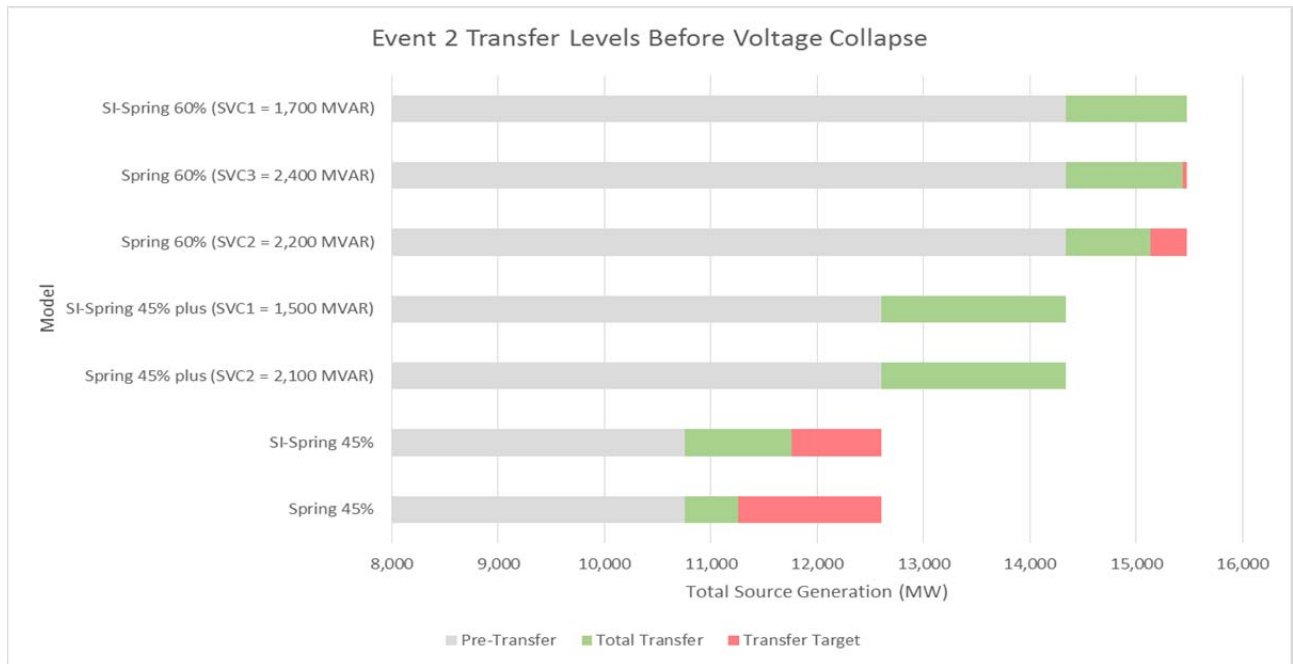


Figure 6.2.2.2.1: Spring Event 2 Holcomb to Buckner 345 kV outage transfers to voltage collapse

SVC¹ locations are Washita, Spearville, Thistle.
SVC² locations are Washita, Spearville, Thistle, Tatonga.
SVC³ locations are Washita, Spearville, Thistle, Tatonga, Smokey Hills.

The 45% renewable penetration operation outage model has 500 MW of less renewable generation capability than the system intact model and requires 700 MVAR of additional SVC to host the Spring 60% renewable generation level, Table 6.2.2.2.

The 60% renewable penetration operation model has 100 MW of less renewable generation capability than the system intact model and requires 800 MVAR of additional SVC to host the Spring 60% renewable penetration generation level point of voltage collapse.

| Model | Delta Transfer (MW) | Transfer Support SVC (MVAR) | Final Transfer State |
|------------------|---------------------|-----------------------------|----------------------|
| Spring 45% | 500 | 0 | Voltage Collapse |
| Spring 45% + SVC | 0 | -700 | Voltage Collapse |
| Spring 60% + SVC | 0 | -700 | Voltage Collapse |

Table 6.2.2.2: System intact compared to operation outage model includes event 2

6.2.2.3 Event 3: Mingo to Setab 345 kV line outage, Figure 6.2.2.3.1

The Spring 45% system intact model with event 3 has voltage collapse at a renewable generation level of 11,800 MW. The SVC addition of 1,600 MVAR extends the voltage collapse point to 14,300 MW.

The Spring 45% operations outage model with event 3 has voltage collapse at a renewable generation level of 11,200 MW. Adding 2,100 MVAR of SVC extended the voltage collapse point to 13,900 MW.

The Spring 60% system intact model voltage collapse point is 15,400 MW with the addition of 2,000 MVAR SVC¹ reactive support.

The Spring 60% operation outage model with event 3 exhibits voltage collapse at 14,800 MW with 2,300 MVAR of additional SVC.

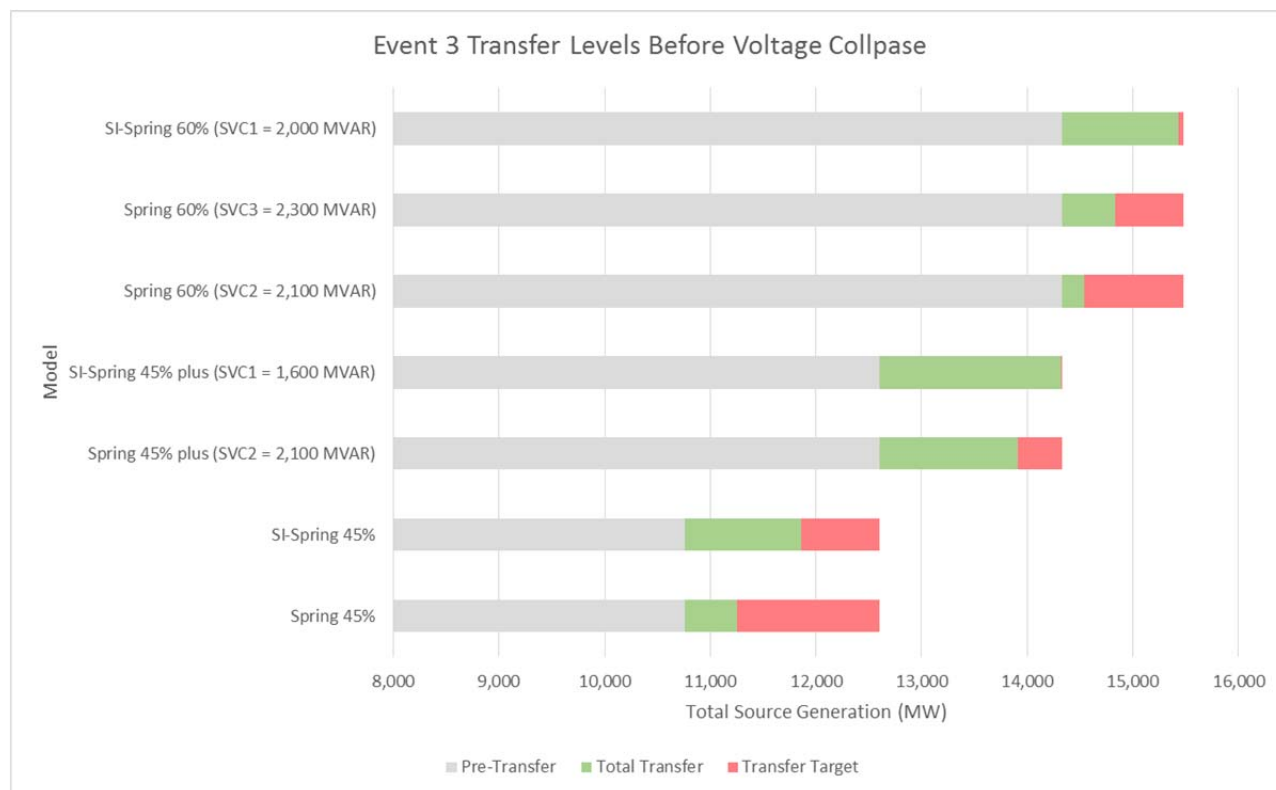


Figure 6.2.2.3.1: Spring Event 3 Mingo to Setab 345 kV outage transfers to voltage collapse

SVC¹ locations are Washita, Spearville, Thistle.

SVC² locations are Washita, Spearville, Thistle, Tatonga.

SVC³ locations are Washita, Spearville, Thistle, Tatonga, Smokey Hills.

The operational base case has 600 MW less margin to voltage stability than the system intact case for event 3, Table 6.2.2.3. The operational base case also requires the addition of more SVC, 500 MVAR.

| Model | Delta Transfer (MW) | Transfer Support SVC (MVAR) | Final Transfer State |
|------------------|---------------------|-----------------------------|----------------------|
| Spring 45% | 600 | 0 | Voltage Collapse |
| Spring 45% + SVC | 400 | -500 | Voltage Collapse |
| Spring 60% + SVC | 600 | -300 | Voltage Collapse |

Table 6.2.2.3: System intact compared to operation outage model includes event 3

6.2.2.4 Event 4: Mingo to Red Willow 345 kV line outage, Figure 6.2.2.4.1

The Spring 45% system intact model with event 4 has voltage collapse at a renewable generation level of 12,000 MW. Adding 1,600 MVAR of SVC¹ extends the voltage collapse point to 14,300 MW.

The Spring 45% operations outage model with event 4 has voltage collapse at a renewable generation level of 11,300 MW. Adding 2,000 MVAR of SVC² extends the voltage collapse point to 13,800 MW.

The Spring 60% system intact model with event 4 has voltage collapse at a renewable generation level of 15,300 MW with the SVC¹ addition of 2,000 MVAR.

The Spring 60% operation outage model with event 4 has voltage collapse at a renewable generation level of 14,400 MW. Adding 2,100 MVAR of SVC³ only extends the voltage collapse limit by 100 MW.

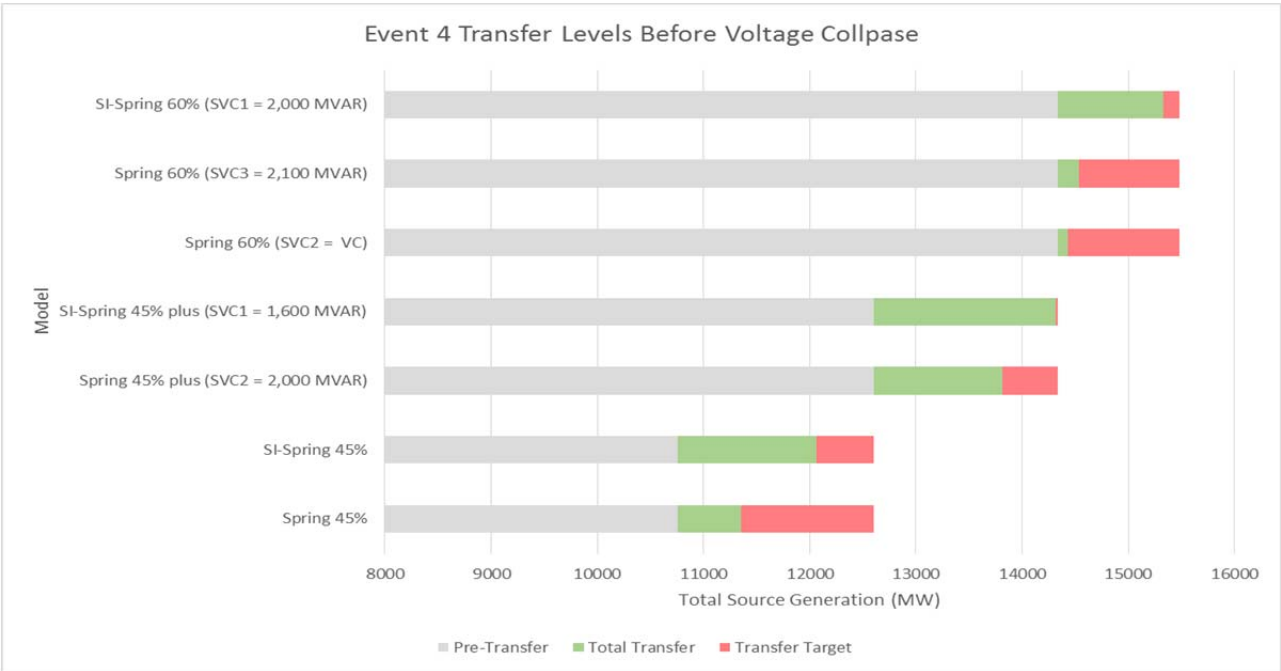


Figure 6.2.2.4.1: Spring Event 4 Mingo to Red Willow 345 kV outage transfers to voltage collapse
SVC¹ locations are Washita, Spearville, Thistle.
SVC² locations are Washita, Spearville, Thistle, Tatonga.
SVC³ locations are Washita, Spearville, Thistle, Tatonga, Smokey Hills.

The operational base case has 800 MW less margin to voltage stability than the system intact case, Table 6.2.2.4. The operational base case also requires the addition of more SVC, 500 MVAR.

| Model | Delta Transfer (MW) | Transfer Support SVC (MVAR) | Final Transfer State |
|------------------|---------------------|-----------------------------|----------------------|
| Spring 45% | 700 | 0 | Voltage Collapse |
| Spring 45% + SVC | 500 | -400 | Voltage Collapse |
| Spring 60% + SVC | 800 | -100 | Voltage Collapse |

Table 6.2.2.4: System intact compared to operation outage model includes event 4

6.2.3 Renewable generation total Dynamic Reactive Reserve (MVAR)

The transfer associated with sinking renewable generation into SPP thermal unit locations requires source, sink, and SVC reactive support. The reactive support from online resources (generation on voltage control, capacitors, SVCs) that do not participate in the real power transfer is not included in the total DRR total calculation. Table 6.2.3 shows how much total reactive support is necessary to support an incremental source to sink renewable generation transfer in the Spring and Fall, operations outage and system intact base case models. The Source and Sink MVAR represents the incremental reactive power required to support the real power Delta Transfer MW. The SVC MVAR is the actual SVC output when the renewable generation is at the Stop MW level. The DRR MVAR is the sum of the reactive power supplied by the SVC, Source, and Sink generation.

| Model Type | Season & Renewable Penetration | Renewable Start (MW) | Renewable Stop (MW) | Delta Transfer (MW) | DRR (MVAR) | SVC (MVAR) | Source (MVAR) | Sink (MVAR) | State |
|-------------------|----------------------------------|----------------------|---------------------|---------------------|------------|------------|---------------|-------------|--------|
| Operation Outages | Spring 30% | 7,100 | 10,700 | 3,600 | 446 | 0 | 278 | 168 | Stable |
| Operation Outages | Spring 45% | 10,700 | 11,700 | 1,000 | 1,148 | 0 | 514 | 634 | VC |
| Operation Outages | Spring 45% + (SVC ²) | 10,700 | 14,300 | 3,600 | 3,239 | 2,000 | 380 | 858 | Stable |
| Operation Outages | Spring 60% + (SVC ²) | 14,300 | 15,200 | 900 | 2,365 | 2,000 | 37 | 328 | VC |
| Operation Outages | Spring 60% + (SVC ³) | 14,300 | 15,400 | 1,100 | 3,046 | 2,100 | 620 | 325 | Stable |
| System Intact | Spring 30% | 7,100 | 10,700 | 3,600 | 277 | 0 | 213 | 64 | Stable |
| System Intact | Spring 45% | 10,700 | 13,100 | 2,400 | 1,722 | 0 | 692 | 1,030 | VC |
| System Intact | Spring 45% + (SVC ¹) | 10,700 | 14,300 | 3,600 | 2,780 | 1,300 | 536 | 944 | Stable |
| System Intact | Spring 60% + (SVC ¹) | 14,300 | 15,400 | 1,100 | 2,039 | 1,400 | 449 | 190 | Stable |
| Operation Outages | Fall 30% | 7,200 | 10,800 | 3,600 | 287 | 0 | 260 | 27 | Stable |
| Operation Outages | Fall 45% | 10,800 | 13,000 | 2,200 | 934 | 0 | -102 | 1,035 | VC |
| Operation Outages | Fall 45% + (SVC ¹) | 10,800 | 14,400 | 3,600 | 2,361 | 1,700 | -240 | 900 | Stable |
| Operation Outages | Fall 60% + (SVC ¹) | 14,400 | 15,400 | 1,000 | 2,141 | 1,500 | 455 | 186 | Stable |
| System Intact | Fall 30% | 7,200 | 10,800 | 3,600 | 257 | 0 | 232 | 25 | Stable |
| System Intact | Fall 45% | 10,800 | 13,100 | 2,300 | 922 | 0 | -115 | 1,037 | VC |
| System Intact | Fall 45% + (SVC ¹) | 10,800 | 14,400 | 3,600 | 1,976 | 1,400 | -23 | 599 | Stable |
| System Intact | Fall 60% + (SVC ¹) | 14,400 | 15,400 | 1,000 | 1,976 | 1,500 | 319 | 157 | Stable |

Table 6.2.3: Spring and Fall base case model Dynamic Reactive Reserve (DRR) MVAR at maximum power transfer

6.3 POWER TRANSFER AND REACTIVE RESERVES

This section provides a short description of how power transfer margins and reactive reserve requirements are defined in industry. The Western Electricity Coordinating Council (WECC) standard voltage stability margin is reference here to demonstrate the concept. WECC¹⁴ maintains 105% transfer path voltage stability margin for Operational Transfer Capability for system normal conditions and for single contingencies. For multiple contingencies post transient voltage stability is required with a minimum of 102.5% Operational Transfer Capability. Figure 6.3.1 shows a plot of bus voltage versus interface flow or load real power (MW) for system normal conditions, single contingency, and multiple contingencies.¹⁵

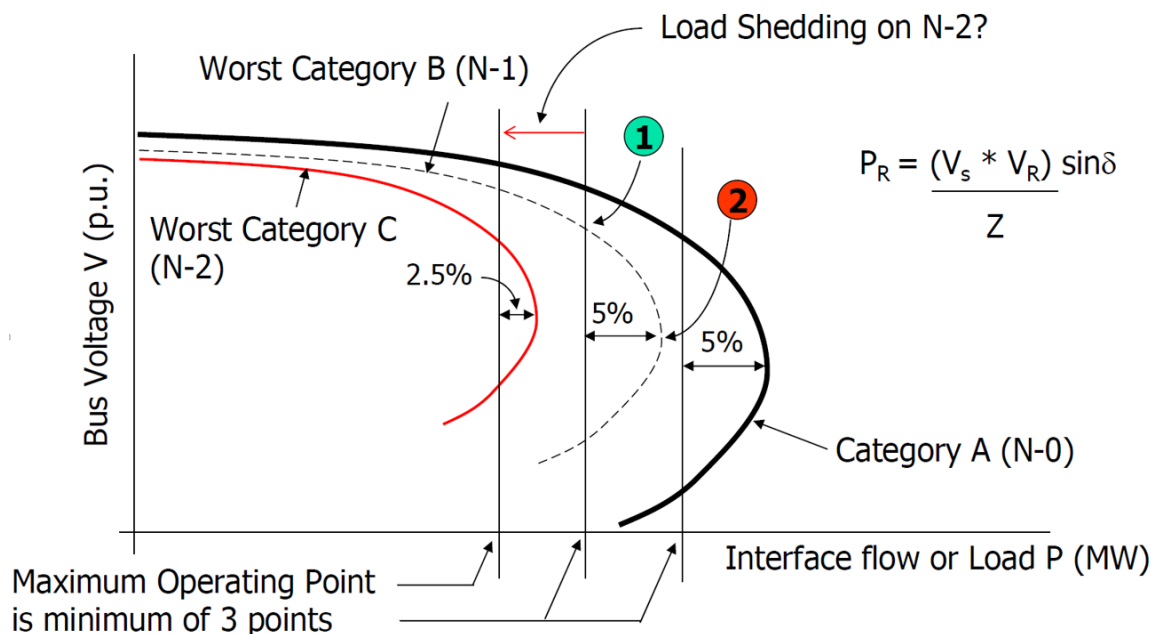


Figure 6.3.1: Interface flow or Load real power (MW) reserve margin.

The maximum operating point 1 for the worst case single contingency would require adequate reactive power (MVAR) reserves to support an additional 5% real power interface flow (MW) or load increase to voltage collapse, point 2.¹⁰ Figure 6.3.2 shows the reactive margin required at the maximum operating point in a voltage (V) versus reactive power (Q) plot.

¹⁴ [Guide to WECC/NERC Planning Standards I.D: Voltage Support and Reactive Power, Reactive Reserve Working Group \(RRWG\)](#), March 30, 2006, Section 3, page 16.

¹⁵ [Reactive \(VAR\) Reserve Margin](#), NARUC joint meeting Electric Reliability Staff Subcommittee & Electricity Staff Subcommittee, November 13, 2005, slides 14 through 18.

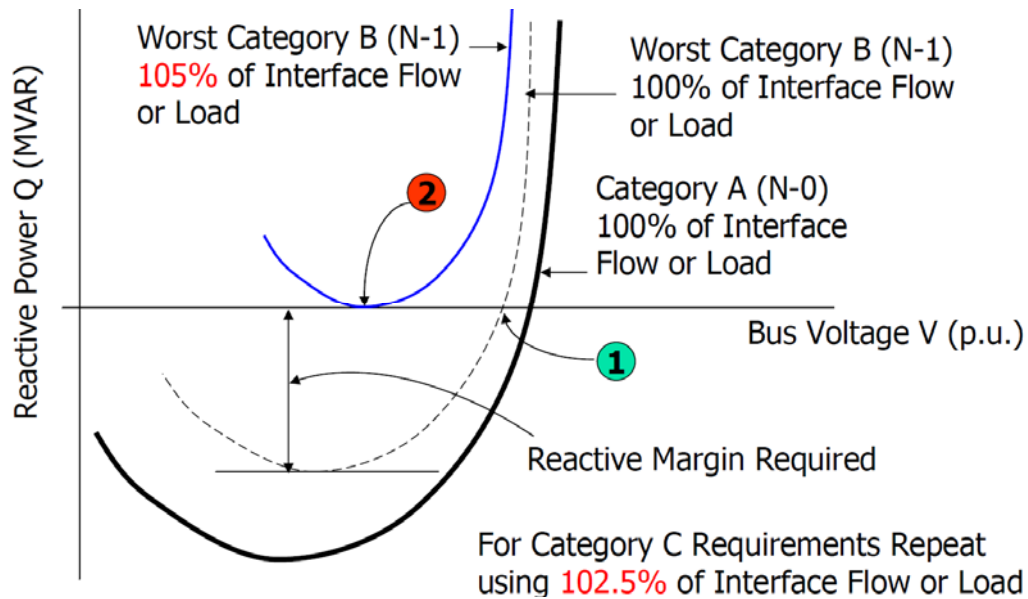


Figure 6.3.2: Reactive power (MVAR) reserve margin.¹⁰

¹⁶There are multiple considerations of uncertainties that drive the need for real power margins and reactive reserve

- Customer real and reactive power demand greater than forecasted
- Approximations in studies (Planning and Operations)
- Outages not routinely studied on the member system
- Outages not routinely studied on neighboring systems
- Unit trips following major disturbances
- Lower voltage line trips following major disturbances
- Variations on neighboring system dispatch
- Large and variable reactive exchanges with neighboring systems
- More restrictive reactive power constraints on neighboring system generators than planned
- Variations in load characteristics, especially in load power factors
- Risk of the next major event during a 30-minute adjustment period
- Not being able to readjust adequately to get back to a secure state
- Increases in major path flows following major contingencies due to various factors such as on-system undervoltage load shedding
- On-system reactive resources not responding
- Excitation limiters responding prematurely
- Possible Remedial Action Scheme failure
- Prior outages of system facilities
- More restrictive reactive power constraints on internal generators than planned.

¹⁶ [Reactive \(VAR\) Reserve Margin](#), NARUC joint meeting Electric Reliability Staff Subcommittee & Electricity Staff Subcommittee, November 13, 2005, slides 14 through 18.

6.4 VSA SUMMARY

The Spring operations model exhibits voltage collapse at a renewable transfer of 11,700 MW. The maximum operating point with a 5% real power (MW) reserve margin would be 11,100 MW. The most limiting single contingency (event 1) transfer limit is 10,700 MW. The maximum operating point with a 5% real power (MW) reserve margin is 10,100 MW.

The Fall operations model exhibits voltage collapse at a renewable transfer of 13,000 MW. The maximum operating point with a 5% real power (MW) reserve margin would be 12,300 MW. The worst single contingency (event 1) transfer limit is 10,900 MW. The maximum operating point with a 5% real power (MW) reserve margin is 10,300 MW.

The Spring system intact model exhibits voltage collapse at a renewable transfer of 13,100 MW. The maximum operating point with a 5% real power (MW) reserve margin would be 12,400 MW. The worst single contingency (event 1) transfer limit is 11,200 MW. The maximum operating point with a 5% real power (MW) reserve margin is 10,600 MW.

The Fall system intact model exhibits voltage collapse at a renewable transfer of 13,100 MW. The maximum operating point with a 5% real power (MW) reserve margin would be 12,400 MW. The worst single contingency (event 1) transfer limit is 10,900 MW. The maximum operating point with a 5% real power (MW) reserve margin is 10,300 MW.

The Spring and Fall operations and system intact maximum power transfers are in Table 6.4.

| Model | % Reserve | Operations (N-0) | Operations (N-1) | System Intact (N-0) | System Intact (N-1) |
|--------|-----------|------------------|------------------|---------------------|---------------------|
| Spring | 0 | 11,700 | 10,700 | 13,100 | 11,200 |
| Spring | 5 | 11,100 | 10,100 | 12,400 | 10,600 |
| Fall | 0 | 13,000 | 10,900 | 13,100 | 10,900 |
| Fall | 5 | 12,300 | 10,300 | 12,400 | 10,300 |

Table 6.4: Renewable generation real power (MW) limits.

The addition of DRR (MVAR) can increase the BES capability to support additional renewable to thermal generation real power (MW) transfer.

The DRR additions to support Spring renewable penetration above 45% are up to 2,100 MVAR in operations conditions and over 1,200 MVAR in system intact conditions for both N-0 and N-1.

The DRR additions to support Fall renewable penetration above 45% are up to 1,700 MVAR in operations conditions and over 1,500 MVAR in system intact conditions for N-0. DRR requirements for single contingency not determined.

Real and reactive power margin criteria are needed to ensure adequate supply of DRR to ensure system voltage security to avoid voltage collapse under normal operating conditions.

WIND INTEGRATION AND SPP RAMPING ANALYSIS

7.1 INTRODUCTION

This section describes analysis of one year of historical data for the Southwest Power Pool (SPP) system. The main purpose is to understand the ramping behavior associated with wind, and to analyze whether and how this makes system operations more challenging. It uses methods developed in ongoing EPRI research, in which SPP participates, to analyze these issues, and as such as well as providing insight for current system operations, helps to benchmark that research and provide SPP a foundation for future analysis and understanding of how increasing wind penetrations will impact the system.

7.2 GENERAL APPROACH AND METHODS USED

The general approach used in the work reported here is to analyze the variability on three major levels. First, variability analysis is carried out where wind, load and net load (load minus wind) is analyzed for ramping behavior. A number of different calculations are carried out, including maximum ramping across the entire year and by time of day and month, ramping based on output of wind or load level, and the use of percentiles to understand how frequently large ramps occur. This is done for a number of time horizons, from one hour to twelve hours, and then for 5-minutes to one hour. Time horizons here refer to the length of the ramps; for each hour of the year the ramp over each time horizon is calculated.

The second level is to characterize the flexibility of the SPP fleet. This is based on static characteristics of each generator, and includes analysis of start times, ramps rates and operating ranges. The purpose is to understand how flexible the system is from a high level. This then leads to the third level which is to analyze the hourly dispatch for the year to understand the flexibility available in each hour, and then compare that to both what actually happened and what could have happened based on results from the variability analysis. This results in a number of metrics being calculated based on the EPRI research which attempt to quantify the likelihood that the system runs out of ramping capability.

As mentioned, this approach is based on certain analysis methods that are well understood in wind integration studies, such as the use of percentiles to measure the likelihood of large ramps. It also applies new EPRI flexibility metrics in order to understand flexibility issues, using the EPRI Inflexion tool. As the data is based on a previous year where there wasn't any specific reliability issues due to flexibility, the idea here is not to use these metrics to determine whether there is insufficient flexibility, as much as understand the current baseline of flexibility sufficiency, so one can understand how this may change in future years.

7.3 DATA USED

Data from March 1, 2014 to Feb 28, 2015 was used. During this period, 12.2% of energy requirements were met by wind energy in SPP. The maximum 5-min penetration was 36% of demand. Curtailment averaged 0.4% of potential wind production (maximum 5-min curtailment was 27% of installed wind capacity). Installed wind capacity increased from 7355 MW at the start of the study to 8560 MW by the study period end. This will be important when interpreting results, as the base against which the results are measured changes. Where possible (i.e. where results are given monthly), we show this as % of installed capacity. Otherwise, results are given in MW, which means the amount of wind in the later part of the study, i.e. Winter 2014/2015, is higher than Spring 2014.

Hourly dispatch data was used based on actual market outcomes. 5-minute data was analyzed to understand ramping issues within the hour, but was not used to analyze dispatches. Additionally, generator characteristics were based on actual characteristics provided to the markets; where this varied over the year, an appropriate value was chosen.

7.4 MAIN INSIGHTS AND CONCLUSIONS

It is shown here that wind increased the ramping behavior of the system, across all ramp lengths. Within-hour ramps were examined using 5-minute average data, while inter-hour ramps were examined using hourly averaged data. This reflects the fact that inter-hour ramps are mostly managed in the Day Ahead Unit Commitment, where hourly data is more appropriate, whereas within-hour ramps are managed using real time commitment and dispatch. Looking at results for hourly averaged data, one hour load ramping was seen to increase by an amount equivalent to approximately 3% of installed wind capacity, when wind was netted from load. This is equivalent to the largest hourly ramp getting 9% larger due to wind. At longer time horizons, the impact of wind increased – for example 4 hour ramps increased at a rate equivalent to 13% of installed wind. For upwards load ramping, there was a significant increase caused by wind when comparing one hour to two hour ramps and six hour to seven hour ramps. These may be horizons where the system could be most challenged in the future. For downwards load ramping, the increase due to wind was a little smaller; this issue may also be managed by curtailment of wind so may not be as problematic. Note that for most of these results, there is a ‘margin of error’ where the actual number will be a little different from year to year; what is most relevant here is overall trends of wind’s impact.

By looking at time of day and month of year, we show the periods during which load ramps a large amount became a little less predictable when wind was added, wind can result in additional periods of large ramping throughout the year, particularly in the winter and spring. While wind impacted these periods most, summer was still the period with largest net load ramping so the very largest ramps weren’t impacted. The use of percentiles to examine the likelihood of large ramps show that wind had a definite impact in the period studied, and whether looking at worst case or something that happens a particular number of times per year (e.g. 5% of the hours), the impact of wind is much the same.

Analysis showed that the largest inter-hour wind ramps tended to happen when total wind production was producing at around half of installed capacity. It was also shown that wind had more impact on lower load conditions than peak demand periods, and that the largest ramps tended to happen at low load conditions. In order to manage such conditions, the generation fleet needs to be capable of meeting hourly up ramping requirements of an average of between 260 MW and 425 MW, depending on risk preference, with maximum hourly requirements for balancing of 1268 MW to 1585 MW during the most variable net load conditions.

Ramping mileage analysis, which looks at the absolute total of up or down ramping in each day, shows that up to 30,000 MW of total ramping was seen in a day, with wind energy additions increasing total ramping by up to 13%. On average, wind added 15 MW of ramping per hour of the year, a 7% increase. The maximum hourly up ramp increased by 258 MW due to wind, which is significantly smaller than the largest wind ramp, showing that very large wind and load ramps didn’t happen together.

Examining 5-minute data, with unconstrained wind, it was shown that wind has little impact on up ramps for time horizons of less than 20 minutes (less than 2% of installed wind capacity in extra ramping). Over 30 to 60 minute time horizons, wind impacts on net load ramping more significantly, from 5%-8% of installed capacity. While relatively small overall, this can still require an additional amount of load following capability. Downwards load ramping is shown to be more impacted by wind power, with an increase of 5%-8% of installed capacity across most time periods within the

hour. Again, while the actual magnitude of the change is thus relatively small, it was also shown that the time of day and month of year of large ramps changes when wind is considered.

Within-hour ramps were examined and shown to vary as a function of wind output, particularly at the 20-minute time horizon and longer. Variability is likely to be higher when wind is producing at medium output. This can be used to determine potential load following requirements. It was shown that, assuming load following would be based on the actual variability of load, by adding wind to the mix, the amount of 20-minute load following required could increase by anywhere from 200 MW to 600 MW on average, depending on risk preference, above the load-only requirements of 900 MW to 1200 MW. However, more work is needed to understand specific load following requirements in SPP, where such a product currently does not exist. Finally, within hour analysis shows that the DVER program has significantly reduced both upwards and downwards net load ramping compared to the ramping required without controllable wind, particularly at shorter time intervals. Down ramps in particular are less significant when DVER is considered showing that wind itself can act to reduce the variability requirements if it is able to do so.

From a generation perspective, one of the more interesting results is that there is a significant operating range (i.e. difference between minimum and maximum output) for many of the generators in the SPP fleet. On the other hand, the ramping ability is relatively constrained, while there is a large range of startup capabilities, from very short in less than an hour, to a lot of units that take 12-24 hours to start.

This flexibility was used in 2014/2015 to manage wind ramping, where no ramping shortfalls were seen. For hourly net load ramps, there was always significantly more up and down ramping than required, even when comparing the actual amount available with worst case events in the datasets. Using the newer EPRI metrics, we show that at longer time horizons there may be issues with ramping behavior, but these can mainly be managed by altering commitment or curtailing wind as the system gets closer to real time. In particular, down ramping is likely to provide challenges to system operators when looking out 7-10 hours ahead, in which they have to ensure sufficient flexibility once they get closer to real time.

This study provides a benchmark for the current SPP system. Further work could be to track how these results change from one year to the next, as wind generation continues to expand in SPP. The EPRI Inflexion tool can be used to continue this analysis, and lessons learned in this study can be used to improve the tool functionality. Operational tools may also be required as wind increase, either in the form of new operating reserve requirements to manage load following, or situational tools that help operators understand ramping requirements. Additional further work may be to examine future system conditions through production simulation and the associated analysis. This would allow SPP to understand how conditions may change and whether or not flexibility challenges will get more severe.

7.5 INTER-HOUR VARIABILITY AND RAMPING ANALYSIS

Increased ramping associated with wind power may cause the net load to become more variable. This could result in an increase in the magnitude of the very largest ramps, increasing magnitude of those ramps that happen more often but are still large, or could alter the timing of when the ramps occur. Here, we split out intra-hour (5-minutes to 1 hour time horizon) from inter-hour (1 hour to 12 hours). This sub-section provides results for inter-hour ramping, with the next subsection focusing on within-hour ramping. A number of different analyses are provided here, based on the first level of the EPRI InFLEXion flexibility assessment tool, with each aiming to provide insight different aspects of the impact of wind on ramping of the system net load. Inter-hour ramping, from 1-hour to 12-hour horizons, is based on hourly average wind and load. Therefore, the analysis is more focused on hour to hour changes, such as those of concern in the day ahead unit commitment; operators need to understand how much additional variability to expect on an hourly basis. 5-minute data as used in the next subsection, allows more focus on within hour issues in real time operations. This section examines time horizons from one to 12 hours with a particular focus on 1-hour and 4-hour horizons.

7.5.1 Maximum Inter-Hour Variability

Figure 1 shows the variability across time horizons from 1 hour to 12 hours. The time horizon here refers to the length of the ramp. For each hour of the year, we calculate the ramp on time horizons from 1 hour up to 12 hours ahead, resulting in 8760 ramp calculations for each time horizon. The largest of these is shown in the figure, which gives the largest ramp, in MW across each of the time horizons.

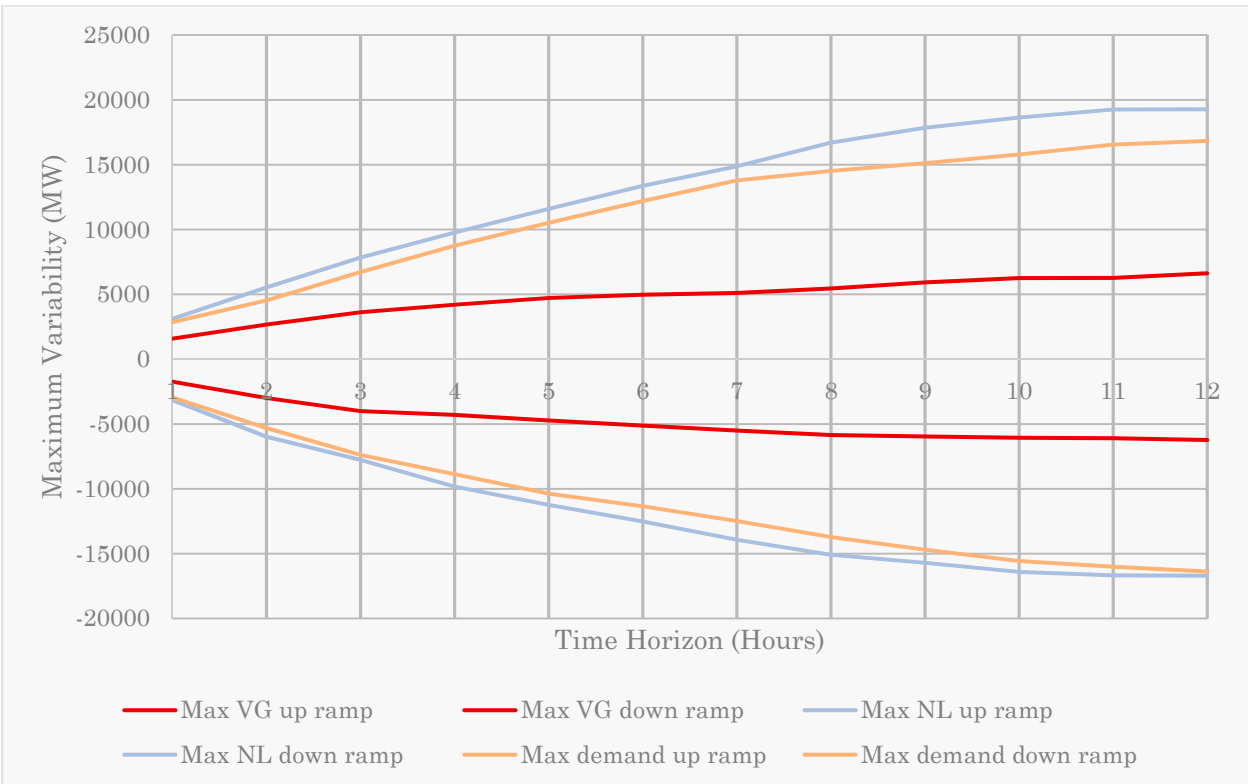


Figure 1: Variability of Demand, Net Load (NL) and Variable Generation (VG) for different time horizons. The y-axis gives the maximum variability of each of these against the ramp length, or time horizon, shown on the x axis

As expected, the size of the maximum variability increased with time horizon – for example, the load, net load or wind changed more across six hours than one hour. It can also be seen that the load

variability was almost as high as net load variability and therefore likely caused the very largest ramps. However, wind does add some additional variability, increasing the size of largest ramps across each time horizon. The difference between load and net load is given in Table 1. This shows, for example, that when wind was netted from load, the largest hourly ramps increased by 258 MW in the upwards direction and 206 MW in the downwards direction. This is approximately 3% of the wind capacity installed by end of the study period, or 3.5% at the start of the period.

Across longer time horizons, the ramp increase due to wind was larger. There was a large jump in maximum up ramping from one to two hours, and again from seven to eight hours. Across all time horizons, the largest up ramps increased in magnitude by an amount equal to somewhere from 30% to 38% of installed wind capacity, depending on the time of year of the ramp (as more wind was installed throughout the year, the specific percentage is not known). Those horizons with large jumps – between one and two hours ahead and seven and eight – may prove particularly challenging when more wind is added.

Down ramping is actually less impacted at longer time horizons, with seven hours being most impacted by wind. These results imply certain time horizons and look aheads could become comparatively more important to system operations in the future than others. Where at present, commitment doesn't need to account for ramps, it may be that in the future, this needs to be considered in operational planning processes.

Table 1: Difference between largest load ramp and largest net load ramp for inter-hour time horizons

| Time horizon (hours) | Up Ramp Difference (MW) | Down Ramp Difference (MW) | Up Ramp Difference (% of installed wind) | Down Ramp Difference (% of installed wind) |
|----------------------|-------------------------|---------------------------|--|--|
| 1 | 258 | -206 | 3% | -3% |
| 2 | 1006 | -670 | 13% | -9% |
| 3 | 1120 | -377 | 14% | -5% |
| 4 | 1013 | -957 | 13% | -12% |
| 5 | 1066 | -857 | 14% | -11% |
| 6 | 1162 | -1167 | 15% | -15% |
| 7 | 1089 | -1438 | 14% | -19% |
| 8 | 2184 | -1366 | 28% | -18% |
| 9 | 2721 | -1013 | 35% | -13% |
| 10 | 2845 | -841 | 37% | -11% |
| 11 | 2701 | -674 | 35% | -9% |
| 12 | 2450 | -312 | 32% | -4% |

The standard deviation of hourly net load variability also increased with wind, from approximately 900 MW to 970 MW. This is a good measure of how much the variability changes from hour to hour across the year. As with other results, this is not an extremely large increase, but does show that at present levels, wind is adding more variability to system operations.

7.5.2 Seasonal Maximum Variability

The largest variability of wind in each season is shown in Figure 2 for different time horizons. As shown, the largest wind variability tended to happen in winter for most horizons; this is somewhat expected given larger installed capacity in winter. One can also see that for up ramps of wind, winter, spring and fall all give similar numbers, particularly for up ramping of wind. Summer then seemed to show a lower variability in both directions. This is likely at least in part due to lower output during this period.

Figure 3 shows the seasonal data for wind, load and net load for one hour ramps. As shown, in all cases, wind increased ramping behavior of load. However, winter has the largest increase. This is likely due to some combination of two factors – first, that load variability is lower in winter, and so adding wind is more likely to have a great impact, especially considering that wind variability is highest then. Second is that there was slightly more wind installed in winter and so the variability may be higher.

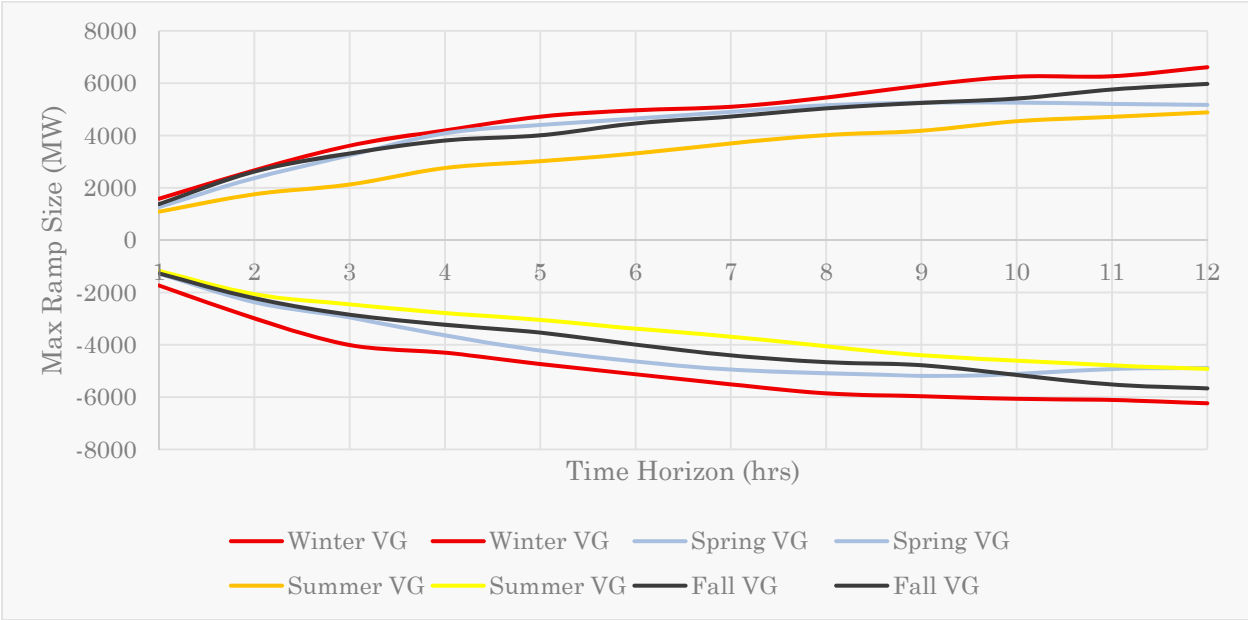


Figure 2: Variability of wind power output for different seasons

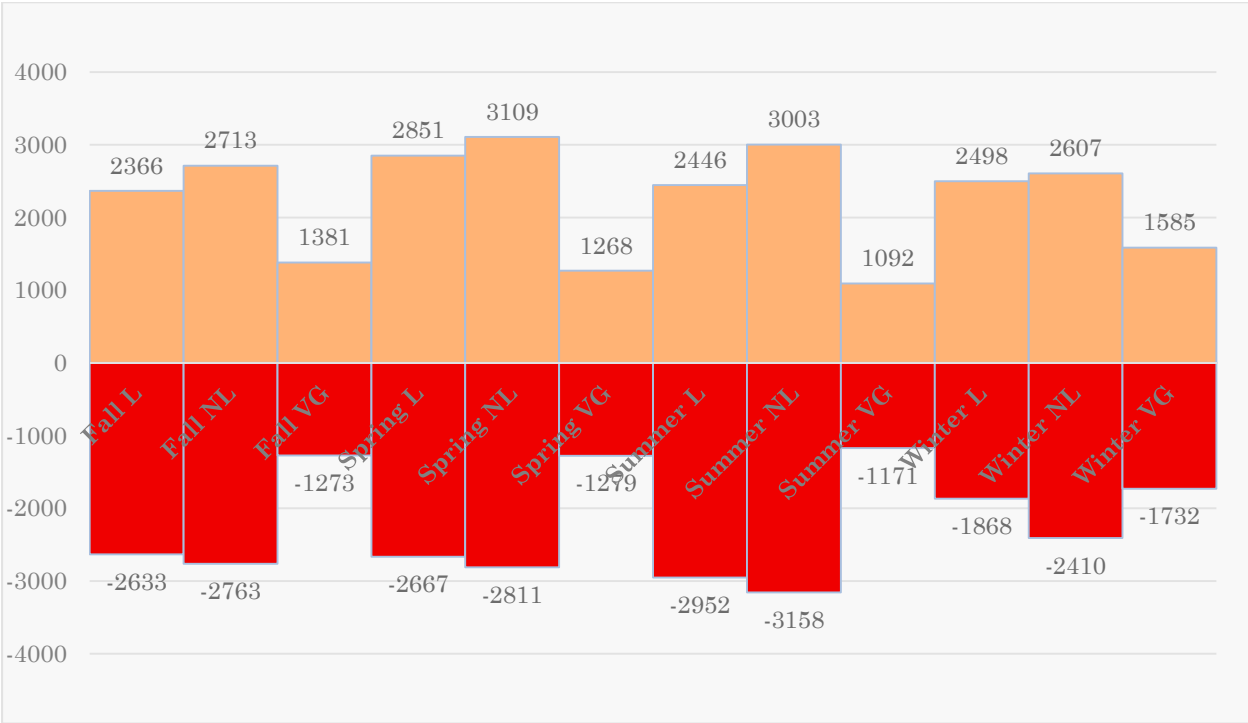


Figure 3: Maximum variability in one hour for wind (VG), load (L) and net load (NL) for different seasons. Orange shows the up ramps and blue shows the down ramps

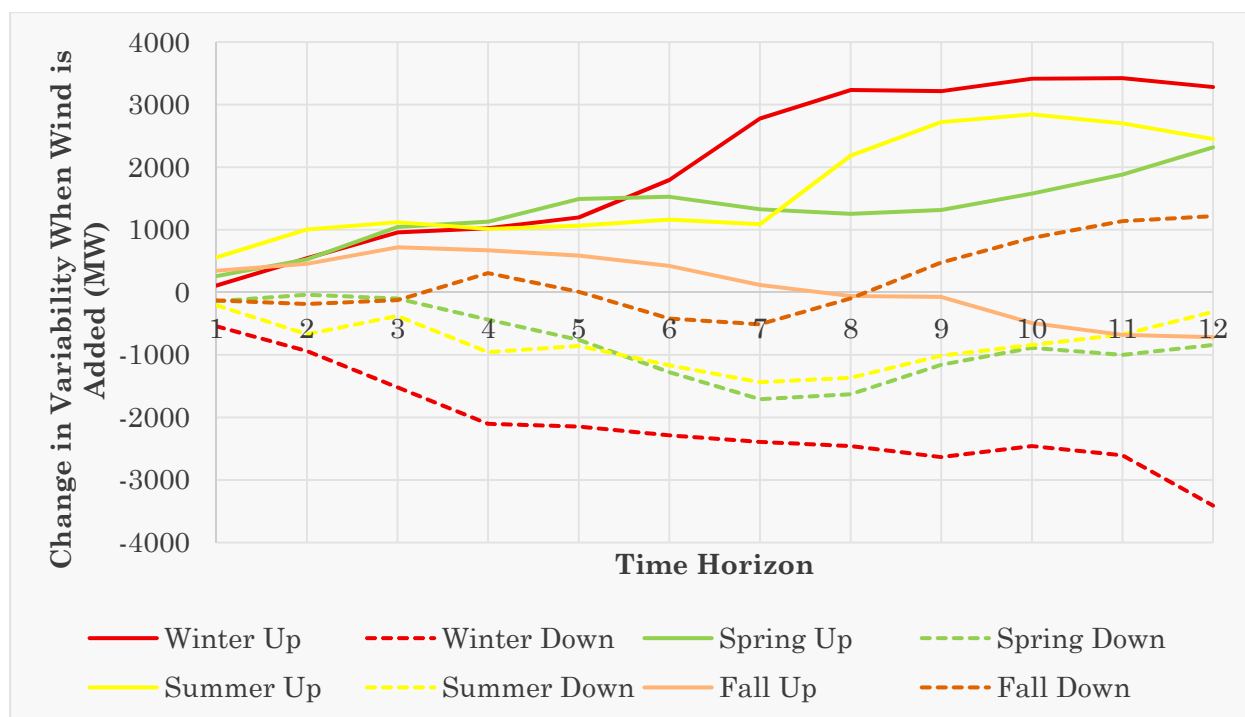


Figure 4: Change in variability when netting wind from load, by season and time horizon. For up ramping, a positive number means ramps are higher, for down ramping a negative value means ramps are higher

We also looked at load and net load for different time horizons. The most relevant result for this is given in Figure 4, which shows change in maximum variability when wind is added. Dashed lines show the reduction in down ramps, solid lines show increase in up ramps (i.e. how much more the system ramps in the worst case in both directions). In most seasons, wind caused ramps to become more significant; down ramps get more negative and up ramps more positive. What can be seen is that winter is most severe, as expected from earlier results. This is particularly true for down ramping, where the difference between winter and other seasons is more noticeable – the additional down ramping caused by wind in winter was up to double that for other seasons. For up ramping, wind added more to the largest ramps in winter from horizons of six hours or later; for shorter time horizons, summer was the season with largest increase in ramps; for example, in the two hour time horizon, wind increased the largest summer ramps by 1 GW. Interestingly, wind doesn't seem to add a lot to ramping in the fall season; it actually reduces the ramps in longer time horizons.

7.5.3 Maximum Inter-Hour Variability by Time of Day and Year

By examining time of day and month of year of wind, load and net load behavior, more insight can be obtained as to how wind impacted ramps. Figure 5 shows the maximum output as a % of installed wind capacity (note the installed capacity assumed is that on the 15th of the month, so may be a little off). Here, each cell represents the maximum ramp in a particular hour of a particular month (i.e. the maximum output as a percentage of installed capacity occurred during the hours of 9, 10 and 11 in February, when the output is equal to 100% of capacity). The main takeaway is that wind output was higher in winter and spring afternoon hours, and didn't reach that high in summer afternoons.

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|----|----|-----|----|----|----|----|----|----|----|----|----|----|
| 0 | 93 | 93 | 91 | 95 | 92 | 91 | 81 | 85 | 86 | 84 | 89 | 92 |
| 1 | 92 | 93 | 90 | 95 | 91 | 90 | 84 | 84 | 84 | 84 | 87 | 92 |
| 2 | 92 | 92 | 91 | 93 | 91 | 88 | 85 | 83 | 84 | 82 | 85 | 92 |
| 3 | 90 | 91 | 92 | 93 | 90 | 85 | 85 | 81 | 83 | 82 | 85 | 91 |
| 4 | 95 | 92 | 91 | 93 | 90 | 85 | 85 | 78 | 82 | 82 | 87 | 92 |
| 5 | 97 | 92 | 91 | 94 | 91 | 85 | 85 | 78 | 82 | 82 | 89 | 92 |
| 6 | 96 | 95 | 91 | 93 | 91 | 85 | 81 | 77 | 80 | 87 | 90 | 91 |
| 7 | 96 | 97 | 90 | 92 | 90 | 87 | 74 | 71 | 79 | 92 | 90 | 92 |
| 8 | 94 | 99 | 92 | 91 | 87 | 88 | 71 | 68 | 82 | 92 | 86 | 91 |
| 9 | 94 | 100 | 93 | 91 | 86 | 88 | 74 | 69 | 85 | 93 | 86 | 89 |
| 10 | 95 | 100 | 92 | 92 | 86 | 88 | 75 | 71 | 87 | 95 | 86 | 89 |
| 11 | 97 | 100 | 91 | 92 | 85 | 91 | 72 | 76 | 87 | 96 | 86 | 88 |
| 12 | 96 | 99 | 92 | 93 | 86 | 91 | 67 | 79 | 85 | 94 | 86 | 89 |
| 13 | 96 | 98 | 91 | 93 | 85 | 91 | 62 | 79 | 83 | 93 | 87 | 91 |
| 14 | 97 | 98 | 91 | 95 | 86 | 91 | 64 | 80 | 83 | 93 | 87 | 94 |
| 15 | 91 | 98 | 91 | 96 | 88 | 91 | 64 | 80 | 83 | 92 | 87 | 96 |
| 16 | 79 | 97 | 93 | 96 | 90 | 90 | 66 | 79 | 83 | 92 | 86 | 97 |
| 17 | 89 | 93 | 93 | 94 | 93 | 91 | 68 | 78 | 82 | 88 | 87 | 98 |
| 18 | 96 | 89 | 93 | 93 | 92 | 92 | 71 | 76 | 82 | 84 | 88 | 96 |
| 19 | 98 | 85 | 94 | 94 | 91 | 92 | 69 | 75 | 82 | 84 | 90 | 97 |
| 20 | 99 | 89 | 95 | 93 | 91 | 88 | 69 | 80 | 85 | 83 | 90 | 97 |
| 21 | 98 | 93 | 94 | 92 | 94 | 90 | 78 | 86 | 85 | 82 | 90 | 97 |
| 22 | 95 | 91 | 92 | 94 | 94 | 88 | 83 | 87 | 84 | 84 | 90 | 95 |
| 23 | 93 | 93 | 91 | 93 | 92 | 91 | 81 | 88 | 86 | 84 | 89 | 94 |

Figure 5: Maximum wind output for hour of day (y-axis) and month of year (x-axis), as % of installed wind capacity on the 15th of each month.

| Difference | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|------------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| 0 | 3,846 | 5,398 | 4,842 | 4,755 | 3,414 | 3,561 | 3,370 | 2,912 | 2,956 | 3,581 | 4,238 | 3,802 |
| 1 | 3,487 | 4,096 | 4,704 | 4,668 | 3,355 | 3,632 | 3,186 | 3,129 | 2,836 | 3,269 | 4,155 | 3,928 |
| 2 | 3,634 | 4,065 | 4,780 | 4,575 | 3,171 | 3,487 | 3,318 | 3,028 | 2,822 | 2,983 | 4,271 | 3,818 |
| 3 | 3,677 | 3,872 | 4,589 | 4,588 | 3,353 | 3,370 | 3,270 | 3,135 | 2,677 | 2,859 | 4,795 | 3,553 |
| 4 | 3,454 | 3,730 | 4,656 | 4,350 | 3,142 | 3,646 | 3,018 | 2,796 | 2,222 | 2,661 | 4,560 | 3,056 |
| 5 | 3,144 | 3,146 | 4,735 | 4,161 | 3,065 | 3,550 | 2,984 | 2,503 | 2,222 | 2,951 | 5,504 | 2,967 |
| 6 | 2,773 | 3,044 | 3,995 | 4,170 | 2,747 | 3,566 | 2,528 | 2,265 | 2,502 | 3,634 | 4,568 | 2,725 |
| 7 | 2,992 | 3,101 | 3,867 | 3,474 | 2,710 | 2,984 | 2,844 | 1,874 | 2,415 | 3,530 | 4,087 | 2,390 |
| 8 | 3,120 | 3,307 | 3,697 | 3,292 | 2,120 | 3,201 | 1,980 | 1,976 | 2,173 | 2,960 | 4,488 | 1,924 |
| 9 | 2,476 | 2,882 | 3,199 | 3,667 | 2,469 | 2,981 | 1,975 | 1,591 | 1,659 | 2,235 | 3,274 | 1,730 |
| 10 | 2,212 | 2,944 | 2,479 | 3,912 | 2,075 | 2,902 | 1,591 | 1,651 | 1,830 | 2,327 | 2,893 | 1,928 |
| 11 | 2,321 | 3,305 | 3,210 | 3,858 | 2,046 | 2,372 | 1,949 | 2,062 | 1,722 | 2,354 | 3,191 | 1,535 |
| 12 | 2,239 | 3,957 | 3,209 | 4,224 | 2,374 | 2,030 | 2,104 | 1,963 | 1,870 | 2,071 | 2,949 | 2,157 |
| 13 | 2,053 | 4,619 | 3,347 | 4,112 | 2,222 | 1,887 | 2,092 | 1,704 | 2,129 | 2,213 | 3,090 | 2,295 |
| 14 | 2,161 | 4,912 | 3,485 | 4,363 | 2,540 | 1,953 | 1,962 | 1,726 | 2,375 | 2,364 | 2,846 | 2,285 |
| 15 | 2,290 | 4,430 | 3,439 | 4,159 | 2,828 | 2,158 | 2,102 | 1,858 | 1,959 | 2,765 | 2,551 | 2,208 |
| 16 | 2,315 | 3,902 | 3,740 | 4,155 | 2,749 | 2,826 | 2,064 | 1,987 | 1,952 | 2,385 | 2,145 | 2,178 |
| 17 | 2,839 | 3,533 | 3,108 | 3,926 | 2,974 | 3,672 | 2,554 | 1,740 | 1,925 | 2,040 | 2,420 | 2,640 |
| 18 | 3,365 | 4,396 | 3,208 | 3,757 | 2,691 | 3,685 | 2,651 | 1,736 | 2,245 | 2,517 | 2,813 | 3,211 |
| 19 | 3,443 | 4,565 | 3,013 | 4,438 | 3,217 | 3,806 | 2,758 | 1,857 | 2,348 | 2,717 | 3,467 | 3,387 |
| 20 | 3,261 | 5,164 | 3,415 | 4,288 | 3,729 | 4,108 | 2,962 | 2,329 | 2,915 | 3,155 | 3,558 | 3,754 |
| 21 | 3,550 | 4,965 | 3,963 | 4,775 | 3,344 | 3,628 | 2,783 | 2,431 | 3,112 | 3,519 | 3,602 | 3,518 |
| 22 | 3,629 | 5,082 | 4,497 | 4,727 | 3,737 | 3,690 | 3,239 | 2,542 | 3,158 | 3,576 | 3,649 | 3,482 |
| 23 | 3,782 | 4,912 | 4,868 | 4,841 | 3,656 | 3,414 | 3,330 | 3,003 | 3,060 | 3,344 | 4,203 | 3,820 |

Figure 6: Reduction in median load by hour of day (y-axis) (x-axis) for each month of year when wind is added to the system (i.e. reduction in net load)

For Figure 6, the data for each hour in a given month (e.g. 9am in February) was sorted from largest to smallest. The median of the data were then calculated for both load and net load. The difference

between these values, which helps understand an average impact of wind, is then plotted, where red colors show the periods with highest impact and green shows lowest impact. The largest average impact for the year studied was in February to April and in November. February to April showed significant changes throughout the day, while November is impacted in the early morning. On the other hand, summer and early fall afternoons showed the smallest MW change due to wind; this would be expected from seasonal results shown earlier.

Figure 7 shows the maximum hourly wind ramping observed during the year of study for the wind fleet, given by hour of day on the x-axis and month of year on the y-axis. This shows that the largest up ramps in wind tended to happen in the evening—the largest observed value is hour beginning 5pm in February, when wind ramps were approx. 19% of capacity. Other than the summer months, other months saw relatively similar ramping behavior. Another interesting result here is that there were no up ramps in hours beginning 6am in July and August and 7am in August.

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|
| 0 | 11% | 11% | 10% | 10% | 4% | 4% | 2% | 3% | 2% | 7% | 7% | 4% |
| 1 | 9% | 10% | 8% | 7% | 6% | 5% | 3% | 3% | 5% | 7% | 4% | 4% |
| 2 | 7% | 11% | 4% | 7% | 6% | 5% | 2% | 5% | 7% | 9% | 5% | 4% |
| 3 | 7% | 7% | 5% | 8% | 4% | 7% | 5% | 2% | 9% | 11% | 3% | 3% |
| 4 | 6% | 7% | 6% | 4% | 4% | 7% | 3% | 3% | 7% | 9% | 3% | 5% |
| 5 | 9% | 6% | 3% | 6% | 4% | 7% | 3% | 3% | 8% | 10% | 4% | 9% |
| 6 | 8% | 4% | 3% | 2% | 2% | 4% | 0% | 0% | 3% | 9% | 4% | 7% |
| 7 | 4% | 6% | 2% | 4% | 3% | 6% | 2% | 0% | 2% | 11% | 4% | 2% |
| 8 | 8% | 6% | 4% | 6% | 8% | 5% | 8% | 5% | 7% | 5% | 6% | 4% |
| 9 | 6% | 8% | 6% | 11% | 6% | 8% | 5% | 7% | 7% | 7% | 10% | 8% |
| 10 | 10% | 13% | 13% | 6% | 5% | 6% | 5% | 5% | 8% | 6% | 13% | 6% |
| 11 | 12% | 16% | 14% | 9% | 8% | 8% | 6% | 4% | 5% | 8% | 13% | 5% |
| 12 | 10% | 11% | 12% | 5% | 9% | 9% | 6% | 5% | 6% | 7% | 10% | 6% |
| 13 | 9% | 7% | 10% | 6% | 9% | 9% | 6% | 7% | 4% | 9% | 9% | 5% |
| 14 | 3% | 9% | 7% | 11% | 7% | 8% | 9% | 10% | 5% | 6% | 6% | 6% |
| 15 | 5% | 6% | 6% | 15% | 11% | 8% | 7% | 7% | 5% | 6% | 7% | 7% |
| 16 | 13% | 11% | 7% | 9% | 7% | 10% | 5% | 7% | 5% | 5% | 10% | 11% |
| 17 | 16% | 19% | 11% | 8% | 7% | 8% | 6% | 6% | 4% | 16% | 15% | 13% |
| 18 | 11% | 13% | 14% | 9% | 9% | 9% | 7% | 9% | 10% | 18% | 14% | 15% |
| 19 | 9% | 6% | 14% | 16% | 12% | 10% | 8% | 13% | 10% | 10% | 13% | 15% |
| 20 | 7% | 7% | 11% | 14% | 12% | 11% | 10% | 14% | 9% | 11% | 10% | 8% |
| 21 | 10% | 6% | 13% | 9% | 17% | 12% | 6% | 7% | 6% | 7% | 6% | 7% |
| 22 | 11% | 10% | 16% | 13% | 15% | 7% | 5% | 5% | 4% | 4% | 5% | 6% |
| 23 | 14% | 13% | 11% | 15% | 11% | 6% | 3% | 4% | 3% | 7% | 4% | 4% |

Figure 7: Maximum hourly wind up ramping by time of day (y-axis) in each month (x-axis) as % of the installed wind capacity on the 15th of the month

Down ramping of wind, which may be a more significant issue from an operational perspective, is shown in Figure 8. This shows that the largest down ramps happened in the early morning throughout the year and all day in the first few months of the year. There are also down ramps during the evening in the winter and spring months. Comparing up and down ramping, it can be seen that winter and spring saw significant ramping throughout the day, whereas summer, and to a lesser extent fall, see more defined periods of ramping. February from 8am to 9am saw the largest down ramps of wind at 20% of capacity.

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|----|------|------|------|------|------|------|------|------|------|------|------|------|
| 0 | -5% | -10% | -5% | -8% | -9% | -10% | -6% | -6% | -6% | -7% | -8% | -8% |
| 1 | -3% | -5% | -7% | -6% | -14% | -12% | -7% | -9% | -7% | -8% | -5% | -5% |
| 2 | -4% | -5% | -7% | -7% | -6% | -11% | -5% | -9% | -5% | -5% | -5% | -6% |
| 3 | -6% | -6% | -8% | -6% | -7% | -15% | -7% | -7% | -6% | -6% | -6% | -9% |
| 4 | -12% | -6% | -6% | -8% | -8% | -15% | -9% | -7% | -7% | -6% | -7% | -9% |
| 5 | -9% | -6% | -8% | -7% | -8% | -12% | -7% | -8% | -11% | -6% | -7% | -6% |
| 6 | -7% | -9% | -7% | -9% | -17% | -8% | -15% | -13% | -11% | -6% | -9% | -6% |
| 7 | -15% | -15% | -10% | -12% | -14% | -5% | -12% | -14% | -11% | -12% | -11% | -8% |
| 8 | -15% | -20% | -15% | -8% | -7% | -8% | -8% | -7% | -9% | -13% | -10% | -10% |
| 9 | -15% | -12% | -10% | -9% | -5% | -5% | -8% | -6% | -5% | -8% | -8% | -11% |
| 10 | -9% | -6% | -6% | -7% | -6% | -9% | -6% | -10% | -8% | -7% | -10% | -8% |
| 11 | -12% | -4% | -8% | -7% | -4% | -7% | -5% | -8% | -4% | -8% | -10% | -7% |
| 12 | -12% | -5% | -8% | -6% | -3% | -5% | -6% | -4% | -7% | -9% | -6% | -8% |
| 13 | -12% | -7% | -8% | -7% | -4% | -5% | -6% | -3% | -4% | -8% | -6% | -9% |
| 14 | -11% | -6% | -6% | -8% | -3% | -5% | -3% | -3% | -3% | -6% | -10% | -12% |
| 15 | -15% | -11% | -5% | -10% | -5% | -3% | -3% | -4% | -6% | -8% | -13% | -8% |
| 16 | -17% | -16% | -8% | -13% | -7% | -3% | -5% | -3% | -4% | -12% | -5% | -3% |
| 17 | -10% | -12% | -11% | -15% | -10% | -7% | -4% | -5% | -8% | -17% | -4% | -3% |
| 18 | -8% | -8% | -9% | -17% | -14% | -7% | -4% | -4% | -4% | -12% | -1% | -2% |
| 19 | -5% | -6% | -5% | -14% | -8% | -5% | -3% | -2% | -6% | -5% | -6% | -3% |
| 20 | -8% | -8% | -7% | -7% | -4% | -3% | -2% | -3% | -4% | -7% | -5% | -4% |
| 21 | -9% | -9% | -10% | -9% | -4% | -10% | -6% | -2% | -5% | -4% | -3% | -7% |
| 22 | -5% | -11% | -7% | -5% | -6% | -8% | -6% | -3% | -5% | -5% | -4% | -8% |
| 23 | -3% | -8% | -5% | -6% | -6% | -10% | -6% | -6% | -5% | -4% | -5% | -7% |

Figure 8: Maximum hourly wind down ramping by time of day (y-axis) in each month (x-axis) as % of the installed wind capacity on the 15th of the month

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|----|-----|-----|------|-----|------|------|------|------|-----|------|------|------|
| 0 | -81 | 836 | 27 | 160 | 215 | 188 | 180 | 159 | 378 | 184 | 180 | 267 |
| 1 | -28 | 63 | 441 | 174 | 414 | 555 | 134 | 390 | 57 | 208 | 74 | 253 |
| 2 | 168 | 96 | 538 | 199 | 45 | 180 | 156 | 296 | 185 | 252 | 219 | 187 |
| 3 | 23 | 264 | 353 | 172 | 124 | 716 | 97 | 376 | 208 | -239 | 326 | 537 |
| 4 | 463 | 405 | 160 | 222 | 152 | 1171 | 201 | 561 | 284 | 278 | 558 | 578 |
| 5 | 94 | 10 | 258 | 4 | 196 | 893 | 222 | 536 | 558 | 131 | 347 | 286 |
| 6 | 269 | 617 | 379 | 329 | 558 | -26 | 973 | 735 | 244 | 101 | 227 | 347 |
| 7 | 775 | 110 | 93 | 545 | 228 | 171 | 636 | 825 | 385 | 229 | 597 | 232 |
| 8 | 431 | 780 | 239 | 176 | 63 | 187 | 560 | 7 | 245 | 657 | 279 | 698 |
| 9 | 439 | 259 | -16 | 153 | 71 | 44 | 278 | 330 | 99 | 306 | 307 | 442 |
| 10 | 224 | -6 | 245 | 212 | 247 | 42 | 99 | 315 | 304 | -12 | 81 | 465 |
| 11 | 346 | 123 | 568 | -1 | 220 | 114 | 121 | 252 | 258 | -76 | 82 | 107 |
| 12 | 877 | 100 | 422 | -71 | -24 | 208 | 445 | 116 | 157 | -197 | 33 | 411 |
| 13 | 766 | 182 | 146 | 167 | -36 | -65 | 219 | -169 | -23 | -13 | 29 | 564 |
| 14 | 673 | 113 | 4 | -73 | 162 | -124 | -152 | 2 | 13 | -274 | 152 | 489 |
| 15 | 708 | 567 | 235 | 119 | 25 | 23 | -68 | -69 | -46 | 110 | 396 | 140 |
| 16 | 558 | 648 | 299 | 462 | 6 | -231 | -170 | -115 | -75 | 250 | -29 | -381 |
| 17 | 246 | 716 | 323 | 741 | 416 | 36 | 31 | -6 | 193 | 282 | 103 | 207 |
| 18 | 330 | 51 | 157 | 925 | 827 | 79 | -94 | -14 | 294 | 150 | -129 | 71 |
| 19 | 11 | 349 | -435 | 367 | 614 | -272 | -70 | -469 | 79 | -177 | 77 | -3 |
| 20 | -43 | 407 | 71 | 438 | 218 | -307 | 75 | -48 | 69 | 4 | -60 | -8 |
| 21 | -55 | 811 | 6 | -18 | -529 | 72 | -34 | -366 | 100 | 18 | -22 | -139 |
| 22 | 26 | 454 | 166 | 23 | -42 | 212 | -106 | 136 | -86 | -40 | 40 | 160 |
| 23 | 97 | 137 | -98 | -13 | -18 | 654 | 17 | 159 | 178 | -132 | 133 | 272 |

Figure 9: Difference in maximum hourly up ramps in net load compared to load by time of day (y-axis) for each month (x-axis). Positive values show an increase in largest up ramps due to wind, while negative values show that wind reduced largest ramps in that hour for the month specified

To understand the impact of this wind ramping on the net up ramping behavior of the system, Figure 9 shows the difference between the largest load up ramps and net load up ramps by month and hour. One thing to notice in a general sense is that there is somewhat less of a pattern to be seen than the

previous graphs that show time of day and month of year ramping. This is due to the fact that when combining wind and load, ramping becomes more random and less based on specific time periods. It is also worth noting that these results are based on one year of data, which means that each of the data points shown is based on, at a maximum, 31 days of data; such data could be skewed by unusual weather patterns. In particular, one can see that in some periods of the year, wind actually never increased up ramps (e.g. August from 7pm-8pm). On the other hand, wind increased ramping of the system during a number of time periods. This includes a few morning load pickup timeframes, as seen in July from 6am-9am, where hourly ramps were up to 970 MW higher. These periods could be difficult to manage in an operational context, and show an important impact of wind. While the very largest net load ramps, as shown in Figure 1, were approximately 250 MW larger than load-only ramps, this shows that wind impacted by causing ramping at less predictable times of the year.

7.5.4 Variability Duration Curves

Ramp duration curves show the magnitude of ramps that occur less than a certain amount of times in a year. They can be useful to understand, at a high level, how much additional ramping wind causes, and provide context into both very large ramps and how much more frequent, but still large, ramps are impacted. These were obtained by sorting the ramp over a chosen time horizon from largest to smallest, and then plotting these. The hourly ramps are shown in this manner in Figure 10. One thing that can be noticed is that when looked at in this fashion, the impact of wind was relatively small. Previous figures showed that wind can make the timing of ramps somewhat more random, but this shows that overall the ramping behavior remains, from a big picture, much the same.

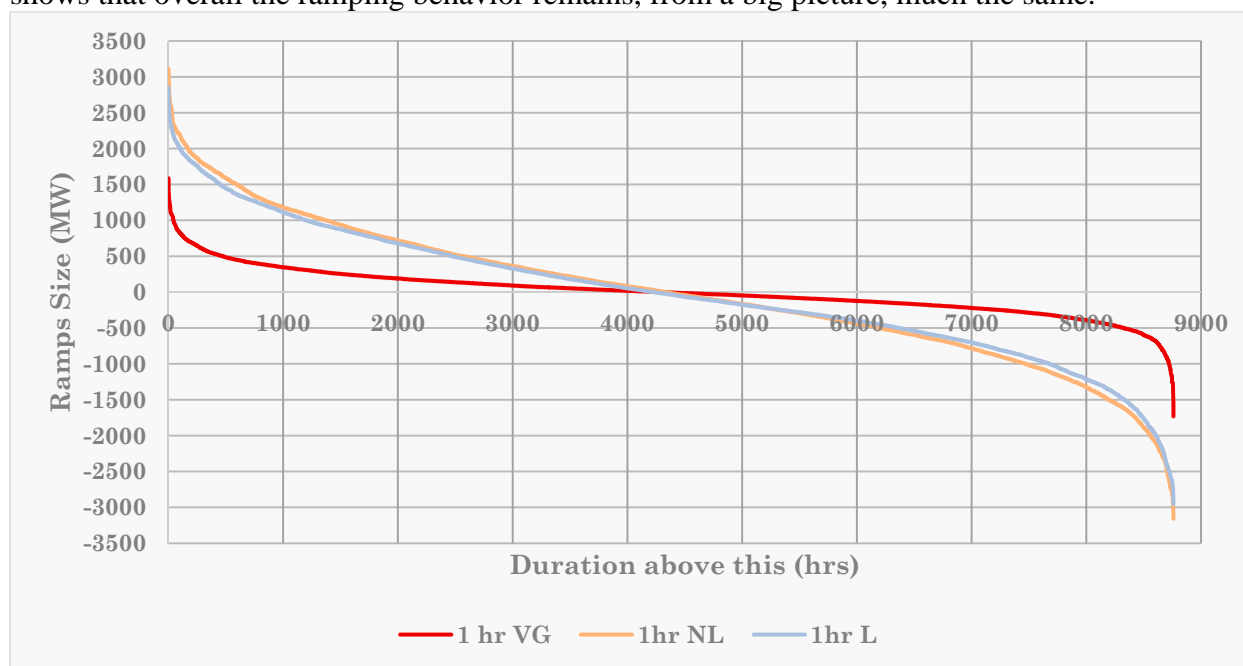


Figure 10: Ramp Duration Curves, showing ramp size versus number of periods for which ramps larger than magnitude shown, for hourly wind (VG), Load (L) and Net Load (NL) ramps

This same result is examined for just the top 100 hours in Figure 11 to understand the very largest ramps. Here, the additional 258 MW of wind related ramping observed in Table 1 can be seen on the very left hand side. One interesting observation about these results is that over 1,400 hours of wind ramps are observed that are greater than this 258 MW value, showing that, while wind did impact on ramping behavior, it often acted to counter demand ramps, and was not a significant contributor to the very large net load ramps.

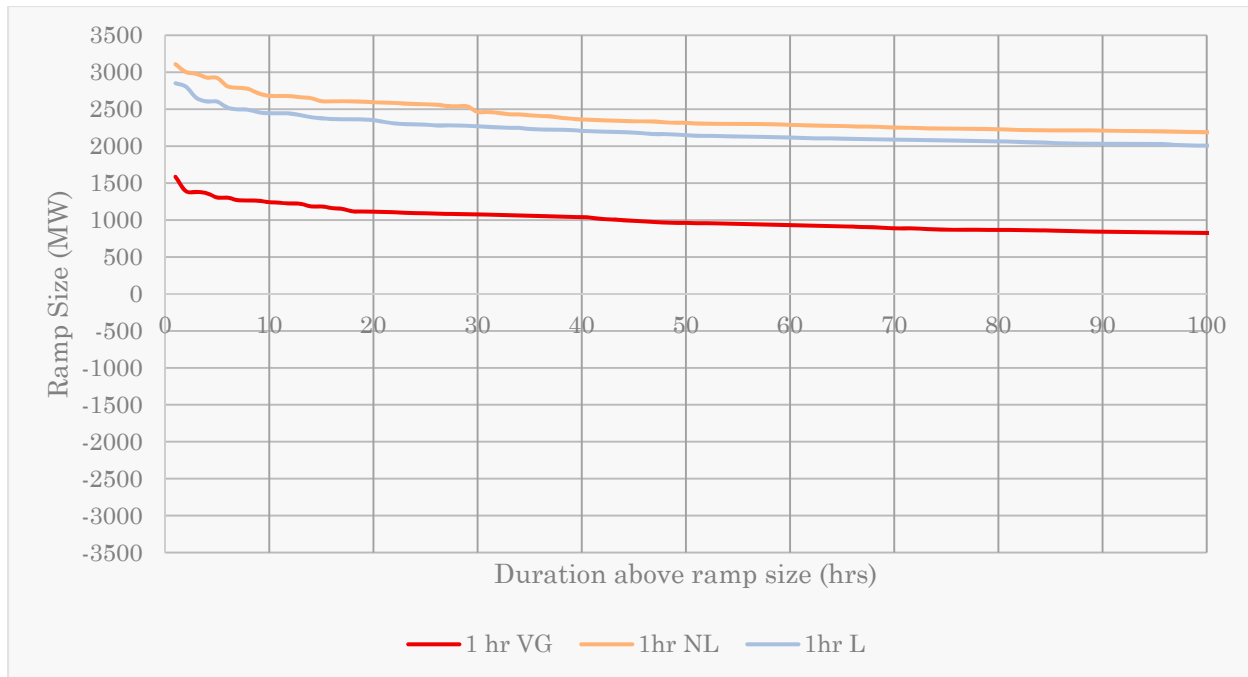


Figure 11: Ramp Duration Curves, showing ramp size versus number of periods for which ramps larger than magnitude shown, for hourly wind (VG), Load (L) and Net Load (NL) ramps – zoomed into just the top 100 hours

7.5.5 Percentile Analysis for Inter-Hour Ramping

A percentile analysis allows for more detailed examination of these duration curves. Here, the n^{th} percentile of largest ramps is examined for load and net load. The concept is to examine whether, even if the very largest ramps aren't impacted significantly, relatively large ramps are larger when wind is added. This can help identify whether wind generation will impact on events that happen more frequently, rather than just the most extreme events. Percentiles here refer to the n^{th} largest ramp, when ramps are arranged in order of magnitude. So if only 100 hours were being analyzed, the 95th percentile ramp would be the 6th largest (5 ramps are larger), 99th would be the second largest, etc. For the actual analysis, 8760 values are used, such that 99th percentile is the 88th largest ramp, 95th is the 439th largest, and so on. Percentiles of 95% and 99% are typical values to examine when analyzing system variability; here we use the format that 0% is the largest down ramp and 100% is the largest up ramp. The 95th percentile are events that happen frequently enough that they would need to be considered a regular part of operations.

Figure 12 gives the 95th, 99th and 100th percentiles of ramping from time horizons from 1 to 12 hours. The 100th percentile (P100) are the same results as shown for maximum variability earlier. It can be seen that the impact of wind is not significantly different in the 95th or 99th percentile than in the 100th, showing wind does not necessarily impact these more frequent events any more than very largest events. It can also be seen that the 100th percentile is approximately double the 95th percentile, showing the very largest events are significantly larger than even other less frequent but large events.

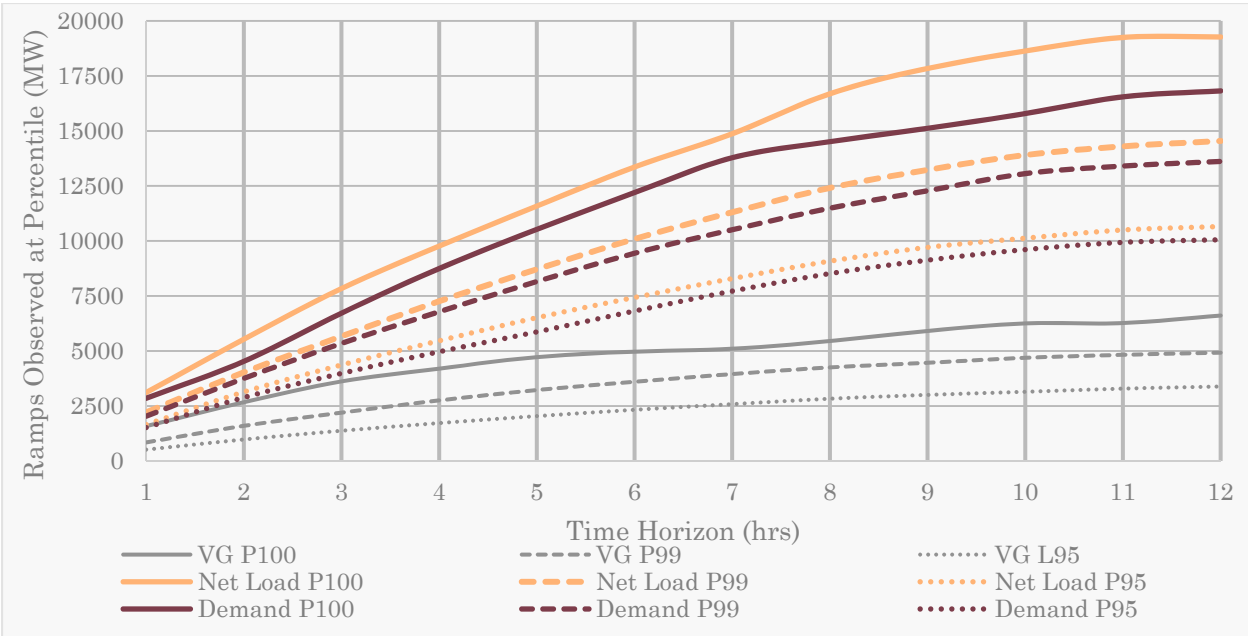


Figure 12: Up ramping of wind (VG), Net Load and Demand for various percentiles for time horizons of 1-12 hours

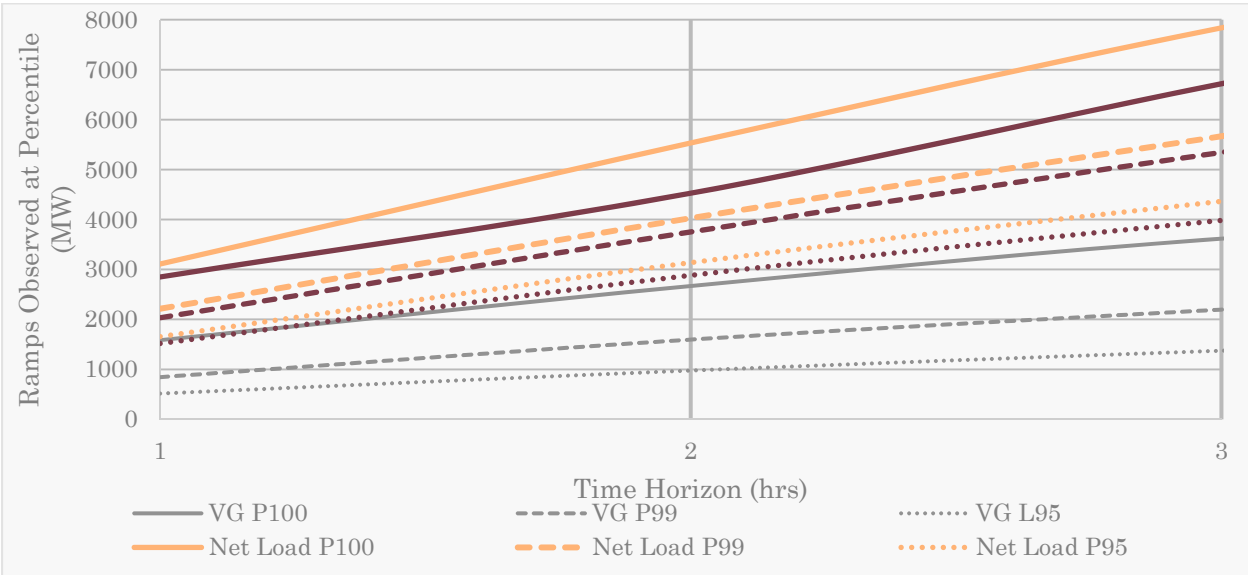


Figure 13: Up ramping of wind (VG), Net Load and Demand for various percentiles for time horizons of 1-3 hours

Zooming in on only the ramps with time horizons of one to three hours, as in Figure 13, shows much the same behavior, with a larger gap between load and net load when looking at the very largest ramps than when looking at large but more frequently occurring ramps. One result of note is that maximum hourly wind ramps were approximately the same as the 95th percentile of net load ramps; this shows that wind ramps can be relatively large, but often end up being somewhat negated by load.

Similar analysis for down ramping draws similar conclusions. Rather than plot the same figures, results for 1 hour and 4-hour ramps are tabulated in Table 2. As can be seen, for one hour up ramps, wind makes the largest ramps and the 95th and 99th percentiles a consistent 9% higher, illustrating the impact is much the same whether only the very largest, or the somewhat large, ramps are examined.

Note that this is not the same as saying that each of the particular largest load ramping hours are 9% larger when wind is added - just that the largest net load ramps, when sorted by size, are approximately 9% larger than load ramps, which may also have happened at other times of the day or year, depending on wind/load correlation. Indeed, this is likely the case as shown in the time of day/month of year figures earlier. Four hour up ramps increased by a similar magnitude, but with less consistency when looking at different percentiles. This implies a little more variation in the impact of 4-hour ramping. Down ramps can be seen to be less uniform for 1-hour ramping. Additionally, the impact is a little lower than for up ramping. This is also true for 4-hour down ramps. In general, 4-hour ramps increased by up to 1000 MW due to wind, but typically, larger ramps that happen a few hundred times per year increased by approximately 500 MW.

Table 2: Ramping at different percentiles for 1-hour and 4-hour wind, load and Net Load ramps

| | 1 hour ramping | | | | | 4 hour ramping | | | | |
|--------|----------------|-------|----------|-------------|----|----------------|-------|----------|-------------|-----|
| 1 hour | VG | Load | Net Load | Diff (NL-L) | % | VG | Load | Net Load | Diff (NL-L) | % |
| Max | 1585 | 2851 | 3109 | 258 | 9% | 4195 | 8754 | 9767 | 1013 | 12% |
| 99th | 845 | 2034 | 2214 | 180 | 9% | 2753 | 6783 | 7262 | 479 | 7% |
| 95th | 516 | 1518 | 1656 | 137 | 9% | 1722 | 4964 | 5463 | 499 | 10% |
| 5th | -500 | -1489 | -1614 | -126 | 8% | -1609 | -5369 | -5867 | -498 | 9% |
| 1st | -821 | -2221 | -2311 | -89 | 4% | -2573 | -7216 | -7723 | -507 | 7% |
| Min | -1732 | -2952 | -3158 | -206 | 7% | -4302 | -8868 | -9824 | -957 | 11% |

7.5.6 Inter-Hour Ramps as Function of Load Level or Wind Output

By looking at ramps as a function of the load level or wind output at the start of the time period, one can understand whether there are any noticeable patterns apparent for ramping behavior. For example, Figure 14 shows this result for wind output. This result is obtained by dividing the data into 20 bins based on output, i.e. all of the hourly ramps observed for when wind output was between approximately 0 MW and 400 MW were put in first bin, 400 MW to 800 MW in the second and so on. These are then sorted from largest to smallest ramps, and the minimum, 5th percentile, 95th percentile and maximum ramps are plotted. This is done for each of the 20 bins for different initial wind output levels, with the result as shown. To give an example, in hours when wind was at approximately 2000 MW, the largest ramp observed in any hour following that is approximately 1200 MW, while the 95th percentile of the ramps observed at that output level is approximately 500 MW.

It can be seen that the largest hourly wind ramps happened in the middle of the output range. This would be expected, due to the nature of the wind power-speed curve, which is most variable in middle of the operating range of a turbine. Smaller changes in wind speed have larger impacts on power output. At higher levels, hourly up ramps are unlikely to be high as wind is already pretty high, while down ramps are not observed to be high, showing that there are no periods when wind is very high and then completely drops off. At longer time horizons, one would expect to see significant up ramps beginning at low output levels, where wind speed picks up across the region over a few hours, or down ramps when wind speed drops off. This is also observed in the data.

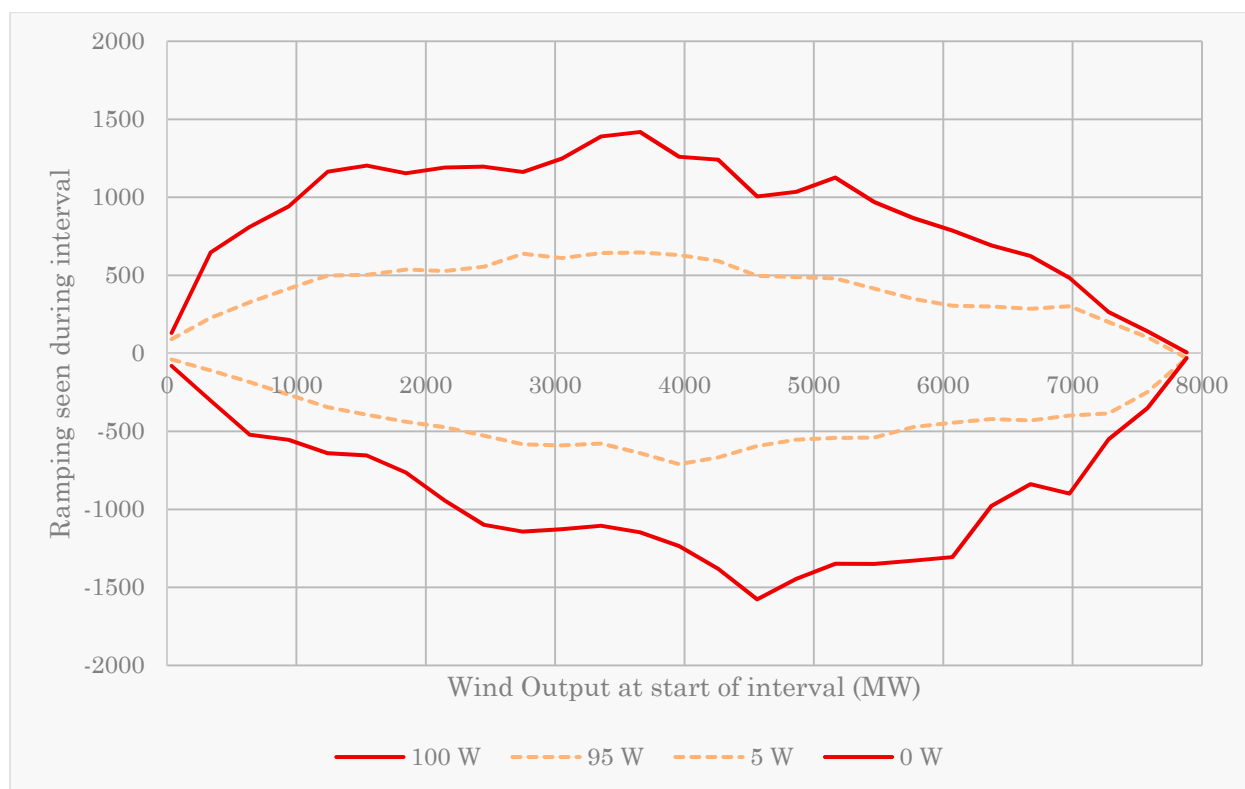


Figure 14: 1 hour wind ramps as a function of output at the start of the hour for 95th percentile and 100th percentile of observed hourly averaged data

Another result of interest is shown in Figure 15, which shows the load and net load ramps as a function of the load (or net load) level at the beginning of the hour. These are binned and calculated in the same manner as the wind ramps. The most obvious result here is that net load is significantly lower in general – there is a shift to the left when wind is subtracted from load, as would be expected. The increase in magnitude can also be seen, as can the fact that the largest net load ramps tend to happen at lower initial levels than the largest load ramps. The reduction at high load is lower than the reduction at low load, showing wind is less likely to be at high output at higher load levels. Also, it can be seen that the gap between 100th and 95th percentiles seem a little greater for net load than load, showing there is more of an impact on net load when looking at 95th percentiles; this is consistent with some earlier results showing that, while wind may not make the worst ramps significantly worse, those less frequent may become worse under certain conditions.

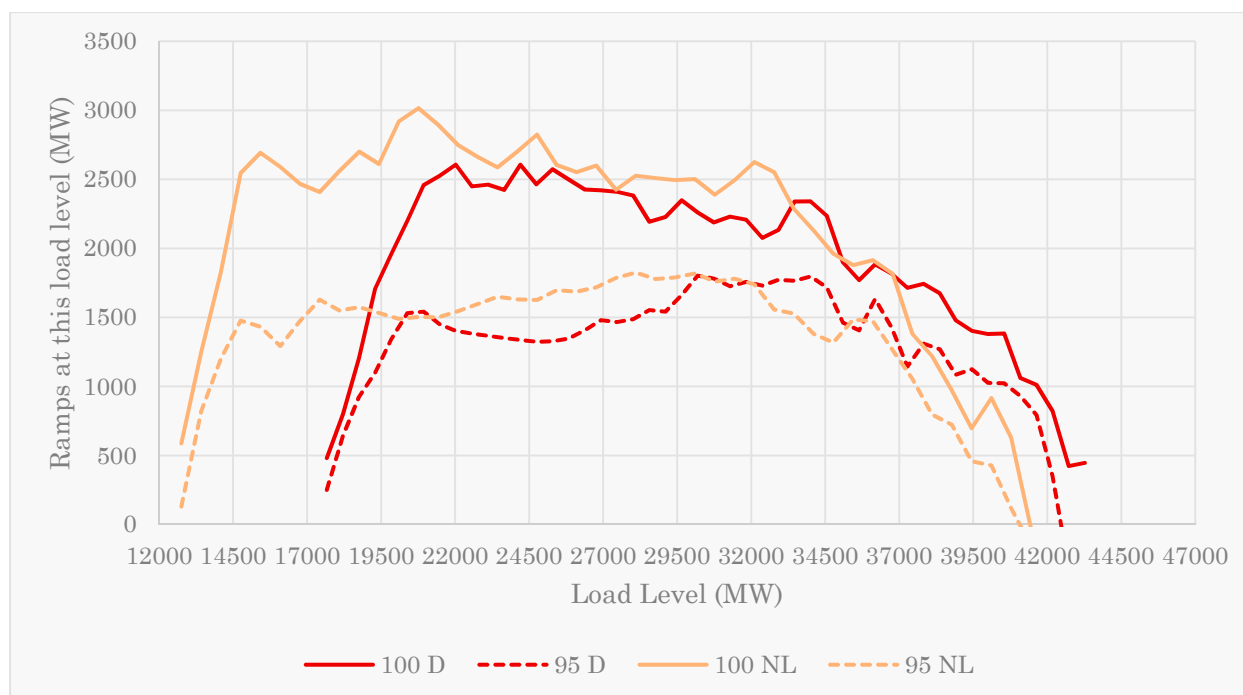


Figure 15: Observed hourly up ramping based on net load level at start of the hour for load and net load maximum and 95th percentile values for hourly averaged data

7.5.7 Inter-Hour Flexibility Requirements

When considering operations, it is worthwhile examining results from the perspective of how much balancing resources an operator may ensure are available for managing variability. Results thus far offer a number of different options to consider these requirements

1. Calculate the maximum (or 99th/95th percentile) variability and obtain this across all hours
2. Base requirements on month and/or time of day
3. Base requirements on maximum (or 99th/95th percentile) variability at wind output level

This last method is similar to current practices at SPP for regulation requirements, which are based in part on wind output level, and is thus used here. By using calculations behind Figure 14 and Figure 15 as a lookup table, we can determine, for each hour, how much balancing capability would be required to separately cover the hourly wind variability (or load variability) at the particular wind output level or load level observed in that hour¹⁷. After binning the data into 10 equal bins based on wind output or load level, the 95th and 100th percentile of ramps is calculated for each of the bins. Then, the resulting lookup table is used to calculate balancing requirements; each hour requires an amount based on the bin it falls into. This calculates wind and load balancing requirements separately; they are not directly correlated and so requirements would need to cover the combination, rather than each separately. This is done here using a ‘square-root of sum-of-squares’ approach (i.e. a geometric approach), as found in various studies performed by NREL and others. Figure 16 shows the requirements over a 5-day period. This shows that load, as expected from earlier, is the main determinant of the balancing requirement, as it is the main determinant of

¹⁷ This is similar to the approach used in numerous wind and solar integration studies, where the requirements for wind, solar and load are calculated separately and then added together. See Ela, E., Milligan, M., and Kirby, B., Operating Reserves and Variable Generation, NREL, August 2011, Available at: <http://www.nrel.gov/docs/fy11osti/51978.pdf>

maximum variability in the system. However, certain hours, during which load requirements are small, will see wind variability being the main factor. For upwards requirements, this happens during the night, when there is very little upwards load variability. During other parts of the day, wind can be seen to add very little to existing load requirements when added in this manner. Obviously, another manner would be to add these requirements linearly, in which case the system can always cover both wind and load separately; the actual requirement will likely come somewhere in between.

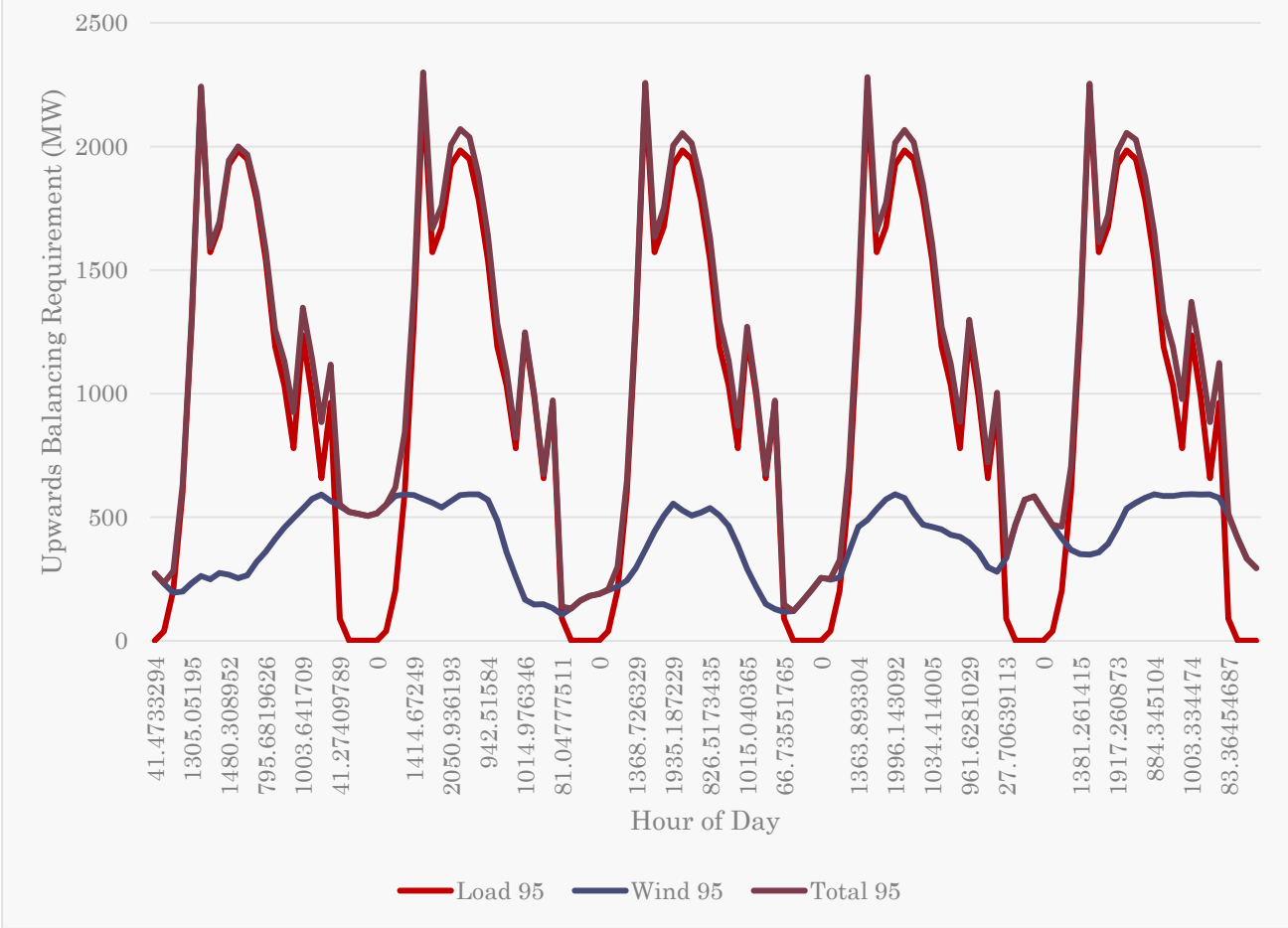


Figure 16: Five days of wind and load requirements separately and combined using geometric sum

The following table summarizes the requirements for load, wind and total one hour balancing observed using the one year of data. It also includes an approach where net load variability is examined using the same approach as the separate load and wind, for reference. Comparing the Combined to Load only, wind can be seen to add an additional 300 MW to the maximum requirement, but 530 MW to the average requirement, to cover all ramps. This compares to an additional 216 MW when planning to cover 95th percentile of all ramps. In both cases, if net load is used instead of combining separate wind and load calculations, the total amount required can be seen to be lower. The difference when looking at 100th percentile requirements is approximately 750 MW, with a smaller different of 317 MW when using 95th percentile of net load ramps.

Table 3: Balancing Requirements based on covering indicated percentiles of hourly load, wind and net load data. Wind and load are combined using a geometric sum

| 100th percentile | | | | 95th percentile | | | |
|------------------|-----------|---------------|---------------|-----------------|-----------|---------------|----------|
| Load (MW) | Wind (MW) | Combined (MW) | Net Load (MW) | Load (MW) | Wind (MW) | Combined (MW) | Net Load |

| | | | | | | | | (MW) |
|----------------|------|------|------|------|------|-----|------|------|
| Max | 2851 | 1351 | 3138 | 3081 | 2280 | 810 | 2419 | 3081 |
| Min | 0 | 57 | 127 | 0 | 0 | 0 | 0 | 0 |
| Average | 1272 | 1100 | 1802 | 1054 | 922 | 485 | 1138 | 821 |

7.5.8 Inter-Hour Ramping Mileage

The final result analyzed related to variability is the ramping mileage. The idea here is to examine if the system is becoming generally more variable, and by how much. Total ramping is calculated for each day by adding the absolute value of each of the 24 hourly ramps together. This is plotted across the year in Figure 17, which shows the daily sum of the absolute value of hourly ramps observed, as well as the cumulative value (shown on the secondary y-axis).

For example if a value here is 24,000 MW that implies that the absolute value of ramps in that day is 24,000 MW, i.e. an average hourly absolute ramp of 1000 MW; either up or down. The red line here is the net load, which can be seen to have more days where the value is higher than the black line. It can be seen that the largest amount of ramping was in the summer months as shown earlier; however, the cumulative result shows that the largest differences due to wind happened in the first few months of the year. Cumulative wind ramping can be seen to be much the same throughout the year, with only a slight increase in the difference as time goes by. This shows that, though the additional installed wind at the end of the study does have an impact, it is not too significant.

Looking at the time series in more detail, daily wind ramping mileage was seen to vary between a minimum of 930 MWs and a maximum of 11,984 MWs. Daily mileage for load alone was between a minimum of 8,753 MWs and maximum of 32,658 MWs, while net load ramping mileage had a minimum of 7,283 MWs and a maximum of 36,859 MWs. Therefore wind increases the largest daily mileage by 13%, while also decreasing the lowest day by 16%. The standard deviation of the mileage increased by 3.5% when wind was added. Cumulatively, the yearly value of ramping mileage increased by 137,583 MWs, which is an increase of 7%, or an average of an additional 15 MW or ramping per hour (against a load only value of 220 MW per hour). This shows general agreement with earlier results, which showed that wind does have an impact on ramping behavior, but that at current levels it is relatively small.

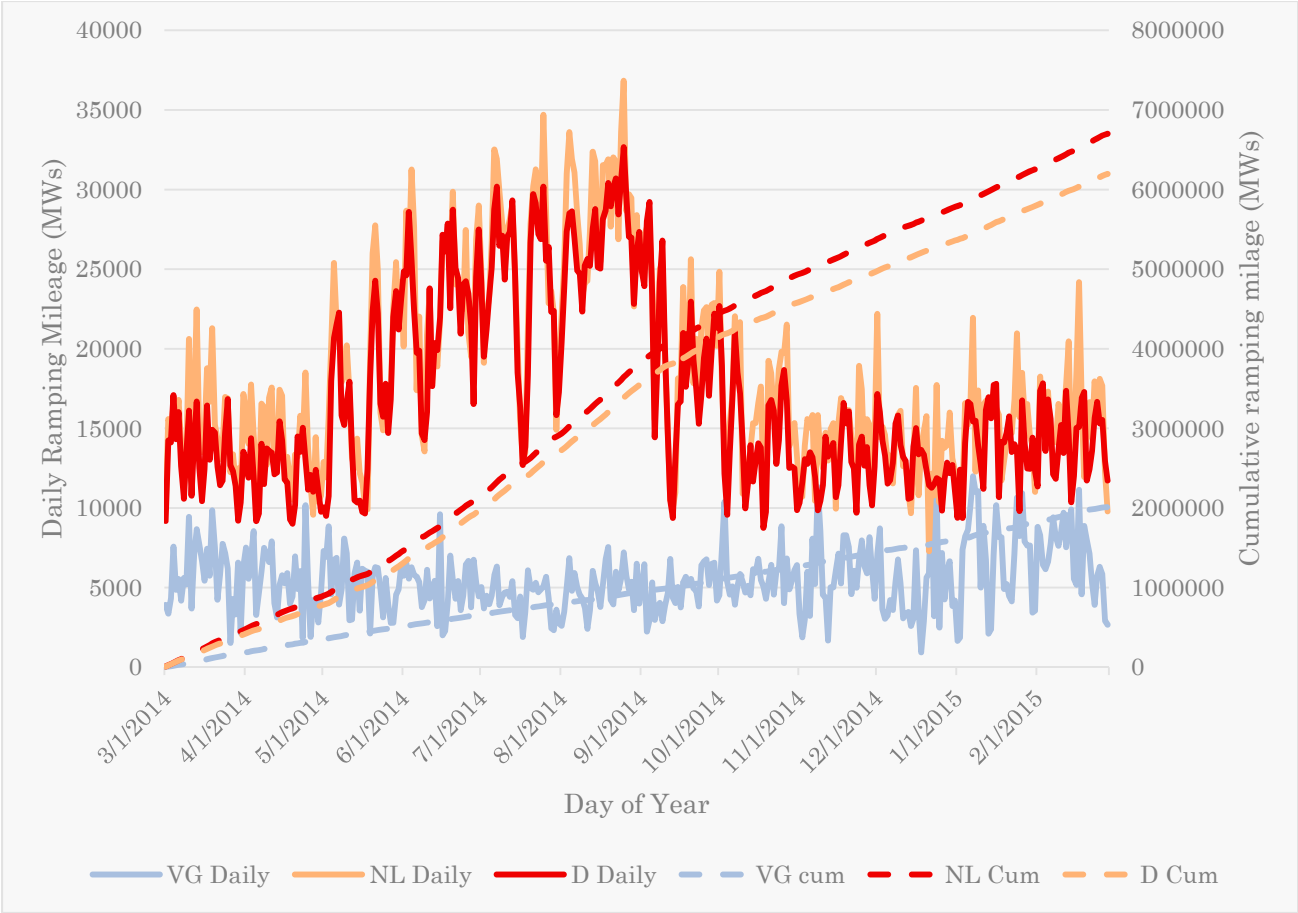


Figure 17: Ramping mileage showing daily sum of absolute wind, load and net load ramps (solid lines) and cumulative absolute value of hourly ramping (dashed lines) – cumulative shown on secondary axis

7.6 WITHIN-HOUR VARIABILITY ANALYSIS

This subsection provides a similar analysis to the previous, but focuses on ramping within the hour. Within hour ramps may require different mechanisms to manage, and so should be considered separately. Within hour ramping is managed through operating reserves (regulation or load following), whereas the inter-hour ramps are related to commitment and dispatch. One thing that should be noted is that the results shown here are based on 5-minute averages, whereas the inter-hour ramps are based on hourly averages. The 5-minute average dataset would be expected to show more variability at the 60 minute horizon, as it is examining the largest 60 minute change in 5-minute average data, whereas the other analysis is looking at the largest 60-minute change in 60-minute average data.

Within the hour, operators will be concerned about short term variability and changes, whereas from hour to hour, the overall energy within that hour is more important. 60-minute ramps using 60-minute averaged data will be significantly smaller than 60-minute ramps using 5-minute average data, where small changes are more likely to happen, that do not persist for very long. This shows the importance of understanding the data source when doing analyses such as here.

Results shown here will, where appropriate, focus on the 20-minute time horizon – this is a useful horizon to look at when determining additional within-hour balancing as it looks over multiple dispatch intervals. Additionally, it is shown early in the analysis that, at the 5-minute level there is not a significant impact from wind, whereas 20-minute ramping show more significant impact. Both the actual wind production, which considers wind being dispatched down (i.e. considers DVER), as well as potential wind (i.e. uncurtailed wind) are examined. Focus is put on the latter as that shows the ramping required, but some examination of actual wind is also provided later in the section.

7.6.1 Maximum Within-Hour Ramps

For each 5-minute period in the dataset, the maximum and minimum ramps in 5-minutes, 10-minutes, 15-minutes, and so on in 5-minute increments until 60-minutes, are calculated. This is plotted in Figure 18. This is for the uncurtailed case; the impact that wind curtailment had on ramping is shown later.

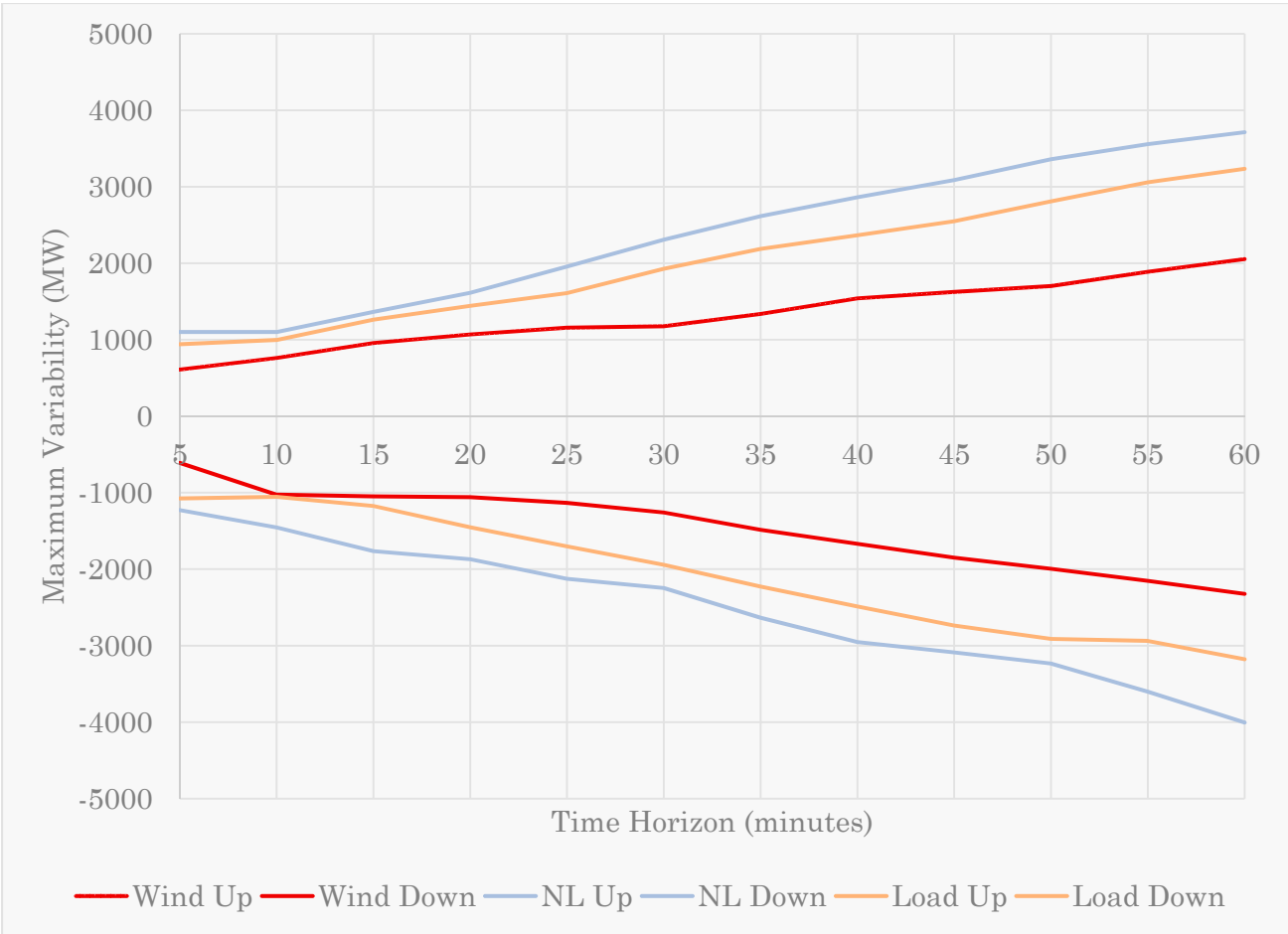


Figure 18: Variability of Demand, Net Load (NL) and Wind for different time horizons for uncurtailed wind. The y-axis gives the maximum variability of each of these against the ramp length, or time horizon, shown on the x axis

Figure 18 shows that, as before, ramps increase in magnitude with longer time horizons. As with inter-hourly variability, load still seems to be the main determinant of maximum ramping, particularly at shorter time horizons. For up and down ramping, 5-minute maximum ramps are driven mainly by load, while for longer horizons, the wind has increasing impact on net load ramps.

[Table 4](#)~~Table 3~~ shows the difference between the largest net load ramp and the largest load ramp, i.e. the difference caused by wind. It also gives these numbers as a % of installed wind capacity at the end of the year studied, to put this in context. A few things stand out here: the first is that at lower time horizons, the wind had a low impact on the very largest ramps. Of over 7 GW of wind, the largest 5-min ramps got 100 MW to 150 MW larger in the up direction and 150 MW to 600 MW in the down direction. This is not unexpected given how long it can take wind ramps to propagate through an area the size of SPP. 20 minute ramps get 2% higher in the upwards direction, but 8% higher in the downwards direction, as a percentage of installed wind capacity. .

When compared with earlier inter-hour results, which used hourly average data as the basis, the results here, using 5-minute average data, show significant more variability when the same time horizon is examined using 60-minute averaged data. Whereas the change caused by wind in the largest 60-minute ramps using hourly data are 258 MW (up) and 206 MW (down), the change in largest ramps due to wind seen when 5-minute data was used were significantly larger, at 480 MW

(up) and 827 MW (down). This is explained by the fact that, when using 5-minute averages, there is inherently more variability than when using hourly averages. For 5-minute data, hourly ramps are calculated using the net change in net load (or wind or load) from one 5 minute period in a given hour (e.g. the xx:05 to xx:10 period) to the same period in the next hour (xx+1:05 to xx+1:10). As these 5-minute averages will not be as smoothed as with hourly data, there is a strong likelihood that more variability will be seen, in both directions.

Table 4: Difference between largest load ramp and largest net load (NL) ramp for inter-hour time horizons

| Time Horizon (mins) | NL minus Load – up | NL minus Load – down | NL minus Load – up (% of installed wind capacity) | NL minus Load – down (% of installed wind capacity) |
|---------------------|--------------------|----------------------|---|---|
| 5 | 158 | -153 | 2% | -2% |
| 10 | 104 | -399 | 1% | -5% |
| 15 | 102 | -591 | 1% | -8% |
| 20 | 169 | -417 | 2% | -6% |
| 25 | 346 | -425 | 5% | -6% |
| 30 | 381 | -303 | 5% | -4% |
| 35 | 427 | -407 | 6% | -6% |
| 40 | 496 | -466 | 7% | -6% |
| 45 | 538 | -352 | 7% | -5% |
| 50 | 552 | -324 | 8% | -4% |
| 55 | 499 | -663 | 7% | -9% |
| 60 | 480 | -827 | 7% | -11% |

This is illustrated in Figure 19, which shows a 3-hour period of wind output. The 5-minute data is shown using the red line, where every single 5-minute period has a different wind output. The 60-minute ramp seen starting in each 5-minute interval is given by the orange line. For example, the largest ramp seen is that starting in the 12th 5-minute period (and ending in the 23rd), at just over 2000 MW. The average output for each hour is shown in light blue– the first level is the average of the 1st to 12th 5-minute interval, the second from 13th to 24th, and so on. These are naturally less variable, where the highest output and lowest outputs within an hour are averaged. The hourly ramps of this average data are thus lower, as they are an average of the 12 5-minute ramps within that hour.

In this report, the previous inter-hour analysis uses hourly averaged data, while this within-hour analysis used 5-minute data. The justification is that, while at shorter time intervals, the 5-minute data is more important to operations (i.e. operators need to know how things change from one real time market interval to the next), at longer time periods, and in the Day Ahead time frame, hour to hour changes are more important. If 5-minute data were used in the inter-hour analysis, the ramps shown in that subsection would have been larger. However, as long as the hourly changes can be met, the 5-minute within-hour analysis can be used to understand within-hour load following requirements, and so shouldn't be used in longer time horizons.

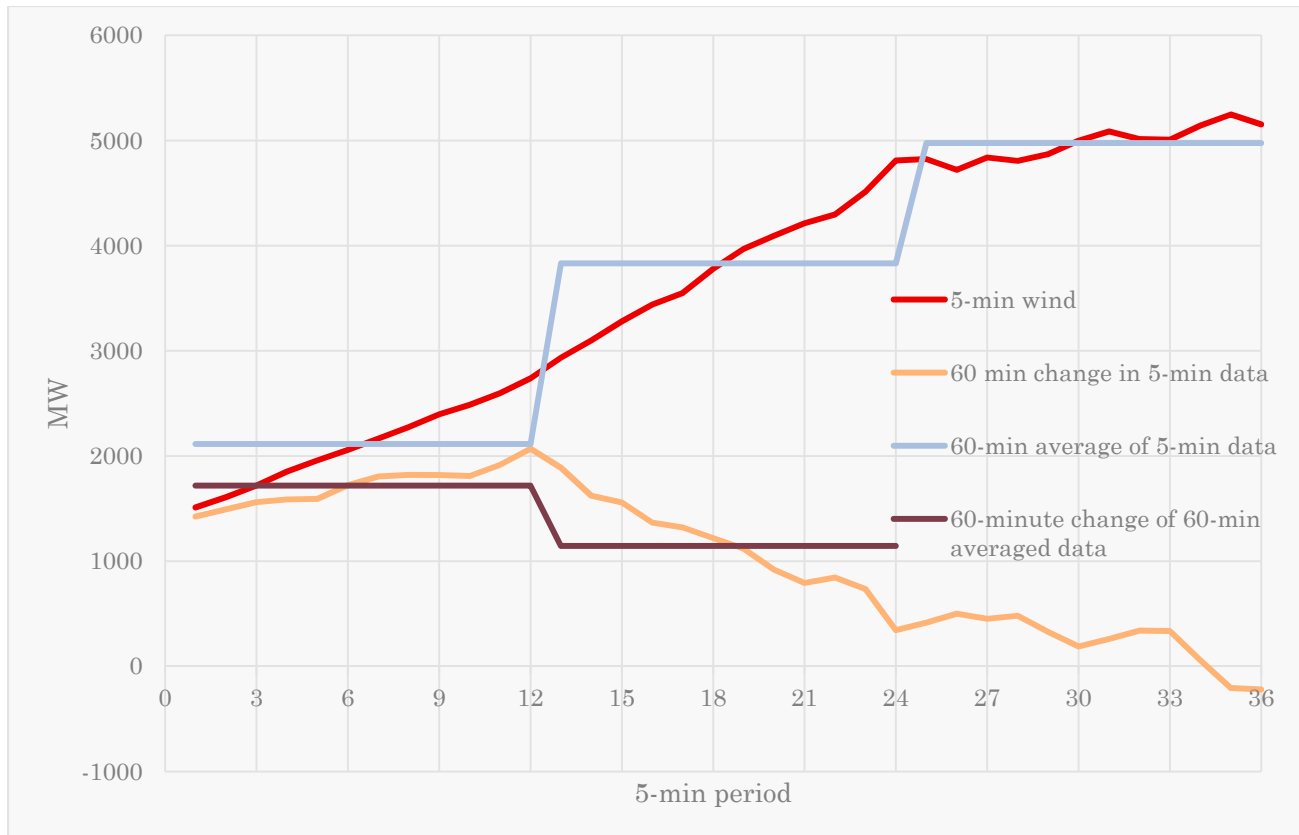


Figure 19: Three hour period of wind ramping, showing how use of 5-minute averaged data can produce different results than hourly averaged data (here, hourly averaged data is used for inter-hour analysis, whereas 5-minute data is used for within-hour analysis)

7.6.2 Maximum Within-Hour Variability by Time of Day and Month of Year

Twenty minutes may be a common time frame for issues such as load following, where sufficient flexibility needs to be carried for the next dispatch interval, as well as the 3 beyond that. Therefore 20-minute data was examined here. First, 20-minute wind down ramping by time of day and month is shown in Figure 20. As can be seen, there is generally not any obvious patterns as regards time of day. The largest down ramps do happen in June, but there is no other specific seasonal pattern.

The difference between load and net load ramping is shown by time of day and month of year in

Figure 20 Figure 21. Similarly to the hourly ramping data shown earlier, there is no clear pattern for when wind can have the most impact. This is both positive and negative – positive in the sense that it doesn't make the most challenging situations worse, but negative in the sense that it may mean that large net load ramps now happen in a less predictable time of the year (note they still may be predicted day ahead or hours ahead, but now we won't always know when the large ramps will happen when looking at an annual basis). Generally, the numbers here are consistent with earlier results, where 20-minute net load ramps are increased by up to approximately 8% -10% of installed wind capacity. This impact of 20-minute ramps here is a little over half of the impact in hourly ramps when 60-minute average data was used, as shown earlier. This would be expected as one would expect some smoothing over time.

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|----|------|------|-----|------|-----|------|------|------|------|------|-----|-----|
| 0 | -8% | -4% | -5% | -8% | -6% | -8% | -7% | -10% | -7% | -6% | -5% | -7% |
| 1 | -12% | -5% | -6% | -10% | -7% | -10% | -6% | -10% | -6% | -7% | -5% | -4% |
| 2 | -6% | -4% | -9% | -6% | -6% | -9% | -6% | -7% | -5% | -4% | -5% | -7% |
| 3 | -6% | -5% | -6% | -7% | -6% | -8% | -10% | -7% | -4% | -6% | -4% | -5% |
| 4 | -4% | -3% | -8% | -6% | -7% | -13% | -6% | -7% | -5% | -4% | -4% | -5% |
| 5 | -6% | -5% | -5% | -6% | -6% | -10% | -9% | -5% | -6% | -4% | -6% | -4% |
| 6 | -5% | -4% | -7% | -10% | -9% | -9% | -8% | -8% | -6% | -4% | -5% | -5% |
| 7 | -8% | -5% | -8% | -9% | -8% | -8% | -8% | -6% | -7% | -7% | -7% | -4% |
| 8 | -7% | -10% | -9% | -5% | -6% | -6% | -4% | -5% | -7% | -8% | -7% | -6% |
| 9 | -8% | -10% | -7% | -5% | -4% | -5% | -4% | -4% | -7% | -8% | -7% | -6% |
| 10 | -7% | -7% | -6% | -6% | -4% | -6% | -3% | -5% | -6% | -5% | -6% | -7% |
| 11 | -6% | -5% | -7% | -5% | -6% | -5% | -4% | -4% | -10% | -5% | -5% | -6% |
| 12 | -5% | -3% | -5% | -4% | -4% | -8% | -4% | -4% | -6% | -5% | -6% | -4% |
| 13 | -6% | -4% | -5% | -4% | -5% | -3% | -4% | -2% | -4% | -5% | -4% | -5% |
| 14 | -5% | -5% | -5% | -4% | -9% | -6% | -3% | -2% | -3% | -4% | -4% | -5% |
| 15 | -5% | -4% | -4% | -7% | -5% | -4% | -3% | -6% | -4% | -5% | -5% | -5% |
| 16 | -8% | -5% | -6% | -6% | -4% | -5% | -2% | -5% | -3% | -5% | -6% | -6% |
| 17 | -9% | -10% | -5% | -8% | -9% | -5% | -4% | -4% | -7% | -11% | -4% | -3% |
| 18 | -6% | -10% | -6% | -9% | -9% | -9% | -5% | -5% | -4% | -6% | -6% | -6% |
| 19 | -4% | -4% | -6% | -8% | -8% | -12% | -4% | -6% | -6% | -5% | -6% | -5% |
| 20 | -3% | -6% | -5% | -5% | -5% | -10% | -5% | -5% | -6% | -10% | -4% | -6% |
| 21 | -4% | -5% | -8% | -10% | -7% | -8% | -5% | -6% | -8% | -7% | -5% | -4% |
| 22 | -5% | -4% | -9% | -8% | -7% | -14% | -6% | -5% | -6% | -6% | -6% | -6% |
| 23 | -7% | -9% | -9% | -7% | -8% | -10% | -7% | -8% | -6% | -7% | -6% | -5% |

Figure 20: Maximum 20-minute wind down ramping by time of day (y-axis) in each month (x-axis) as % of the installed wind capacity on the 15th of the month – uncurtailed case

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
|----|-----|-----|-----|-----|------|-----|------|-----|------|------|-----|-----|
| 0 | 31 | 158 | 52 | 503 | 68 | 309 | 350 | 578 | 155 | 113 | 69 | 58 |
| 1 | 792 | 159 | 145 | 493 | 93 | 296 | 229 | 384 | 242 | 220 | 32 | 171 |
| 2 | 288 | 32 | 500 | 177 | 84 | 279 | 114 | 267 | 352 | -306 | 57 | 281 |
| 3 | 96 | 71 | 199 | 190 | 218 | 437 | 217 | 158 | 22 | 208 | 11 | 153 |
| 4 | 2 | 170 | -9 | 32 | 58 | 671 | 164 | 448 | 273 | 51 | 118 | 127 |
| 5 | 103 | 33 | 388 | 13 | 109 | 384 | 218 | 261 | 371 | 181 | 83 | 119 |
| 6 | 76 | 168 | 352 | 243 | 331 | 367 | 245 | 384 | 159 | 32 | 127 | 160 |
| 7 | 231 | 133 | 422 | 371 | 89 | 190 | 480 | 385 | 261 | 283 | 62 | 271 |
| 8 | 157 | 176 | 475 | 24 | 363 | 254 | 209 | -28 | 228 | 150 | 256 | 421 |
| 9 | 58 | 437 | 108 | 167 | -142 | 49 | 58 | 39 | 53 | 57 | 198 | 181 |
| 10 | 207 | 291 | 16 | 18 | 137 | 280 | -1 | 103 | 29 | -22 | -13 | 526 |
| 11 | 209 | 207 | 331 | -10 | 124 | 117 | 89 | 74 | 284 | 1 | 78 | 242 |
| 12 | 163 | -28 | 253 | 10 | 234 | 121 | 136 | 62 | 42 | 138 | 380 | 168 |
| 13 | 206 | 94 | -35 | 42 | 111 | 69 | 100 | -87 | -75 | -193 | 26 | 354 |
| 14 | 26 | 95 | -59 | 107 | 19 | 184 | 83 | -15 | 98 | 29 | 173 | 288 |
| 15 | 48 | 197 | 104 | 294 | 217 | -2 | -45 | 248 | -22 | 110 | 120 | 75 |
| 16 | 456 | 106 | 103 | 251 | 191 | 116 | 36 | 18 | 164 | 225 | 56 | 203 |
| 17 | 220 | 543 | 185 | 380 | 285 | 57 | -110 | 108 | 191 | 155 | 121 | 156 |
| 18 | 362 | 668 | 69 | 260 | 421 | 267 | 118 | 102 | -14 | 104 | 33 | 277 |
| 19 | 117 | 112 | -42 | 324 | 310 | 462 | 74 | 29 | -57 | -222 | 344 | 179 |
| 20 | -40 | 6 | 133 | 1 | 13 | 233 | -46 | -17 | -116 | -7 | 101 | 201 |
| 21 | 246 | 256 | 480 | -57 | 149 | 239 | -34 | 172 | -82 | 160 | 239 | 262 |
| 22 | 141 | 208 | 75 | 579 | 168 | 477 | 264 | -57 | 125 | 187 | 85 | 134 |
| 23 | 149 | 71 | 83 | 170 | 357 | 325 | 315 | -34 | 133 | 26 | 23 | 315 |

Figure 21: Difference in maximum 20-minute up ramps in net load compared to 20-minute load ramps by time of day (y-axis) for each month (x-axis). Positive values show an increase in largest up ramps due to wind, while negative values show that wind reduced largest ramps in that hour for the particular month

7.6.3 Variability Duration Curve

The next analysis, as given for the inter-hour ramping analysis, is to examine ramp duration curves. Again, this is done for the 20-minute time horizon here. The overall duration curve is given in Figure 22. This shows the number of hours above a certain level for wind, load and net load. As before, it is difficult to see when looking over the full year whether wind impacts significantly; there seems to be some increase, but in general it is relatively small.

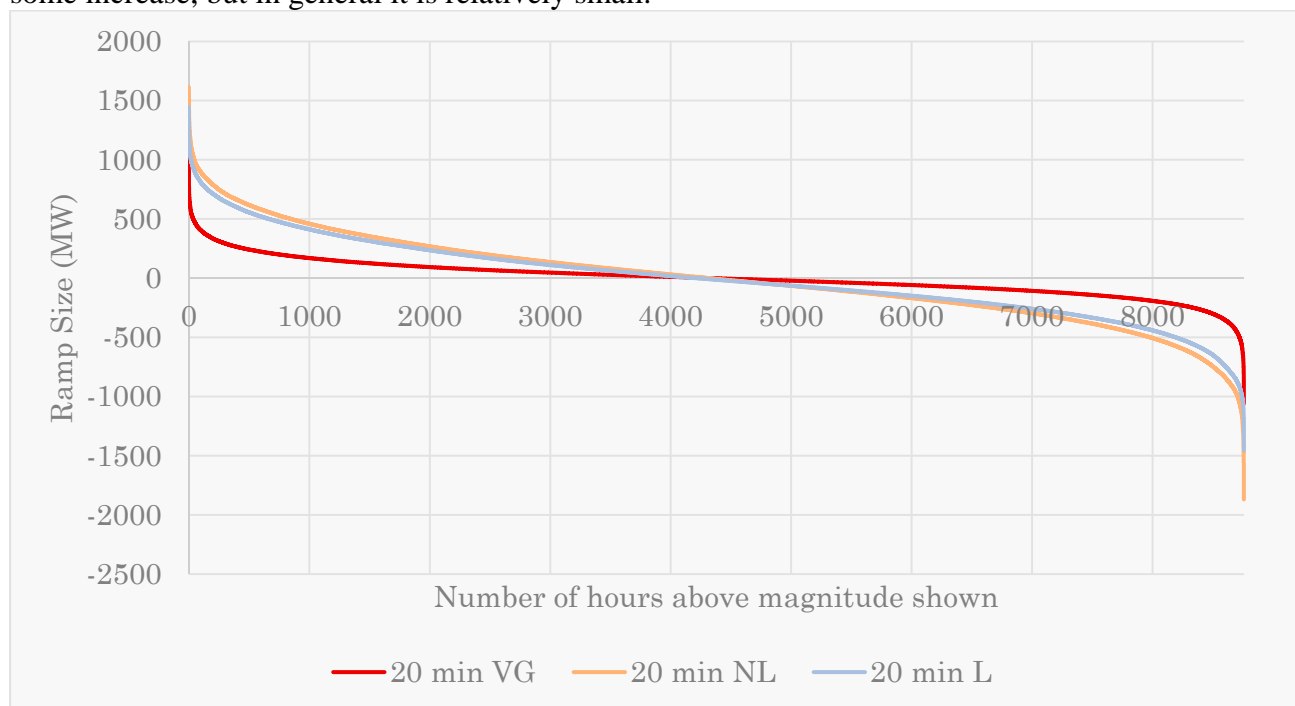


Figure 22: Ramp duration curve for 20-minute wind, load and net load ramps

To examine the impact of wind in more detail, the 100 largest 20-minute ramps are shown for wind, load and net load in Figure 23. This shows that wind does increase the size of the very large ramps, but as before, not by a very large amount. It can also be seen, and will be shown in more detail in the next section, that the very largest ramps (e.g. top 3-5) are significantly higher than the next largest, shown by the upturn on the very left hand side of the graph. This indicates that a few hours caused the most significant ramping needs in the year studied, and most other hours had far less ramping. It is interesting to note that this impact of the uptick for the last few hours is most pronounced for wind, and is also a little more pronounced for load than net load.

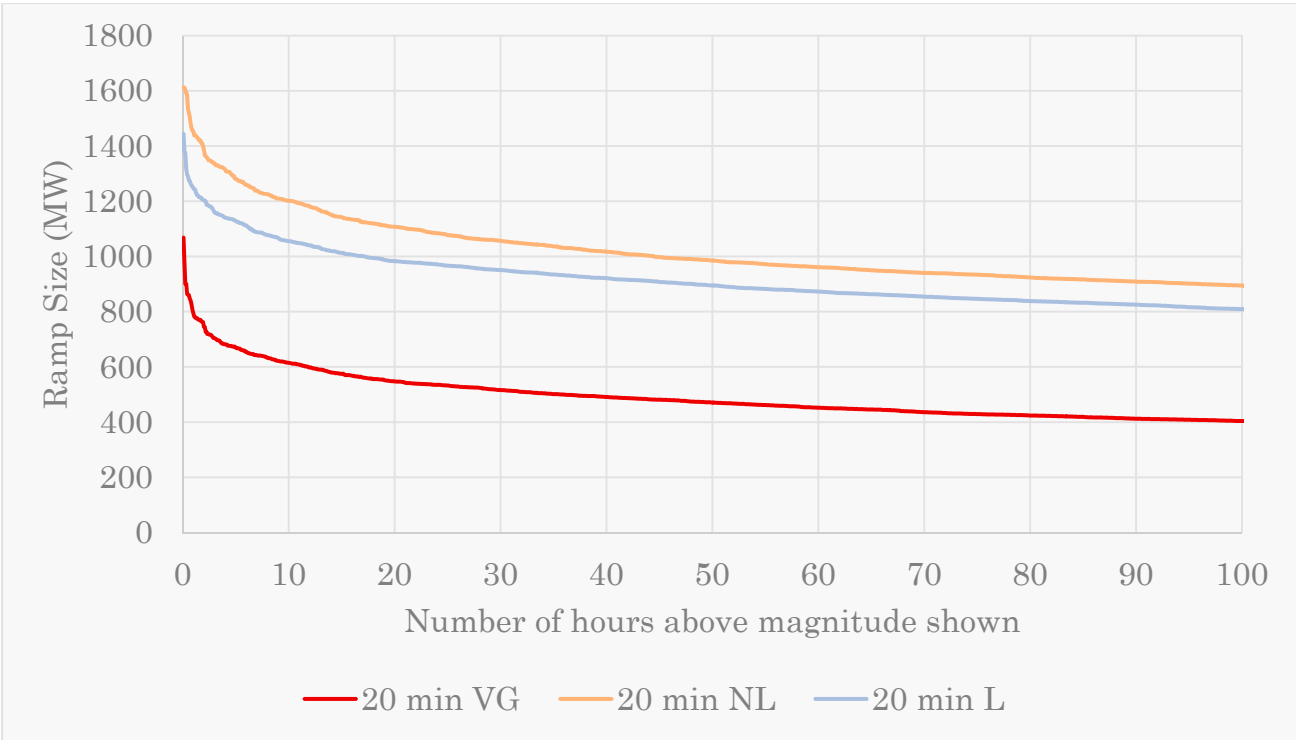


Figure 23: Top 100 hours of ramp duration for 20-minute ramps

7.6.4 Percentile Analysis for Within-Hour Ramping

As with the inter-hour ramps, it is instructive to look at percentiles of ramps for the within-hour ramping. The same method is used to determine these values, where the ramps are lined up in order from largest to smallest and then the n^{th} percentile is chosen. We look at 100th, 99th and 95th here, as well as their converse for down ramps (0th, 1st and 5th). As similar trends are seen for down and up ramps, only up ramps are examined here.

Figure 24 shows the different percentiles for wind, load and net load ramping. The solid lines show the same information as with the maximum ramps figure. Here, we can see a big gap between the very largest net load and the 99th percentile of net load, and a similarly, though not quite as big gap between maximum load and 99th percentile of load. This implies that, for 20 minute ramps, the very largest ramps happen very infrequently, and then those that happen 1% or 5% of the year tend to be significantly lower. This is not seen in every system, and may mean that SPP does not need to manage the very largest ramps through reserves, but instead could use interchange and potentially demand response or wind curtailment to get through these periods.

Values are also given in

Table 5 for 5-minute and 20-minute ramps. Here, it can be seen that, for 5-minute ramping, up ramps get approximately 15% larger, whereas down ramps get 14%-22% larger when wind is added, with a greater impact on more frequently occurring percentiles. 20-minute ramping is mostly between 10%-15% greater when wind is added, with the exception of the very largest down ramp, which is now 30% lower. Other than this last point, the ranges seen in the within-hour ramps, where ramps are 10% to 20% larger, are a little higher than longer inter-hour ramps which tended to be in the 5%-12% range, as shown in Table 2. This shows wind can have more impact in shorter time frames, but also reflects the use of 5-min averaged data, which tends to be more variable, as explained earlier. A final interesting result about this percentile analysis is that 20-minute ramps tend

to be about 3 times larger for 95th and 99th percentiles, but only twice as large for the 100th percentile results. This shows that there are some very large 5-minute ramps that happen very infrequently in the dataset studied that smooth out at 20 minutes.

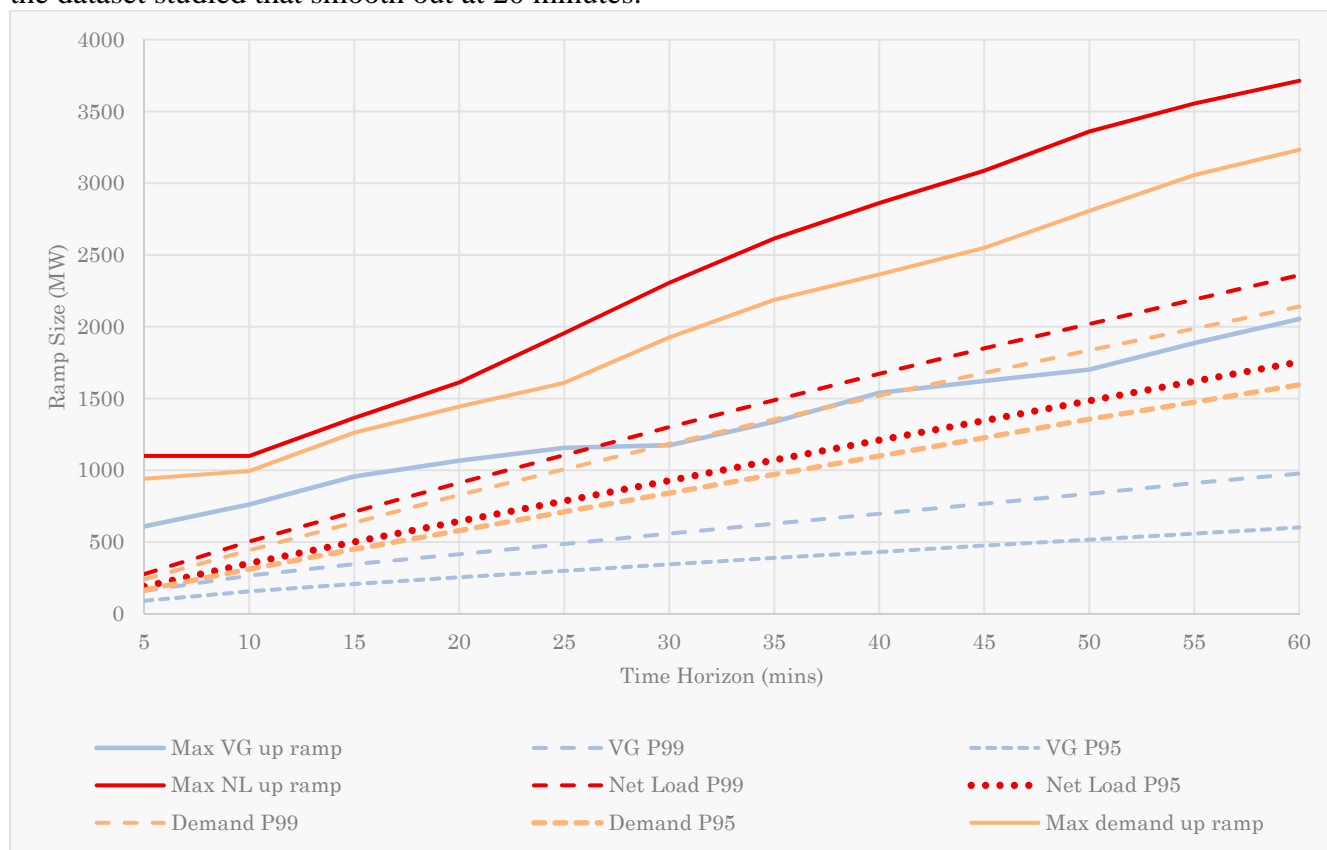


Figure 24: Up ramping of wind, Net Load and Demand for various percentiles - time horizons of 1-12 hours

Table 5: Statistics for percentile analysis of wind, load and net load for 5- and 20-minute ramping

| | 5-minute ramping | | | | | 20-minute ramping | | | | |
|--------|------------------|-------|----------|-------------|-----|-------------------|-------|----------|-------------|-----|
| 1 hour | Wind | Load | Net Load | Diff (NL-L) | % | Wind | Load | Net Load | Diff (NL-L) | % |
| Max | 609 | 941 | 1099 | 158 | 17% | 1068 | 1444 | 1612 | 169 | 12% |
| 99th | 160 | 240 | 277 | 37 | 15% | 415 | 828 | 912 | 84 | 10% |
| 95th | 90 | 166 | 190 | 25 | 15% | 255 | 580 | 644 | 64 | 11% |
| 1st | -88 | -159 | -191 | -33 | 21% | -246 | -551 | -630 | -79 | 14% |
| 5th | -156 | -237 | -290 | -53 | 22% | -412 | -823 | -928 | -105 | 13% |
| Min | -612 | -1076 | -1229 | -153 | 14% | -1060 | -1453 | -1869 | -417 | 29% |

7.6.5 Within-Hour Ramps as Function of Load Level or Wind Output

The previous results mainly focus on flexibility by time period of the year, or look at overall requirements. Another way to examine needs is to look at the variability as a function of the output level. By binning the data into a suitable number of groupings, and then examining the largest ramps (and various percentiles) for each output level, the relationship between wind output (and load/net load) and ramping can be understood. As shown in Figure 25, there is not a clear relationship between 5-minute ramps and output level. The largest ramps, in both up and down directions, seem to happen when wind is close to maximum output, but with very little difference compared to ramps at other output levels. For 95th percentile ramps, the largest magnitude seen is at approximately 7000 MW wind output, i.e. at this output level the largest 5-minute up ramps tend to occur. However, it can be seen that the actual magnitude is still relatively small. For down ramping, the very largest ramps tend to happen at close to maximum output, as do the largest 95th percentile ramps. This shows that the most significant concerns are likely due to high wind speed cut out, or similar behavior.

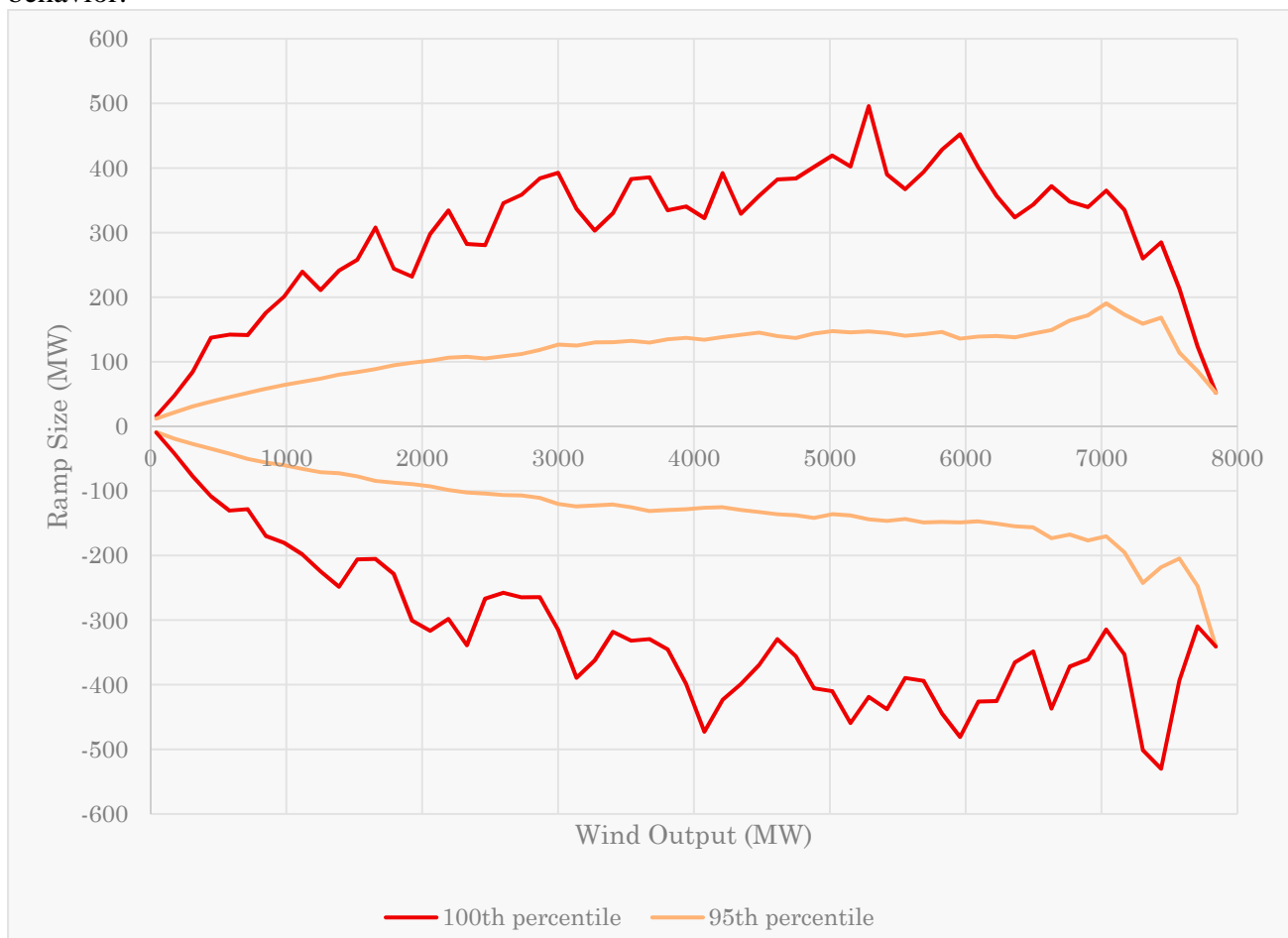


Figure 25: 5-minute ramps as function of wind output for different percentiles of up and down ramping

20-minute ramps as a function of output level are shown in Figure 26. Here, more of a pattern is seen, as is similar to shown earlier for hourly ramps. The largest up ramps tend to occur in the middle of the output range, both in the largest case and the 95th percentile case. The 95th percentile case could be seen as the amount of wind ramping that would need to be managed to ensure that 95% of all ramps are covered. For down ramps, it can be seen that there is some high speed cut-out, or similar that causes very large wind down ramps when wind is close to its maximum output level.

Again, this would be expected for 20-minute ramps, but may not be as obvious for the hourly averaged data shown earlier. The biggest gap between maximum and 95th percentile occurs in the middle of the output range, showing that this is the output level at which the very large ramps tend to happen less frequently.

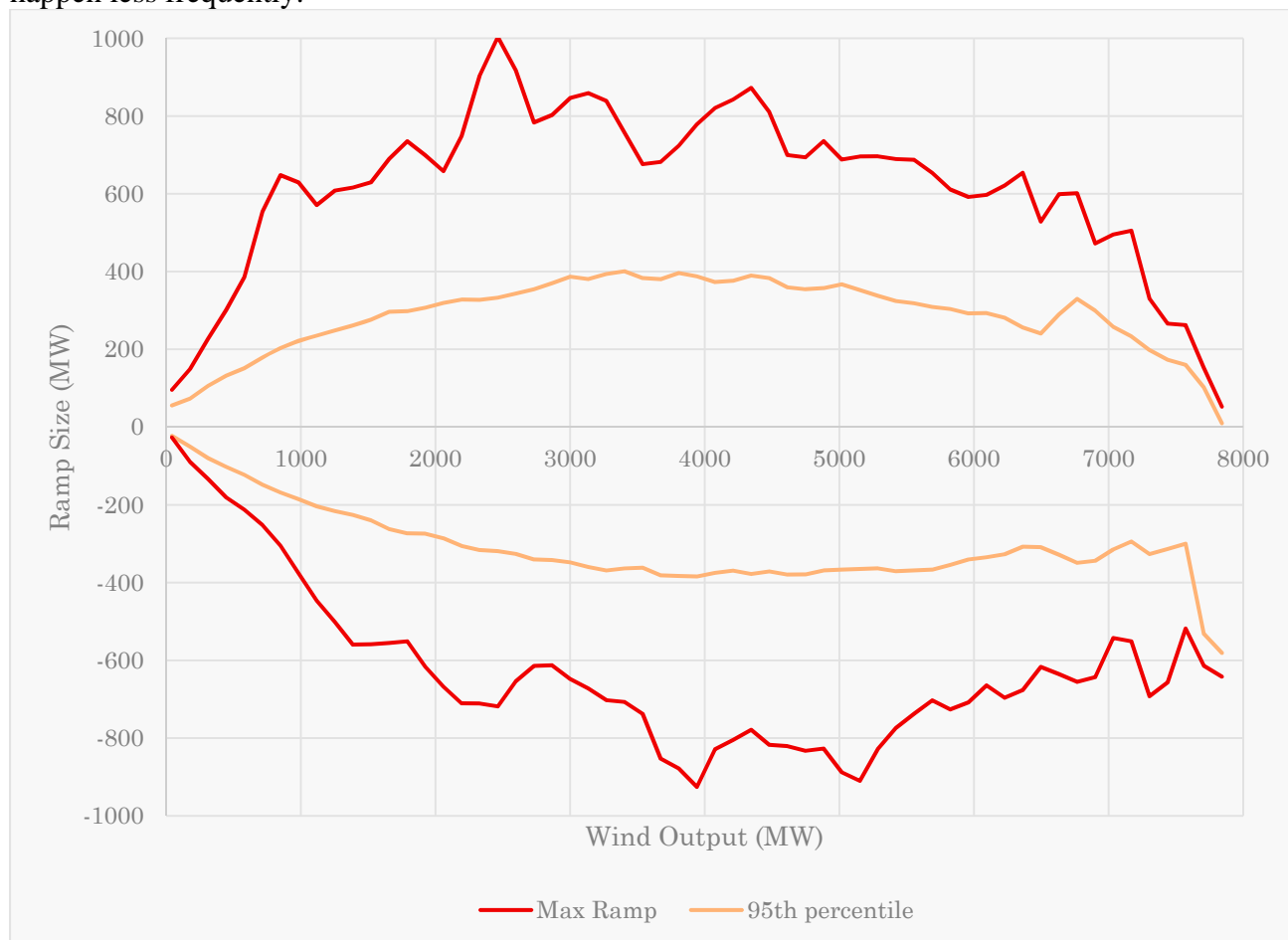


Figure 26: 20-minute ramps as a function of wind output

The final result to examine as a function of level is load and net load. This is shown for 20-minute up and down ramping for the 100th and 95th percentile in Figure 27. As with hourly ramping shown earlier in Figure 15, the most noticeable aspect to this graph is the reduction in net load compared to load, with lowest net load levels being considerable lower than load, while highest load levels are only a little greater than net load. This indicates that wind output at high load levels is not that high, as may be expected (though study of capacity value is out of scope of the ramping analysis here). As before, the highest net load ramps are noticeable higher than load ramps, and tend to occur at lower load levels; this likely helped manage the ramps as more generation is available. The difference between 100th percentile of load and net load also seems greater than the difference between 95th percentile load and net load, again as shown earlier.

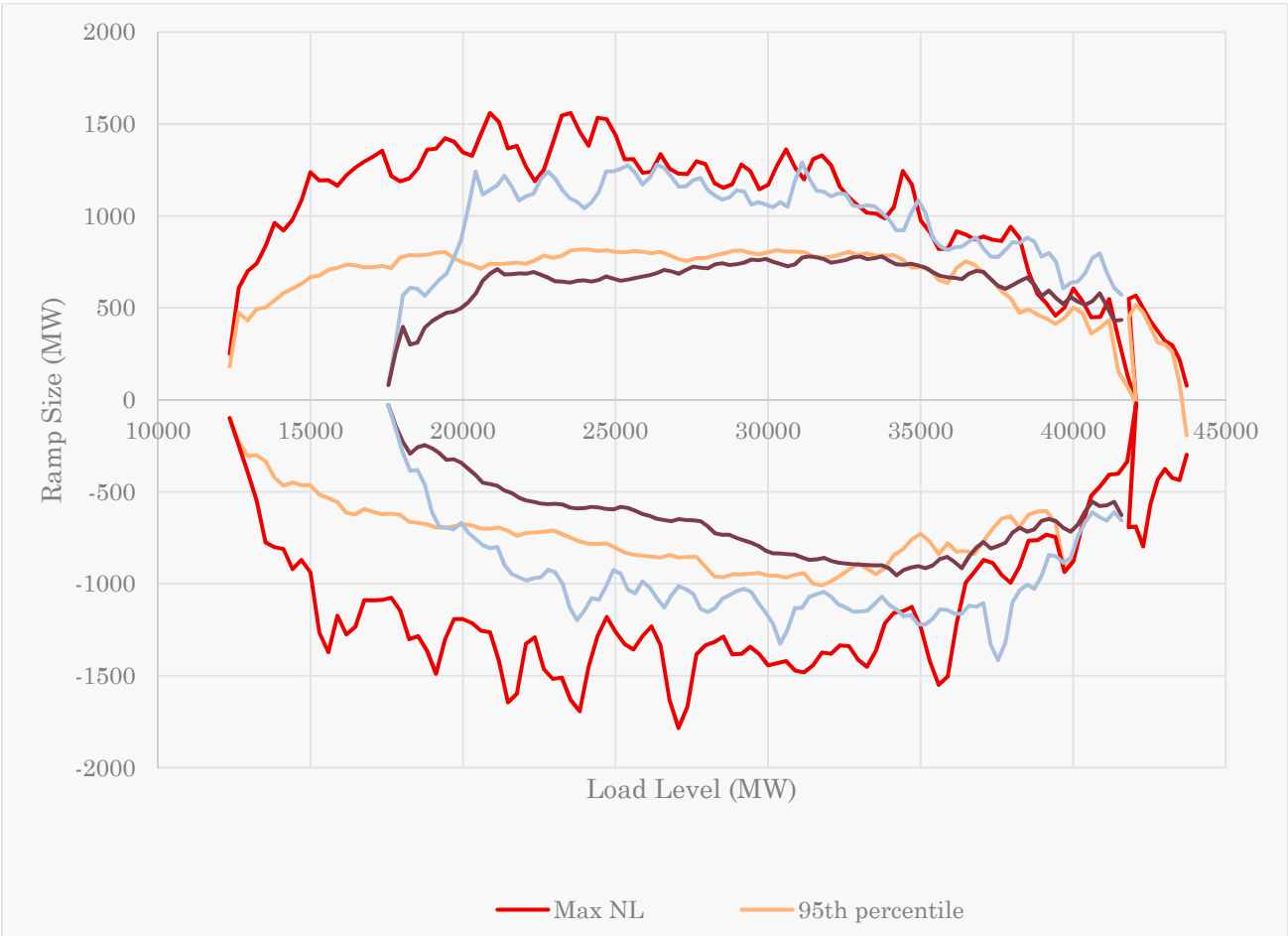


Figure 27: 20-minute ramping as function of load level for different percentiles of occurrence

7.6.6 Within-Hour Flexibility Requirements

As with the inter-hour analysis, one potentially interesting result is to examine how much balancing may be required due to the wind and load variability. A similar method as with hourly ramping is followed for 20-minute ramps. The 100th and 95th percentiles were used to understand how the results may vary depending on risk preference, and load, wind and net load were all examined individually. The statistics for this are given in Table 6.

Table 6: Balancing Requirements based on covering indicated percentiles of 20-minute load, wind and net load variability. Wind and load are combined using a geometric sum

| 100th percentile | | | | 95th percentile | | | |
|------------------|-----------|-----------|---------------|-----------------|-----------|-----------|---------------|
| | Load (MW) | Wind (MW) | Combined (MW) | Net Load (MW) | Load (MW) | Wind (MW) | Combined (MW) |
| Max | 2851 | 1351 | 3138 | 3081 | 2280 | 810 | 2419 |
| Min | 0 | 57 | 127 | 0 | 0 | 0 | 0 |
| Average | 1272 | 1100 | 1802 | 1054 | 922 | 485 | 1138 |

As shown in Table 6, if balancing requirements had been calculated in this manner for the year studied, wind would have combined with load to make 20-minute balancing requirements on average approximately 50% higher to meet 100th percentile or maximum ramps or approximately 20% higher

to meet 95th percentile ramps. This corresponds to somewhere from 2% to 5% of installed capacity. It can also be seen that maximum requirements are significantly higher than average, and that in most cases there may be periods when no balancing is required in the upwards direction (as there will definitely be a down ramp based on the data studied).

This type of analysis could be useful to help inform the general magnitude of a load following need for SPP. It is likely that such a requirement would be based on the 95th percentile rather than the very largest ramps. If the load-only target would be approximately 900 MW of load following, then wind would increase that by an average of 200 MW in each period. On the other hand, looking at net load only, there is actually a reduction compared to load. This is due to the fact that load is being reduced by wind, and in this case that may outweigh any additional variability. However, it is not clear that the approach to calculate net load is an appropriate one; previous studies have tended to calculate the components individually, and then added together using an approach such as that used here.

7.6.7 Within-Hour Ramping Mileage

One final analysis of the within-hour uncurtailed dataset provided here is to examine overall ramping mileage. As with the inter-hour ramping, this takes an absolute value of all ramps and sums across the day. This is then summed across the year also to compare general ramping behavior of wind, load and load net of wind. This is given for the 5-minute averaged data in Figure 28, where each point on the graph is one day. As can be seen, there are a lot of days when overall ramping is higher for the case with wind, and there is clearly cumulatively more ramping across the year. This can be compared with the earlier result, which used hourly averaged data. When summed across the year, there is approximately 1,500,000 additional MWs of ramping, or an additional 4150 MWs per day, or approximately 14 MWs per 5-minute period. This is compared with 15 MW more per hour when using hourly averaged data, showing that 5-minute averaged data is significantly more variable. Looking at individual days, Table 7 summarizes the impact of wind. It can be seen that wind increases average ramping in a day by approximately 19%, while the day with maximum ramping is 15% larger and day with lowest ramping is 8% larger. This again shows that wind has more of an impact on average days than on the most extreme cases, as discussed throughout this analysis.

Table 7: Ramping Mileage Summary Statistics for 5-min averaged data (uncurtailed wind)

| | Wind (MWs) | Load (MWs) | Net Load (MWs) | Impact of wind (MWs) | Impact of Wind (%) |
|------------------------------------|------------|------------|----------------|----------------------|--------------------|
| Average Ramp - Day | 11489 | 21741 | 25891 | 4150 | 19% |
| Average Ramp - 5 mins | 39.89183 | 75.49047 | 89.8997 | 14 | 19% |
| Largest ramping in one day | 21875 | 35980 | 41522 | 5542 | 15% |
| Smallest Ramping in one day | 2455 | 12598 | 13550 | 952 | 8% |

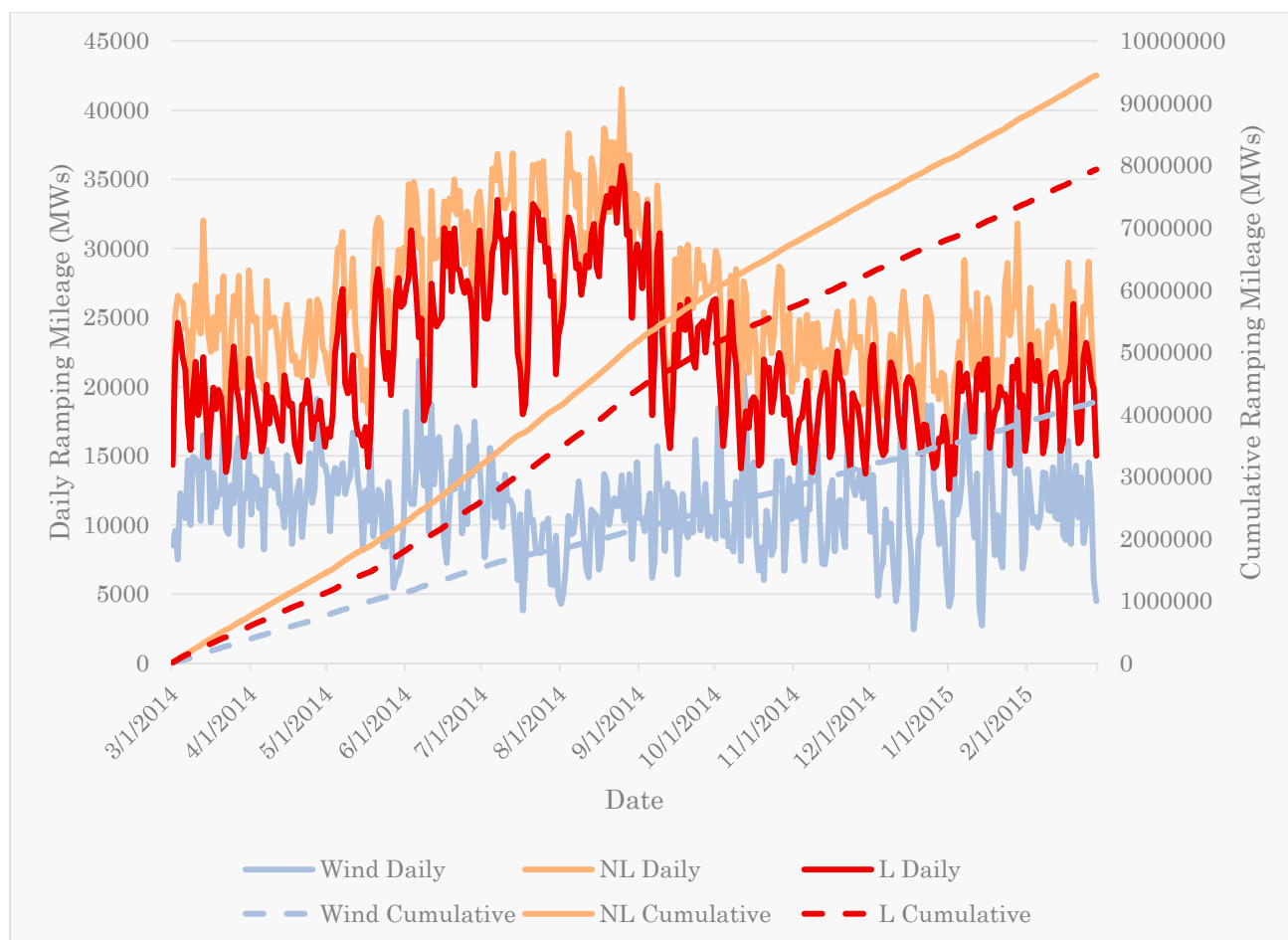


Figure 28: Ramping mileage showing daily sum of absolute wind, load and net load ramps (solid lines) and cumulative absolute value of 5-minute ramping (dashed lines) – cumulative shown on secondary axis

7.6.8 Impact of curtailment on ramping

While not directly related to ramping, it is nonetheless instructive to examine how much curtailment can help reduce ramp sizes. Most of the analysis done in this subsection focused on unconstrained wind, i.e. the wind that was available. This is the wind that SPP would aim to accommodate, so the variability introduced by this wind is what needs to be managed. However, in recent years, there has been a lot of good evidence that wind itself can be used to mitigate some of the ramping behavior. This is evident in SPP with the DVER program, which will focused more on economic curtailment due to transmission constraints, could also be used to reduce ramping requirements. For downwards ramping, this is relatively obvious, as wind can be reduced to reduce net load down ramps. Net load up ramps can likely not be reduced in the same manner; however, by curtailing DVER-enabled wind, the up net load ramps will happen from a lower starting point of wind, reducing their impact and ensuring generation is available to manage this ramp. Therefore, we examined the 5-minute averaged data for the actual wind production here and compared with the unconstrained data. Focus is put on the largest ramps and the percentile analysis done earlier, as other aspects (such as time of day/month of year and mileage) produce less insightful results. This is given for the year of data examined in Figure 29. As shown, the largest impact curtailment has is to reduce the shorter time frame ramps. This would be expected as curtailment often does not last particularly long. It can be seen that up ramps are reduced in all time horizons, though the impact at longer time horizons is minimal, whereas the impact on downwards wind ramps is minimal beyond 20 minutes. This would

be expected as up ramps may be a reason for DVER to be deployed, as the market cannot dispatch enough generation off and the price of energy becomes low or negative. On the 5-minute level, up ramps are reduced by 230 MW and down ramps by 112 MW. This is approximately 38% reduction in 5-minute ramps for upwards and 18% for downwards. For 20-minute ramps, there is a reduction of 21% upwards and 17% downwards. Thinking back to the balancing requirements calculated for 20-minutes, this shows that, even though wind may introduce such balancing requirements, DVER enabled wind may be able to provide some of the balancing themselves, especially if there is an economic incentive to do so. It seemed that, in the year of data studied here, this did happen and short time horizon ramps were reduced using the DVER program (or other curtailment).

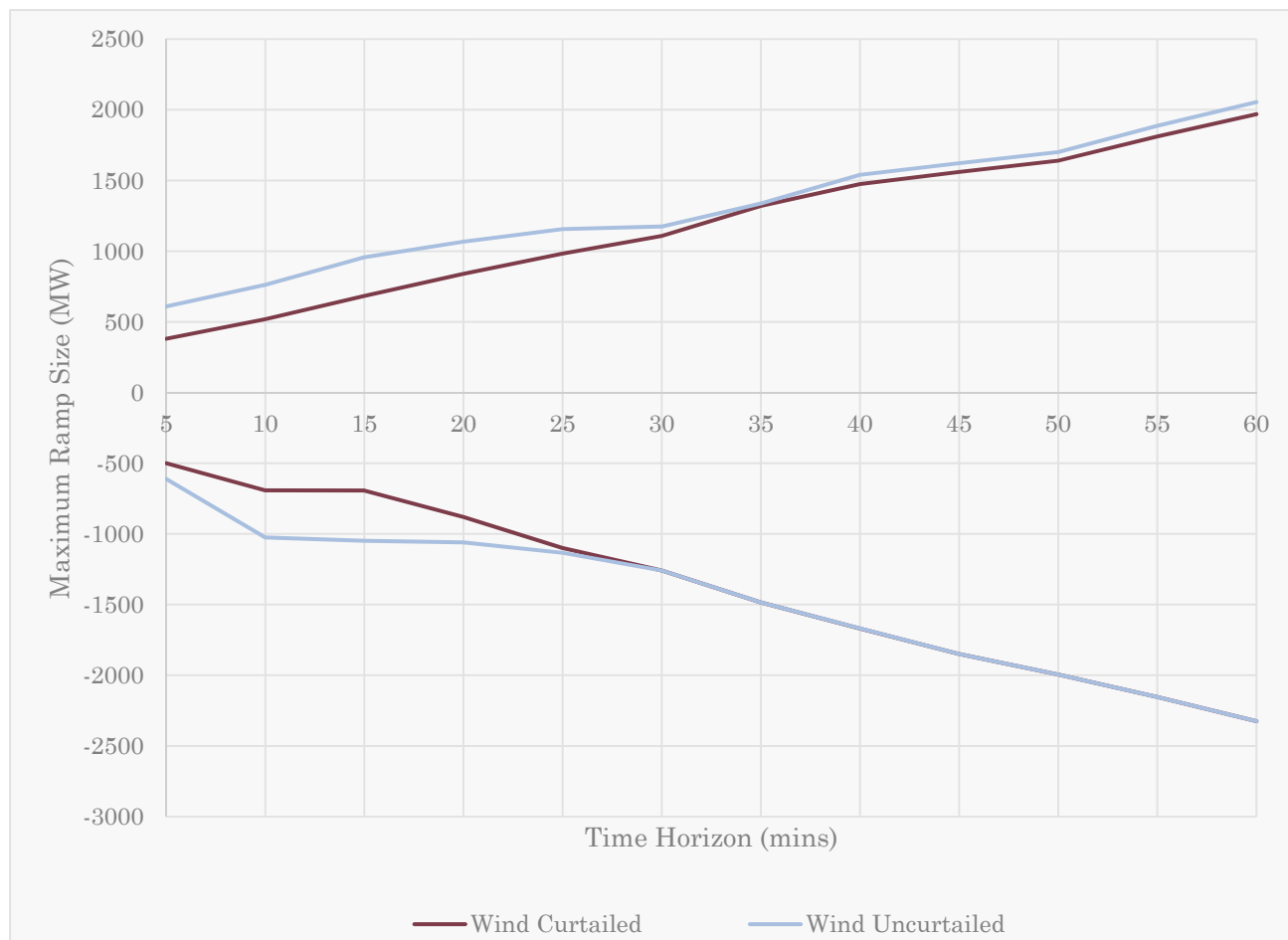


Figure 29: Maximum wind ramps for curtailed and uncurtailed wind (5-minute average data)

Looking at net load, the curtailment of wind also had an impact on reducing ramps, as shown in Figure 30. As expected, down ramps are impacted most, with the magnitude of the largest down ramps out to 25 minutes being impacted in a noticeable manner. These would have occurred when wind was increasing quickly, and so was curtailed to avoid ramp down of generation that may not have been possible. On the other hand, up ramps can also be reduced by curtailing wind, particularly at short time horizons. This would happen by curtailing wind before the ramp, such that when wind does start to ramp down, it is not causing as much of an impact on net load up ramping. This would be an important way to deal with short term ramps, in particular, where there may be periods when ramping resources may not be available. For down net load ramping, the reduction at 5-minutes was 12% of the original ramp size, and 8% at 20-minutes. For up ramping, only 5-minutes (13%) and 10-minutes (9%) showed a reduction.

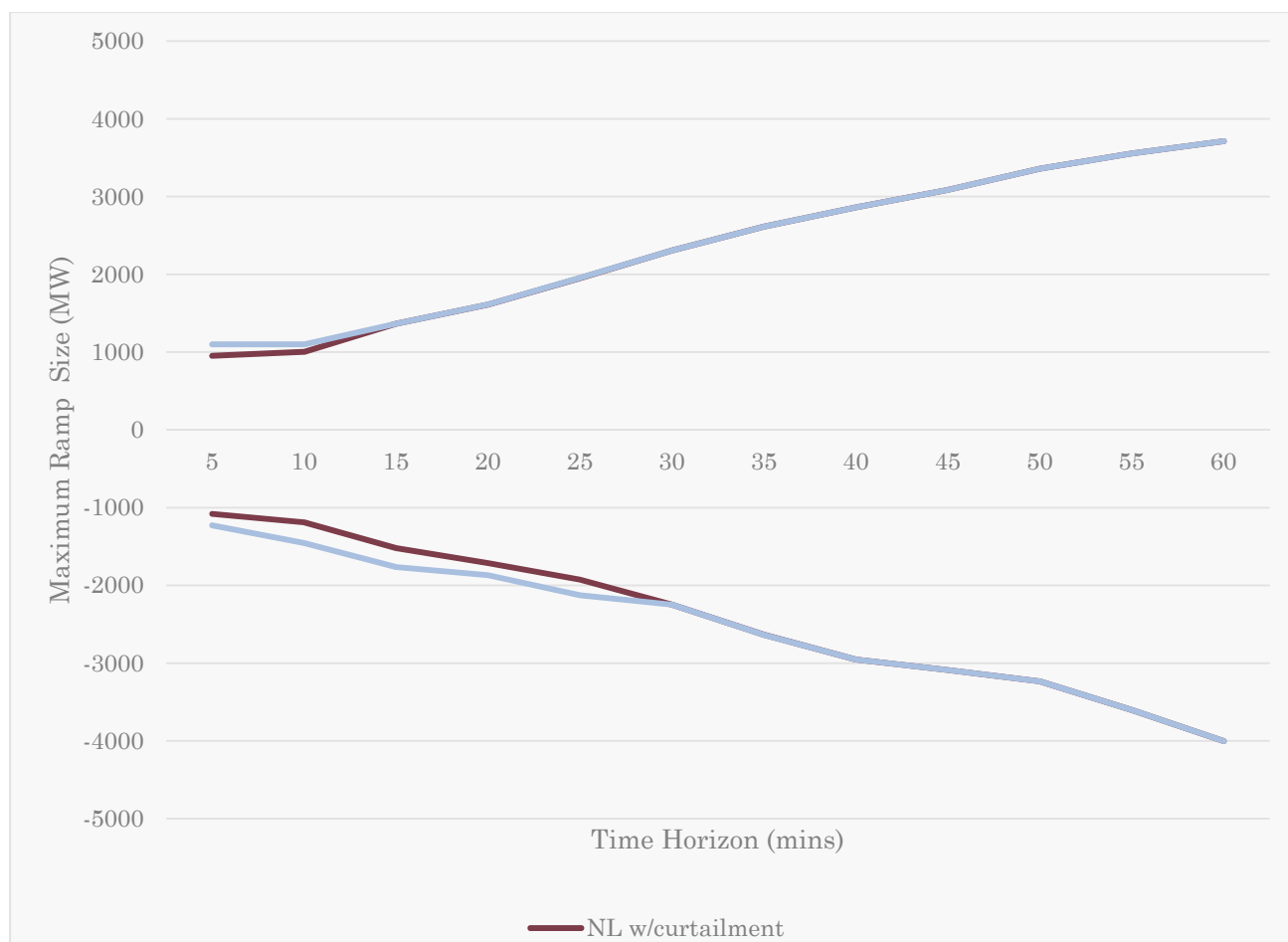


Figure 30: Maximum Net Load Ramps for Within-Hour time horizons, with and without wind curtailment for year of data studied

As mentioned already, the within-hour studies done here were all based on uncurtailed wind, to examine maximum ramping requirements. However, these results show that curtailment, through DVER or similar programs, can provide a key tool to manage ramping. The inter-hour results are all based on actual wind production, so already include any curtailment that may have happened. Based on results for longer horizons here, the impact on longer ramps is likely non-existent or at least very small.

7.7 GENERATOR FLEXIBILITY CHARACTERISTICS

The second level of analysis here, and in the EPRI Inflexion tool, looks at the characteristics of the generation fleet. This doesn't consider actual generator dispatch but instead focuses on the technical capabilities of the fleet. The next chapter will examine the operations over the study year. Here, only thermal plants are analyzed; while wind itself can also provide flexibility, through being dispatched as a Dispatchable VER, this is not considered here.

7.7.1 Operating Range

The operating range of a dispatchable resource is the range over which it can typically operate. This is calculated as the difference between minimum stable level and maximum stable output. Minimum stable level may actually change during the year, but that is not considered here, and only one value is used. The method used to examine this issue in this study is to calculate the range as a % of installed capacity for each resource. Generally, a range of 50% or above is considered relatively flexible.

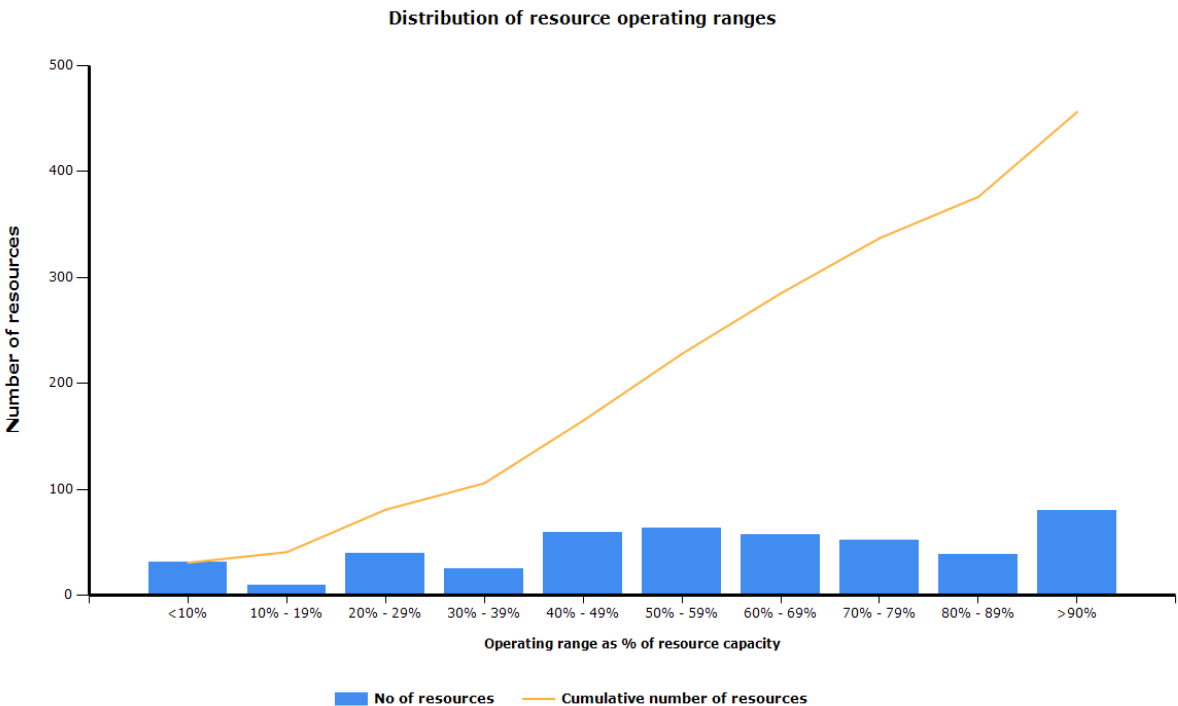


Figure 31: Number of resources with different Operating Ranges as % of resource capacity

Figure 31 shows the number of resources in the SPP system for each operating range, as well as the cumulative number with at least the indicated operating range. Out of a total of approximately 450 resources, one can see that the largest amount are in the 90%-100% range, i.e. they can operate from 10% or less to 100% of installed capacity. One can also see that there is a relatively large spread, showing that the units in SPP have a wide variation in their operating ranges. Figure 19 shows this in a slightly different way – instead of number of resources, this shows installed capacity of resources. Again, much the same thing is seen, though here the MW of installed capacity at lower operating ranges can be seen to be relatively lower than just looking at number of units, implying that those with lower ranges are smaller unit. It can be seen from looking at the cumulative number (orange line) that approximately two thirds of the installed capacity has an operating range greater than 50% (as the 50% bar corresponds to approximately 20,000 MW out of a

total of 60,000MW, showing that 20,000 MW has less than 50%). This large operating range shows that the SPP system likely has significant range to manage variations in net load. However, it should be noted that economics are not considered here; obtaining the flexibility may be expensive.

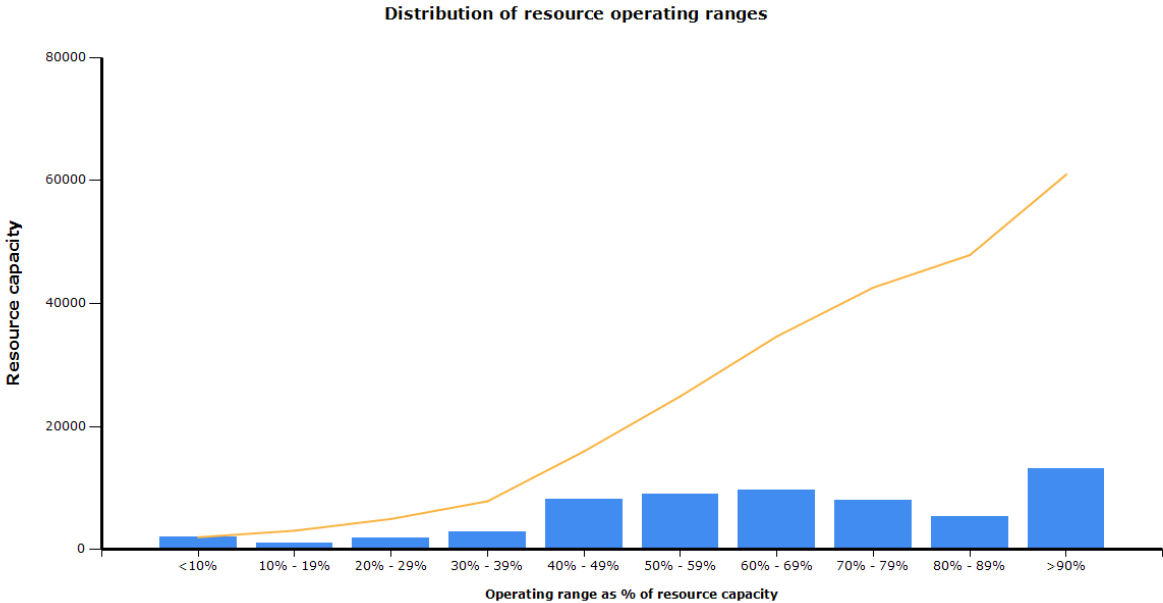


Figure 32: MW of installed capacity for different Operating Ranges, as % of resource capacity

7.7.2 Generator Ramp Rates

While the operating range in SPP seems to be relatively flexible, ~~Figure 33~~~~Figure 20~~ shows that there seems to be less flexibility when the ramp rate capabilities are examined. Here, ramp rates are given as % of installed capacity per minute. It can be seen that a large majority of the units have less than 10% ramp rates. This is nonetheless relatively typical of generators, so it is not a surprising result. It can be seen that the vast majority of units have less than 20%/min ramp rates, indicating that ramping in the system will be achieved by moving multiple generators around at once rather than relying on a small number of resources.

7.7.3 Start Times

While start time can vary depending on the condition of a unit, one set of start times are assumed here. ~~Figure 34~~~~Figure 21~~ shows the spread of start times. As shown, a large amount of capacity can start in less than one hour. Then, a similar amount can start in 2 to 7 hours, with large amounts also being able to start up in 10, 24 and 36 hours. A few generators have very large start times. This distribution appears pretty typical of what one would expect when examining market data. Many generators will report approximate start times and thus round to nearest 12 hours. There is also a steady climb in the cumulative result from 2 hours up to 24 hours, after which time most resources can start.

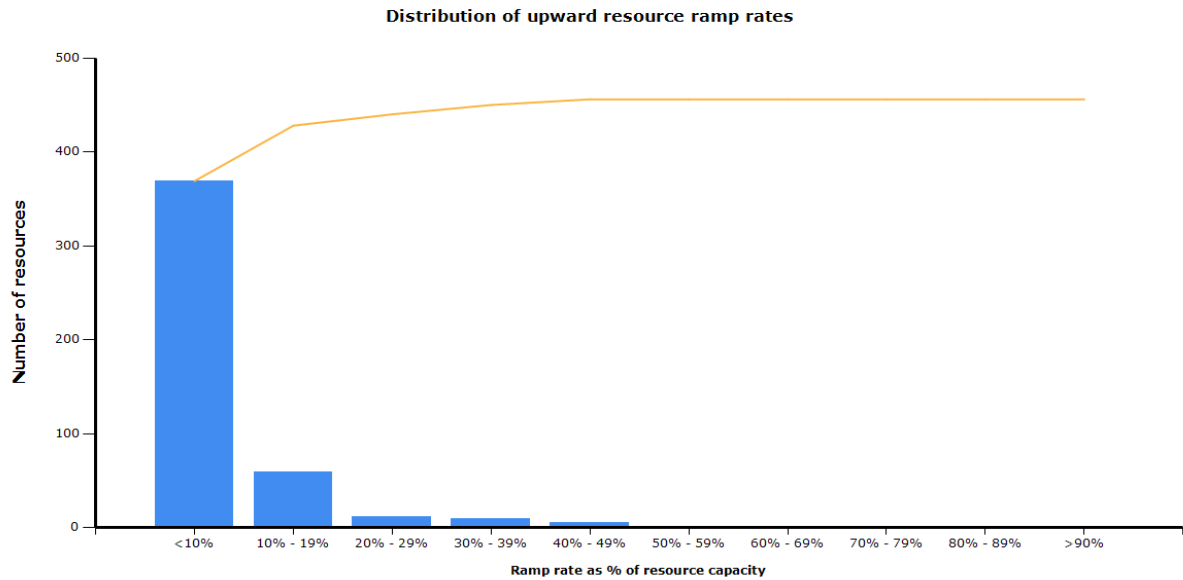


Figure 33: Number of units with ramp rates in each range, as % of installed capacity

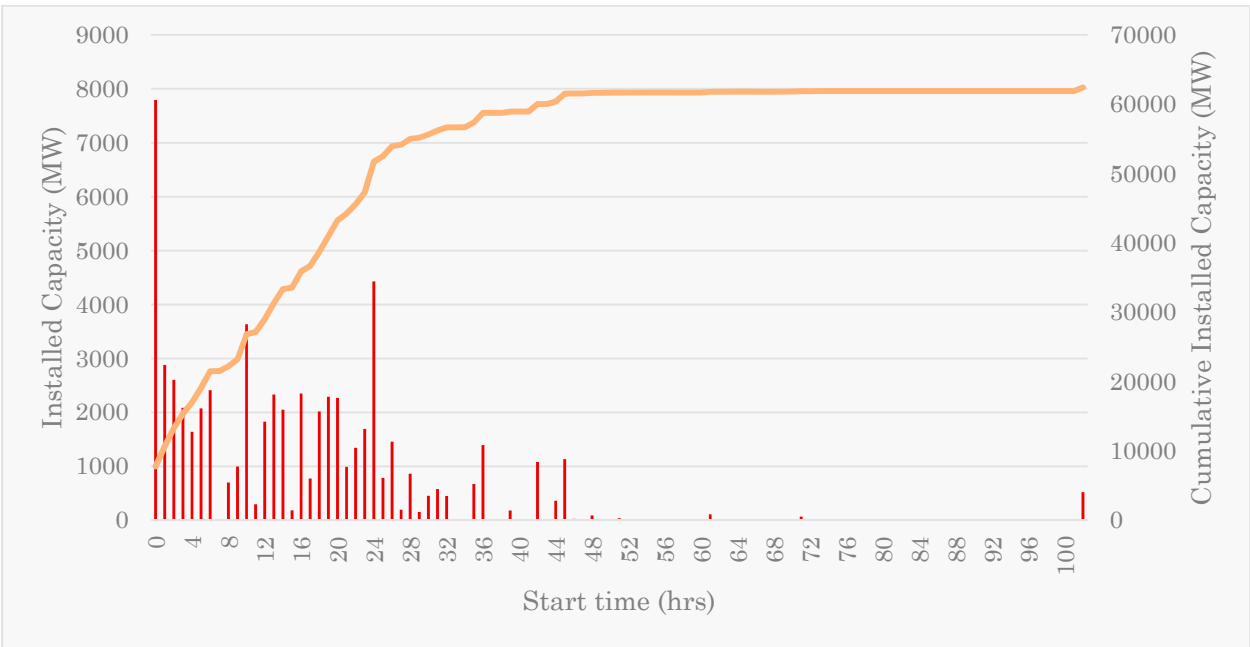


Figure 34: Installed capacity for different start times. Cumulative numbers are on the right hand axis

From the results in this section, one can determine that the SPP system has a relatively large amount of flexibility in terms of operating range; however ramping may still cause an issue, and ensuring commitment of longer start units to provide this flexibility may be important. These issues are examined in more detail for one year of data in the next section.

7.8 FLEXIBILITY ADEQUACY ASSESSMENT

The final level of detail included in EPRI tool focuses on the ability of the generation resources on the system to meet flexibility requirements, based on the actual dispatches of the fleet for the year of data provided. This examines flexibility available in each period of the year based on the dispatch and the flexibility characteristics, and compares to the required ramping capability. As this is based on the dispatch, more flexibility may actually be available that was not committed, so it is not necessarily examining the need for more flexibility resources to be built. In the long term, these analyses should help SPP determine if new operational or market processes are required to manage ramping.

Results here are based on hourly dispatches, as 5-minute conventional generator dispatches were not available in a manner that would have allowed these calculations to be done, due to data size limitations in the current version of the EPRI tool. Such calculations could be done in further work, which could also examine simulations of future years. The calculations on the hourly data that are done here start with analysis of the flexibility available, and then examine a number of system flexibility metrics that are being developed and tested in the associated EPRI research projects. As such, the results here can be used to benchmark the current SPP system against these metrics.

7.8.1 Available Flexibility

Available flexibility was calculated for each hour of the year, as shown in [Figure 35](#)~~Figure 22~~ for hourly ramps. This uses the dispatch of each generator, together with its assumed flexibility characteristics as described in previous section, to determine how much flexibility was available. If a generator was online, upwards flexibility is calculated as the amount of available headroom, subject to ramp limits. If offline, flexibility is assumed available if the unit can start in less than the time horizon examined (one hour in this case). There is also logic that ensures generators in the process of starting up or shutting down are accurately accounted for.

The figure shows that, across the year, a relatively consistent amount of hourly upwards ramping was provided, normally between 8,000 MW and 15,000 MW, with a few exceptions. Comparing this to the variability studied earlier, e.g. in Figure 1, it can be seen that the lowest amount of available ramping was always at least a number of multiples of even the largest ramps. This is expected, as the SPP system in 2014/2015 always did have sufficient ramping capability. Looking at this in more detail for one week in August, as in [Figure 36](#)~~Figure 23~~, it can be seen that the amount varied in a manner similar to load shape. The largest amount is available in the early hours of the morning, with less available in the afternoons and evenings. This would be expected as during peak load periods, the system would require less ramping capability to be held back to meet additional increases in load.

[Figure 37](#)~~Figure 24~~ shows the available flexibility from coal and gas, the two major sources, as well as total. In most hours, gas provided between 6,000 MW and 10,000 MW of flexibility, while coal provided between 1,500 MW and 6,000 MW. This is based on the dispatch of these resources, where coal as a baseloaded resource was more likely to be producing closer to maximum capacity, while gas may have headroom or be offline and with enough flexibility to start up in less than an hour. Again, this shows that there were not any hours when a very low amount of flexibility is available. There seems to be more than enough gas in all periods (always greater than 5,000 MW) to manage the very largest ramps in net load, shown earlier to be a little over 3,000 MW. The fact that the worst case flexibility available is very unlikely to happen at the largest requirement means that it was unlikely there would have been a flexibility-related ramping shortfall in SPP during the study period.

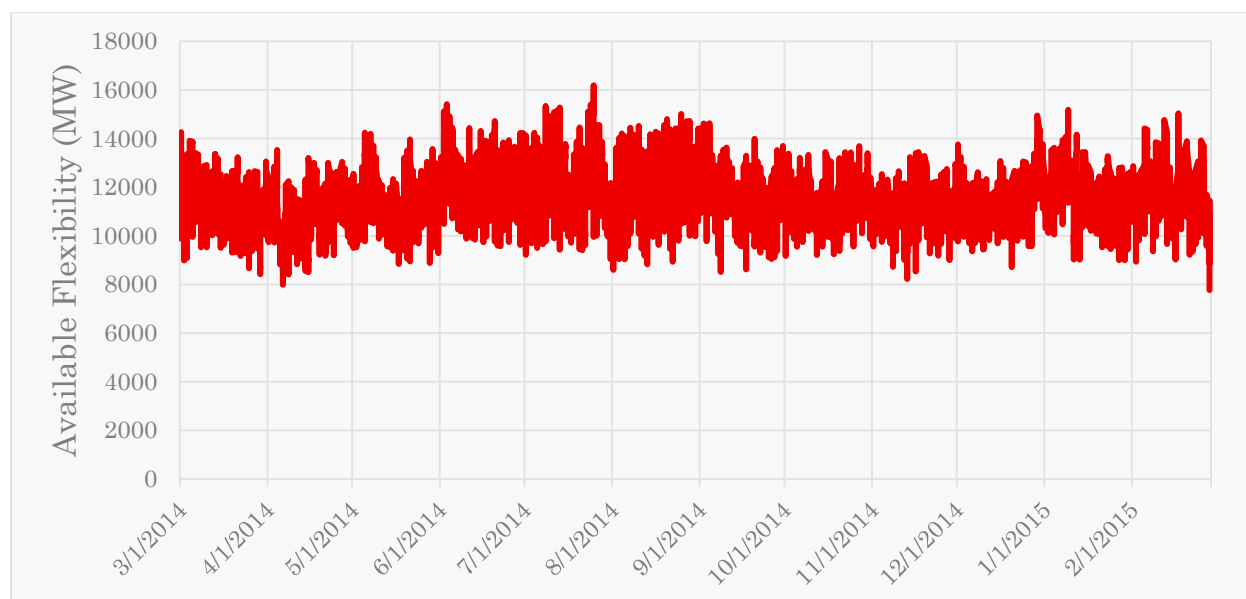


Figure 35: Available Flexibility for hourly up ramps based on March 2014-Feb 2015 dispatch

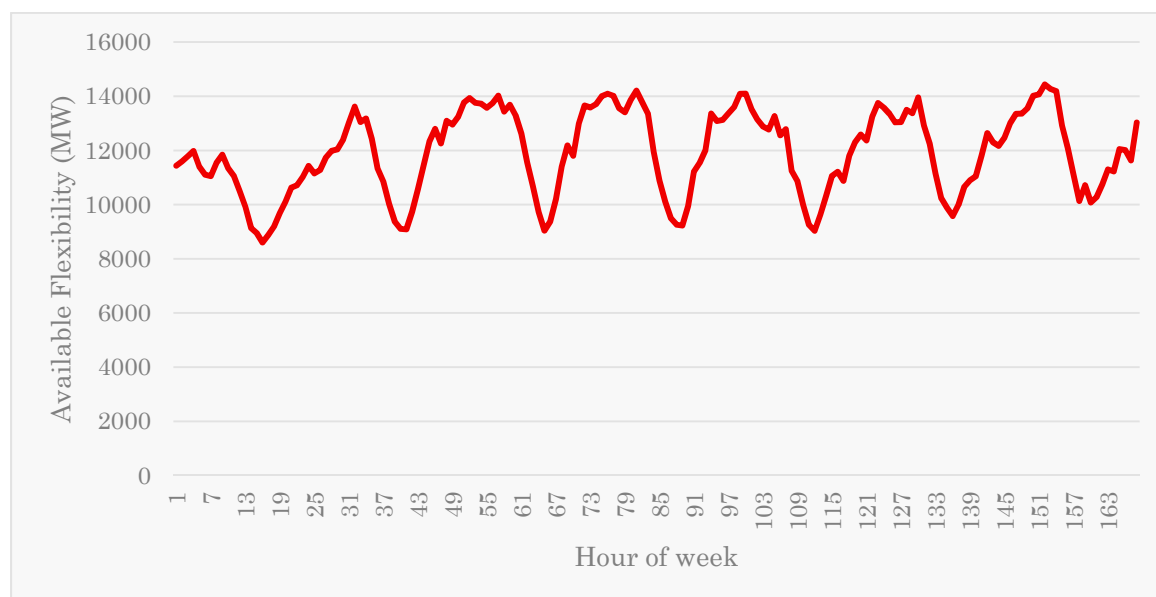


Figure 36: Available flexibility for first week in August

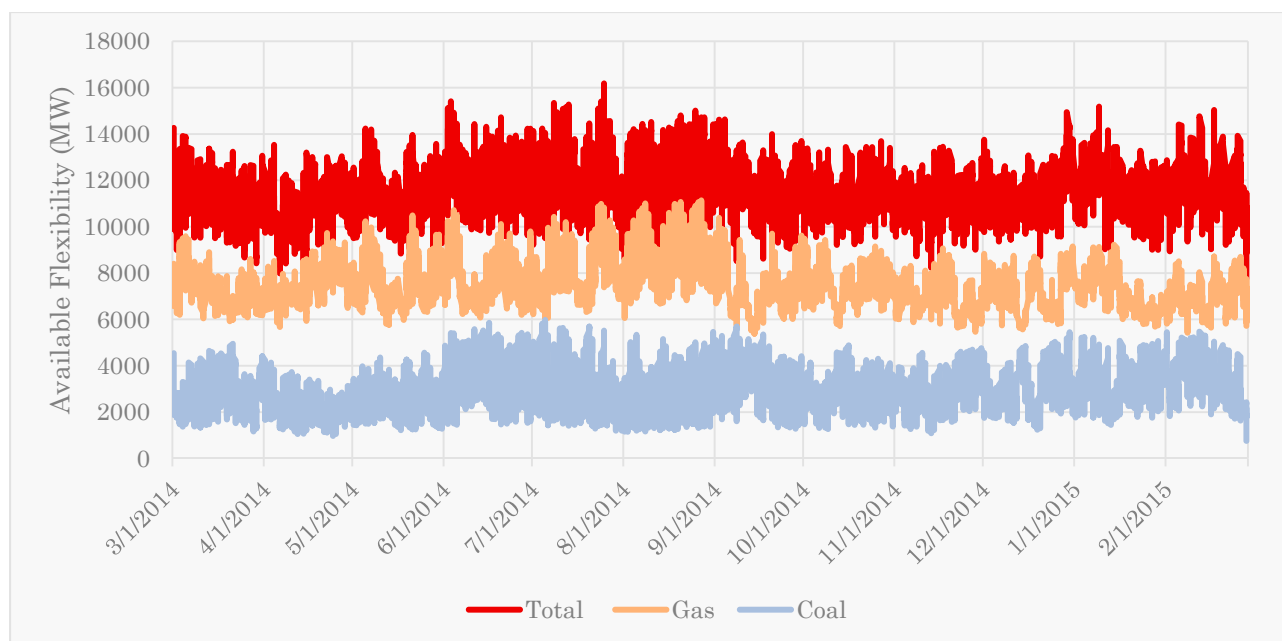


Figure 37: Available flexibility from gas, coal and total of all resources for hourly up ramping

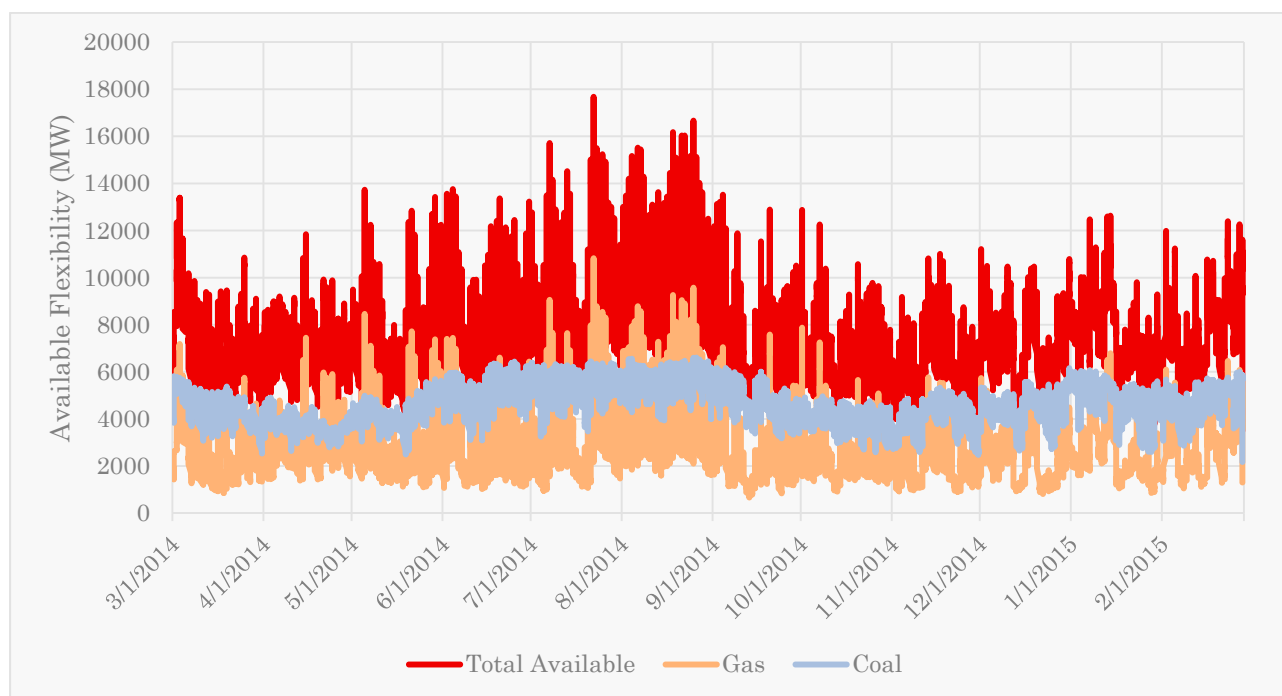


Figure 38: Available flexibility from gas, coal and total of all resources for hourly down ramping

Figure 38 **Figure 25** shows the same analysis, but this time for down ramping. Here, coal generation often has more flexibility available than gas resources, as it is more likely to be online. Gas generation varies between approximately 600 MW and 10,000 MW of downwards flexibility, while coal varies between 2,000 MW and 6,000 MW. Total downwards flexibility varies between 3,500 MW and over 17,500 MW. Once again, this is significantly more than the requirement; however it is now a little closer to the maximum requirement than in the case with up ramping showing that downwards flexibility may be more challenging. It should be kept in mind though that downwards

flexibility issues caused by wind can be managed by curtailing that wind, whereas upwards flexibility may be more challenging.

The next step in this analysis is to look at the flexibility available after the flexibility required was consumed- that is the net flexibility. We examine this in two main manners. The first is to compare what actually happened – that is how much flexibility was actually required in every hour in the dataset. The second method is to compare it to what could have happened. Results in the previous section showed how one could calculate balancing requirements that are based on wind output. By comparing the actual flexibility available to a requirement based on covering a certain percentile of all potential ramping that may be seen based on the data, you can calculate the net flexibility that an operator may expect to have if a large ramp happened.

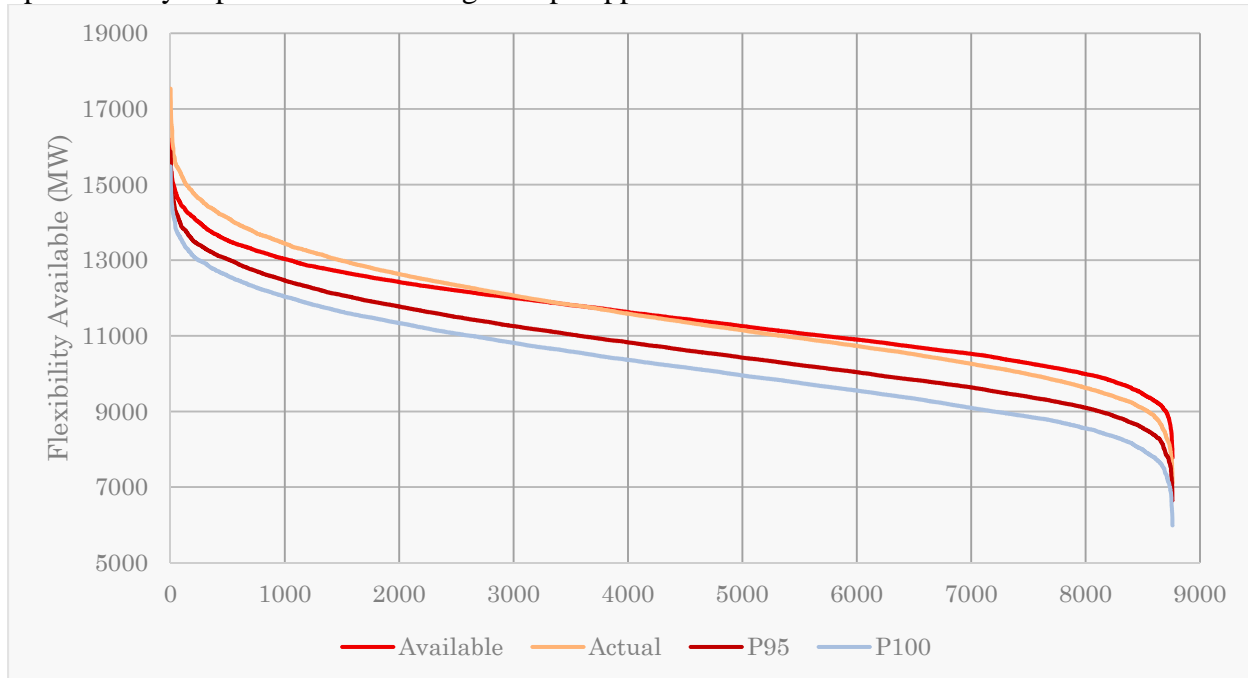


Figure 39: Ramp Duration Curve for Flexibility Available, and Net Flexibility Available, after either the actual ramps or 95th or 100th percentile ramps are accounted for, for hourly up ramping

This is shown in [Figure 39](#)~~Figure 26~~ for the hourly up ramps, as a duration curve sorted from largest to smallest. Actual ramps can be seen to sometimes increase the amount of net flexibility available, showing that sometimes the actual behavior meant that during periods when a lot of up flexibility was available, load ramped down. If instead one compares to 100th and 95th percentiles of available flexibility, then you can see that there is a reduction in available flexibility, particularly on the right hand side, which may be of most interest. The bottom 100 hours are zoomed in on in [Figure 40](#)~~Figure 27~~. As shown, whereas available flexibility is always greater than 7,500 MW, once the largest potential ramps are accounted for based on the particular net load at the time, the amount of additional ramping that could have been managed is reduced to 6,000 MW. This is still plenty of available flexibility, but shows that it starts to become a little close to being a concern when examined in this manner.

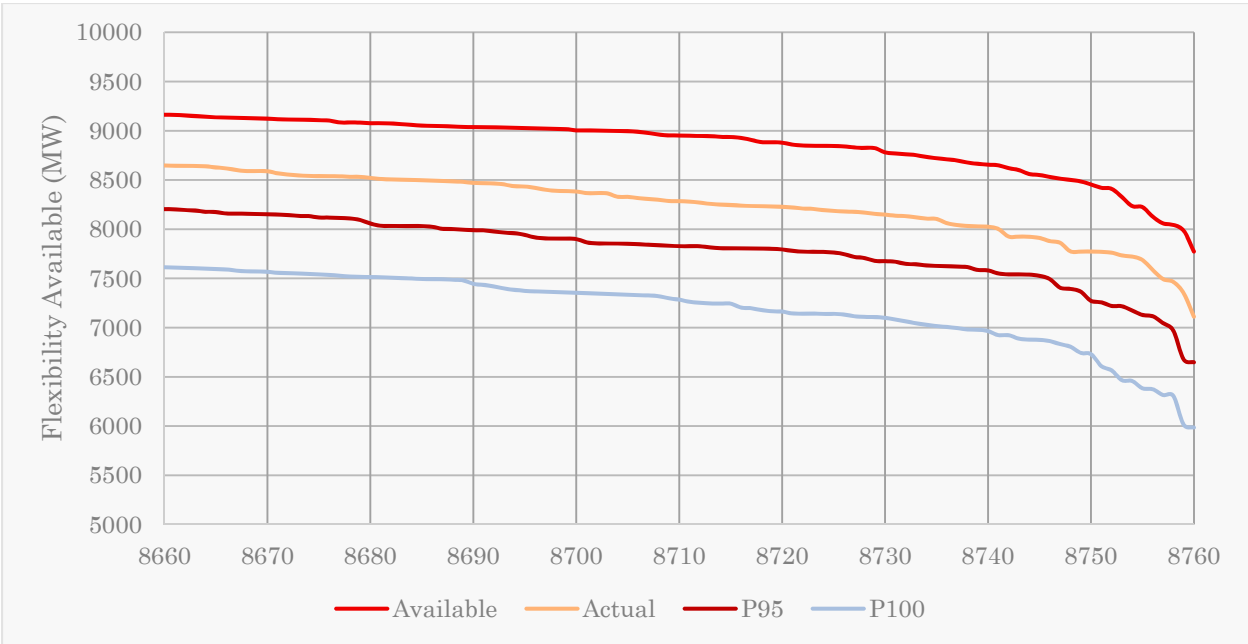


Figure 40: Bottom 100 hours of Ramp Duration Curve for Flexibility Available, and Net Flexibility Available, after either the actual ramps or 95th or 100th percentile ramps are accounted for, for hourly up ramping

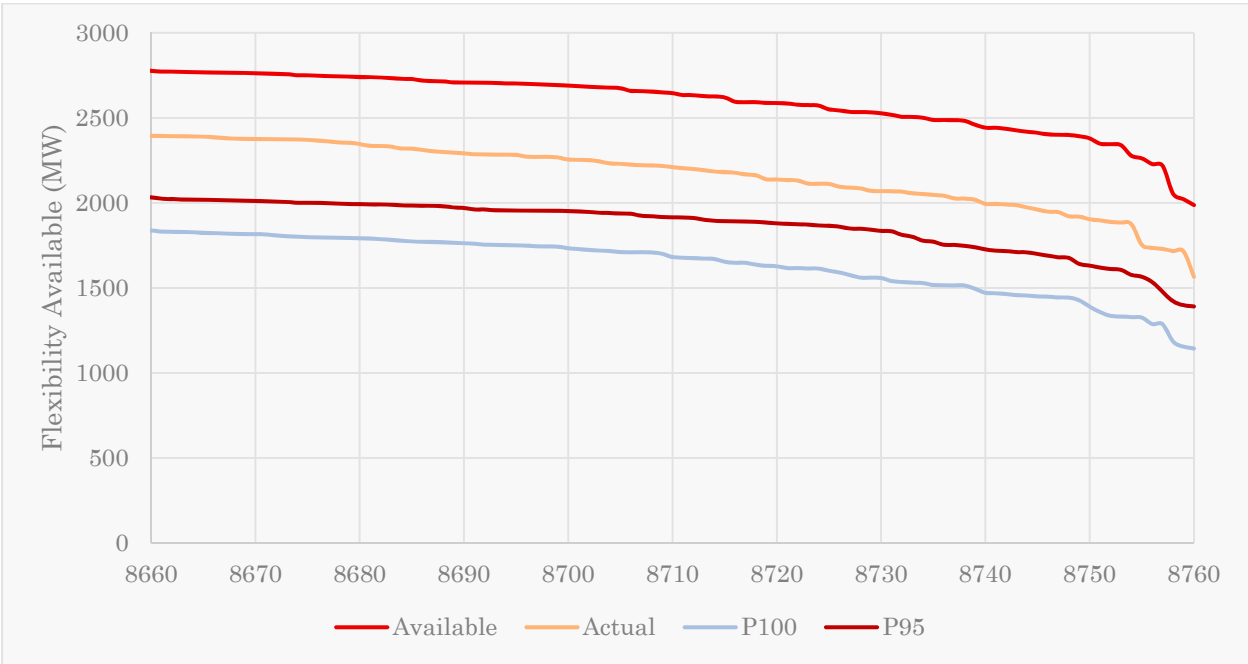


Figure 41: Bottom 100 hours of Ramp Duration Curve for Flexibility Available, and Net Flexibility Available, after either the actual ramps or 95th or 100th percentile ramps are accounted for, for hourly down ramping

The same calculation is made for the down ramping direction in [Figure 41](#)[Figure 28](#). As before, the system is a little closer, though still not particularly close, to running out of down ramping. When the largest down ramps are considered, there is a reduction in the worst case to a little over 1,000 MW of spare additional flexibility that could have been consumed before running out. When the fact that this is a worst-case analysis is considered, this shows that hourly down ramping isn't a particular concern, but could be tracked in the future to determine if this is getting tighter.

7.8.2 Flexibility Adequacy Metrics

The final set of results analyzed is based on a number of EPRI-developed flexibility metrics.¹⁸ The first of these is Periods of Flexibility Deficit (PFD). Here, for each hour examined, the analysis just described for net available flexibility is calculated across each time horizon from one hour to twelve hours. Then, the number of time periods when the net flexibility is less than zero are counted. It should be noted that the comparison is between the actual flexibility available in the dispatch and the largest potential ramp under the net load condition in that hour, rather than the actual ramp. It is thus conservative approach, and is more likely to reflect a situation where an operator is concerned that, if a large ramp happens they would run out of ramping, than an actual shortage. In reality, an operator would likely try to alter the commitment of generation on the system to improve the situation, such that PFD is a metric that tracks how often this issue occurs rather than being reflective of actual shortages.

As can be seen in ~~Figure 42~~~~Figure 29~~, there are no periods in time horizons less than 4 hours when flexibility may be short, even when comparing the lowest amount of flexibility available with the highest amount that could possibly be required under the net load conditions present. However, at longer time horizons, when comparing the amount available to very large ramps in each hour that are reflective of the worst net load ramps for the net load level in that hour, there may be some situations when the system would be seen to have a chance of not having sufficient ramping. In reality, this was likely managed by the fact that, as the time horizon got shorter the issue was resolved, with wind forecasts becoming more accurate, and the possibility of altering imports/exports. If there was a shortage in shorter time horizons, then operators may have needed to take action. In future years, this may be something operators could track, such that they know that, for example, 8 hours out there is a chance of needing to commit more generation. However, they wouldn't have to do this until maybe 4 hours out. It wouldn't be a reliability problem as much as something to be tracked. It can be seen that down ramping has a significantly higher number of challenging periods than up ramping. As mentioned earlier, this can be managed by curtailing wind, or potentially increased exports, so the concerns that may be associated with this may not be particularly significant. The result shows that, for example, in just over 100 hours of the year, there are situations where, if a large 10 hour down ramp were to occur, the current commitment would need to be altered to manage the ramps.

The Expected Unserved Ramping is a second metric calculated that, for each period reported in PFD, counts up the shortfall in ramping. This is shown for the system studied in ~~Figure 43~~~~Figure 30~~. As shown there, the ramping deficit that would potentially require a change in commitment or dispatch to manage is 80,000 MWs. While that number sounds large, when compared with ramping mileage calculated earlier, it is less than 1.5% of total ramps; note again that this is comparing the actual dispatch against worst case, and the fact that such a small number is seen shows that even these down ramps are not particularly challenging.

¹⁸ For more on these metrics, see the EPRI white paper, "Metrics for Quantifying Flexibility in Power System Planning", available at www.epri.com

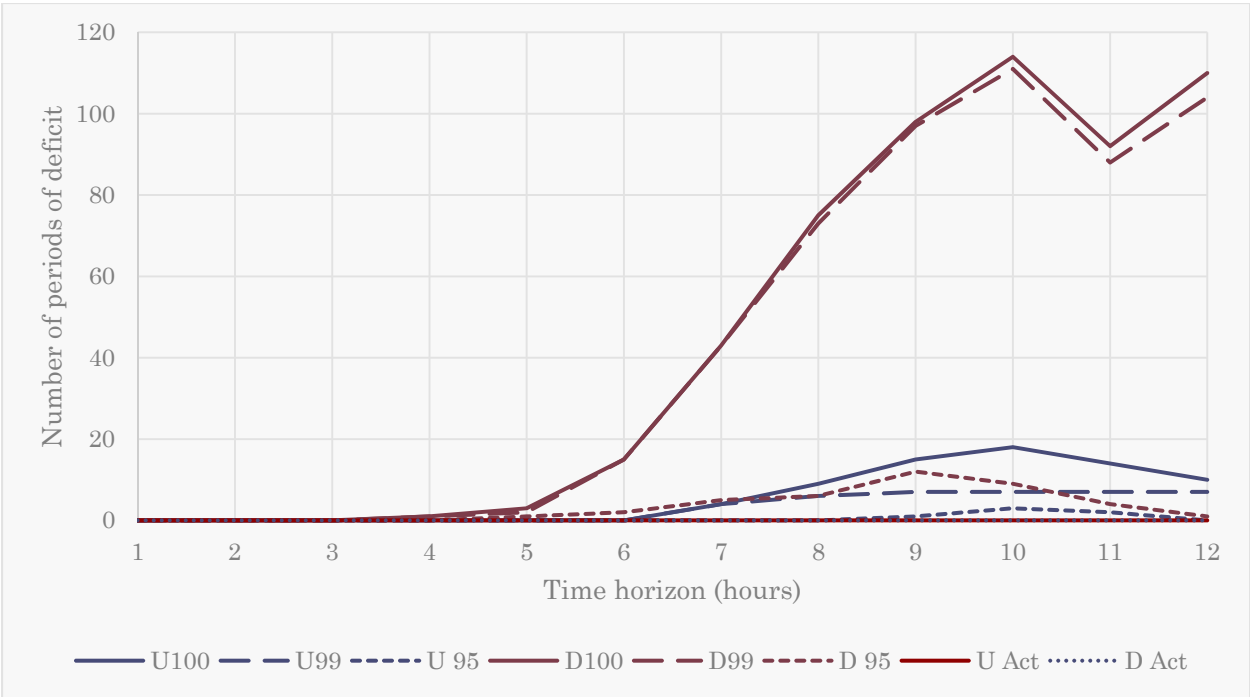


Figure 42: Periods of Flexibility Deficit for time horizons of 1 to 12 hours for flexibility requirements based on different net load ramping percentiles.

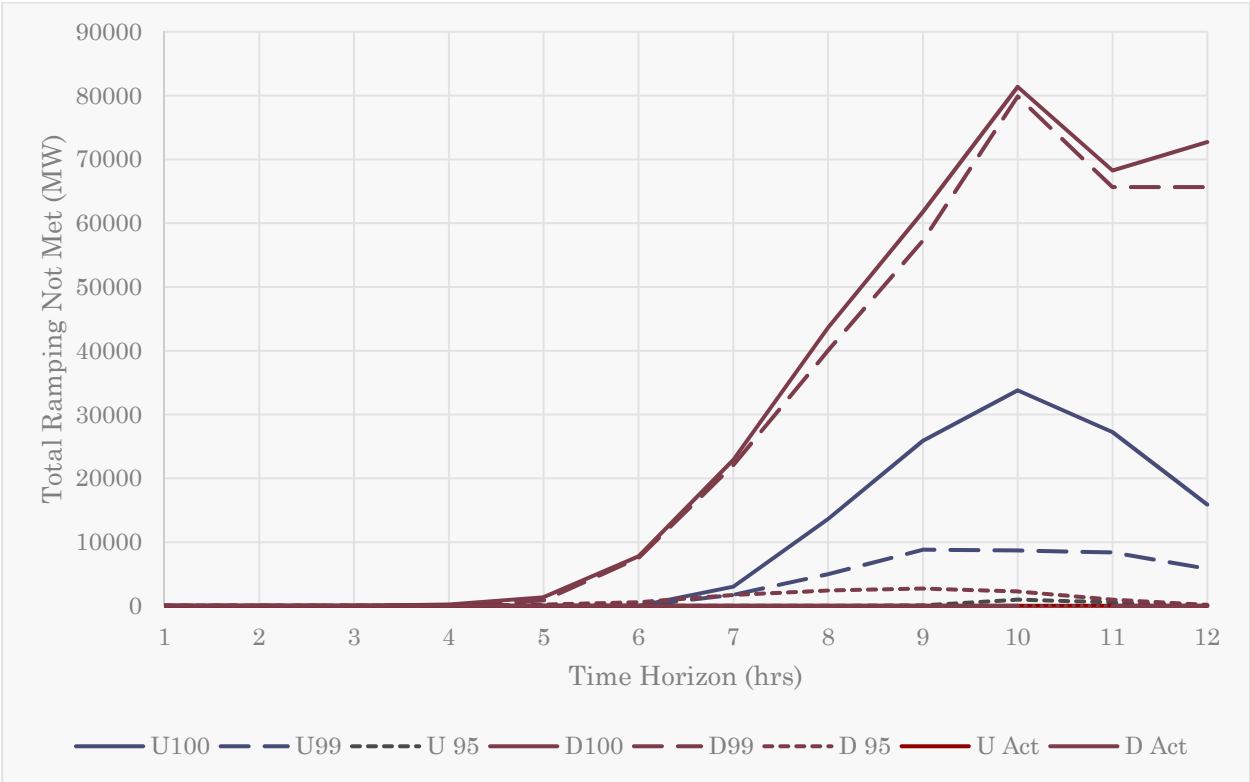


Figure 43: Expected Unserved Ramping for time horizons of 1 to 12 hours for flexibility requirements based on different net load ramping percentiles

The very last metric calculated is a probabilistic metrics known as Insufficient Ramp Resource Expectation. Here, the two time series as described earlier, one of flexibility available and one of

flexibility required, are used in a probabilistic calculation that convolutes the two time series. This then results in a calculation that reflects that likelihood of insufficient ramping being present. This is reported for the dataset studied in [Figure 44](#)~~Figure 31~~, where the up ramps are on the left hand axis and down ramps are right hand axis. Again, at shorter time periods the system was not likely to run short of ramping. Even at longer time horizons, the likelihood is that the ramps will be too high for the dispatch less than once every two years (and these can still be managed by altering commitment within the shorter time horizons). However, down ramping is again seen to be potentially more significant a challenge. From two hour and above time horizons, there is a likelihood that the ramps may cause a problem, up to 400 times per year. This is somewhat reflected in reality, where wind curtailment does occur.

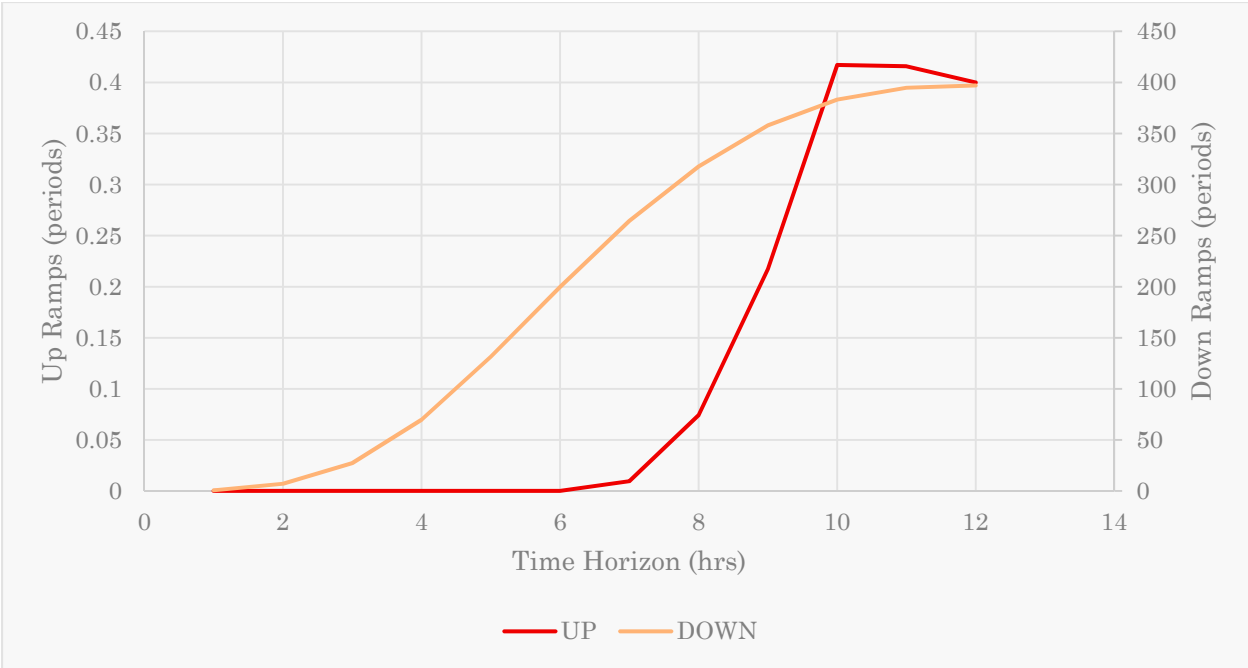


Figure 44: Insufficient Ramp Resource Expectation for SPP for year studied

APPENDICES

1. Open Electrical: AC Power Transmission³

Introduction

Consider the following model depicting the transfer of AC power between two buses across a line, Figure 1.

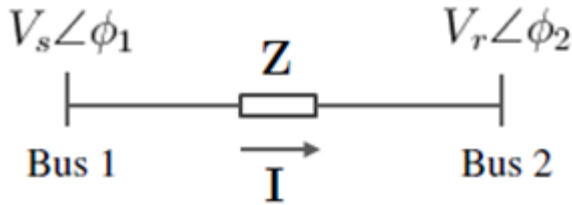


Figure 1. Simple AC power transmission model

Where $V_s = V_s e^{-j\phi_1}$ is the voltage and phase angle at the sending end

$V_r = V_r e^{-j\phi_2}$ is the voltage and phase angle at the receiving end

Z is the [complex impedance](#) of the line.

$I = \frac{V_s - V_r}{Z}$ is the current phasor

The [complex AC power](#) transmitted to the receiving end bus can be calculated as follows:

$$S = V_r I^*$$

At this stage, the impedance is purposely undefined and in the following sections, two different line impedance models will be introduced to illustrate the following fundamental features of AC power transmission:

- The power-angle relationship
- PV curves and steady-state voltage stability

Power-Angle Relationship

In its simplest form, we neglect the line resistance and capacitance and represent the line as purely inductive, i.e. $Z = j\omega L = jX$. The power transfer across the line is therefore:

$$\begin{aligned}
 S &= V_r \left[\frac{V_s - V_r}{jX} \right]^* \\
 &= \frac{V_r e^{-j\phi_2} (V_s e^{j\phi_1} - V_r e^{j\phi_2})}{-jX} \\
 &= j \frac{V_s V_r}{X} e^{-j(\phi_2 - \phi_1)} - j \frac{V_r^2}{X} \\
 &= \frac{V_s V_r}{X} \sin \delta + j \frac{V_r}{X} (V_s \cos \delta - V_r)
 \end{aligned}$$

Where $\delta = \phi_2 - \phi_1$ is called the power angle, which is the phase difference between the voltages on bus 1 and bus 2.

We can see that active and reactive power transfer can be characterized as follows:

$$\begin{aligned}
 P &= \frac{V_s V_r}{X} \sin \delta \\
 Q &= \frac{V_r}{X} (V_s \cos \delta - V_r)
 \end{aligned}$$

Plotting the active power transfer for various values of δ , we get, Figure 2:

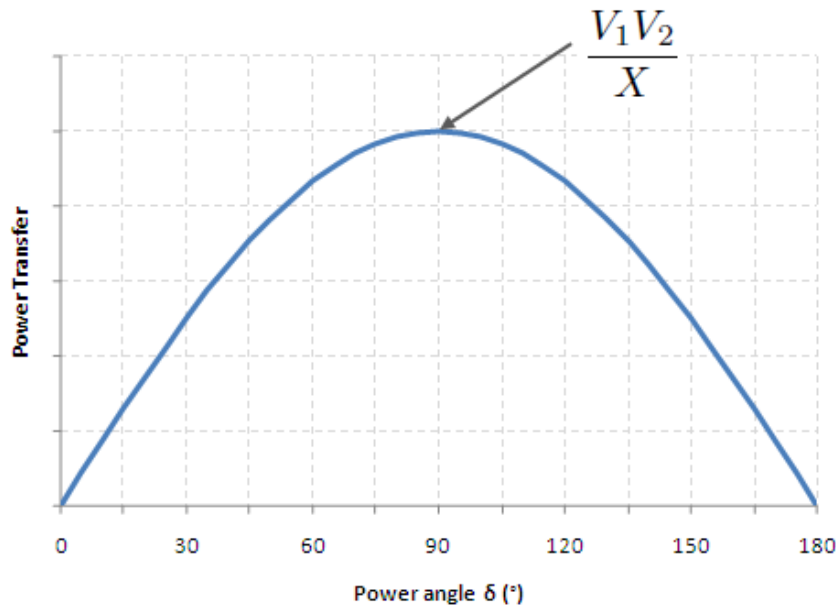


Figure 2. Active power transfer characteristic for a lossless line

The figure above is often used to articulate the **Power-Angle Relationship**. We can see that in this simple model, power will only flow when there is a phase difference between the voltages at the sending and receiving ends. Moreover, there is a theoretical limit to how much power can be transmitted through a line (shown here when the phase difference is 90°). This limit will be a

recurring theme in these line models, i.e. lines have natural capacity limits on how much power they can transmit.

Steady-State Voltage Stability Limits

The lossless (L) line model can be made more realistic by adding a resistive component, i.e.

$Z = R + jX = Ze^{j\theta}$. The power transfer across the line is therefore:

$$\begin{aligned} S &= V_r \left[\frac{V_s - V_r}{R + jX} \right]^* \\ &= \frac{V_r e^{-j\phi_2} (V_s e^{j\phi_1} - V_r e^{j\phi_2})}{Ze^{-j\theta}} \\ &= \frac{V_s V_r}{Z} e^{-j(\phi_2 - \phi_1 - \theta)} - \frac{V_r^2}{Z} e^{j\theta} \end{aligned}$$

From the above equation, the active and reactive power transfer can be shown to be:

$$\begin{aligned} P &= \frac{V_s V_r}{Z} \cos(\delta - \theta) - \frac{V_r^2}{Z} \cos \theta \\ Q &= -\frac{V_s V_r}{Z} \sin(\delta - \theta) - \frac{V_r^2}{Z} \sin \theta \end{aligned}$$

From the active power equation, we can solve for the voltage at bus 2 using the quadratic equation, i.e.:

$$V_r = \frac{-b \pm \sqrt{b^2 - 4ac}}{2a},$$

Where $a = \frac{\cos \theta}{Z}$

$$\begin{aligned} b &= \frac{V_s}{Z} \cos(\delta - \theta) \\ c &= -P \end{aligned}$$

By keeping the voltage at bus 1, power angle and line impedance constant, we can plot the effect of increasing the active power on the voltage at bus 2 on a PV curve, Figure 3.

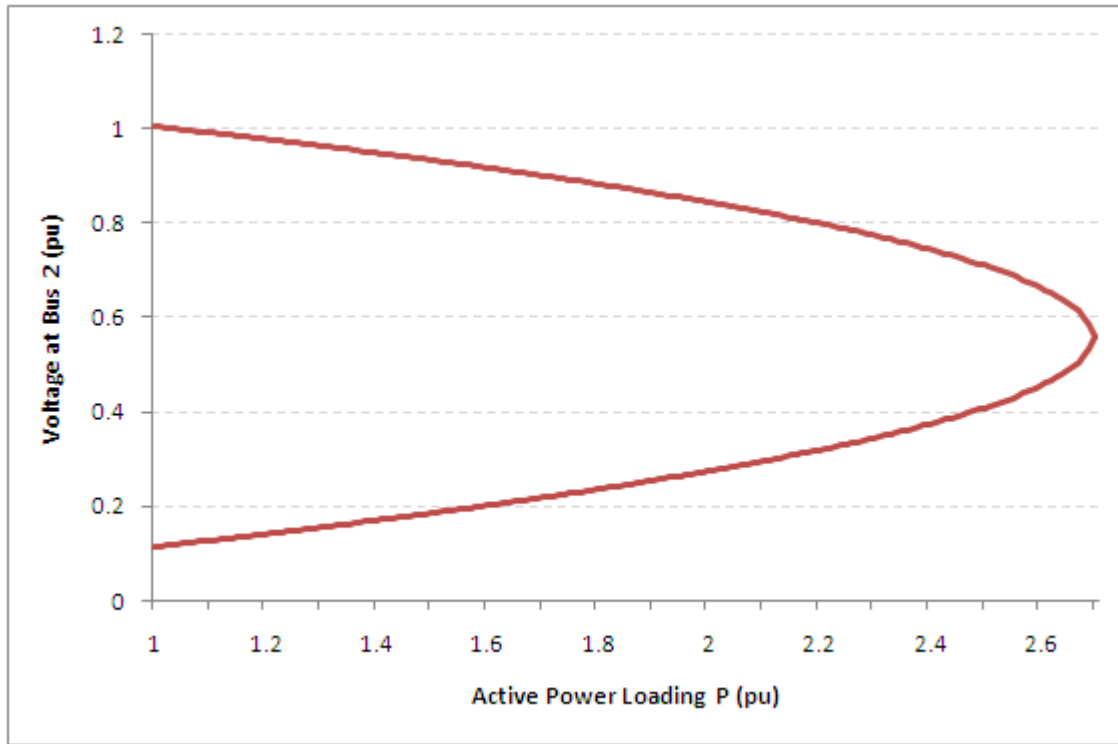


Figure 3. PV Curve at Bus 2 for a RL line

The PV curve shows that the voltage at bus 2 falls as the active power loading increases. The voltage falls until it hits a critical point (around 2.7pu loading) where the quadratic equation is no longer solvable. This is referred to as the "nose point" or "point of voltage collapse", and is the theoretical steady-state stability limit of the line.

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