Wind Integration Study Team

Dynamic Transfer Capability Task Force

Phase 1 Report

March 16, 2011

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Executive Summary

The Electric Power industry is in a time of transition as it moves from an operating model where power transfers between Balancing Authorities ("BAs") were generally fixed for the hour to one where there could be significantly increased intra-hour power flow variations. Drivers for this new operating model include installation of renewable generation, in the Northwest this is primarily wind generation, and demand from transmission customers to have increased intra-hour scheduling flexibility.

Dynamic Transfers, namely schedules that can change within an hour, have been reliably used for decades, albeit on a relatively low scale. A notable example in the Northwest is some of the Mid-C generation that is be used for load following/AGC response in remote Balancing Authority Areas ("BAAs"). With the move to increasing levels of wind penetration and customer requests for new dynamic transfer arrangements, many transmission planners and operators have become concerned about the need to limit Dynamic Transfer Capability ("DTC") across designated paths and flowgates in order to safeguard system reliability.

Powertech Labs, BPA and CAISO have published studies on DTC limits. In October 2010 the Joint Initiative's Wind Integration Study Team ("WIST") assembled a Task Force of technical staff, primarily from Northwest and California transmission providers and sub-regional entities, to further explore the issue of DTC Limits. The fundamental DTC limit question is: How much can the power flowing across the system vary and how frequently can it vary, while still ensuring that all of the intervening operating conditions are reliable given that system operators can only readjust the power system a few times an hour?[1]

Among Task Force members there were a range of perspectives as to whether a DTC limit lower than a path's System Operating Limit ("SOL")[2] would be needed to ensure system reliability, and in part these perspectives seemed correlated with the availability of automated RAS and voltage control on their respective system. However, all members agreed that the issue of DTC limits was significant and merited further investigation.

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[1] There are several proposals being considered to reduce the standard scheduling time period between operator initiated schedule adjustments, including 30 minutes as planned for implementation in the Northwest in July 2011 and 15 minutes as recently proposed by FERC. It is helpful to remember that reducing the scheduling time period between operator adjustments does not make the underlying power flow variations go away, but rather the way the system is operated would be changed and there would be an acceptance of some higher costs (e.g. increased maintenance of voltage switching equipment);

[2] Most DTC TF members view DTC as a component of the System Operating Limit ("SOL") such that the total of all schedules, including Dynamic Schedules, could never be scheduled above the SOL.

The purpose of the Task Force is to facilitate increases in Dynamic Transfers without compromising system reliability. Its work was organized into three phases: Phase 1 defined the issues and framed the problem; Phase 2 will develop a proposed DTC limit methodology that could be applied by transmission providers to their system; Phase 3 will refine the DTC limit methodology in light of the experience gained by Transmission Providers as they apply the DTC methodology to their systems and will identify some possible system improvements to increase DTC Limits. While the PNW transmission system is the focus of these three phases, the conclusions in this report have been presented to WECC, and it is anticipated that the work of this Task Force will continue to provide information for any subsequent investigations by the larger WECC membership.

While providing greater operational flexibility, increases in Dynamic Transfer Capability will likely require system enhancements to improve the ability of the transmission system to respond automatically to variations in intra-hour transfers. Improvements may take the form of enhanced state-awareness, automation of controls, additional reactive equipment, increased maintenance costs for new and some existing equipment and added staff at the Balancing Authority/Transmission Operator Control Centers and/or WECC Reliability Centers.

In theory, all flowgates in a path between a dynamic source and a dynamic sink, including those in parallel, could have DTC limits established. A common methodology should enable adjacent BAs to determine DTC limits for common flowgates in a consistent manner using standard terminology. Specific differences in systems however may dictate that for some flowgates that are interties between BAAs there could be a DTC limit for each side of the flowgate. Consequently, the dynamic transfer between the remote source and sink would be limited by the most restrictive DTC limit in the path, just as is the normal practice for System Operating Limits. These differences however point to the need for each Balancing Authority to develop their own DTC limits based on their expert knowledge of their system.

The conclusions of this Phase 1 report are:

1. The development of variable wind based generation has resulted in an increasing number of requests for new dynamic transfers across NW transmission. How these new uses could affect the transmission system and the determination of dynamic transfer limits merits investigation.

2. Path Operating Agents of a common path could apply the same DTC limit methodology and determine different DTC limits because of:

    a. Different perspectives and characteristics on either side of the path;
    b. Differences in their systems (e.g. Automated or Manual RAS, automated voltage control);
    c. Different determinations of what level and frequency of power flow variation would be acceptable on their system;
    d. Different tolerances for increased wear and tear on system equipment

This is analogous to what currently happens in determining SOLs independently prior to the operating hour. Ultimately, the most restrictive limit determined by a Path Operating Agent will govern the path's actual operation in real-time.

3. The CAISO, BPA and Powertech Lab DTC studies all showed voltage change at critical buses to be a key component in determining increased DTC limits. Some Task Force members also saw voltage change as important because the SOL studies are based on a recommended voltage profile and the manual adjustments necessary to restore this voltage profile following large deviations take time to implement.

4. Continued reliance on manual actions for RAS arming and voltage control may hinder the expanded use of Dynamic Transfers.

5. In the industry, there are differences over what is meant by Dynamic Transfer Capability Limits as some focus on the total quantity of schedules that could change within an hour and others focus on the limits on variability in power flow during the hour. In Phase 2 it is hoped that the DTC TF will define a new term to reflect the limit on power flow variations across a flowgate in between scheduling periods.

1. Introduction

Members of the Northwest Power Pool ("NWPP") have witnessed a dramatic increase in wind generation in recent years. At the end of 2010, there was 7,800 MW of installed wind generation in the NWPP footprint and this is expected to increase to 13,500 MW by July 2012. Wind generation is variable and as a result it contributes to increasingly large and frequent variations in power flow across the transmission grid. Transmission planners and operators are tasked with reliably managing the power system and they are concerned these new intra-hour power flow variations, layered on top of historic dynamic transfer arrangements and potentially new requests for dynamic transfers, will pose a threat to system reliability.

Power flows change across the power system as system conditions change, such as customer demand or generation dispatch, however, historically these changes have been predictable and within a range that has been found acceptable for system operation. The vast majority of power flow variations were accommodated within a scheduled ramp period at the top of every hour. Aligned with this practice, most energy transactions between BAs are scheduled as "Static" transfers that are fixed for the hour. Faced with increasing amounts of intermittent generation, many Balancing Authorities and their customers want the right to dynamically transfer power with counterparties. "Dynamic" Transfers are not fixed for the hour; in fact, they specifically enable the power transfer to vary inside the hour as a function of the sending or receiving counterparties' requirements.

Should a limit be imposed on the total amount of Dynamic Transfers that could flow across a defined path? Could a Balancing Authority grant increased intra-hour scheduling flexibility without compromising system reliability? These were two of the questions that surfaced after BPA published its Dynamic Transfer Limit Study in February 2010. Some argued that, provided the path was always operated below its System Operating Limit, there should be no limits imposed on Dynamic Transfer Capability ("DTC"), especially as the variations contemplated with Dynamic Transfers are measured in terms of minutes, rather than fractions of a second as in the case of major system disturbances. Others pointed out that some paths require very careful voltage management and arming of Remedial Action Schemes at defined flow levels to ensure system reliability and that this could not be guaranteed if a wide range of unpredictable operating points were frequent and possible at any point in an hour.

As there were no clear cut answers to these questions, in October 2010 the Joint Initiative Wind Integration Study Team formed a Task Force to investigate Dynamic Transfer Capability Limits. Its purpose was to develop a technical consensus on how to determine Dynamic Transfer Capability limits and identify options for enhancing Dynamic Transfer Capability without compromising system reliability. Its members were primarily technical staff employed by electric entities/agencies, utilities or sub-regional planning groups from the Pacific Northwest, California and British Columbia.

To date the work process involved reviewing previous Dynamic Transfer studies, performing statistical analysis of power variations, working through case studies, running some sensitivity studies and identifying further studies to be run. The ultimate goal is to develop a DTC Limit methodology that could be applied by individual Balancing Authorities to determine the need to apply limits on Dynamic Transfers for particular paths that they are responsible for. The Task Force has begun the work towards developing a DTC Limit Methodology, however, more work needs to be done. Figure 1 shows the 3 phase process that is envisaged in order for DTC limits to be calculated on a wide-spread basis via a common methodology.

DTC TASK FORCE PURPOSE: To facilitate increased dynamic transfers without compromising system reliability.

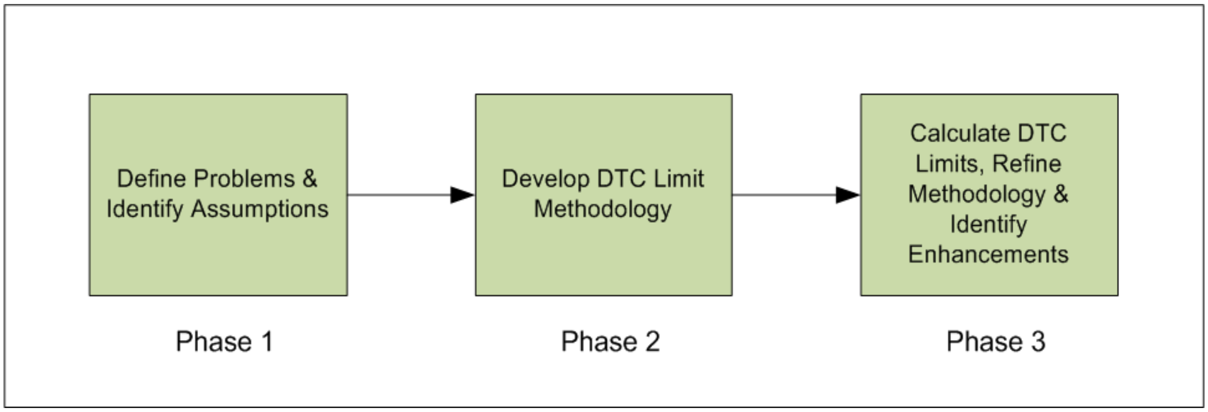

Figure 1: DTC Task Force Purpose & Work Phases

This Phase 1 report begins by documenting the nature of the emerging dynamic transfer problem. It briefly discusses the DTC studies done by BPA, CAISO and BC Hydro's Powertech Labs. Next it describes some of the initial steps taken towards a broad DTC Limit Methodology. Summaries are provided for issues and threats identified during Task Force discussions as well as some of the options that could enhance DTC. The report wraps up with a discussion of next steps and the Phase 1 conclusions.

2. Nature of the Emerging Dynamic Transfer Problem

What has changed?

Under normal conditions, historic operation of the WECC system has been mostly static, with little variation in power flow or bus voltage. Within the hour, variations attributable to load are typically slow moving and these variations routinely follow a predictable daily load curve. While large changes may occur during ramp periods or contingencies, ramps are predictable, controllable and known in advance, and contingencies are infrequent with their effects already taken into account when computing the SOLs. In consequence, the grid and its controls were designed for system conditions that were largely static with capability to withstand the credible and most probable disturbances.

How much intra-hour schedule variation is too much? An Analogy:

Power System Operators have some responsibilities that are akin to those of an airline pilot and an air traffic controller. Consequently, consider some airline analogies to understand some concerns Power System Operators might have about Dynamic Transfers.

Airplanes are designed to take-off and land; hence the magnitude of acceptable change of elevation, depending on the aircraft, can be up to 35,000 feet. It is accepted that there will be a large elevation change once at the beginning of the flight and once at the end of the flight….or in the middle of the flight if there is an on-board emergency.

Assume now that there could be a net societal benefit if the airplane adjusted its cruising altitude continuously during a flight. Should a limit be imposed on how much elevation change would be permitted and how frequently these changes could occur?

The decision to impose a limit would depend on an assessment of some critical factors, including:

1. the airspace
2. the airplane
3. the customers involved

The Airspace can accommodate airplanes changing elevation, however, the changes need to be planned and controlled. The objective when permitting elevation change is:

1. Ensure the safety of all aircraft and their passengers;

The Airplane is capable of making large elevation changes provided the right conditions have been put in place, however, when considering repeated or continuous elevation changes, other considerations would need to be evaluated, including:

1. Burden placed on the flight crew;
2. Maintenance implications for the aircraft;
3. Impact on the aircraft's lifespan (e.g. metal fatigue due to pressure cycling).

The Customers involved accept the elevation changes associated with take-off and landings, on-board emergencies and even adjustments to avoid turbulence, however, repeated and large elevation changes could negatively impact the customer's experience due to:

1. Disruption of in-flight service;
2. Increased susceptibility to air sickness;
3. Increased ear pain from repeated air-pressure changes.

Whether a limit is imposed on the magnitude, frequency or rate of elevation change would depend on the overall assessed impact: to a large extent it would be tied to the amount of incremental risk the airline and the industry are comfortable with and the impacts they believe customers would be willing to accommodate. Lastly, the limit would also depend largely on the level of automated controls the airplane is equipped with.

Regulation has historically been held in a very few generators out of all those available. For example, although BPA's balancing area includes 31 federal dams, Grand Coulee and Chief Joseph are used for over 70% of the regulation for all of the BPA balancing area. This regulation has been primarily for following load movement throughout the hour. Yet even with this concentrated service, the variability remains very low. (It should also be noted, as relevant to our discussion of dynamic transfer, that transmission in and around these two projects has been designed to accommodate these uses. This is not true for all resources.)

So what is changing? Wind integration brings new challenges by introducing an energy source that is neither fixed for the hour nor operated in a manner that provides effective load following. As illustrated in Figure 2, the typical variation for wind generation is much higher than the variation associated with load changes.

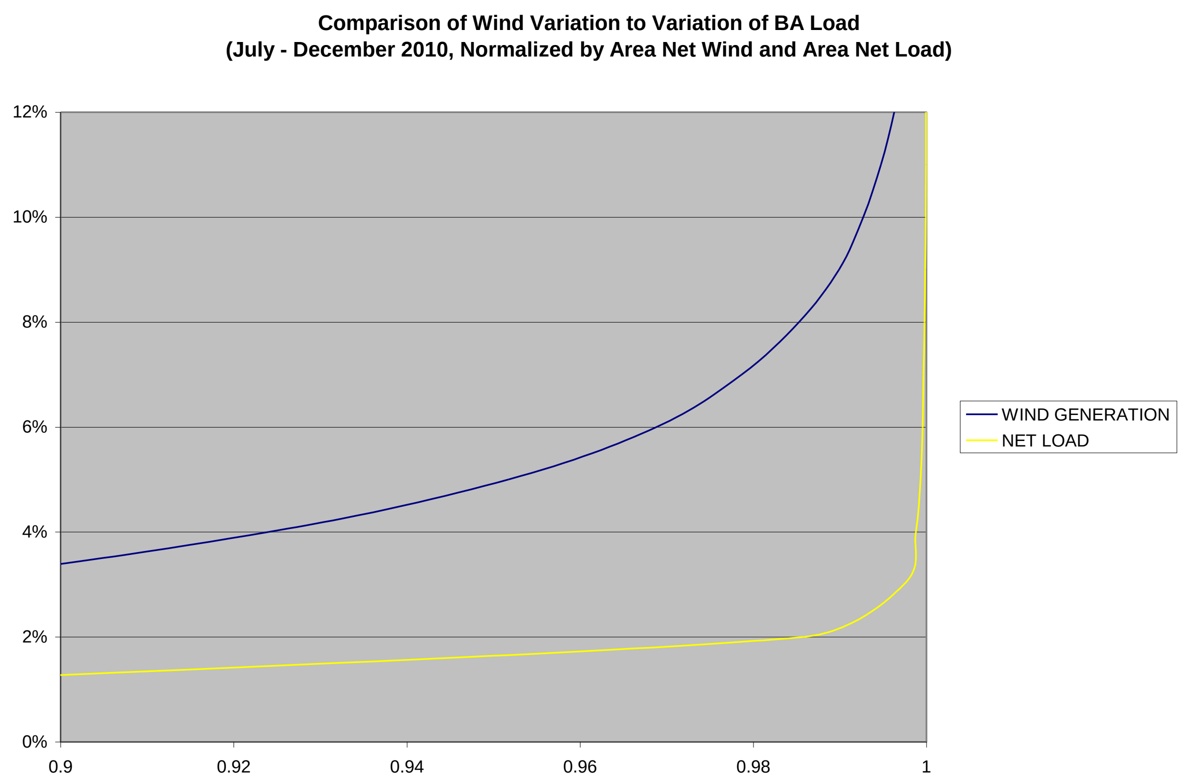

Figure 2: Variation of Wind and Load in the BPA BAA

Types of "Non-Static" Transfers

Of the thousands of transmission schedules implemented every day, most are standard hourly schedules, aka "Static Schedules", that are fixed for the hour and ramped in and out only during the set 20 minute period at the top of the hour. There are relatively few schedules that change outside of the ramp periods because there are very few dynamic transfer agreements or dynamic signals currently implemented. In general, "non-static" transactions fall into four major categories described below, and it is generally accepted that the historic levels of "non-static" or dynamic transfers have been managed by the system operators without undue concern.

1. **<u>On Demand Obligations</u>** – These are schedules that can be manually activated during the delivery hour. There is no change on a second to second basis. Once ramped in, they are static for the remainder of the hour, thus are not really dynamic.

   Examples include:

   - **On Demand Rights -** Only one change per hour is allowed and must call dispatch with the requested change.
   - **Contingency Reserves -** Once-in-a-while delivery of contingency reserves provided by the pool.

2. **<u>Remote Loads/Resources</u>** – These are energy schedules from a remote resource or to a remote load. Remote in this context means that the load or resource does not have a direct physical connection to the customer's main system but generation control signals for it are telemetered into the BAA. These transactions follow the actual remote load so normally do not change rapidly.

   Examples include:

   - Colstrip's fixed hourly output was "dynamically transferred" (via pseudo ties) to multiple load serving BAs on the coast of Oregon & Washington (up to 1310 MW could be Dynamically Transferred to owners outside of Montana);
   - Mid-Columbia Generators to load serving BAs located primarily in Washington and Oregon to deliver energy and ancillary services;
   - Loads in a remote BAA being supplied dynamically from a different BAA (i.e. current example BPA's load in Idaho (~350 MW))

3. **<u>Generation Inputs between remote BAAs</u>** - Dynamic schedules that are used to deliver generation inputs for ancillary services such as regulating or contingency reserve from one BAA to another. The actual flow for this transaction type can have significant within hour variations, change rapidly, and can't be anticipated.

   Examples include:

   - Deliveries from the BCH or BPA BAA to the CAISO (limited to 550 MW in LLH, 200 MW in HLH),
   - Deliveries to BAA composed solely of wind resources, such as the Glacier Wind BA.

4. **Remote Resources used for generation inputs to a BAA** - The remote resource is used to provide generation inputs as regulation, contingency reserve or imbalance energy to an Attaining BAA. In this case, the flow can change rapidly to meet the customers balancing needs.

   Examples include:

   - BPA's Customer Supplied Generation Imbalance (CSGI) program

While most dynamic transfers have been managed by the system operators without undue concern, limitations have been imposed on some paths, notably BC-US and COI, for several years as a result of operational concerns. Because of the potential increase in intra-hour variability resulting from wind generation in the NW, and the corresponding increasing interest in managing this variability using remote resources, Balancing Authorities are looking for ways to manage these challenges, and expanded frequency and magnitude of Dynamic Transfers is being explored as an option.

Increasing Demand for Dynamic Transfers

Operationally, Dynamic Transfer Capability is a specialized use of existing transmission capacity (i.e. DTC does not represent additional capacity for a Path). The transmission set aside for dynamic transfers must be dedicated at the expense of transactions that are fixed for the hour. It is important to note that in any given hour the sum of all transfers on a given path, including all dynamic transfers, can never be scheduled above that path's System Operating Limit. While providing greater operational flexibility, Dynamic Transfer Capability may come at the expense of lower utilization factors, the cost of new equipment and/or increased O&M, all of which may be necessary to support the enhanced flexibility. The addition of transmission lines and associated system upgrades such as reactive power support, special protection systems, etc., would reduce the impact and likelihood of lower utilization factors. Also, the extent of the impact on the utilization factor depends on the (1) extent of the acceptable risk, (2) how the Dynamic Transfer Capability is implemented by the operators, and (3) the operating philosophy for scheduling intermittent resources. The DTC TF will explore these and other related issues in the next phases of this effort.

Dynamic transfers can increase transmission operating flexibility. The increased penetration of wind generation has led to an increasing need for new balancing resources. Many of the resources that could be used for this regulation and imbalance are located in parts of the system that are electrically remote from the wind projects they could balance. Dynamic transfer allows BAs to access these remote resources across intermediate BAAs. Having access to resources throughout WECC, while possibly attractive financially, are still subject to transmission constraints that may restrict a purchasers ability to dynamically schedule from the resource to the load.

Location of the balancing resources relative to the wind generation can have a dramatic effect on what actions must be done by the transmission operator to facilitate the use. Since the variability of wind generation is matched by balancing resources that are moving in a complimentary direction to the wind generator, impacts to the intervening system grows as the transmission distance between the two resources increases.

Impact of Dynamic Transfers on Transmission Operations

The impact of Dynamic Transfers will vary from one BAA to another because the complexity, level of automation and age of control schemes available to operators vary. For instance, many BAs have assumed that rapid changes on the transmission system are infrequent, and that a slow movement from one operating point to another is the norm. Dynamic transfers challenge this fundamental assumption and make it clear that the old control strategies, largely manual, are not sufficiently flexible to accommodate unrestricted expansion of dynamic transfer.

Care must be taken to reasonably assure that system operators have the tools, skills, and information for real time operations. Many dispatchers still have manual control of several functions (e.g. RAS arming and voltage switching) and increased dynamic scheduling may increase workload and the skills required of the operators. There may be a need for fundamental changes to the current mix of manual and automated controls. The wide impact of rapidly changing flows are likely to impact multiple PNW systems, possibly requiring greater coordination of procedures, voltage control, and other real-time activities by system operators of neighboring utilities. Examples of system impacts include:

<u>Remedial Action Scheme (RAS) arming:</u>

Many utilities have installed remedial action schemes that trip generation to maintain system reliability when a contingency (loss of one or more transmission elements) occurs. System Operators arm and disarm RAS (that is, set it to deploy or disable it) on different generating units as power flows change, thus insuring that an appropriate amount of generation is tripped if a contingency occurs. Many RAS settings require manual adjustments. Before limiting the dynamic capability on its interties, BPA found that power flows were changing more quickly than its system operators could coordinate the arming and disarming of RAS. Increasing dynamic transfer capability will require that provision be made for effective management of remedial action schemes and other reliability controls.

<u>Voltage control and reactive power reserves</u>

Power flow on transmission lines can dramatically affect transmission line voltage. When power flows change, transmission operators take a variety of actions to maintain voltage. These actions include switching reactive power devices, switching transmission lines in or out of service, and changing generation patterns to ensure that sufficient dynamic reactive power reserve is available for response during contingencies.

Under some conditions (such as outage conditions or high load), voltage is particularly sensitive to the power flow on the transmission system and system operators must take frequent action to maintain voltage at an acceptable level. A dynamic scheduling limit was imposed on the Northern Intertie after large voltage variations were observed when rapid movement of the dynamic schedules on top of high static transfers caused the Custer 500 kV voltage to move repeatedly outside of its normal operating range thereby requiring multiple operator adjustments in some hours.

The DTC TF focused considerable effort in quantifying the range of normal voltage deviations at important 500 kV and 230 kV substations across the Northwest, BC and Northern California. The goal was to establish benchmarks of what normal voltage deviation looks like in order to quantify the voltage deviation impacts that dynamic transfers could have on the same critical substations. These results are documented in Appendix B.

Reactive power margin calculation may be a basis for SOL determination. The first and most effective voltage control is from dynamic sources such as generators. When flows are relatively static manually switched devices can keep up with the changes to retain an adequate amount of dynamic reactive power reserve for contingency response. Insufficient ability to keep up could require the use of dynamic reactive power that is needed to be held for contingency response thus requiring additional generation to be left unloaded on-line to provide the var support or additional switching actions to keep up with the var demand. These are obstacles, however they are not insurmountable. For instance, for a given operating condition, one way to determine the appropriate action would be to establish a proxy for the effective reactive reserves (i.e., available reactive power at the neighboring plants and un-switched reactive devices at the neighboring buses), needed to maintain adequate margin at the critical buses. This could be used as an indicator of the magnitude of dynamic transfers that can be supported real time at a given operating point.

Changes to System Operating Limit (SOL)

No reliability criteria specifically address performance criteria associated with dynamic transfer limits. However, there are ways in which dynamic transfers can cause path violations based on current reliability criteria.

In the power flow simulation used to set SOLs, loads are represented as constant power because system voltage and power flows are presupposed to move slowly enough for devices such as distribution level LTCs, voltage regulators, and switched capacitors to complete their regulation changes and restore voltage at the load points before the transmission operating point shifts again. If flows change too much or too quickly before corrective action can be taken, then the model conditions assumed in the SOL studies may be inaccurate and the new operating point may be unreliable. Post-transient power flow simulations for various snapshots of the system would be needed to address this issue.

Another assumption is that voltage control, reactive power reserve, RAS and other post-contingency automatic actions, are able to be set up properly and kept within an acceptable operating range. If dynamic variations move the operating point faster than manual action can reset these controls, then the SOL, which assumes all of these quantities are correctly set, is invalid.

Another common example would occur where two paths are associated by a nomogram or where a path SOL is related to the output of a dynamically scheduled generator. It may be necessary to limit the dynamic transfer capability of the path to prevent a violation of the path SOL because the dynamic transfers could drive a change on the associated path SOL without a corresponding change in the flow.

Alternatives to Dynamic Transfers

Transmission operators throughout WECC are being pushed to move away from hourly scheduling to sub-hourly or continuous ramping of resources. To some degree this push is a result of variable generation, however, there are other reasons as well, including purchasing of balancing and regulation services from independent providers when BAA resources are insufficient. Intra-hour scheduling (30 min intervals), or FERC's suggested 15 minute markets, provide a means of accessing resources for immediate needs with lower financial risk.

Most utilities schedule power generation and transmission by the hour. Since wind power can change output dramatically within an hour, one way to reduce gaps between schedules and real-time output is to schedule generation and transmission more frequently. The magnitude and frequency of within hour ramps that can occur from large amounts of wind appears to tax the transmission system to a much larger degree than traditional slower changes and ramps. This will require a lot of new systems, training for operators, and full implementation may require significant transmission system investment.

With the increased need to provide flexibility in following sub-hourly variation, a variety of new tools are being considered. Whether the implementation of this flexible service is done using Dynamic Transfer (Dynamic Scheduling or Pseudo-Tie) or Intra-hour Scheduling, the same transmission issues arise as the frequency of schedule changes increases. Both implement the same thing to a greater or lesser degree: allowing greater flexibility for generating resources to move within the hour.

Truing up the schedule more frequently does not affect the physics of change. While schedule ramps are generally controllable, increasing the frequency of generation ramps has the potential of increasing the number of actions taken, units deployed, RAS armed, etc., regardless of whether fully dynamic transfers are implemented, or if intra-hour scheduling is introduced. While minimal at 30 minutes, as the scheduling interval is reduced from 30 minutes to 10 minute increments, the behavior and the effects more nearly approximate fully dynamic transfers.

The Wind Integration Study Team's (WIST) DTC Task Force was formed in 2010 to allow representatives of transmission operators throughout the region to identify limiting factors and build a technical consensus on a methodology to evaluate the limit of the system to provide this dynamic service. This work will eventually lead to a broad consensus for quantifying both the risks of increased dynamic transfer and the mitigations necessary to increase the portion of the existing transmission capability available to accommodate dynamic transfer. The close coupling of major PNW transmission paths, and their combined effect on voltages within the transmission system, require an approach that takes the interrelationships into account and faithfully represents how dynamic transfer, implemented on a system wide basis, effects grid reliability as a whole.

The New Operating Context – High Levels of Wind Penetration in the PNW

At the end of 2010, there was 7,800 MW of installed wind generation in the NWPP footprint and this is expected to increase to 13,500 MW by July 2012. As a result wind generation and its variability is already a significant factor in the day to day operation of the power system and one whose impact will increase. Figure 3 below highlights the transmission challenge of wind integration in the Northwest as it shows wind pockets with projected project generation relative to flowgates: transmitting wind resources from its sources to load centers involves crossing numerous flowgates.

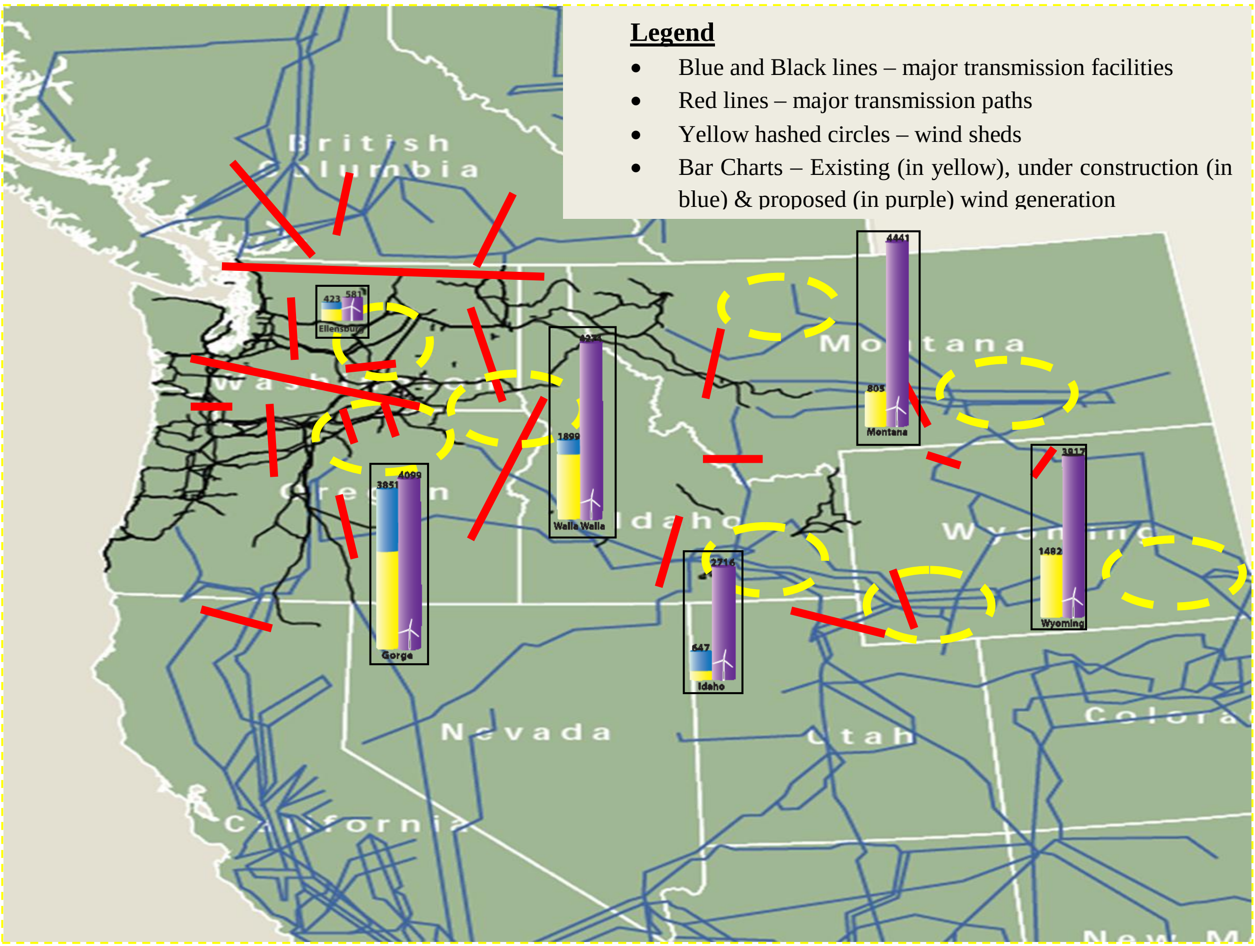

Figure 3: Wind Integration & Transmission Flowgates

While wind integration is not the sole use of dynamic transfers, understanding the variability of wind is seen as an important component in determining appropriate DTC limits. Consequently, the DTC TF spent considerable time trying to quantify wind generation by transmission region and in particular its variability as the change and rate of change of wind production will have the greatest impact on DTC. Results of these investigations are shown in Appendix C.

3. Review of DTC Studies published by WECC Members

There were two significant DTC studies published by WECC members in the last twelve months: BPA published its "Dynamic Transfer Limit Study Methodology"[3] in February 2010 and CAISO published its "Impact of Dynamic Transfers on Interfaces"[4] study in January 2011. In addition, BC Hydro's Powertech Labs published a study in June 2008 on the "Impact of Dynamic Scheduling on Regional Voltages"[5] A comprehensive summary of the CAISO study is provided in Appendix D.

There is some overlap between the studies, for instance, the CAISO and BPA studies explored the need for DTC limits for the California Oregon Intertie (Path 66) whereas the Powertech and BPA studies both explored the need for DTC limits for the Northwest to BC Intertie (Path 3). The BPA and Powertech studies both identified a need for DTC limits, whereas the CAISO study determined that no DTC limit lower than the Path rating was required for the south-side of COI. To understand these different conclusions it is helpful to explore some of the similarities and differences between the studies and systems:

1. Similarity: Importance of monitoring system voltages:
    a. All three studies focused on system voltages as each entity identified voltage variation as a critical parameter to be monitored when determining the need for a DTC limit.

2. Different definitions of Dynamic Transfer Capability:
    a. BPA and Powertech defined DTC as the amount of variation that could be accommodated across a flowgate
    b. In its 2011 study CAISO defined DTC as the maximum amount of aggregated intermittent energy that could be scheduled, while recognizing that only a fraction of the aggregated intermittent energy would result in regular variations in flow across a flowgate during a specified time interval.

3. Different Methodologies:
    a. BPA adopted a voltage sensitivity approach;
    b. CAISO adopted a contingency response approach to determine voltage response;
    c. Powertech adopted a Time Step simulation approach to assess voltage impact.

4. Different control assumptions:

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[3] BPA Feb 2010 DTC study: http://transmission.bpa.gov/wind/dynamic_transfer/DTLS_methodology_F.pdf Further information from BPA on Dynamic Transfers: http://transmission.bpa.gov/wind/dynamic_transfer/default.cfm

[4] CAISO Jan 2011 DTC study: http://www.caiso.com/2aff/2aff9e9150530.pdf Further information from CAISO on Dynamic Transfers: http://www.caiso.com/2476/24768d0a2efd0.html

[5] Powertech Labs Jun 2008 DTC study: link found at: http://www.columbiagrid.org/eventdetails.cfm?EventID=545&fromcalendar=1

    a. BPA manually arms its RAS and manually switches its voltage control devices for small voltage changes;
    b. CAISO and BC Hydro arm their RAS automatically and allow for some automated voltage control.

5. Different assumptions about Dynamic Transfers and timeframes:
    a. BPA assumed that there would be no additional operator actions during the scheduling hour to manage the Dynamic Transfers;
    b. CAISO Operations includes system redispatch by market software every 5 minutes to ensure system balance, and the transmission system has devices that can automatically adjust the normal voltage variations within their design specifications.

A common DTC methodology should enable adjacent BAs to determine DTC limits for common flowgates in a consistent manner and that it should enable a standardization of terms for describing system variability. However, given that different systems have different control schemes and physical properties, it is entirely possible that different BAs will determine different DTC limits for a jointly operated flowgate, just as it is normal for BAs to determine from their respective systems different System Operating Limits for a jointly operated intertie.

4. Initial Steps towards a DTC Limit Methodology

During Phase 1, the DTC Task Force worked on defining the DTC problem and probing various approaches to setting DTC limits. Developing a DTC methodology was assigned to Phase 2, although it is expected that it will follow on from the initial steps taken to date. Appendix E describes in greater detail the issues that a DTC Methodology would need to address and Appendix F proposes a framework for carrying out DTC limit studies.

Key issues that impact DTC limits are:

1. Locations and characteristics of the variable generation sources in the BAA;
2. Amount and frequency of acceptable voltage variation across the transmission system; and
3. Assumptions made on the priority of DTC vs. SOL during capacity trade-offs and the allowance for increased switching of voltage equipment and operator actions.

Three case scenarios were explored to identify DTC impacts. They were:

1. **Scenario A:** Balancing resources are provided adjacent to the variable generation source. For this scenario there would be no DTC implications as the variability issues are resolved locally;
2. **Scenario B:** Balancing resources are provided adjacent to the load; consequently, the variability of the source will be reflected along the transmission path between the source and

sink. As a result there will be DTC implications for the flowgates between the source and sink.

3. **Scenario C:** Balancing resources are provided remotely from the source and the sink. Consequently, variability is seen between the Generation Source and load, the Balancing Resource and load, and potential on the paths between the Generation Source and Balancing Resource. This scenario has multiple DTC implications for the flowgates between the source and sink and between the Balancing Resource and the sink.

There was general acceptance among Task Force members of the following principles:

- There are limits on the amount of variability that could be reliably accommodated across a transfer path without any additional operator initiated adjustments;
- Studies would need to be run to determine the DTC limits; and
- The transmission providers involved in operating a transfer path are best placed to determine their respective DTC limits.

5. Emerging Issues and Threats

During Phase 1 discussions several additional issues and threats associated with increased variations in power flows across the transmission grid were identified. A secondary goal of the Task Force was to capture and document these concerns so that they could be tracked in subsequent phases and their potential impact on DTC limits monitored. A summary of the issues is provided in this section and further details are provided in Appendix G.

Issue	**Description of Concern**	**Evaluation**
Sub-synchronous Resonance	Identified as a concern for the Montana to Northwest path, the question was whether wind generation that displaced Colstrip generation could trigger conditions whereby Colstrip would be susceptible to Sub-synchronous resonance.	Not a credible threat provided the assumption that wind generation is integrated at Broadview or further west continues to hold true. If wind generation in Montana is integrated at the Colstrip bus then the issue should be revisited.
System Inertia	Identified as primarily a concern for COI, the question was whether wind generation displacing large hydro generation would negatively impact the transient stability performance south of John Day.	While system inertia assumptions may need to be more clearly defined in SOL studies, the base assumption is that many of the large federal hydro units could be operated in Synchronous Condense mode, thereby maintaining access to their contributions to system inertia.
Unscheduled Dynamic flows	With the pilot programs to move away from CPS2 to RBC (Reliability Based Control) there is concern that greater inadvertent between BAAs could reduce the available DTC.	As part of the WECC pilot project to evaluate RBC, it is recommended that the impact of RBC on the available DTC for critical paths be assessed.
Voltage support assumptions	Displacement of conventional generation (including Gas Turbines) will change the voltage support assumptions that can be used in SOL studies.	Modeling voltage support from all generators will be a critical part of any future DTC Limit methodology.
Frequency Responsive Reserves	Does increased wind generation require increased levels or reassessment of Frequency Responsive Reserves?	This issue was not evaluated during Phase 1 of the Task Force's work.

6. Options for Enhancing DTC

Enhancing DTC implies increasing the transmission system's ability to respond automatically to variations in intra-hour power transfers. This section summarizes the broad categories for enhancing DTC; more detailed descriptions of possible options are provided in Appendix H.

Automatic Voltage Control: Maintaining reliability in the wake of large variations in power flow requires that system voltages be controlled within the limits assumed by SOL studies. Options for voltage control include:

a) StatComs provide fast voltage support;
b) SVCs (Static Var Compensators) provide rapid voltage support;
c) Mechanically Switched Capacitors;
d) AutoVar Schemes

One finding of a Phase 1 sensitivity study was that relaxing the voltage variation limit at five critical 500 kV buses did not significantly increase the calculated DTC using BPA methodology, because the voltage variation problems were simply moved to adjacent buses, which then became the next most constraining limits. In Phase 2 it will be important to determine the impact on DTC of adding voltage support devices at critical 500 kV and 230 kV buses. The assumption is that there may need to be multiple, appropriately sized devices, strategically located to respond to a variety of scenarios.

Automated RAS arming: Maintaining reliability implies that appropriate RAS actions will take place for any given operating point, consequently, it is very important to ensure that RAS arming be quickly modified to reflect variations in power transfer levels. The costs of automating RAS arming will vary from one BA to another and it depends largely on whether they are starting with a "man-in-the-loop" RAS philosophy.

Changing SOL assumptions: SOL studies have generally assumed limited variation between the operating point and the studied SOL point, for instance, BPA assumes a 300 MW deadband for its COI Voltage Stability SOL studies. By increasing the assumed deadband it may be possible to increase DTC limits, however, it may come at the cost of a decreased SOL or increased risk of overtripping of Generation in the event that RAS action is required.

Staffing Levels: System Operator adjustments are critical to ensuring a reliable starting point for any variation in power transfer. The amount of variability that can be accommodated will depend on how frequently it is assumed that operators will readjust the system profile. Moves to 30 minute scheduling, or even 15 minute scheduling, will help in managing more intra-hour variability as it will ensure regular system adjustments.

Flexible AC Transmission Systems (FACTS): Use of the state-of-the-art FACTS technology such as Unified Power Flow Controllers (UPFC) can make use of the latent capacity as well as providing reactive power support which would increase the DTC and likely the SOLs as well.

Transmission Lines: Upgrading the existing transmission system or construction of new transmission lines would contribute to substantial increase in SOL which would result in an increase in the DTC.

7. Next Steps

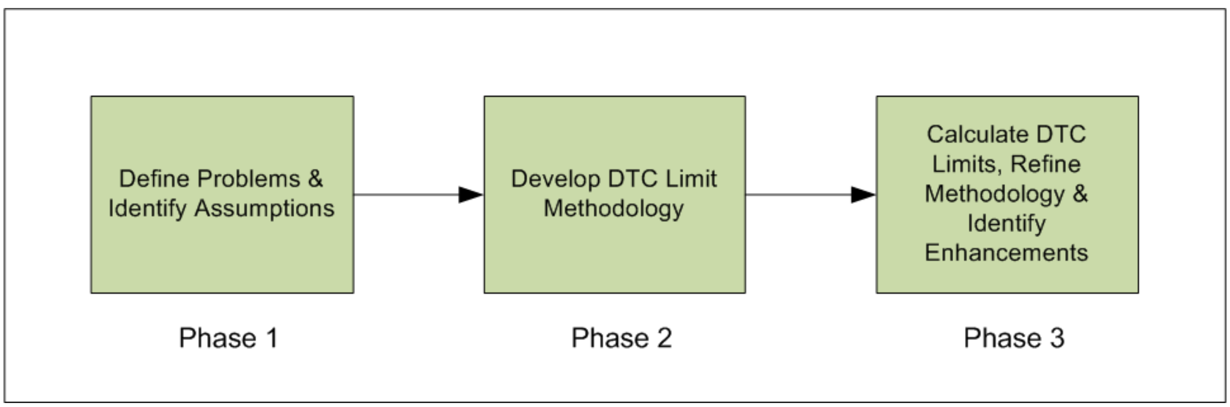
In Phase 1, the WIST DTC Task Force defined the DTC problem and confirmed that it is a legitimate issue that Transmission Providers should study in order to determine their system's DTC limits and risks. The Task Force proposes that its members continue to meet to complete the following goals:

Phase 2: Develop a common DTC limit methodology

Complete by June 2011

Phase 3: Calculate DTC limits for several paths/flowgates in the WECC;
Identify some specific projects to enhance DTC transfer levels;
Refine the DTC methodology to reflect lessons learned by individual BAs;
Present methodology to WECC Members for buy-in.

Complete by October 2011



8. Conclusions

The issue of Dynamic Transfer Capability Limits is significant and merits investigation. To carry out this task, Joint Initiative Wind Integration Study Team convened a DTC Task Force in October 2010 with the purpose of determining how to increase dynamic transfers without compromising system reliability. A specific goal for the Task Force is to develop a common DTC limit methodology that could be applied by Transmission Providers to their respective systems. Conclusions of this Phase 1 report are:

1. The development of variable wind based generation has resulted in an increasing number of requests for new dynamic transfers across NW transmission. How these new uses could affect the transmission system and the determination of dynamic transfer limits merits investigation.

2. Path Operating Agents of a common path could apply the same DTC limit methodology and determine different DTC limits because of:

    a. Different perspectives and characteristics on either side of the path;
    b. Differences in their systems (e.g. Automated or Manual RAS, automated voltage control);
    c. Different determinations of what level and frequency of power flow variation would be acceptable on their system;
    d. Different tolerances for increased wear and tear on system equipment;

3. This is analogous to what currently happens in determining SOLs independently prior to the operating hour. Ultimately, the most restrictive limit determined by a Path Operating Agent will govern the path's actual operation in real-time.

4. The CAISO, BPA and Powertech Lab DTC studies all showed voltage change at critical buses to be a key component in determining increased DTC limits. Some Task Force members also saw voltage change as important because the SOL studies are based on a recommended voltage profile and the manual adjustments necessary to restore this voltage profile following large deviations take time.

5. Continued reliance on manual actions for RAS arming and voltage control may hinder the expanded use of Dynamic Transfers.

In the industry, there are differences over what is meant by Dynamic Transfer Capability Limits as some focus on the total quantity of schedules that could change within an hour and others focus on the limits on variability in power flow during the hour. In Phase 2 it is hoped that the DTC TF will define a new term to reflect the limit on power flow variations across a flowgate in between scheduling periods.

Appendix A – Glossary

Average Capacity Factor: Average hourly energy during a specified time interval (e.g. typically one year) divided by its maximum installed capacity.

Balancing Authority (BA): The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Balancing Authority Area (BAA): The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Dynamic Schedule: A telemetered reading or value that is updated in real time and used as a schedule in the Automatic Generation Control (AGC) and the Area Control Error (ACE) equation and the integrated value of which is treated as a schedule for interchange accounting.

DSS (Dynamic Scheduling System): An application that is currently being supported and developed by the Joint Initiative participants. The DSS is intended to provide a common dynamic communication infrastructure and protocol that will allow participating entities to purchase or sell capacity and energy on a dynamic basis.

Dynamic Transfer: A term that refers to methods by which the control response to load or generation is assigned, on a real-time basis from the Balancing Authority to which such load or generation is electrically interconnected (native Balancing Authority) to another Balancing Authority (attaining Balancing Authority) or other controlling entity on a real-time basis. This includes dynamic arrangements within the Balancing Authority Area, Dynamic Schedules, and Pseudo-Ties.

Dynamic Transfer Capability (DTC): The capability of the transmission system to continuously accommodate the ramp of a resource(s) over a pre-determined range, such that the control of the electrical output of such resource(s) can be varied from moment to moment by a Dynamic Transfer Entity other than the host utility/host Balancing Authority Area operator.

Dynamic Transfer Entity: A load, generator, generation provider, Transmission Customer, (Customer), or other party that is using transmission to affect a Dynamic Transfer.

Energy Imbalance: Difference occurring between hourly scheduled amount and hourly metered (actually-delivered) amount associated with transmission to a load located in a Balancing Authority Area or from a generation resource located within a Balancing Authority Area.

MVAR: The portion of electricity that establishes and sustains the electric and magnetic fields of AC transmission equipment. Reactive power is provided by generators, synchronous condensers, or capacitors and directly influences system voltage.

Pseudo-Tie: A telemetered reading or value that is updated in real-time that represents generation or load assigned dynamically between Balancing Authorities and used as a tie line flow in the effected Balancing Authorities' AGC/ACE equation, but for which no physical Balancing Authority tie actually exists. To the extent that no associated energy metering equipment exists, the integration of the telemetered real-time signal is used as a meter MWh value for interchange accounting purposes. A Pseudo-Tie facilitates a power transfer between Remote Loads and/or Resources that are part of the same Balancing Authority Area.

Remedial Action Schemes (RAS): Method of gaining transmission capacity through automatic post-contingency control actions (e.g. tripping generation, inserting capacitors, etc.). In the NERC glossary, these are also known as Special Protection Schemes.

Supervisory Control and Data Acquisition (SCADA): Used by Transmission Operations System Operators to monitor and control the transmission system.

Wind Integration Study Team (WIST): The Northern Tier Transmission Group and ColumbiaGrid formed the Wind Integration Study Team to facilitate the integration of renewable generation into the northwest transmission grid. The initial focus of the group is to support the technical study needs of existing subregional and regional initiatives. WIST has provided a technical peer review of the BPA Dynamic Transfer Limit Study.

Appendix B – Voltage Variations at Critical 500 kV and 230 kV Substations

This Appendix summarizes the Task Force's work to establish a baseline for existing variation at key points on the bulk system. Voltage variations were calculated using the following process:

- The maximum and minimum voltage at selected critical 500 kV, 345 kV and 230 kV buses were determined within each 5 minute period for 2009 (NB: Round Mountain 500 kV voltage records were from 2010 as the 2009 data had been archived and was not readily available);

- The difference between the maximum and minimum values was calculated to form a voltage delta;

- Positive and negative voltage deltas were separated from one another;

- The percentile of positive and negative voltage deltas at each bus was calculated.

The full results of this analysis are shown in Table A1 on the following page. For example, the 95th percentile of positive voltage deltas at Gordon M. Shrum was calculated to be 0.26%. This means that 95% of the 5-minute samples varied by at most 0.26% (or 1.3 kV as GMS is a 500 kV bus). In general, we found that the 95th percentile of voltage variations at critical buses in the western system occur below 0.40% (2.0 kV on a 500kV base).

Table A1 - Summary of Positive and Negative 5 minute Voltage Deltas (%) at Critical 500kV, 345kV and 230kV Buses

Percentile	Number of Occurrences	BC Hydro				BPA			IPCO		CAISO
		G. M. Shrum 500kV	Williston 500kV	Kelly Lake 500kV	Ingledow 500kV	Custer 500kV	Monroe 500kV	Echo Lake 500kV	Borah 345kV	La Grande 230kV	Round Mountain 500kV
90%	29 times a day	0.13	0.23	0.30	0.26	0.35	0.32	0.31	0.32	0.33	0.25
		-0.13	-0.24	-0.32	-0.33	-0.39	-0.32	-0.32	-0.32	-0.33	-0.25
91%	26 times a day	0.15	0.25	0.32	0.29	0.39	0.32	0.32	0.32	0.33	0.25
		-0.15	-0.26	-0.32	-0.33	-0.39	-0.33	-0.32	-0.32	-0.33	-0.25
92%	23 times a day	0.17	0.28	0.32	0.33	0.39	0.32	0.32	0.32	0.33	0.25
		-0.17	-0.29	-0.32	-0.37	-0.39	-0.37	-0.34	-0.32	-0.37	-0.25
93%	20 times a day	0.20	0.31	0.34	0.36	0.41	0.38	0.32	0.33	0.39	0.25
		-0.20	-0.32	-0.36	-0.39	-0.44	-0.39	-0.38	-0.33	-0.39	-0.25
94%	17 times a day	0.24	0.35	0.40	0.39	0.46	0.39	0.36	0.37	0.40	0.25
		-0.23	-0.36	-0.40	-0.46	-0.46	-0.39	-0.39	-0.36	-0.40	-0.25
95%	14 times a day	0.26	0.40	0.40	0.46	0.49	0.39	0.39	0.40	0.40	0.25
		-0.26	-0.40	-0.41	-0.49	-0.51	-0.42	-0.39	-0.40	-0.40	-0.25
96%	12 times a day	0.30	0.40	0.48	0.53	0.52	0.45	0.39	0.45	0.40	0.38
		-0.29	-0.40	-0.48	-0.53	-0.52	-0.45	-0.45	-0.45	-0.40	-0.38
97%	9 times a day	0.36	0.47	0.56	0.59	0.59	0.52	0.45	0.48	0.46	0.51
		-0.34	-0.47	-0.56	-0.59	-0.58	-0.52	-0.48	-0.48	-0.46	-0.51
98%	6 times a day	0.45	0.60	0.72	0.66	0.70	0.65	0.54	0.48	0.47	0.51
		-0.45	-0.60	-0.72	-0.66	-0.65	-0.65	-0.58	-0.48	-0.51	-0.51
99%	3 times a day	0.68	0.80	0.88	0.79	0.91	0.84	0.81	0.64	0.60	0.76
		-0.70	-0.76	-0.88	-0.79	-0.84	-0.84	-0.82	-0.64	-0.60	-0.76
99.5%	1.5 times a day	0.94	1.00	1.04	0.93	1.04	0.97	1.04	0.82	0.73	0.89
		-0.95	-1.00	-1.04	-0.92	-0.98	-0.99	-0.97	-0.78	-0.66	-0.89
99.95%	once a week	1.90	2.00	1.84	1.64	1.56	2.21	1.56	1.58	1.62	1.27
		-1.65	-1.80	-1.60	-1.46	-1.43	-2.18	-1.47	-1.43	-1.86	-1.32
99.99%	once a month	2.96	2.44	5.59	2.63	2.12	2.60	1.95	2.55	3.82	2.03
		-2.19	-2.22	-3.89	-2.27	-1.87	-2.45	-1.64	-2.10	-3.77	-1.66
99.999%	once a year	5.26	3.25	7.06	3.98	3.04	3.40	2.62	5.75	7.38	4.24
		-5.34	-2.79	-5.41	-2.92	-2.39	-5.35	-1.94	-3.26	-5.75	-3.72
100%	-	7.60	3.85	7.84	5.06	3.64	3.57	2.73	7.93	7.64	5.71
		-7.86	-2.80	-5.59	-2.96	-2.44	-5.97	-2.08	-3.35	-6.29	-3.94

Appendix C – Wind Variability as related to DTC

Whereas utilities have had to manage the natural variability and uncertainty of loads for many years, most traditional generating resources have been dispatchable, especially during the time horizon of within-hour operations. With the entry of wind generation and other VERs, utilities are adding generating resources that are no longer dispatchable in the traditional sense. In addition these sources are, in the context of the tools and data available to the dispatcher, fluctuating unpredictably in the real time operations time scale.

As one would expect, wind generation varies with the wind itself, and the variation in wind does not match that of load. Figure A1 below, based on one year of actual data recorded from June 2007-May 2008, illustrates the lack of correlation of wind and load, either by magnitude or season.

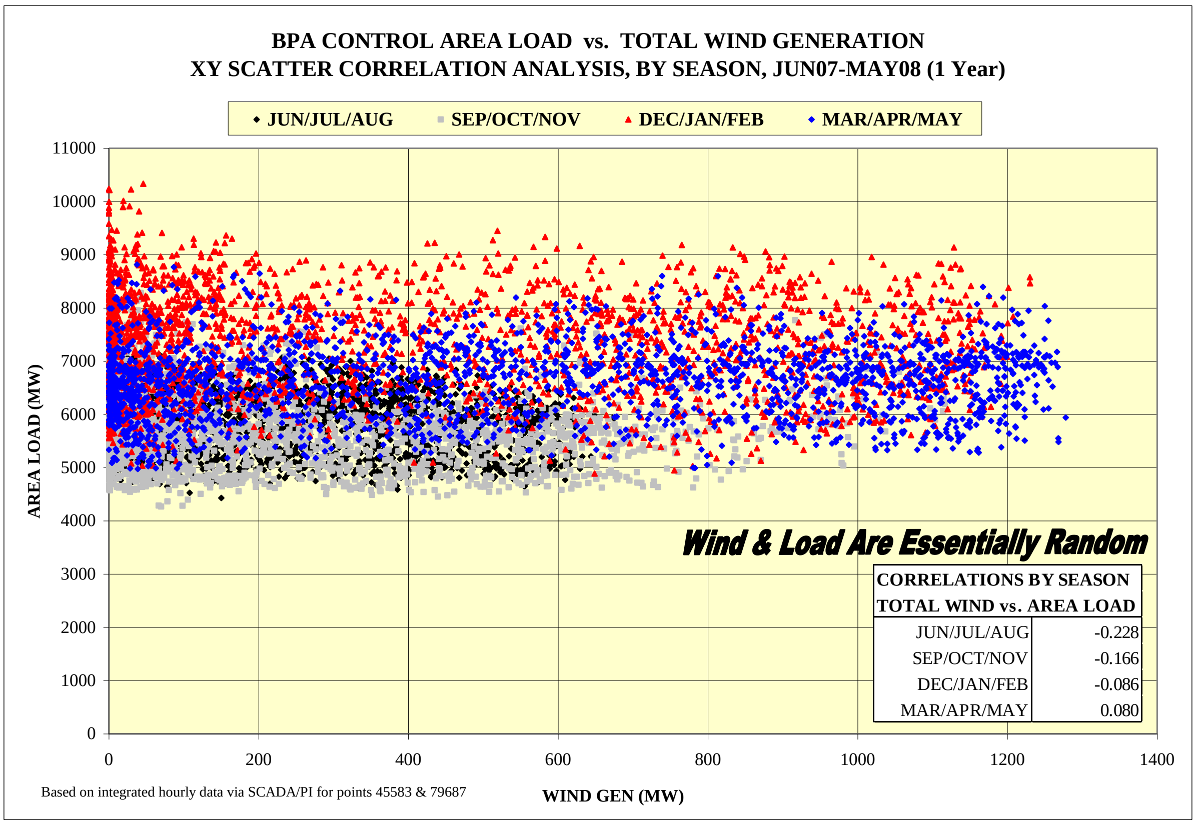


Figure A.1: BPA Control Area Load vs. Total Wind Generation Correlation Analysis, June 2007 – May 2008

It follows that with the independence of wind generation and load, and the lack of dispatchability, wind generators present a new and growing influence on system variability. Since the physical demands of electrical system operation requires that load and generation match at all times, the variability of wind generation also manifests itself in the new variations of traditional resources that are used to follow and balance out the variations of the wind generation from its scheduled output. At sufficient penetration levels, wind generation increases the overall uncertainty and variability of system operations.

Wind Variability Charts by Region

This section shows the time variability of wind in the NW. These charts show the wind generation by time of day and month for each BA.

BPA Data

The BPA wind is mainly in the Columbia River gorge area but there is also wind in SE and Central Washington. The BPA chart shows that the wind is most likely during the evening and nighttime. The wind is also most pronounced between March and September. The wind is most consistent throughout the day in December and January (at medium levels), February (low levels) and March/April (higher levels). There was ~2500 MW of wind in the BPA BA by Dec 2009 and the 2009 capacity factor was 28.8%.

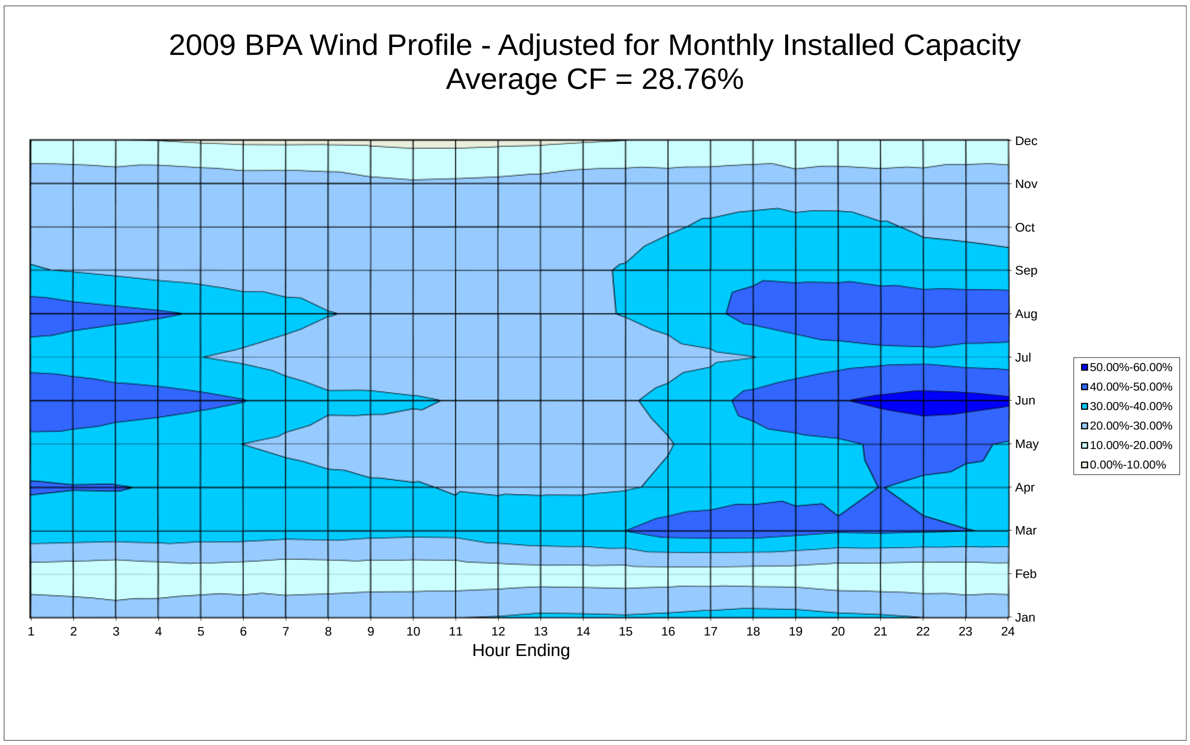


Figure A.2: 2009 BPA Wind Profile

CAISO Data

The CAISO wind data is shown below. This wind is lightest in the winter months and heavier during summer. During the hotter summer months, the wind is heaviest into the evening and nighttime. There was 2,935 MW of wind in the CAISO BA and its capacity factor was 22.2% in 2009.

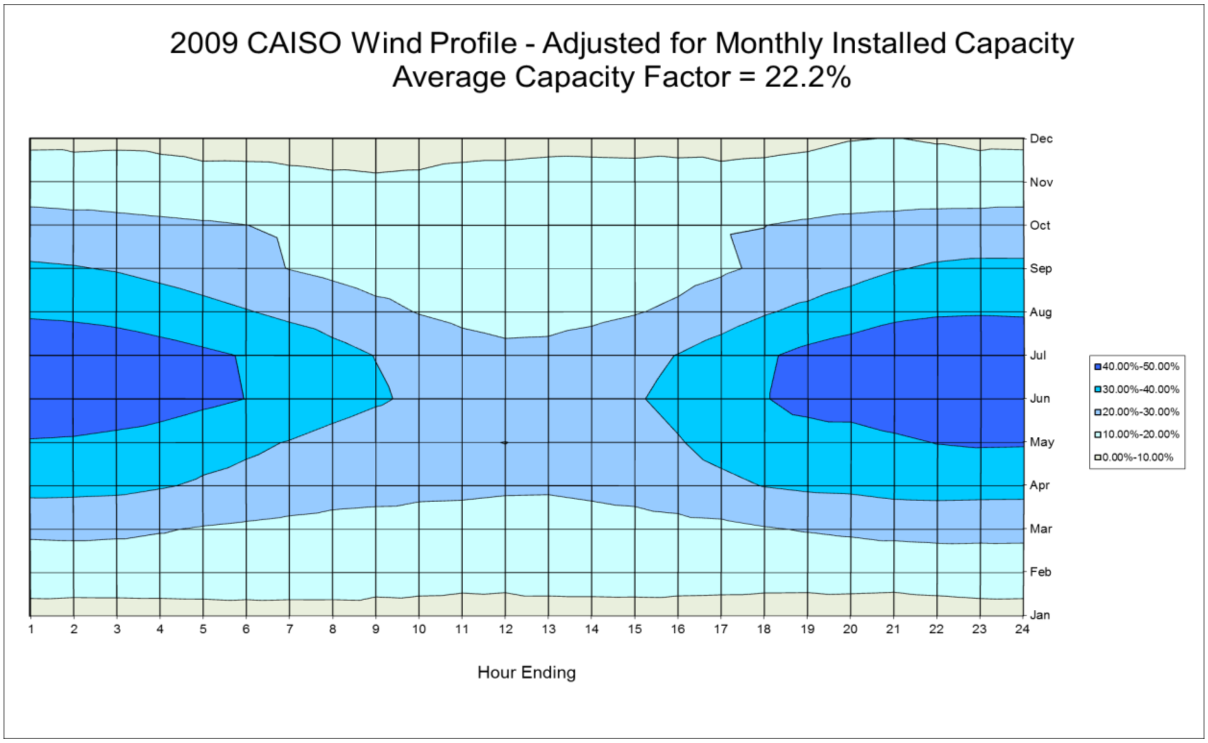


Figure A.3: 2009 CAISO Wind Profile

Northwestern Energy Data

The Northwestern Energy wind fleet in Montana had the characteristics shown below in 2009. This wind is more consistent throughout the day with more wind in the fall, winter and spring months and less wind in the summertime. There was less than 500 MW of wind in the NWE BA in 2009 and its capacity factor was 38.2%.

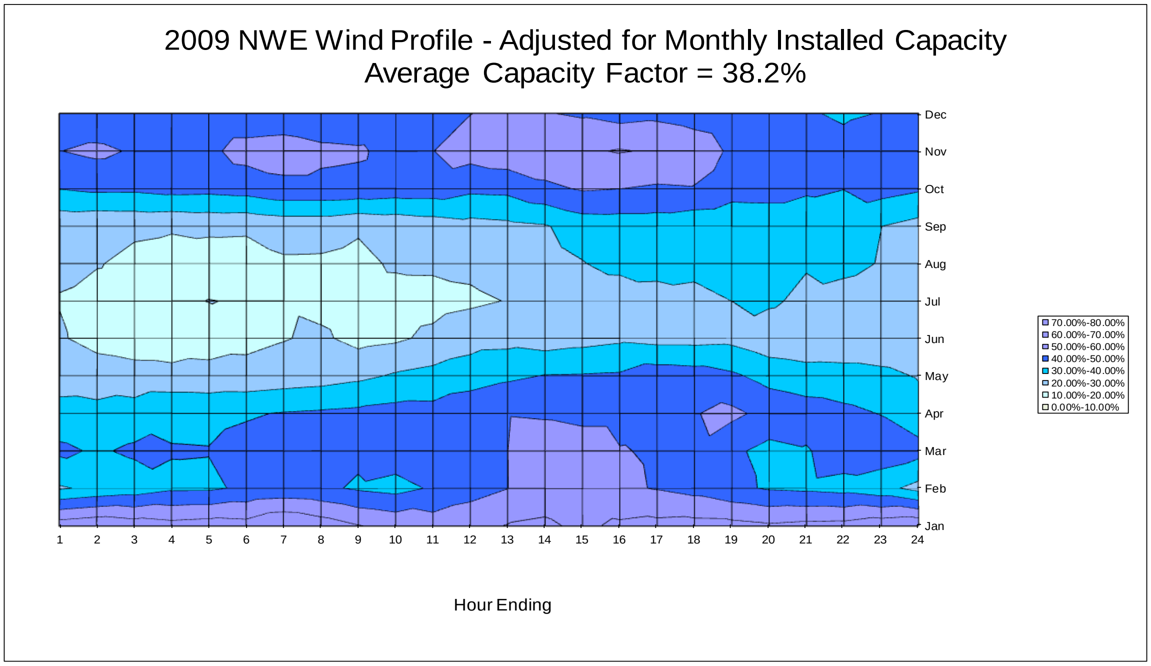


Figure A.4: 2009 NWE Wind Profile

PacifiCorp West Data:

The PacifiCorp West wind is located mostly in SE Washington and is similar to the BPA wind. The PacifiCorp wind is heavier during the evening and nighttime. The wind is most consistent throughout the day in December and January (at medium levels), February (low levels) and March/April (higher levels). There was approximately 520 MW of wind in the PacifiCorp BA by December 2009 and the 2009 capacity factor was 24.8%.

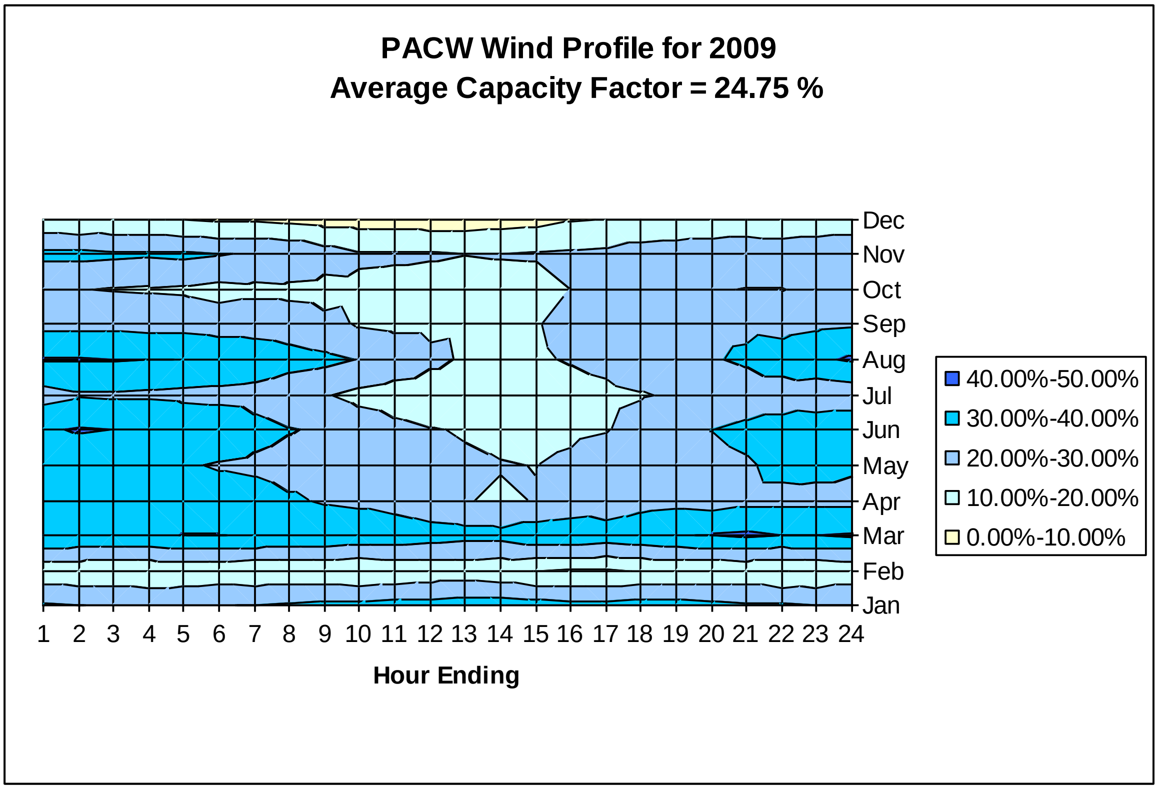


Figure A.5: 2009 PacifiCorp West Wind Profile

PacifiCorp East Data:

The PacifiCorp East (Wyoming) wind is heaviest during winter and spring. This wind has more variation by month versus time of day. There was approximately 1100 MW of wind in the PacifiCorp East BA by December 2009 and the 2009 capacity factor was 23.8%.

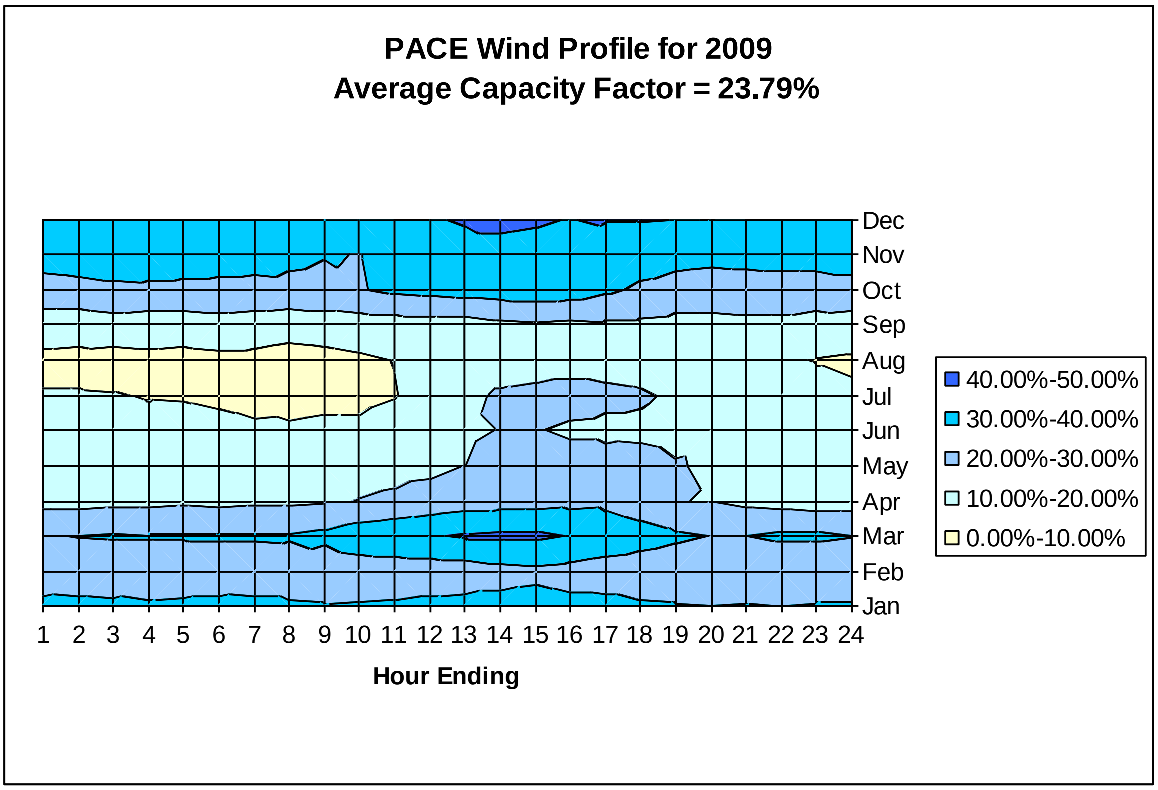


Figure A.6: 2009 PacifiCorp East Wind Profile

IPC Data

The Idaho wind is lightest in the middle of the day during the summer. It is heaviest in the evening especially in the spring and fall. It is most consistent throughout the day early in the year and late in the year with heavier wind late in the year. There was ~175 MW of wind in the Idaho BA by December 2009 and the 2009 capacity factor was 23.3%.

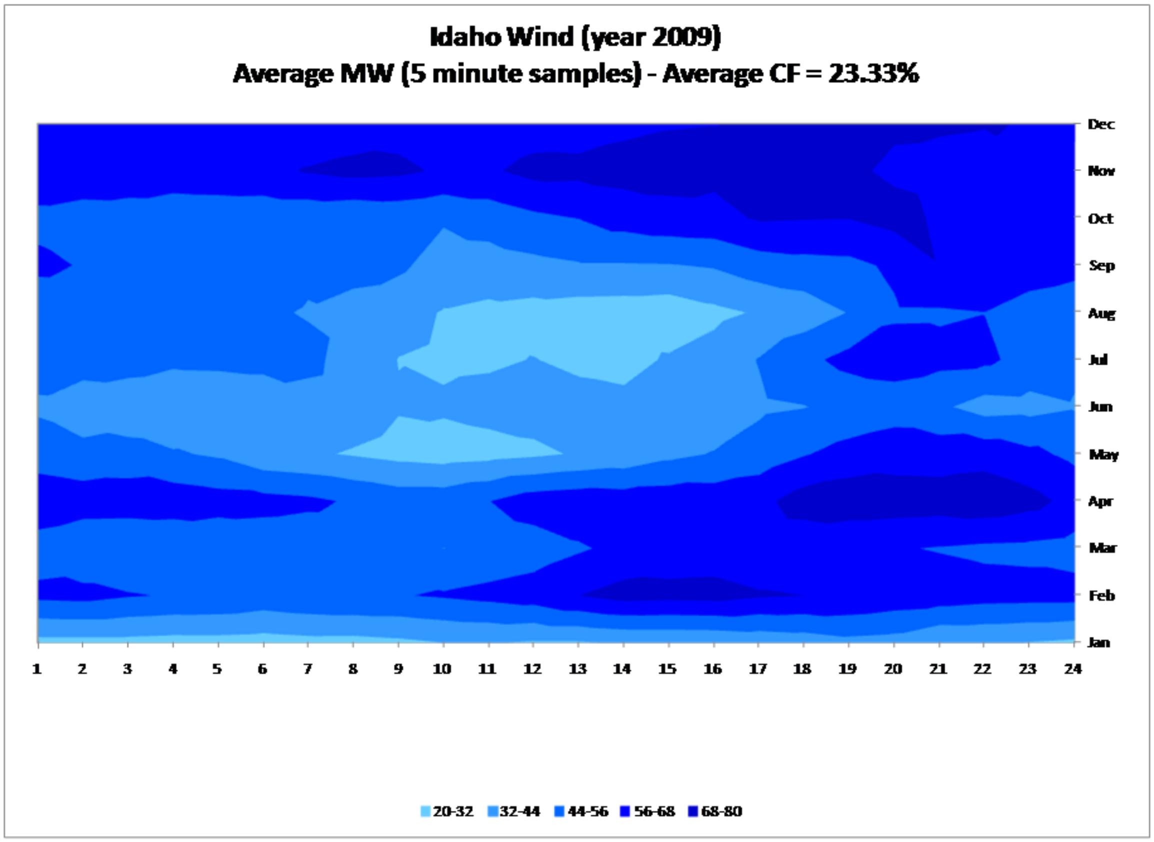


Figure A.7: 2009 Idaho Wind Profile

BC Hydro Data

The BC Hydro BA wind data is shown below. This wind is most consistent throughout the day in the spring and September through December. The wind blows very hard and steady though October and November. There is usually more wind in the evening. There was less than 500 MW of wind installed in BC in 2010 and BC's capacity factor was approximately 15% during 2010.

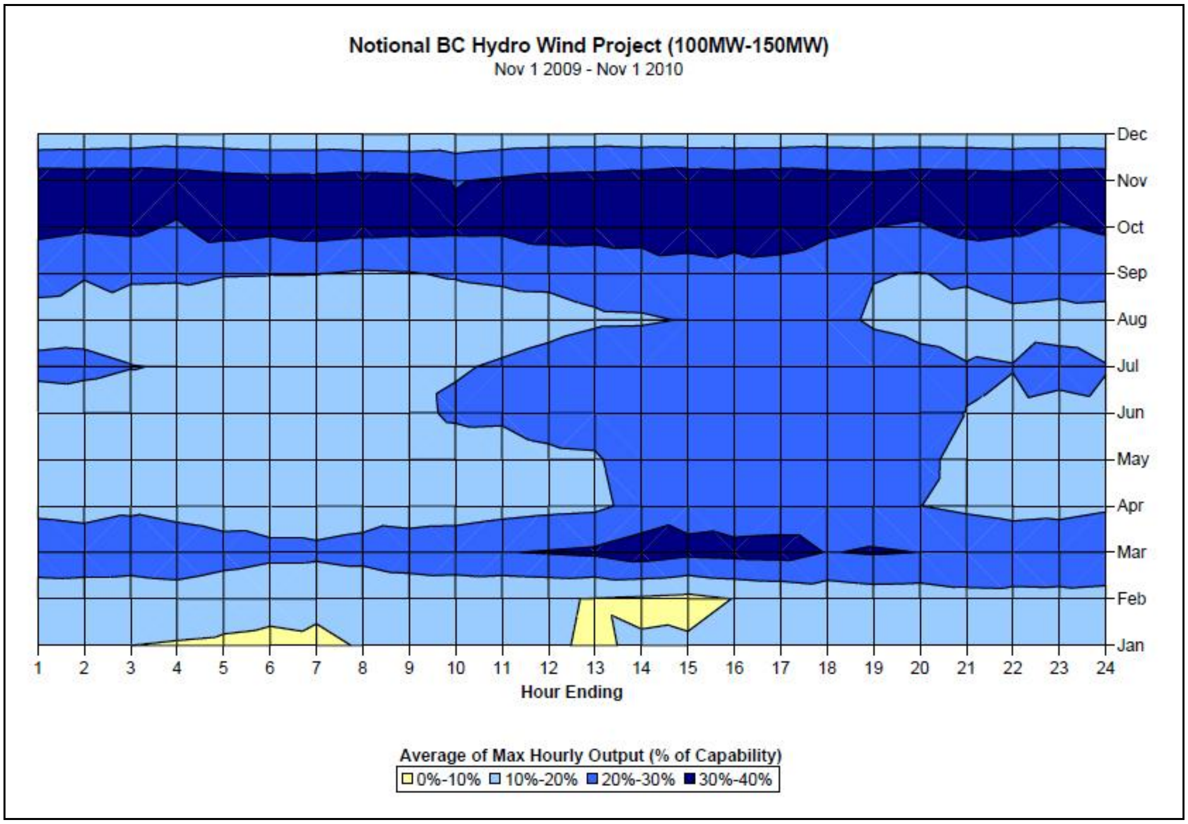


Figure A.8: 2009 BC Hydro Wind Profile

Wind Variation Plots

To show the variation in power transfers that can show up on the system, plots of change in wind output are included below. These charts show the ramps in both the upward and downward directions within a 5 minute time period for BPA and CAISO BA wind. These charts show the hours of the day on the x-axis and months of the year on the y-axis. Just like the topology plots above, all days of the year are averaged and shown on one point of the chart using a contour in the charting. The higher ramps show up as darker coloring. For example, the maximum up-ramps on the BPA wind show up in the late afternoon. The pattern of occurrence of down-ramps is less pronounced. The ramp information for CAISO shows that the ramps in California are less pronounced than those in the Northwest.

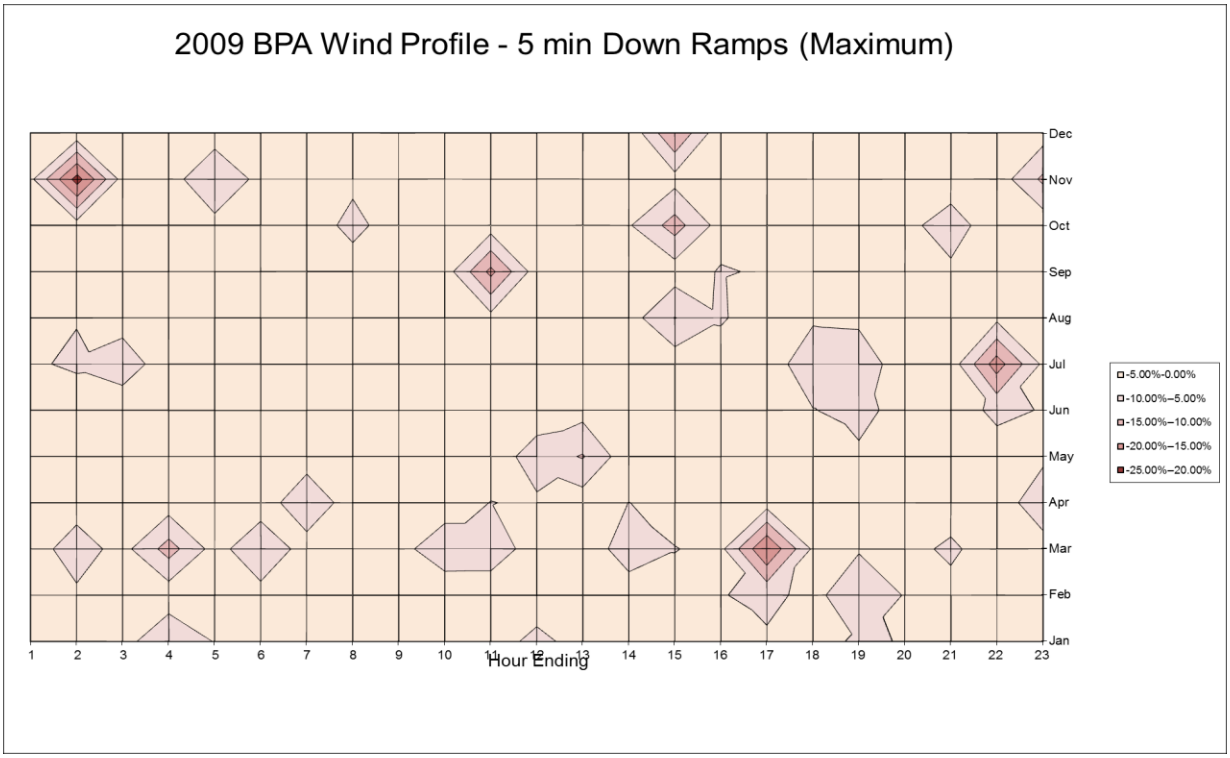


Figure A.9: 2009 BPA Wind Profile – 5 min Down Ramps

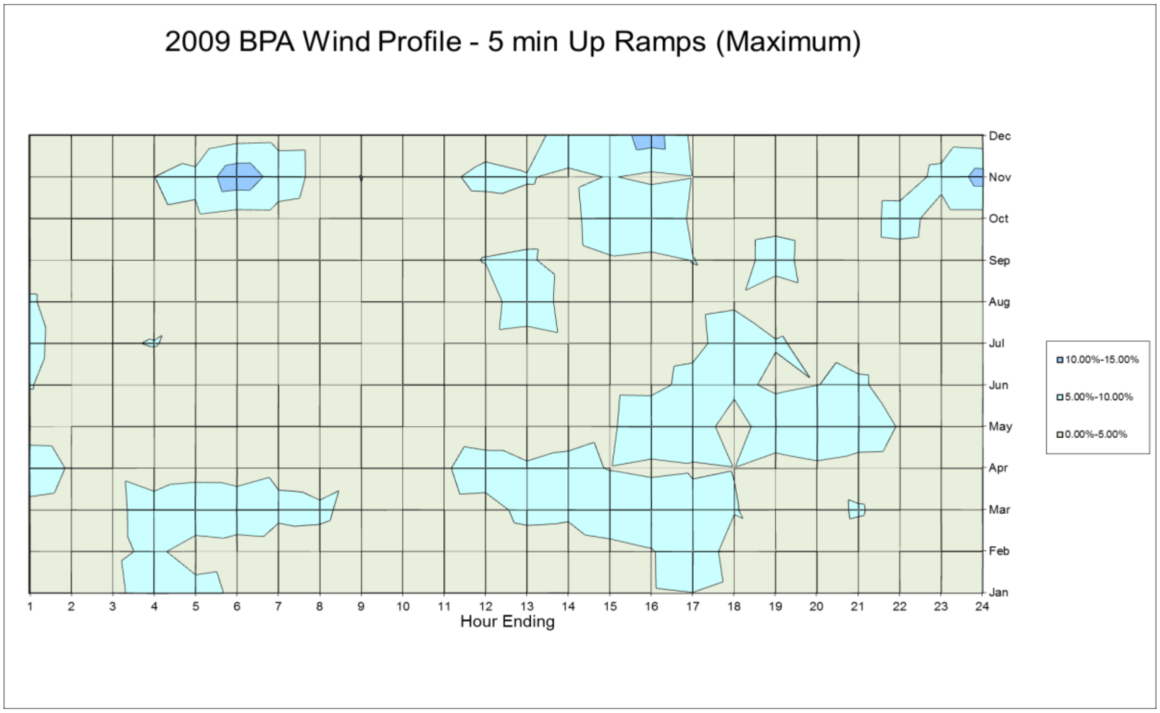


Figure A.10: 2009 BPA Wind Profile – 5 min Up Ramps

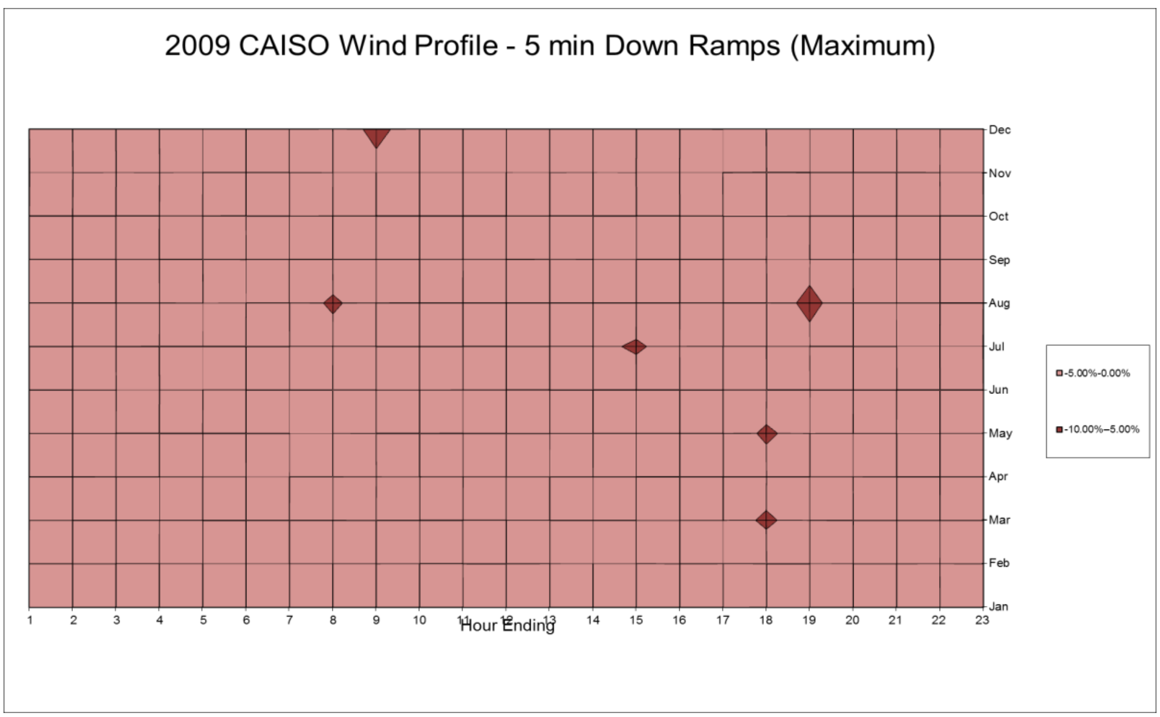


Figure A.11: 2009 CAISO Wind Profile – 5 min Down Ramps

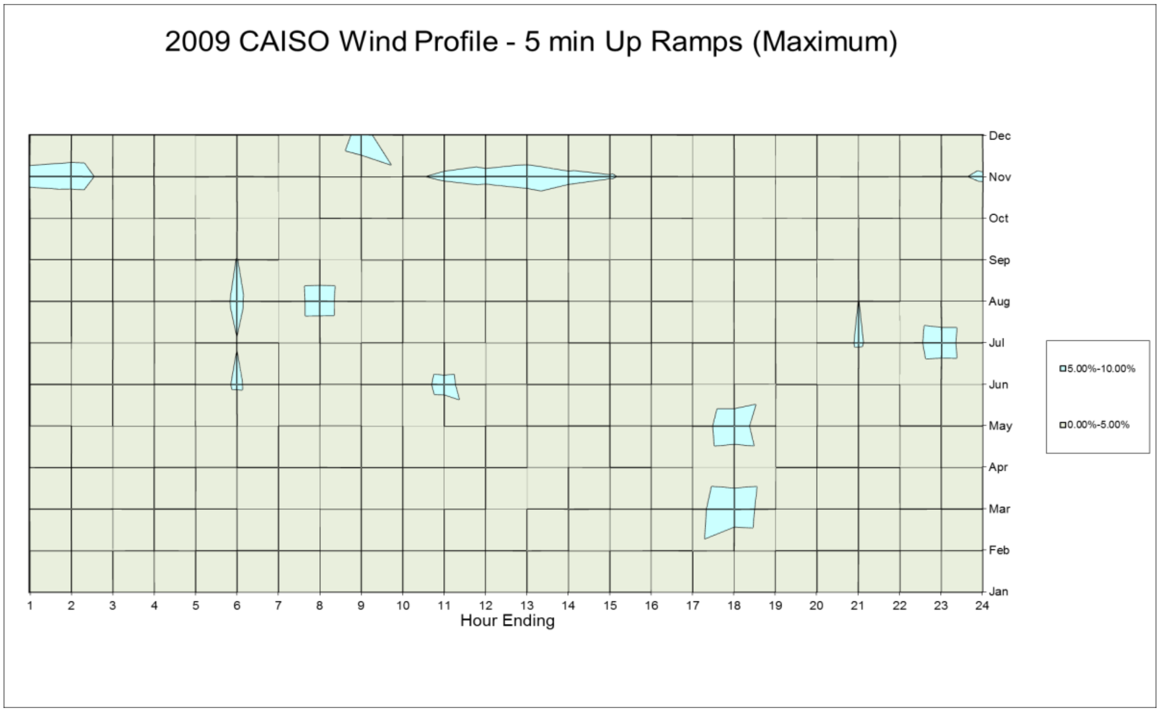


Figure A.12: 2009 CAISO Wind Profile – 5 min Up Ramps

Wind Diversity Work

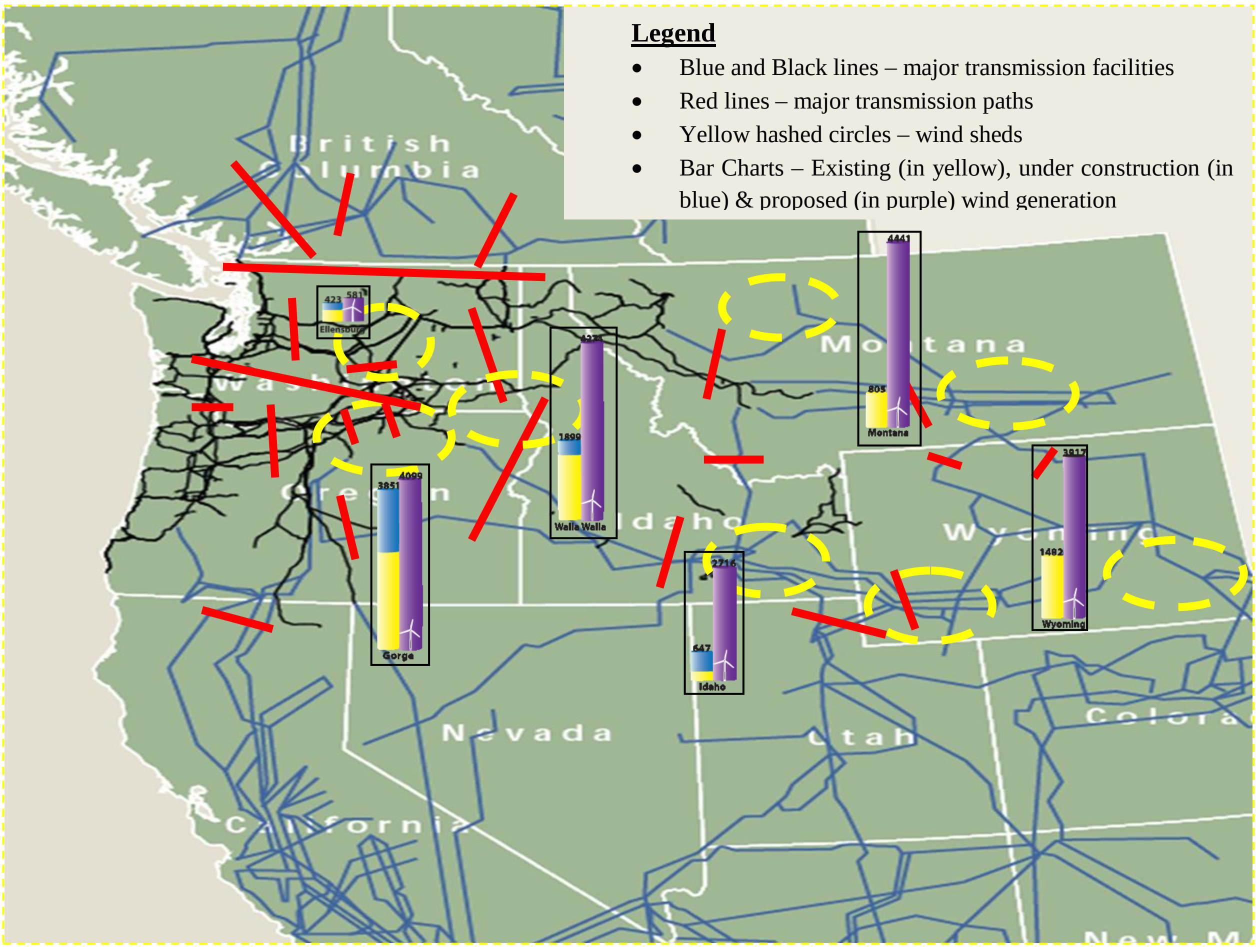


Figure A.13: Wind Integration & Transmission Flowgates

The wind areas shown in the above path map typically have different wind characteristics. Some are in different wind sheds with very different characteristics. Others are in the same wind sheds but have different ramp up and ramp down times as pressure changes move through the area. These differing wind characteristics and timelines will show up on the transmission system as wind generation changes and causes changes in flows on the transmission system. Since the wind generation is not dispatchable, wind generation owners will need to forecast wind generation to provide transmission schedules. To cover possible ramp up and down events, they will likely want to arrange for dynamic transfers on the system to cover this operation.

Using the NREL climatic data, the characteristics of wind in different wind sheds were compared. The wind areas that were analyzed include the Columbia River Gorge, the Walla Walla area, the

Ellensburg area, Southeastern Idaho, Central Montana, NE Montana, SE Wyoming and SW Wyoming. The red squares show the maximum expected ramp events that would have occurred in each of these areas. The blue diamonds show all the possible pair combinations of these areas. As can be seen by this data, the diversity between these areas usually results in reduced ramps if areas are combined. Most of the single areas (red squares) are in the left (positive) or right (negative) sides of this graph and the blue diamonds are in the middle (lower ramps). Although combining the generation in different areas results in reduced ramps, if there are any transmission paths between the two areas in question, these transmission paths would experience the full ramps that occur between the areas.

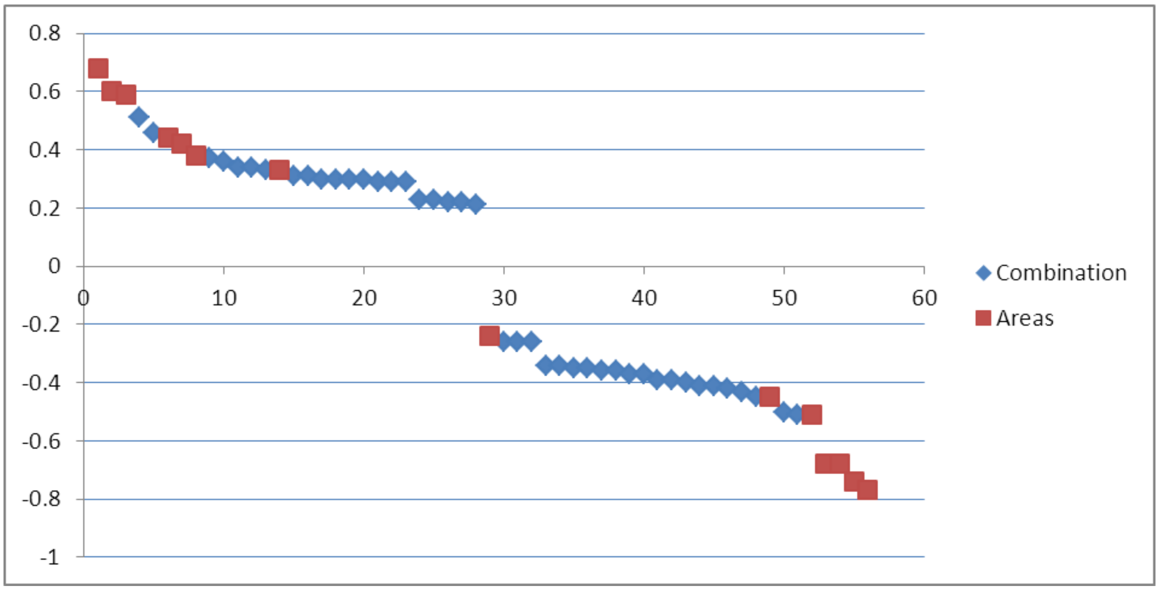


Figure A.13: Comparison of Actual Wind versus Calculated NREL Data

The CAISO did an analysis of the change in wind that could occur if the COI were loaded completely with potential NW wind. They used the 10 minute characteristics of undeveloped NW wind which is mostly in the Walla Walla area. This information is shown in Table 2 below.

Using the NREL wind data, 4900 MW was aggregated to simulate a full loading of the COI. The maximum positive ramp change that occurred in the aggregate data was 1388 MW between any 10 minute period and the maximum negative ramp change was -1672 MW. These ramps would be expected to occur once a year. The maximum negative excursion that is expected to occur once every two weeks is -780 MW. The maximum negative excursion that is expected to occur once every 1.5 days is -301 MW. As shown in Table 2, the comparable positive deltas occur at approximately the same frequency and magnitude. The expected ramps for the composite wind data are quite low.

The NREL data was compared to actual BPA wind data. The BPA wind fleet is predominantly in the Columbia River Gorge area but there is also wind around Walla Walla and Ellensburg. The BPA wind data was also prorated from 2,569 MW to 4,588 MW to be comparable to the CAISO analysis. In these data, the maximum positive ramp change that occurred was 1,145 MW and the maximum negative ramp change was -1180 MW. The maximum negative excursion that is expected to occur once every two weeks is -558 MW and -282 MW once every 1.5 days. The actual wind data from BPA was similar to the CAISO/NREL data but showed somewhat reduced excursions in both the positive and negative directions. These data are shown in the tables below.

Table A.2 - Aggregate Wind 10-min Delta Statistics (@5000MW)

	CAISO	**BPA**
Max Output	4889	4588
Maximum Positive Delta	1388	1145
Average Positive Delta	48	50
Median Positive Delta	24	29
% of Positive Deltas	48%	43%
Maximum Negative Delta	-1672	-1180
Average Negative Delta	-46	-41
Median Negative Delta	-26	-24
% of Negative Delta	52%	53%
% of 0 deltas	NA	4%

Table A.3 - Expected ΔV from Dynamic Schedule (@ 5000MW)

% Expectation	Frequency	Expected 10-Minute Negative Wind Delta		Expected 10-Minute Positive Wind Delta	
		CAISO	**BPA**	**CAISO**	**BPA**
-	Once per year	-1672 MW	-1180 MW	1388 MW	1145 MW
99.90%	Once every 2 weeks	-780 MW	-447 MW	868 MW	559 MW
99%	Once every 1.5 days	-301 MW	-228 MW	376 MW	226 MW
95%	Four times per day	-148 MW	-138 MW	166 MW	154 MW
90%	Eight time per day	-108 MW	-102 MW	108 MW	117 MW

Appendix D – Summaries of CAISO's 2010/2011 DTC Study

Introduction

In January 2011, the CAISO published the final report from a study performed under contract by GE Energy. The objective of the CAISO study (Final Report on Impact of Dynamic Schedules on Interfaces, January 6, 2011, available at http://www.caiso.com/2aff/2aff9e9150530.pdf) is to explore the impact of dynamic transfers of renewable generation across interfaces into the CAISO, including impacts on voltages at the CAISO boundary and within the CAISO, and impacts on regional stability due to resources that would be transferred into the CAISO market. The CAISO study has not intended to address limitations on dynamic transfers that may exist within transmission systems that are external to the CAISO. The scope of study of dynamic transfers is specifically defined to consider the variability of intermittent wind and solar photovoltaic (PV) resources. Other potential aspects of dynamic transfers, such as hourly or sub-hourly schedule changes, would be controllable by the CAISO and thus are not within the scope of study. Two technical aspects of system performance have been evaluated:

1. **Steady-state voltage changes**
2. **Oscillatory response**

To consider the greatest sources of potential impact to the CAISO system, the study has evaluated two interfaces:

1. **California Oregon Interface (COI), and**
2. **West of River (WOR).**

The CAISO's analysis begins by aggregating wind and solar PV profiles to statistically characterize their expected variability. This statistical analysis evaluated the change in wind or solar PV generation from one 10-minute point to the next. These statistics provide a measure of how often relatively severe changes in power can be expected. For example, when 99% of changes in power (ΔP) per MW of dynamically scheduled wind or solar generation are within a given range, the statistical expectation is that more severe events will occur, on average, less than once per day. Daily tap motions and capacitor switching are presently expected during system operations. Wind and solar variations that result in normal switching or other control actions over a similar period are judged acceptable. The statistics of wind variation dictate that faster variations, e.g., on a period shorter than 10 minutes, will be of smaller amplitude.

From the power flow analysis, the CAISO's analysis calculates the change in voltage (ΔV) associated with such a change in power, as well as the potential impact of that ΔV on transformer tap motion and shunt capacitor switching. Since the power flow analysis was performed with the COI and WOR interfaces near maximum, the focus was on the negative changes in power.
Finally, the CAISO's study examined the impact of wind and solar PV availability on small signal oscillatory performance. The dynamic performance evaluation incorporated extremely conservative

assumptions. Specifically, all variable renewable generation in a given area (i.e., wind in the Northwest, and solar PV in the Southwest) was oscillated at a single bus at one of the identified power swing frequencies. This test, which has a negligible risk of occurrence, provided maximum impact on grid oscillations. The assumption underlying this test is that common-mode oscillation of the renewable generation will be worse than any variation that might occur in operation, and therefore provides a conservative upper bound.

At the COI interface, the maximum allowed power flow is 4800 MW. Therefore, the theoretical maximum dynamic schedule is also 4800 MW. The study represents this maximum dynamic schedule by a 5000 MW aggregate wind profile. The statistical analysis shows that 99% of the time, the expected 10-minute drop in wind generation would be 301 MW or less. The power flow analysis showed that this would result in at most a 0.012 per-unit (pu) change in voltage on the 500 kV system near COI. Changes on the lower voltage system, closer to loads, are considerably smaller, indeed being too small to result in additional transformer tap motion or shunt capacitor switching. The maximum 10-minute drop during a year of data was a one-time occurrence of 1672 MW. The power flow analysis shows that this would result in up to a 0.065 pu ΔV, which would likely cause some tap motion and shunt capacitor switching. The wind data shows that voltage changes of this magnitude will be rare, and will not occur in rapid succession. There is no significant risk of tap hunting or rapid on/off cycling of shunt devices.

The dynamic analysis at COI showed that an extreme test, driving all of the dynamically scheduled wind generation at a characteristic frequency with a peak-to-peak magnitude that exceeded the interface limit, still resulted in damped oscillations. At magnitudes greater than 3000 MW peak-to-peak, some protective relays operated depending upon the system condition and fault event. The study finds that there is no credible wind variation that can cause oscillatory destabilization of an otherwise stable system. Details of this part of the CAISO's study may be found in the Final Report on Impact of Dynamic Schedules on Interfaces.

The following sections describe highlights of the study method and results for COI, since this is the interface between the CAISO and the Pacific Northwest. A similar analysis in the CAISO's study examined the WOR interface, where the maximum allowed power flow, and thus the theoretical maximum dynamic schedule, is 10,100 MW. The study represents intermittent dynamic transfers on WOR by a 15,000 MW DC/ 11,550 MW AC aggregate solar PV profile. The statistical analysis showed that that 99% of the time, the expected 10-minute drop in solar PV generation would be 412 MW or less, resulting in a 0.004 pu change in voltage. This is too small to result in additional transformer tap motion or shunt capacitor switching. The maximum once-per-year drop is 523 MW, which would result in a 0.005 pu change in voltage. The dynamic analysis of the WOR interface again shows that driving all of the dynamically scheduled solar PV generation with a peak-to-peak magnitude that exceeds the interface limit still results in damped oscillations, with some operation of protective relays, and increased duty of nearby SVCs depending upon the system condition and fault event.

Study Approach: Wind and Solar PV Statistical Analysis

The study's wind and solar PV profiles are aggregations of a year (2006) of 10-minute profile data from the National Renewable Energy Lab (NREL) Western Wind and Solar Integration Study (WWSIS). For the COI interface, the aggregate profiles represent about 2700 wind sites in Oregon and Washington. Among individual 30 MW sites, sorted from best to worst capacity factors, the top sites were combined into aggregate profiles of approximately 2500, 5000, 10,000, and 15,000 MW ratings. The selected profiles are cumulative, such that the 5000 MW profile consists of the 2500 MW profile plus the next best 2500 MW of wind sites, and the 10,000 MW profile consists of the 5000 MW profile plus the next best 5000 MW of sites. For simplicity, these descriptions are rounded numbers, and the actual profiles are multiples of the 30 MW plant size, as follows:

Table A.4 – NREL WWSIS Data

Description	2500 MW	5000 MW	10,000 MW	15,000 MW
Total Rating	2490 MW	4980 MW	9990 MW	15,000 MW
Maximum Output	2447 MW	4889 MW	9775 MW	14,663 MW
Minimum Output	0 MW	3 MW	13 MW	16 MW
# of Oregon Sites	24	39	90	187
# of Washington Sites	59	127	243	313
Total # of Sites	83	166	333	500

To statistically characterize the profiles' expected variability, the analysis has evaluated the change in generation from one 10-minute point to the next, which then produces the expected change in power (ΔP) per MW of dynamic scheduling.

The following figure is a scatter plot of the 10-minute changes in output for the 5000 MW aggregate wind profile. The maximum positive 10-minute change during the year of data is about 1388 MW, and the maximum negative 10-minute change is -1672 MW.

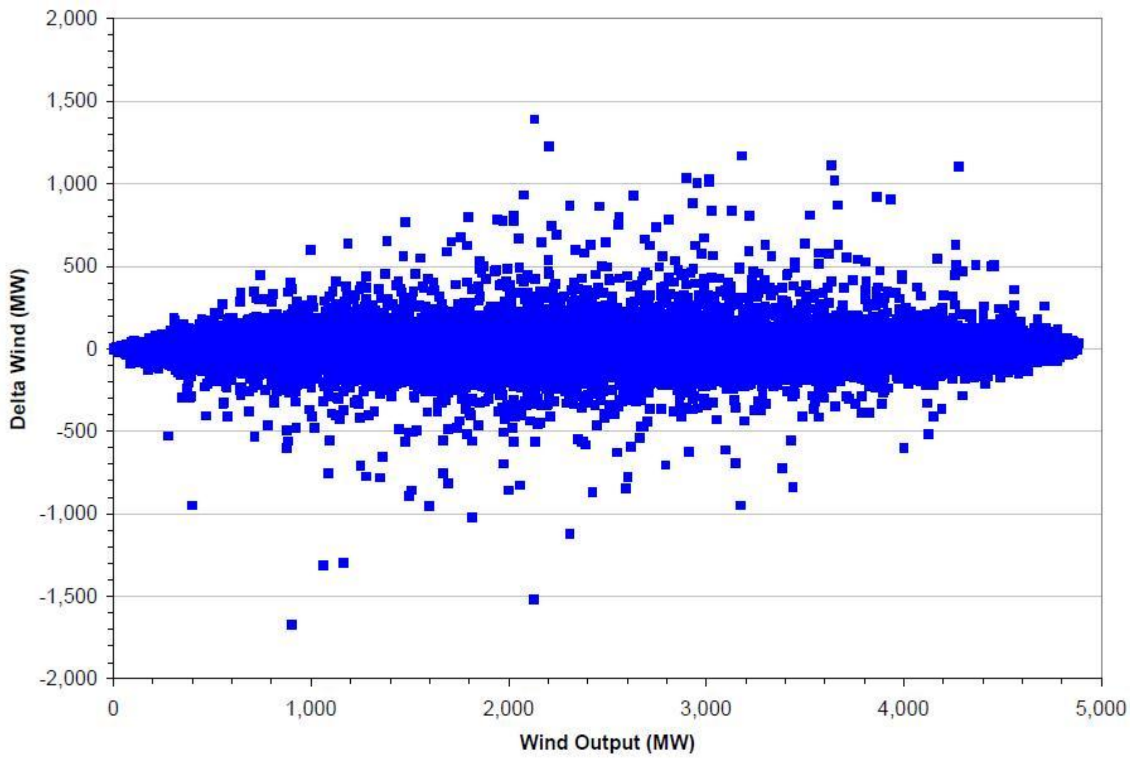


Figure A.14: 10-minute changes in wind output

The aggregate wind profile 10-minute variability statistics are summarized in the following table, for decreases in generation. Focusing on the 5000 MW wind profile that is closest to the full COI capacity, the extreme variations is a decrease of -1672 MW, but the average negative delta is -46 MW, the median negative delta is -26 MW, and 99% of the negative deltas are below -301 MW. This means that once every day and a half, wind farms with a total rating of 5000 MW would be expected to produce one 10-minute drop in power of 301 MW or more.

Table A.5 – NREL 10-minute variability statistics

Expectation	Frequency	2500 MW	5000 MW	10,000 MW	15,000 MW
	Once per year	-785 MW	-1672 MW	-2554 MW	-3199 MW
99.9%	Once every 2 weeks	-393	-780	-1257	-1543
99%	Once every 1.5 days	-155	-301	-495	-611
95%	Four times per day	-80	-148	-250	-324
90%	Eight times per day	-57	-108	-182	-239

Study Approach: Steady-State and Dynamic Power Flow Analysis

The CAISO modified a standard WECC 2018 heavy spring power flow base case to develop the primary study data for COI, and also used a 2020 summer peak case from the CAISO's Comprehensive Transmission Plan with 33% renewable resource integration for sensitivity analysis. In the 2018 case, the CAISO added 1074 MW of wind generation, replaced the Southern California Edison (SCE) area model with the one from the 2020 heavy summer case of the 2011 CAISO Transmission Expansion Plan (keeping the load at the level of the 2018 heavy spring case), and added upgrades to represent the SCE's Tehachapi Renewable Transmission Project in Southern California. For the 2020 COI sensitivity database, the CAISO increased Northwest generation by 1242 MW and decreased SCE generation by 1012 MW.

Each of the three 500 kV lines across the Oregon – California border, comprising the COI interface, is series compensated. Shunt capacitors and reactors are also located near the COI interface, in particular 1079 MVAr of line connected shunt reactors in the Pacific Gas & Electric (PG&E) area near COI, which switch with their associated lines and do not respond to voltage variations. The following voltage-controlled mechanically-switched shunt capacitors are modeled as type 4 SVDs, which switch in steps when the voltage goes outside a deadband:

Table A.6 – COI Voltage Deadbands

Bus Name	Voltage (kV)	B (MVAr)	Spring Database		Summer Database	
			Scheduled Voltage (pu)	Voltage Deadband (pu)	Scheduled Voltage (pu)	Voltage Deadband
30015 Table Mt	500	454	1.060	+/- 0.08	1.060	+/- 0.08
30020 Olinda	500	200	1.079	+/- 0.02	1.079	+/- 0.02
30035 Tracy	500	600	1.070	+/- 0.02	1.070	+/- 0.02
30042 Metcalf	500	350	1.037	+/- 0.02	1.050	+/- 0.03

To evaluate the impact on voltage performance (ΔV) of variations in imports (ΔP) representing dynamic scheduling, a change in imports is achieved by tripping generation at John Day. This site is relatively far from the COI interface, but provides a large change in interface flow per MW of generation tripped (i.e., a high distribution factor), and minimizes the impact of the lost reactive power support on the measurement of ΔV resulting from the ΔP across the interface. The model balanced the tripped generation using increased generation within the CAISO, using three redispatch procedures: (1) redispatch of individual generators in proportion to their MVA rating, while not exceeding their maximum capacity, (2) redispatch within the maximum capacity while excluding baseload generation, and (3) using designated individual generators. The CAISO identified and used the following as the most critical contingencies for analysis of the COI interface: (1) loss of 2 Palo Verde generators, including SPS tripping of 120 MW of load in Arizona, (2) loss of the Pacific DC Intertie, including SPS tripping of Northwest generation, (3) loss of 2 San Onofre generators, and (4) loss of 2 Diablo Canyon generators.

The CAISO study calculated the ΔV / ΔP characteristics for six types of voltage control regulations:

1. No action: No regulation other than generator voltage control
2. Continuous SVD control: Only SVCs with continuous action regulating (PSLF type 2 SVDs)
3. LTC action: Only LTC transformers regulating
4. All SVD action: SVCs with continuous action and switched shunts regulating (PSLF type 2 and 4 SVDs)
5. SVC and LTC: SVCs, switched shunts, and LTC transformers regulating
6. SVC, LTC, and PAR: SVCs, switched shunts, LTC transformers, and phase angle regulating transformers acting

For all combinations, each generator was allowed to regulate the voltage on its terminal, within its reactive power capability. All bus voltages at 230 kV or above were monitored in WECC, and bus voltages at 115 kV or above were monitored near the COI interface. Pre- and post-contingency voltages less than 0.95 pu or more than 1.10 pu were recorded, and voltage changes from pre- to post-contingency greater than 0.001 pu were also recorded. All interface flows were monitored as well as area flows in PG&E, San Diego, and SCE, and all SVC and LTC movements were monitored.

The CAISO's dynamic analysis evaluated the impact of variable renewable generation on oscillatory performance of the COI and WOR interfaces. Its goals were to characterize the frequency components of interface power swings in response to critical faults, to test whether renewable generation oscillating at those frequencies could adversely affect system damping, and therefore, to identify any need for a limit on the amount of dynamic scheduling across these interfaces. The study identified the dominant swing modes across the two interfaces using PSLF dynamic simulations, identifying the critical disturbances for each interface and using critical fault events to simulate power swings across each interface. Further details are described in the Final Report on Impact of Dynamic Schedules on Interfaces.

Study Results: Voltage Performance

To identify any dynamic schedule limitations on the COI interface due to steady-state voltage performance, the combined wind and solar PV statistical analysis and power flow analysis indicate the resulting occurrence of shunt capacitor or reactor switching events and LTC transformer tap motions. The Final Report on Impact of Dynamic Schedules on Interfaces contains a number of graphs illustrating the results, of which only an illustrative sample is included here.

The following graph shows a scatter plot of ΔV for the monitored buses for each of three changes of generation (553 MW, 1106 MW, and 1521 MW), for all six of the voltage control options, each sorted from highest to lowest impact independently for each control option. The X axis is a count of data points corresponding to the number of voltages recorded for each scenario, as having impacts exceeding the thresholds stated above. The initial condition for all scenarios is a stressed case with COI heavily loaded, and when imports are reduced, system voltages increase and the ΔV values are nearly all positive. The control option with only LTC action shows the largest ΔV at nearly every bus for all changes of generation, followed by the no-action, and continuous action, control options. Options with switched shunts active (all SVD action, SVC & LTC action, and SVD, LTC, and PAR action) have lower voltages, and some ΔV values are negative, due to shunt capacitors switching off following the reduction in imports. The 500 kV buses in Northern California and Southern Oregon have the largest ΔV, including the Maxwell, Round Mountain, Olinda, Malin, and Captain Jack 500 kV buses.

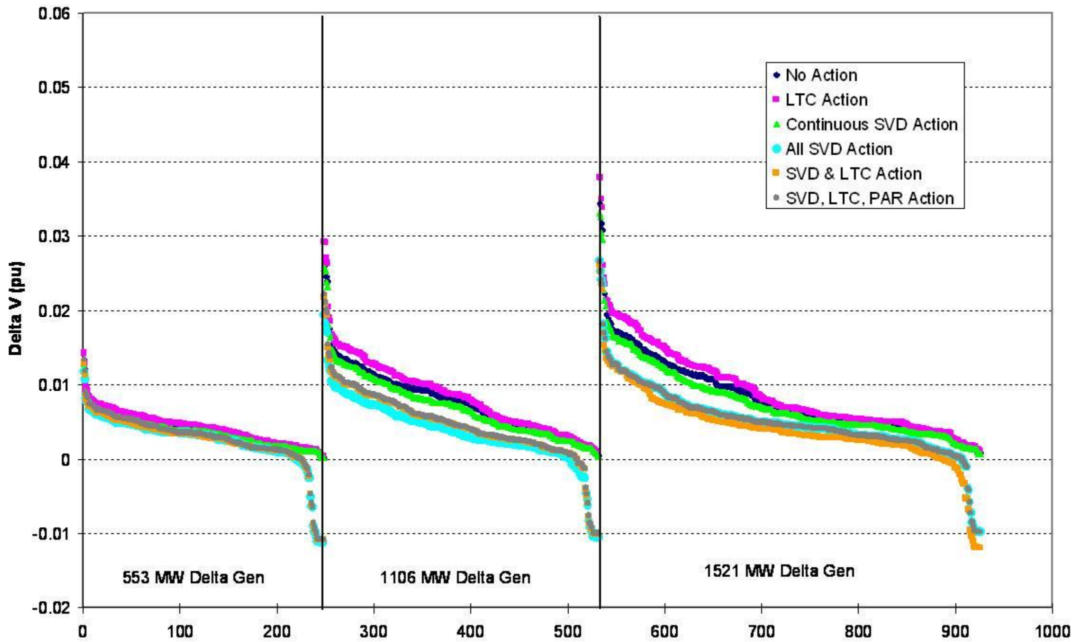


Figure A.15: COI 500kV buses ΔV vs ΔP generation

For the first plot, showing the impact of a 553 decrease in generation, the graph shows that about 250 buses have voltage changes (ΔV) of more than 0.001 pu. For the case of a 1106 MW change in generation, about 300 buses have ΔV exceeding 0.001 pu, and about 400 buses met the reporting criteria for a 1521 MW change in generation. For a 1521 MW reduction in Northwest generation, the Round Mountain 500 kV bus voltage increases by 0.034 pu with no control action, 0.038 pu with only LTC control, and 0.033 pu with continuous SVD. The majority of buses have a ΔV value of less than 0.02 pu for the 1521 change in generated power.

Another way to view the ΔV/ΔP of the different scenarios is for an individual bus. The following is a plot of the Round Mountain 500 kV bus voltage, plotted against ΔP generation, showing the ΔV for the six control options. For a 553 MW reduction in Northwest generation, ΔV is between 0.012 and 0.014 pu for the different control options. For a 1512 MW reduction in generation, ΔV ranges from 0.025 pu for full SVD and LTC action, to 0.038 pu with only LTC action. This is the largest ΔV for any of the monitored CAISO buses.

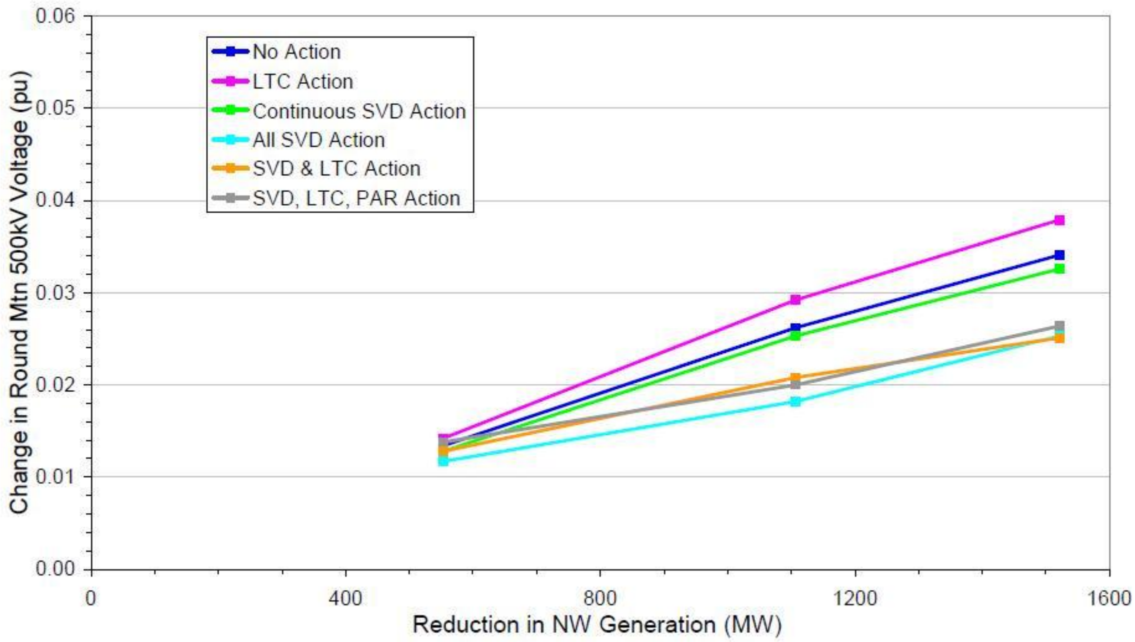


Figure A.16: Round Mountain 500 kV ΔV vs. ΔP generation

One of the concerns with the voltage variations caused by dynamic scheduling is excessive LTC tap motion and shunt capacitor or reactor switching. Excessive capacitor switching will only be an issue when ΔV caused by the change in imports plus ΔV caused by capacitor switching exceeds the voltage control deadband. The values of ΔV for capacitor switching will vary depending on system conditions, but assuming that the control deadband of an automatically switched capacitor will be set to at least two times the ΔV for capacitor switching, the largest ΔV for capacitor switching would be 50% of the voltage control deadband. This leaves another 50% of the deadband for import variations. The Final Report on Impact of Dynamic Schedules on Interfaces lists details of the voltage changes and deadbands for LTC transformers and switched shunt controls, observes that the study's simulations show little switching within the CAISO, and concludes that even large changes in imports should not cause excessive amounts of equipment switching.

From the steady-state analysis with all lines in service under spring conditions, the largest ΔV/ΔP occurs at the Round Mountain 500 kV bus. With no control action, ΔV/ΔP is 0.0024 pu per 100 MW ΔP. With only LTC controls active, the value is 0.0039 pu per 100 MW. Based on these values, the expected ΔV for the expected 10-minute wind ΔP is as follows, for the 5000 MW wind profile scenario and representative sensitivity cases:

Table A.7 – 5000MW wind profile, expected ΔV for the expected 10-minute wind ΔP

Expectation	Frequency	5000 MW	Spring, ΔV No Action	Spring, ΔV SVC Action	Summer, ΔV SVC Action
	Once per year	-1672 MW	0.040 pu	0.038 pu	0.037 pu
99.9%	Once every 2 weeks	-780	0.019	0.018	0.017
99%	Once every 1.5 days	-301	0.007	0.007	0.007
95%	Four times per day	-148	0.004	0.003	0.003
90%	Eight times per day	-108	0.003	0.002	0.002

In summary, once every two weeks a drop in wind of 780 MW or more will result in a voltage change of 0.02 pu or greater, which could result in a shunt capacitor or LTC switching cycle. Once per year, a more significant change in voltage can be expected. The ΔV with a line out-of-service would be higher, but the frequency of occurrence would be lower due to the low likelihood of both a line outage and a large change in wind generation.

Conclusion

The conclusion of the CAISO's study is that under extreme conditions (e.g., combinations of 500 kV line or multiple generation unit outages, once-per-year changes in dynamically scheduled renewable generation output, and unrealistic aggregate wind and/or solar PV behavior), it may be possible to trigger excessive shunt capacitor switching, transformer tap motion, SVC response, and/or protective relay operation. However, the expected variability from the wind and solar PV generation when dynamically scheduled up to the overall maximum will not result in large changes in voltage or excessive duty on voltage regulating devices. The expected change in voltage caused by dynamic scheduling is somewhat sensitive to the CAISO's generation redispatch and to system operating condition (spring vs. summer peak), but the sensitivity is relatively low and does not change the study's conclusions.

Therefore, based on considering high levels of imports of intermittent resources during both normal and abnormal operating conditions, the CAISO's analysis shows that within the CAISO's footprint, no limits are required on dynamically scheduled variable generation other than the existing interface limits. Neighboring Balancing Authorities may have limitations within their systems that could impact the level of renewable resources that may be dynamically transferred to the CAISO.

Appendix E – Desired Characteristics of a DTC Methodology

The primary goal of the DTC Taskforce is to develop a DTC methodology that all Balancing Authorities could apply to determine the Dynamic Transfer Capability (DTC) limits for their key internal and external flow gates. This section identifies some characteristics that are desired in the new methodology:

- The methodology should be flexible enough to accommodate DTC limit calculations over a wide spectrum of timeframes. For example, this may include:

    - off-line results that are calculated days, months or years ahead of time,
    - on-line results that are calculated at each change in the BA's schedule (15 to 60 minutes) or
    - Real-time results that are calculated every few minutes or after a change in the system state.

- The methodology should enhance the knowledge of how a BA can reliably operate their system with high levels of variable generation on-line. This would provide BA's with the following:

    - The means to identify critical pieces of power system equipment, control equipment and/or operator practices/tools that are restricting a given BA's DTC.
    - Suggestions and examples of power system equipment, control improvements and/or operator practices/tools that could be used to improve a given BA's DTC. (refer to Section 8.0)
    - Characterization of the use of DTC for different generators, loads and schedules.

- The methodology should be repeatable and transparent and enable a BA to safely and reliably meet existing system performance requirements (eg. post contingency voltage dip, withstand next MSSC) at any given operating point while worst-case dynamic transfers are occurring frequently and unpredictably.

- It is expected that if BAs operate within the DTC limits they determine, that they would be exposing themselves to similar levels of risk as compared to the 2010 system. For example, measures of SAIDI, SAIFI, LOLE and/or LOLP should not increase proportional to the increase in dynamic transfers for a given BA if they are operating continuously within their DTC limit.

- It is also expected that the DTC limits would be set such that power quality for loads would not be notably degraded.

- The methodology should provide a BA with a technique to discern between scheduled dynamic transfers, scheduled static transfers and unscheduled inadvertent flows while being flexible enough to accommodate sustained flows resulting from Reliability Based Control (RBC) algorithms

The methodology should lend itself to broad adoption by BAs within WECC and other NERC regions.

Appendix F – Possible Framework for a DTC Methodology

There are up to three types of entities involved with the determination of DTC: the variable resource (i.e. wind generator), the load entity, and the balancing resource which provides power to the load as a function of changes in the variable resource's output. It is worth noting that there could be multiple flowgates between the source and the load as well as the balancing resource and the load, each of which could have DTC limitations.

It is assumed that steady state power flows will be kept below respective SOLs and that automatic devices will respond to regulate the system voltage where available. However, some of the voltages that occur as a result of the changing power flows could be outside the normal operating range until manual adjustments are made to restore them to nominal levels. Consequently, prior to the manual adjustments being made, the system with an abnormal voltage profile could be deemed to be in a stressed condition, and as such if a disturbance occurred on the critical elements, the system may experience unacceptable post disturbance voltage levels, or even lose transient stability and/or voltage stability.

From the scenario described above, two potential issues emerge that need to be addressed when considering DTC limits: the frequent switching of devices to regulate the voltages; and the reliability of the system before manual adjustments. To ensure system reliability, in particular when there are limited automatic controls for voltage or RAS arming, a well devised methodology of determining DTC would be necessary. Listed below are conceptual steps of determining DTC.

Step 1 - Establish critical parameters:

- Decide suitable time duration to account for the automatic control actions (e.g. 5 or 10 minutes) which in turn could be used to define the DTC time frame. Ensure the time is sufficiently long to allow appropriate manual actions to bring the system voltages to the appropriate levels.
- Use historical data to estimate the maximum wind MW ramp for the selected time frame and ensure it is within the capability of balancing resources.

Step 2 - Fix study assumptions:

- Determine timeframe covered by the analysis for the applicable DTC: (e.g. 1 year, 1 season, 1 month, 1 day, 1 hour).
- Select a maximum voltage deviation that is deemed acceptable from the point of view of additional equipment wear and tear caused by switching to regulate the voltages
- Establish a list of available automatic control devices in the study area that would operate within the chosen DTC time frame (e.g. 5 or 10 minutes).
- Determine the automatic RAS functions within the time frame

Step 3 - Identify scenarios and impacted flowgates:

- Identify the location, amount, and maximum wind resource variation within the selected time frame as well as the location of the balancing resources; this would facilitate the determination of the transmission flowgates that are to be affected by the power re-dispatch.
- Use distribution factors from the balancing resource in identifying the flowgates that could be significantly impacted by the power re-dispatch.

Step 4 - DTC Analysis for each flowgate:

- Ensure the re-dispatched power flows through flowgates are below their respective SOLs.
- Ensure the voltage deviations after generation re-dispatch by balancing resources before manual adjustments are below the selected limit.
- Identify credible, relevant and critical contingencies for the scenarios.
- Apply credible contingencies and assess post disturbance performance, to ensure meeting the voltage variation, transient stability and voltage stability requirements. Apply the applicable RAS actions within the DTC time frame.
- Determine the maximum DTC from the balancing resource based on chosen level of risk, such as the expected largest voltage change, or number of large wind variations in a year.

Appendix G – Issues & Concerns related to DTC Limits

Sub-synchronous Resonance

Sub-synchronous resonance (SSR), the phenomena, has been known to be the cause of severe damage to large synchronous generators. The end result of SSR is shaft fractures on generators at rated speed, which can also endanger the safety of plant personnel. The primary cause of SSR in an electric grid is the *Induction Generator Effect* (IGE) which occurs in transient operation. This happens when there is loss of a transmission line near the large generators, and the oscillations caused by the disturbance produces sub-synchronous currents. These currents, in turn produce a magnetic air gap field in the armature of the generator which rotates at sub-synchronous speed resulting in the damper cage of the generator to rotate at sub-synchronous speed. The system's (generator, transformer and transmission line) impedance decreases as a result of the damper cage operating as induction generator, and may reach negative values. At very low or negative values of system impedance, the disturbance is intensified further and when the frequency of the disturbance matches the frequency of the generator shaft, the oscillations are amplified causing severe if not permanent damage to the generator shaft. The energy stored in the capacitor banks, which are in service on lines carrying high currents, also contribute to SSR currents.

SSR protection is an important aspect for large power plants in the electric grid. The large generating plants in WECC are necessarily equipped with SSR protection, an example being the "*Colstrip"* generating plant in Montana. The SSR protection disables the series capacitors on the transmission lines if the current falls below a particular value set by the plant depending on the size of the generators and inserts the capacitors back in series when the current increases.

With the increase in generation caused mainly by renewable sources like wind, the SSR phenomenon must be taken in to effect to mitigate any potential incidents leading to damage/failure of the wind generators or conventional generation near the wind source. The wind generators are mainly doubly fed induction motors, so the induction generator effect will be common on the transmission system. A *Static Var Compensator* (SVC) with a voltage regulator is usually employed at wind farms to provide dynamic reactive power support. In theory, the same SVC when equipped with a SSR damping controller, is shown to effectively damp the SSR oscillations. The *Thyristor Controlled Series Capacitor* (TCSC) is also shown to damp the sub-synchronous oscillations when provided with closed loop current control.

System Inertia

For an electric grid, system inertia can be defined as the total amount of kinetic energy stored in all the spinning turbines and rotors of generators which are online. The inertia determines the response of the grid to the frequency deviations caused due to system disturbances. Given a particular disturbance in the form of unbalance between generation and demand, the inertia constant (M) of the system would limit the rate of change of frequency. Thus slower change in frequency (characteristics of a stiffer system with high inertia) provides sufficient response time to control the frequency unbalance. The ancillary factors contributing to inertia would be the load and the MW transfers.

For an interconnection with large amount of wind generation, there is higher deviation in the wind power output owing to the unpredictable characteristics of wind. Typically, wind farms are characterized with having low or zero contributions to system inertia. This mainly depends on the type of wind turbine installed. A fixed speed turbine is known to contribute to the system inertia primarily due to the inertia of the generator and wind turbine rotor. But a variable speed turbine controls grid power independently and thus decouples the generator torque from grid frequency. Thus they have virtually zero inertia contribution to the power system. And the latter are the preferred and popular turbines because of some benefits including their compatibility with non synchronous interfaces.

As observed and reported by the different BAs in the WECC interconnect, there is a direct correlation between larger frequency deviations and large amounts of wind generation. And with the forecasted increase in wind generation across the system, there will be times in the day when wind generation will dominate the generation dispatch. Thus, from a dynamic stability point of view, large amounts of wind generation will make the system unable to absorb the unbalances owing to the intermittent nature of wind without risking the stability, power quality and, or frequency control. This would call for future undertakings of measures needed for developing efficient and reliable procedures to maintain system inertia or promoting the use of storage devices, such as flywheel to be combined with wind farms in system operation.

As mentioned earlier, the ancillary factors like load demand and path transfers would help in controlling the inertia, but control in such a fashion would call for formulation of a stringent procedure since they are not easy to control. When wind generation is the dominating the generation dispatch, the system will be at a risk for instability issues. To counter that effect, braking or reducing the long distance MW transfers and bringing the local generation online would serve to make the system more stable. This would however facilitate the need to increase regulating reserves near load pockets or establishing secondary reserves especially for wind generation. Or the future wind farms should have some storage devices like flywheels built in with them.

Combining the wind farms with storage devices could provide a means for storing surplus energy and thus improve the wind farm inertia. This would in turn help in preventing the instantaneous power oscillations due to the unpredictable characteristics of wind. A flywheel energy storage (FES) system is an example for an energy storage device.

Reliability Based Control (RBC)

Reliability based control defines a method of relating the frequency and ACE limits for the system. This relationship is based on the current state of the system and the system protection settings. The figure below will provide a better explanation of the RBC model.

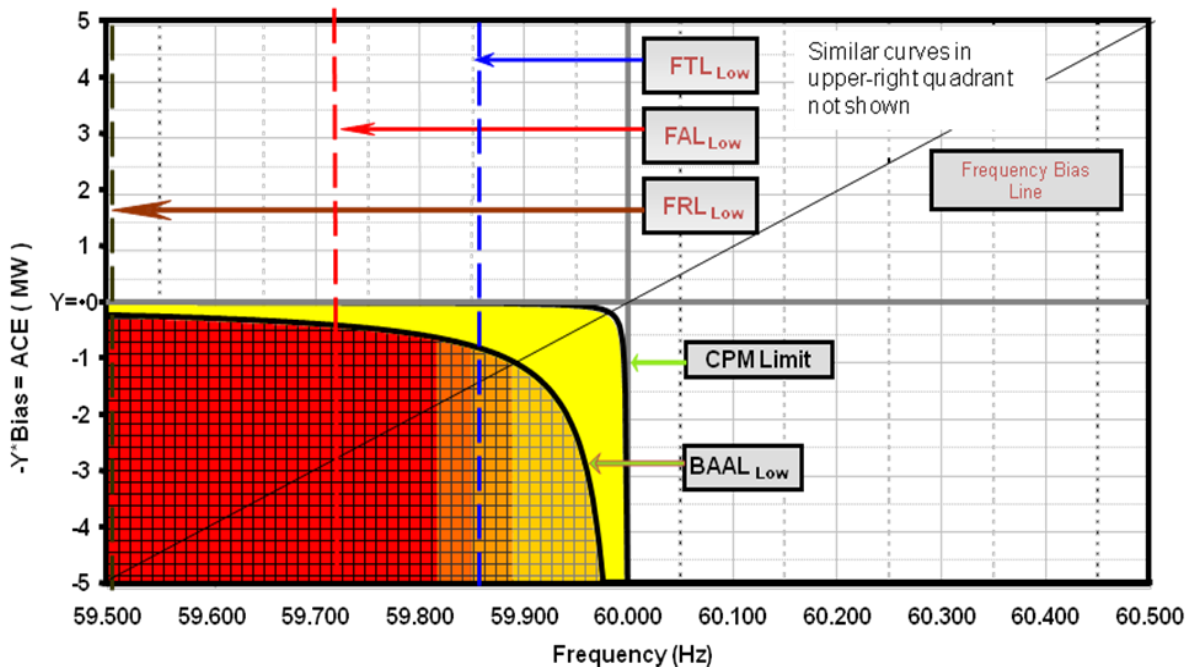


Figure A.17: RBC Frequency – ACE Relationship

The graph describes the frequency and ACE relationship for a particular BA. As seen above, the system can be defined in a four quadrant operating system, with frequency limits established on either side of the scheduled 60 Hz. They are defined as:

Frequency Trigger Limit (FTL): This triggers the alarm that operating beyond this limit is acceptable for a *limited* time before the risk to the interconnection becomes unacceptable. For the WECC interconnection, it is calculated and set at 59.856 Hz.

Frequency Abnormal Limit (FAL): The system should always be operated within this limit. Operating beyond the FAL would expose the interconnection to unacceptable level of risk and failure to comply with this limit would result in the violating BA incurring a heavy penalty. For the WECC interconnection, it is calculated and set at 59.7 Hz.

Frequency Relay Limit (FRL): Operating beyond this limit would result in tripping of frequency related relays on over and under frequency and in turn shedding the area load. For the WECC interconnection, it is set at 59.5 Hz.

Balancing Authority Allowed Limit (BAAL): The BAAL limit is a dynamic limit proposed to replace the CPS2 standards. Its main purpose is to cap the ACE, either in negative or positive direction depending on the system condition.

In other words, it would pose a strict limit if the ACE is negative and the BA is under generating and vice versa. On the other hand, it would provide a less conservative limit to the BA if its ACE is low and the system frequency is high, and vice versa. A balancing authority can violate the BAAL for a maximum period of thirty 'consecutive' minutes, before they are held for violating the standards.

The final tool depicting the frequency and ACE relationship which includes the BAAL is shown below:

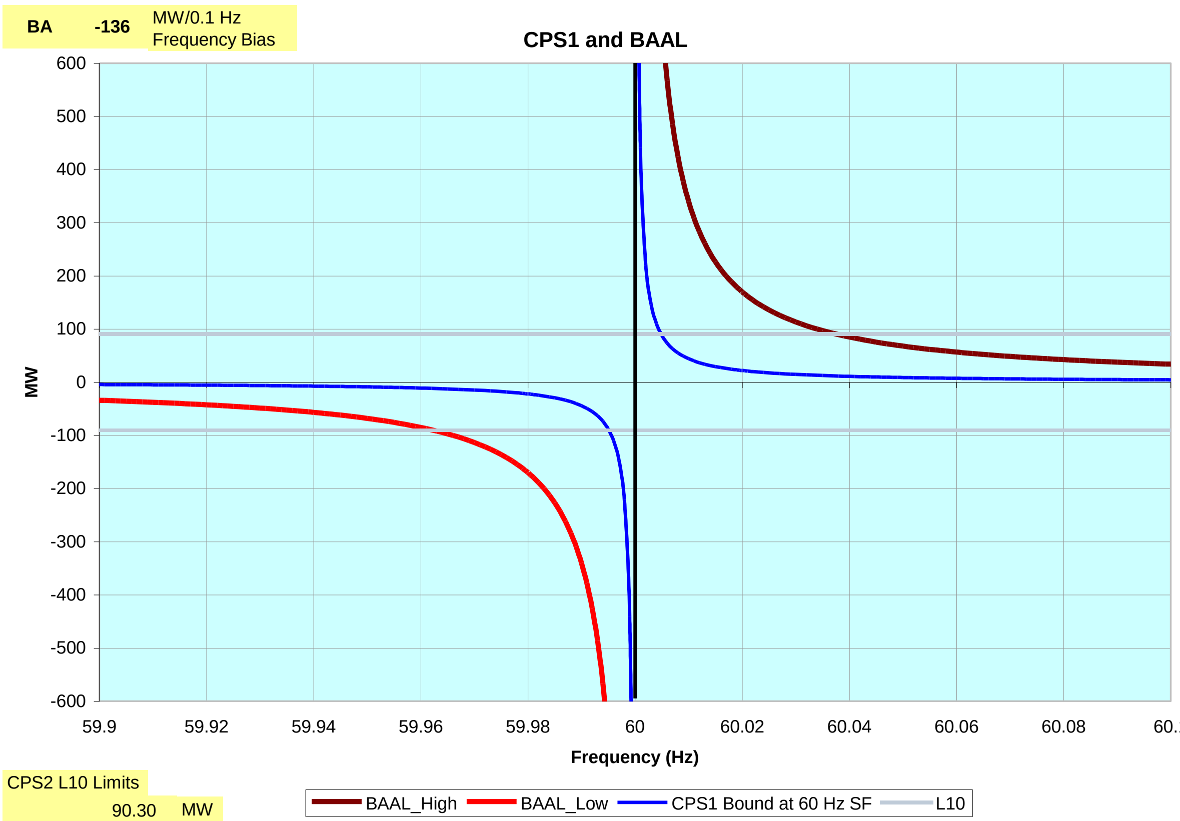


Figure A.18: Frequency – ACE Relationship with BAAL

Application of RBC to Dynamic Transfers

According to RBC, the unscheduled flows due to sudden ramp up or ramp down of wind generation we can accommodate provided the system frequency error has an opposite polarity to the direction of the ramp. If not, then measures need to be implemented to arrest the frequency deviation to a frequency nadir. DTCTF would be looking in to the application of RBC to dynamic transfers across paths and intertie lines in Phase II of the report.

Appendix H – Options for Enhancing DTC

The impact of Dynamic Transfers will vary from one BA to another because the complexity, level of automation and age of control schemes available to operators varies. For instance, many BAs have assumed that rapid changes on the transmission system are infrequent, and that a slow movement from one operating point to another is the norm. Dynamic transfers challenge this fundamental assumption and make it clear that the old control strategies, largely manual, are not sufficiently flexible to accommodate unrestricted expansion of dynamic transfer.

As a basic principle, the transmission system can be engineered to facilitate widespread use of dynamic transfers. This requires some changes from what is currently done, as the system currently is managed and designed for operation in a static manner. Allowing transmission operation to be wholly dynamic up to the rating of the path – equivalent to making dynamic flexibility available to all schedules – is in theory possible, provided that:

- Adequate visibility and personnel at the RC, BA, and TOP for monitoring with respect to impact on reliability,
- Complete automation of controls whose settings are changed as a function of power flow,
- Adequate dynamic reactive available throughout the system to maintain voltage such that neither quality of service or reliability is compromised when power flow changes,
- Costs of installation and maintenance of this equipment is not prohibitive.

Based on the listing of critical elements and concerns developed in phase 1, the Task Force identified a number of enhancements to the system and its control mechanisms that would improve the ability to manage dynamic transfers and thereby could lead to an increase the total dynamic transfer capability available for use.

No work has been done to date in quantifying the relative impacts or value of these enhancements. This listing is intended to merely indentify the options, describe how they relate to dynamic transfer limitations, and in a broad sense give indication of the qualitative merits of each.

Options for Enhancing DTC

When speaking of enhancing dynamic transfer capability, what is generally meant is some combination of increasing the number of distinct dynamic transactions handled simultaneously, increasing the magnitude of changes allowed in an hour, or increasing the ramp rate at which they occur.

While achieving these three objectives generally implies increasing the ability of the transmission system to respond automatically to variations in intra-hour power transfers, the options for doing this properly fall into four categories: 1) improve the ability of human resources (system operators and support staff) to manage the a workload that is changing in response to the changing operation of the system, 2) install equipment that automatically manages the systems that are most effected by changing power flows, 3) choose to accept greater impacts to service quality, cost, or additional risk that may be a consequence of increased intra-hour power transfers, or 4) require the variable resource and the transmission provider to operate such that service quality, cost, or additional risk from intra-hour power transfers are not changed.

The first two of these options (#1 & 2) improve the capability to manage dynamic transfers so that increased use can be accommodated without compromising the current level of transmission service provided. The last two (#3 &4) declares acceptable whatever impacts are experienced when dynamic transfer use is increased, even if the impacts result in a measureable decrease in the quality of service provided.

It is likely that further analysis would show that some combination of the options available in all four categories will provide the best option for long-term enhancement of dynamic transfer capability with low additional risk to the reliability of the transmission system, and at the least cost to customers and transmission users.

Addressing Human Resource Needs

System operators have the tools, skills, and information for real time operation of a power system that is relatively static during the hour. Many system operators still have manual control of several functions (e.g. RAS arming and voltage switching) and increased intra-hour transfers may increase workload and the skills required of the operators. Engineering support staff workload may also be impacted if increased dynamic and intra-hour transfers require more frequent updating of system operating limits and other operating instructions. The wide impact scheduling changes impact multiple PNW systems, so accommodating these on an intra-hour basis may require greater coordination of procedures, voltage control, and other real-time activities by system operators of neighboring utilities.

All of these functions require constant real-time state awareness with the ability to recognize potential risks and make effective decisions that set in motion mitigating actions. By addressing the impact of intra-hour scheduling on the system operator and support staff, increased use of dynamic transfers and other intra-hour scheduling methods can be accommodated without compromising the current level of transmission service provided.

- **Hire more operators to monitor critical paths:** As larger changes to the system operating point occur within a given scheduling period (1 hour, 30min, 15min), there will be an increased need for operators to be present and available to make necessary switching or RAS arming operations. Since control centers are operational 24x7, another position typically means up to 5 additional people, with additional support personnel. An additional position would address the added workload of monitoring, taking control actions, and decision making when events occur. It may be necessary to have specific dispatchers monitoring variable generation resources and their impacts to critical paths, so as to allow greater focus and attention on these specific issues.

- **Improved real-time tools**: The increased reliance on system operators to maintain state awareness, the ability to determine correct actions, and make decisions when needed for reliability should be a continuing priority for transmission providers. Improved system monitoring, decision making tools, and clear authority to take action allow higher levels of dynamic transfers when the system may be stressed as a result of unusual loads, generation patterns, transmission outages, or unplanned events. Transmission providers should continue to focus on improving the accuracy of their forecasting systems. Accurate wind forecasts will help operators prepare for large wind ramps, and assess the level of mitigating actions that may be needed to taken to prevent voltage excursions prior to them occurring.

- **Hire more operational support roles:** Employing more operational support roles who can analyze various sources of data could be critical to managing variable generation. Increased state awareness in unusual and changing conditions requires the support of additional staff working on system analysis, forecasting tools, and keeping system operating limit studies appropriate for current conditions. The analysis of wind and weather data, historical ramp up and down periods, voltage deviations, changes to system topology, availability of reactive power support, etc., will help inform the short-term actions of operators. These types of analysis reduce the uncertainty of operations with variable resources, allowing for higher levels of dynamic transfers with less risk of getting into an unstudied or unknown operating condition.

- **Development of operational procedures to manage expected changes of variable generation:** New coordinated procedures may be necessary for effective management of the effects of intra-hour variations. Similar to operational procedures that are in place to manage morning and evening load peaks, procedures should be developed to manage large fluctuations in path flow due to variable generation. These procedures might include guidelines that would help operators choose which reactive power devices would be most effective in regulating voltage on a path, and at which point in a large ramping event that the equipment should be switched. Properly coordinated procedures provide greater certainty of taking appropriate actions when system reliability is a risk, thereby allowing for higher levels of dynamic transfers before an event placing the system at risk occurs.

Potential System Reinforcements

Engineering the transmission system to facilitate widespread use of dynamic transfers requires automating many of the manual control strategies that were designed for operation that is relatively unchanging throughout the hour. Automating many controls that currently are done manually, or with "man in the loop" control schemes would improve the ability of the system to respond to power changes in a timely manner. Automation of equipment and schemes is proposed as an expedient means of addressing the issues raised by intra-hour variation, as it may take significantly more time, experience and research to work towards a point where dispatchers can reliably predict large changes in system state. Installing equipment that automatically manages the systems that are most effected by changing power flows, would ensure that the system is continually kept in an operating state (voltage, RAS, etc.) appropriate to current conditions.

There are a number of system reinforcements that could be implemented to better regulate voltage and accommodate large changes in power flow over transmission paths. Automated voltage and reactive control schemes allow for faster response to changes caused by varying power flow. Automation allows operators to concentrate on state awareness and problem solving rather than maintaining voltage profiles. By ensuring that profiles are always optimally set up there is no risk of operators lagging behind.

- **Automated switched shunt devices:** Installation of switched shunt capacitors and reactors at major 500kV buses, with automation to switch devices in and out as voltage approach upper and lower limits of acceptable voltage operating limits, would help reduce workload on transmission operators. The shift from manual switching to automatic switching is important, as it reduces human error related risk.

- **Installation of half-step reactive power devices:** Reactive power devices existing on the system that were designed for operation under very specific conditions (post-contingency action, loss of major reactive power support, etc) may only provide large step voltage regulation. Switching these existing devices on and off would only provide a course form of control, which may be ineffective in helping to regulate bus voltage changes for fluctuations in power flow caused by variable generation. With installation of a smaller reactive power device that could be used to counter larger step changes (i.e. 25MVAR capacitor bank to help counter 50MVAR inductor steps), the existing reactive power equipment would be more functional.

- **Installation of Dynamic Reactive power Devices**: With a greater cost, dynamic reactive power devices bring greater functionality and finer control.

  - **Static VAR Compensation (SVC):** Static VAR compensation provides reactive power injection/absorption with near instantaneous response to changes in system voltage. This is a distinct advantage over mechanically switched devices, which have slower switching times. Since these devices are operated close to their zero-point, they have a great range of ability to respond to voltage deviation.

  - **Static Synchronous Compensation (STATCOM):** Similar to the SVC, a STATCOM can provide near instantaneous response to changes in system voltage. Unlike a SVC, which uses thyristor controlled reactors and capacitors to switch in discrete steps, a STATCOM can provide continuously variable injection/absorption of reactive power, which provides an even finer and faster control of voltage regulation.

The task force identified some possible substations where reactive power support devices could be installed to provide greater voltage regulation on transmission paths where there are existing dynamic transfer limits. Since reactive power can not be transmitted long distances as real power can, it is important to select locations that are centrally located on paths. In general, the substations located below are major bulk receiving points of power for each of the subsequent paths. The locations are preliminary, and WIST will be performing comprehensive analysis on these locations to determine effectiveness of increasing DTC in subsequent phases of the DTC Task Force.

- **Montana – Northwest Path**: Garrison 500kV, Taft 500kV, Bell 500kV
- **North of Hanford:** Hanford 500kV, Vantage 500kV
- **West of Cascades North:** Monroe 500kV, Schultz 500kV
- **South of Allston:** Allston 500kV, Ostrander 500kV
- **COI (BPA BA):** Malin 500kV, Captain Jack 500kV
- **COI (CAISO BA):** Round Mountain 500kV
- **COI (SMUD BA):** Olinda 500 kV, Tracy 500 kV

Another system reinforcement that would accommodate large changes in power flow over transmission paths is the automation of RAS. Many utilities have installed remedial action schemes that trip generation to maintain system reliability when a contingency (loss of one or more transmission elements) occurs. Maintaining reliability requires that appropriate RAS actions will take place for any given operating point, consequently, it is very important to ensure that RAS arming is quickly modified to reflect variations in power transfer levels. System Operators arm and disarm RAS (that is, set it to deploy or disable it) on different generating units as power flow changes, thus insuring that an appropriate amount of generation is tripped if a contingency occurs. Since of the critical RAS settings require manual adjustment, large, rapid, unanticipated changes in flow cannot be followed.

Automated schemes not only allow for faster response to changes, but also allow operators to concentrate on state awareness and problem solving rather than maintaining proper arming. Most importantly, automatic arming significantly reduces the risk associated with human error by ensuring that gen drop is always set up appropriately for the SOL.

The costs of automating RAS arming will vary from one BA to another, the complexity of the scheme, and the importance of the scheme to interconnected reliability. It also depends largely on whether RAS automation efforts are starting from a "man in the loop" RAS philosophy.

- Automatic RAS arming requires hardware and digital communication updates into generation plants that are to be tripped.
- It requires greater number of plants available for tripping so that the automation can make appropriate arming decisions in a number of generation scenarios.
- Full automatic arming also requires coordination and agreements with multiple utilities that are impacted, and requires the plant operator to allow the transmission operator to reach into the plant and take the necessary action without generator operator oversight.
- Automation has to meet all of the design and operating criteria specified by NERC standards and the WECC RAS sub-committee.

There are also system reinforcements that would contribute to substantial increases in the overall capability and stiffness of the system, or by providing better management of the flow patterns across existing transmission.

- **New Transmission Lines:** Although building a new transmission line to increase DTC seems unlikely, it might be a good idea to consider adding new metrics to the transmission planning process that would translate increases in voltage stability to any increases to DTC. If the implementation of the DTC results in reduction of SOL and this reduction is frequent and substantial then upgrading the existing transmission lines or construction of new transmission lines can mitigate the reduction in SOL thereby maintaining the desired DTC.

- **Flexible AC Transmission Systems (FACTS):** FACTS devices make use of voltage-source converters which can control both real and reactive power. UPFCs which are a specific FACTS devise behave as a very fast phase shifting transformer with the advantage of being able to inject or absorb reactive power without the need for shunt capacitors. Their response time is less than a cycle so they can also help with any flicker problems. A UPFC can redirect the power flow thereby could make use of any unused transmission capacity.

- **Installing series compensation and new phase-shifting transformers:** to manage varying loop flow problems would provide room for variation prevents dynamic transfers from causing power flow to bump back and forth across an SOL by ensuring that the room set aside for the DT is in fact available on the path (not taken up by loop flows).

Criteria for Dynamic Transfer Study

An option for increasing Dynamic Transfer capability that cannot be ignored is to choose to accept greater impacts to service quality, cost, or additional risk that may be a consequence of increased intra-hour power transfers, in effect declaring acceptable whatever impacts are experienced when dynamic transfer use is increased, even if the impacts result in a measureable decrease in the quality of service provided.

Simply ignoring the effects may have impacts on customer quality and reliability that are not well understood at this time. The risks of these impacts fall to the transmission operator, not the generator operator that is causing the variation. In the case of dynamic transfers, the consequence is expected to be largely in the form of unanticipated costs, or unexpected loss of quality (voltage deviation, SOL curtailments, higher incidence of need to freeze dynamics). Instability is unlikely, but could result at some level of system event because system operators did not have adequate state awareness or because the system did not operate as expected when an event occurred.

The amount of existing DTC available on transmission paths is greatly influenced by specific criteria chosen in the power flow study. Loosening these criteria may allow for greater DTC as long as a transmission provider is willing to accept to a change in its operational philosophy. Although these changes may bring some added risk and costs, this may provide a significant increase in the ability to integrate and dynamically schedule variable generation.

The specific methodology used in determining DTC is a subject of phase 2, however, some of the criteria that could be used are:

- **Degree of voltage variation:** Greater voltage variation at HV buses loosens the constraints in the power flow study used to determine an amount of DTC available on a transmission path. This may be a valid option to increasing existing dynamic transfer limits established by transmission providers. The WIST DTC Taskforce is evaluating what level of voltage variation at HV buses is acceptable. It is still uncertain whether allowance of greater variations will cause any reliability risks or noticeable impacts to the underlying transmission or distribution system.

- **Response of existing reactive power equipment:** It is up to the transmission provider to establish which pieces of equipment on its system could be operated to help manage voltage deviations from variable generator power fluctuations. Within this context, there may be existing devices that could be better utilized if they are allowed to operate for variable generation fluctuations. Increased switching on existing devices could increase the frequency of maintenance cycles, which may bring drive higher annual costs. These costs may be acceptable to transmission customers who are interested in dynamically scheduling their resource.

Operate so that the impacts are not noticeable

This final category requires that the variable resource and the transmission provider to operate such that the impacts are not noticeable, and includes a wide variety of options ranging from steps the variable generator can take to appear, from a transmission system perspective, more like a conventional generator, to those the transmission provider could take to minimize the exposure of the system to dynamic transfers when the system is most sensitive to their effects.

By finding mechanisms to restrict the magnitude, ramp rate, or volatility of changes, generators needing the flexibility would more closely approximate the static behavior expected of conventional generators, while still having dynamic transfer capability available when needed. From a scheduling point of view, this might appear as two levels of service, namely slow ramping DTC (or intra-hour scheduling on fixed increments such as 15 min), and a more limited fast ramping DTC.

- Location of Balancing Resources: If there are dynamic transfer limits that do not allow an owner of variable generation to dynamically schedule over a path, the generation operator might look for alternative balancing resources that are located closer to the variable resource, with the acknowledgement that local balancing resources may provide less economical operation than other resources located farther away. If there are balancing resources alternatives to satisfy this arrangement, the impact of a specific variable energy resource on a path will be significantly less, as the balancing resource will flatten the schedule, reducing intra-scheduling period variability.

- Another possible arrangement would be the development of a single balancing resource (i.e. simple cycle gas plant) for multiple variable resources where there are similar POR/POD combinations. For example, the owners of three wind projects located in Southeast Washington with PODs in close electrical proximity (i.e. Western Washington) might decide to co-develop and operate a resource to balance the net output of the three wind projects, rather than each individual owner opting to choose different resource. Co-development and operation may be more economically viable than individual ownership.

- Energy Storage: As energy storage technology improves, it may be possible in the future to limit the severity of wind energy down-ramps. Rapidly dispatchable energy storage, such as battery banks or flywheels could be deployed as wind drops off, which would slow the ramp rate of a project or many projects, translating to softer fluctuations in power transfer over a transmission path.

Wind Plant Control Measures: There may be methods to accommodate more dynamic transfer for owners of generation who are open to the possibility of greater limitations on the physical capabilities of their plants.

- Reduce Ramp-up Rates: Limiting a variable resource to a statistically significant wind ramp (based on historical records) may result in very little operational constraints on the resource over a given period of time. Statistical analysis of a particular variable resource might indicate that the 95th percentile of ramp up rates is 15MW over a five minute period. The most severe ramps, possibly 100MW over five minutes, may occur very infrequently over a yearly timeframe. The incremental benefits of allowing an unconstrained ramp up might be negligible, and begs the question as to whether allowing fully unconstrained ramping is a worthwhile benefit to resource owners. Considering the growing amounts of variable generation on the system, this may be a relevant method of preserving, and fully taking advantage of possibly limited amounts of DTC on the system.

- If the variable resource in question is a wind resource, there are several methods that could be employed to limit the ramp-up rate. One method would involve programming the wind plant controller to feather blades so ramp up rates do not exceed a chosen ramp rate as wind speeds increase. Another alternative might involve setting a wind output cap as to limit the full output of the plant. This could be accomplished by feathering each turbine blades when wind speeds hit a certain speed. A final, but less desirable method, might involve opening individual wind turbine breakers to control the max output of the plant. The most desirable means to limit ramp rates would be the first option, as this would still allow a wind project to reach its full production. Generation owners would very unlikely find it unacceptable to operate their wind project with a maximum capacity less than the design nameplate of their wind farm.

Early results show that dynamic transfer capability is expected to vary with system condition. Transmission providers could facilitate more dynamic transfer capability by identifying the conditions where dynamic transfer is less and restrict use only during those periods. Another possibility is to modify current system operation to accommodate the use of dynamic transfers if policies dictate that use to be the priority – in effect trade off capacity for flexibility.

Summary

The impact of Dynamic Transfers will vary from one BA to another because the complexity, level of automation and age of control schemes available to operators varies. As a basic principle, the transmission system can be engineered to facilitate widespread use of dynamic transfers. This requires some changes from what is currently done, as the system currently is managed and designed for operation in a static manner.

Based on the listing of critical elements and concerns developed in phase 1, the Task Force identified a number of enhancements to the system and its control mechanisms that would improve the ability to manage dynamic transfers and thereby could lead to an increase the total dynamic transfer capability available for use.

In general, better management of dynamic transfers requires modification to operation such that:

i. Adequate visibility and personnel at the RC, BA, and TOP for monitoring with respect to impact on reliability,
ii. Complete automation of controls whose settings are changed as a function of power flow,
iii. Adequate dynamic reactive available throughout the system to maintain voltage such that neither quality of service or reliability is compromised when power flow changes,
iv. Costs of installation and maintenance of this equipment is not prohibitive.