EXH. GEM-3
DOCKETS UE-170033/UG-170034
2017 PSE GENERAL RATE CASE
WITNESS: GEORGE E. MARSHALL

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY,** **Respondent.**	**Docket UE-170033** **Docket UG-170034**

SECOND EXHIBIT (NONCONFIDENTIAL) TO THE PREFILED DIRECT TESTIMONY OF

GEORGE E. MARSHALL

ON BEHALF OF PUGET SOUND ENERGY

AUGUST 9, 2017

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Dockets UE-170033 and UG-170034
Puget Sound Energy
2017 General Rate Case

NWEC-RNW-NRDC DATA REQUEST NO. 014

NWEC-RNW-NRDC DATA REQUEST NO. 014:

Has PSE conducted any transmission engineering studies regarding whether the current transfer path rating of the Colstrip transmission system will be maintained after the closure of Colstrip Units 1 and 2? If the answer is "yes," please provide a copy of any and all such studies. If the answer is "no," please indicate whether and when PSE plans to conduct such analysis.

Response:

Puget Sound Energy ("PSE") is not the Transmission Operator of the Colstrip Transmission System ("CTS") and is not best situated to conduct, and has itself not conducted, "any transmission engineering studies regarding whether the current transfer path rating of the Colstrip transmission system will be maintained after the closure of Colstrip Units 1 and 2." However, please see the following attached studies that consider the impacts of Colstrip retirements:

Attached as Attachment A to PSE's Response to NWEC-RNW-NRDC Data Request No. 014 is a PDF of NorthWestern Energy's "EPA 111-D Consideration Retirement of CS units 1&2" dated April 2015.

Attached as Attachment B to PSE's Response to NWEC-RNW-NRDC Data Request No. 014 is a PDF of NorthWestern Energy's "EPA 111-D Clean Power Plan Consideration Study: Retirement of All Coal-Fired Generation in Montana" dated November 2015.

Attached as Attachment C to PSE's Response to NWEC-RNW-NRDC Data Request No. 014 is a PDF of Northern Tier Transmission Group's Draft "NTTG Study Report for the 2016-2017 Public Policy Consideration Scenario" dated May 8, 2017.

Attached as Attachment D to PSE's Response to NWEC-RNW-NRDC Data Request No. 014 is a PDF of ColumbiaGrid's "Economic Planning Study Impacts from Coal Shutdown Final Study Report" dated June 18, 2015.

As discussed above, PSE is not the Transmission Operator of the CTS and has not conducted any transmission studies regarding whether the current transfer path rating of the Colstrip transmission system will be maintained after the closure of Colstrip Units 1 and 2. See the discussion of the Acceleration Trend Relay ("ATR") and the discussion of some of the complexity of analyzing the response of the ATR in Attachment A, NorthWestern Energy's "EPA 111-D Consideration Retirement of CS units 1&2" dated April 2015. See also Attachment B, NorthWestern Energy's "EPA 111-D Clean Power Plan Consideration Study: Retirement of All Coal-Fired Generation in Montana" dated November 2015 at pages 9-10:

> "Currently, the Colstrip units are protected by the ATR which senses acceleration on the four coal-fired units and trips a combination of the units in order to maintain stability on the transmission system. While the ATR itself would no longer be required if all of the Colstrip facility is taken out of service, a RAS or multiple RASs will be necessary to protect the transmission system during outage and contingency events. Any RAS can only be developed once the state of the system is known."

In general, the location and characteristics of a replacement resource may affect the path rating.

ATTACHMENT A to PSE's Response to NWEC-RNW-NRDC Data Request No. 014

EPA 111-D Consideration
Retirement of CS units 1&2

April, 2015
Regional Electric Transmission Planning

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Executive Summary

The Environmental Protection Agency (EPA) is using its authority under section 111 of the Clean Air Act to issue standards, regulations or guidelines, as appropriate that address carbon pollution from new and existing power plants, including modifications of those plants. Northern Tier Transmission Group (NTTG) received a Public Policy Consideration (PPC) request to investigate retiring 2 coal plants at Colstrip with alternative generation in the form of renewable wind. NWE also analyzed the impact of replacing coal at Colstrip with either combined cycle gas, wind or a combination of both types of generation. The goals of the analyses were to discover if the different types of generation created any impacts to the transmission system and to determine if the maximum export on Path 8 (western transmission corridor from Montana to the interface with the Bonneville Power Administration and Avista) of 2200 MW could be maintained.

Engineering Study

Northern Tier Transmission Group

The Northern Tier Transmission Group (NTTG) received a Public Policy Consideration (PPC) request in the first quarter of the biennial planning cycle. The PPC request, submitted by Renewable Northwest Project (RNP), stated:
“RNP would like to understand the transmission impacts associated with retiring 1) Colstrip units 1&2 and replacing the respective amounts of capacity with proportional amounts of wind capacity in Montana.”

The Technical Work Group (TWG) developed a study plan in response to the PPC request. The Study Plan was approved by the NTTG Stakeholders and the NTTG Planning Committee and is available on the NTTG website. The study details include:

1. Use of the 2024 TEPPC cases that had been run through the production cost model process; these cases were also used by the TWG to develop the Regional Transmission Plan.
2. Assumption that the wind would be modeled at the Broadview 500 kV bus as two 305 MW wind farms at full output where the entirety of one farm could be tripped off as quickly as a coal plant at Colstrip.
3. Assumption of no new transmission or facilities.
4. Assumption that the change occurs in 2020.

TWG ran steady-state analysis only for this PPC. The TEPPC cases are not dynamics-ready and there is no requirement that TWG run dynamics for a PPC study. There was a lot of discussion around the idea of running dynamics for this PPC request, however, it was generally concluded that it would take too much time to convert a TEPPC Production Cost Model case into a dynamics-ready case.

Limitations

Colstrip is a uniquely placed generation facility in the Western Interconnection. The four units that make up Colstrip are at the end of a long 500 kV corridor that ultimately ties into the Pacific Northwest. Because of the location and size of the Colstrip plan, there is a device called the Acceleration Trend Relay (ATR) that protects the Colstrip generators and the transmission system during an outage on the 500 kV corridor.

The major limitation to the PPC study is that the ATR is inherently a dynamic device. In order to get a rough idea of how the system would respond following a major 500 kV event, estimated ATR tripping was used based on past studies and events. The ATR is very sophisticated and the PPC study only provides a very rough idea as to how the system could truly respond.

Results

The TWG looked at two scenario cases: a standard heavy summer case and a case with increased Path 8 exports. With the assumptions listed above, the TWG found that the transmission system generally responded similarly to wind at Broadview as it did to coal at Colstrip. The results of this limited, steady-state study neither imply nor suggest that a one-for-one substitution of wind for coal is feasible without further study or possibly system improvements.

Discussion

At this time, the software used to model the response to the ATR is proprietary to NorthWestern Energy (NWE). NWE is working with a power system software vendor to develop a model that all parties can use. Until the model is validated and other vendors have had a chance to collaborate, NWE is still the only utility that is capable of dynamically modeling the response of the ATR. Because of this unique situation, NWE has determined it would perform a high-level dynamics study to better understand the implications of replacing coal with either wind or some other resource.

NWE Study - 2015 Transient Stability Analysis

NWE used a dynamics-ready 2015 case to analyze the impact on the ATR of replacing coal at Colstrip with either combined cycle gas, wind or a combination of both types of generation. The goals of the analysis were to discover if the different types of generation created any impacts to the transmission system and to determine if the maximum export on Path 8 of 2200 MW could be maintained. NWE also evaluated whether there would be any impact to the import capability into Montana.

Case Prep

The Corette plant was assumed to be offline. Corette has been offline permanently since early March 2015. Colstrip 1&2 each generate approximately 300 MW of net generation onto the transmission system. NWE considered both steady state and transient stability in this analysis and studied the following scenarios, in all cases Path 8 exports were at 2200 MW:

1. Colstrip 1&2 online, no additions (unmodified comparison case)
2. Colstrip 2 offline, no additions
3. Colstrip 1&2 offline, no additions
4. Colstrip 1&2 offline, 300 MW wind at Colstrip
5. Colstrip 1&2 offline, 300 MW wind in the Broadview (west of Billings) area
6. Colstrip 1&2 offline, 300 MW combined cycle gas modeled in the Alkali Creek area
7. Colstrip 1&2 offline, 300 MW combined cycle gas in the Alkali Creek area and 300 MW wind at Colstrip
8. Colstrip 1&2 offline, 300 MW combined cycle gas in the Alkali Creek area and 300 MW wind in the Broadview area

In cases 2-6, generation in Montana was redistributed to account for the net loss of generation. By doing this, NWE was able to maintain exports of 2200 MW in all the cases.

Results

The transmission system responded similarly to outages for all eight cases, both steady-state and dynamically and was capable of achieving 2200 MW of exports on Path 8. Again, these results neither suggest nor imply that a one-for-one substitution of coal at Colstrip for another type of generation is feasible without further study or possible system upgrades.

Considerations

Frequency

The Colstrip units are geographically located in the northeast of the Western Interconnection at the end of a long 500 kV corridor. The large size of the Colstrip units combined with the length of the 500 kV corridor create frequency concerns not typically seen elsewhere in the Western Interconnection. The Colstrip units will accelerate rapidly for outages on the 500 kV corridor and that rapid acceleration and increase in frequency could impact the Western Interconnection if it were not for the ATR which trips Colstrip generation during an event. Ostensibly, if alternate generation were to replace Colstrip, there would be fewer high frequency concerns for a major contingency on the 500 kV corridor.

On the other hand, for loss of a major generator inside or outside of the NorthWestern Energy system, system frequency decreases and Automatic Generation Control (AGC) kicks in and large units such as Colstrip supply much needed spinning reserves to the interconnect. If alternate generation were to replace Colstrip, it would need to provide the same capability to meet our Balancing Authority Operating Reserves criterion. Typical wind machine packages don't include a speed governor required for this type of action. The fuel (wind) is variable by nature and is not controllable for spinning reserve. Therefore, new generation would need to have other means of responding to this type of event.

Total Transfer Capability, Path Capacity

The capacity of a line does not decrease when a resource is removed much like a garden hose's capacity does not disappear when the water spigot is shut off. That being said, it is possible that the path rating/transmission capability might have to be reduced due to resource limitations. This does not mean the capacity is not there, just that the system is not physically capable of reaching those types of flows with the reduced amount of resources available. In other words, without Colstrip generation to "push" through the garden hose, transmission capability out of Montana will also reduce – nearly at a one-for-one basis to the amount of generation reduction.

Local Area

Any time generation is added or removed from the system, extensive study work is required to assess any impact to loads and transmission near the generation. If the alternate generation resources are at or near Colstrip, there may be no change in the Colstrip area but if not, system improvements may be required.

While high-level impacts to the local area were analyzed, the study did not focus on load growth or future local area projects.

Voltage Support

The Colstrip facility currently provides important voltage support to the transmission system in eastern Montana, and is vital in keeping the Montana 500kV system within its voltage limits. Any replacement alternate generation would need to be capable of providing equal voltage support capability so that there is no negative affect to the system or stress on nearby generation. If a variable alternate generation resource such as solar or wind was chosen, additional dynamic and/or static VAR devices may be necessary to maintain adequate voltage on the 500kV system. In general, the alternate generation resource will need to boost voltage under heavy generation output and suppress voltage under low generation output. As a side note, capital investments in devices to provide voltage support in the Billings area were planned and installed recently, in large part due to the known closure of the Corette Coal Fired plant in Billings. That facility traditionally provided significant voltage support in the Billings area.

ATR

The Acceleration Trend Relay (ATR) monitors the acceleration on each of the four Colstrip units. If the ATR senses rapid acceleration on any of the units, it makes a decision as to how many units to trip offline such that the stability of the transmission system is maintained and the Colstrip units and local and regional transmission system are protected. Removing any combination of Colstrip units has little-to-no impact on the ATR by design. For the removal of any of the four units, the acceleration and speed values seen by the ATR will look roughly the same and the ATR will act accordingly for all major contingencies.

In order to avoid negatively impacting the owners of the remaining Colstrip units, a new Remedial Action Scheme (RAS) or modifications to the ATR may be needed. If a new RAS was to be designed, it would likely need to act faster than the ATR in order to not cause excess tripping of the remaining Colstrip generation. Since the ATR usually reacts within 1/10 of a second, the new RAS would need to act faster than that, and trip for contingencies anywhere on the 500 miles of 500 kV transmission lines west of Colstrip, which could be very costly depending on what type of tripping scheme was used.

If a modification of the ATR logic is necessary, the several utilities that own the ATR, collectively known as the Colstrip transmission partners, all have to agree on any changes to the ATR. Other issues include extensive hardware modifications, planning and engineering work. All these things would be needed in order to properly tie the resource into the ATR logic, but would not be possible without very detailed information on exactly what type of resource is chosen. The development or modification of any RAS is far outside the scope of any request that has been made by any group, and it would vary depending on what type of generation was chosen.

To sum all that up; the addition of any other form of generation in place of Colstrip is practically guaranteed to have an effect on the response of the ATR. However, with a good amount of thought and engineering, a RAS, or modification of existing RAS, could most likely be designed such that effect is reduced. This is likely to be a complex, time intensive and costly process. However, it should be noted that a fundamental reason for the ATR is allow the transfer capability to be as high as it is to transmit Colstrip energy. The tripping that occurs at Colstrip would need to be built into replacement generation as well in order to maintain reliability and transfer capability.

Impact to Import Capability

None of the studied changes to the transmission system impacted the import capability on Path 8 (from the west into Montana).

Economic Impact

The analysis above does not consider the economics, viability or other infrastructure requirements associated with a large build out of wind generation or gas generation in eastern Montana as replacement to Colstrip generation. We do not take a position regarding the economics of wind generation in Montana and ability to find a customer, presumably outside of Montana, for a large wind resource. With regard to gas generation, if Colstrip generation was shut down, presumably transmission capacity would be available on the Colstrip 500 kV system for replacement generation. There is multi-party ownership of this transmission capacity. However, significant consideration would be required of gas transportation and gas supply for large scale gas generation in eastern Montana.

Conclusions

The goals of these studies were to discover if replacing coal with alternative types of generation created any impacts to the transmission system. It should be noted that economics were not considered in this study, but are discussed at a high level below.

TWG found that the transmission system responded comparably for wind at Broadview or coal at Colstrip. The results of this limited, steady-state study neither imply nor suggest that a one-for-one substitution of wind for coal is feasible without further study or possibly system improvements.

NWE analyzed the impact on the system for replacing coal at Colstrip with either combined cycle gas, wind or a combination of both types of generation. For all cases studied, the transmission system responded similarly for both the steady-state and dynamic assessments. The path capacity would not change and frequency concerns would lessen. Also, the addition of an alternate resource in place of coal will have an effect on the response of the ATR and may very well necessitate the design of a new RAS.

Again, these results neither suggest nor imply that a one-for-one substitution of coal at Colstrip for another type of generation is feasible without further study or possible system upgrades.

ATTACHMENT B to PSE's Response to NWEC-RNW-NRDC Data Request No. 014

EPA 111-D Clean Power Plan Consideration Study:

Retirement of All Coal-Fired Generation in Montana

November, 2015
Regional Electric Transmission Planning

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Executive Summary

The Environmental Protection Agency (EPA) is using its authority under Section 111 of the Clean Air Act to issue standards, regulations or guidelines that address carbon pollution from new and existing power plants, including modifications of those plants. NorthWestern Energy (NWE) performed a high-level analysis of the impacts to the transmission system should all coal-fired generation power plants in the NWE balancing authority be shut down. This is an update to similar study work and a report done by NWE in April 2015. The April report focused on the impact of the shutdown of Colstrip Units 1 and 2 only.

NWE studied six different configurations:

1. No coal-fired generation, no 500 kV.
    a. Scenario 1 with the addition of a 250 MW natural gas-fired generation plant modeled in Billings.
2. No coal-fired generation, no other system changes.
    a. Scenario 2 with the addition of a 250 MW natural gas-fired generation plant modeled in Billings.
3. No coal-fired generation, 2520 MW of wind added to the system
    a. Scenario 3 with the addition of a 250 MW natural gas-fired generation plant modeled in Billings.

The goals of the analyses were to discover if the local area can still be served reliably, whether it is possible to keep the 500 kV transmission system intact if there is no coal-fired generation, and what impacts to the path flows these different configurations have on the import and export capability of the external paths.

It is important to note that this is a transmission study only, performed for the purpose of understanding the potential physical or operational impacts to the transmission system of the shutdown of all coal generation in NWE's balancing authority area. Certain assumptions were required in order to test the critical operating scenarios under heavy and light loading situations. The economics, costs, or the viability of replacement generation from a supply perspective or other required infrastructure to develop these configurations that are key to actually seeing any of these to fruition are not considered in this analysis. In addition, assumptions regarding the future use of, or absence of, the Colstrip 500 kV Transmission System are approached from the technical perspective and the contractual perspective.

The high-level results of the analysis are as follows:

A. Coal-fired generation is a key component of the transmission system. Coal-fired generation provides power that is reliable, consistent, and predictable. The loss of coal-fired generation on the NWE transmission system severely inhibits NWE's ability to either export or move power through the system. The large coal-fired generators act as dampeners to stability events in that they help reduce the impacts of the stability event. Without coal-fired generation, there are fewer "dampeners" and the system has a reduced ability to reliably respond to events.

B. The Clean Power Plan could require a total shutdown of all the coal-fired generation in Montana. The coal-fired plants are listed in Table 1.

Table 1: Coal-Fired Generation Plants in Montana

Plant	MW
BGI	65
Colstrip	2306
Hardin	115
Montana One	41.5

If all the coal-fired generation in Montana were decommissioned, then additional resources would be needed. Natural gas-fired generation is a consistent, predictable, and reliable source of energy. Wind and other non-predictable renewable generation present complications such as the requirement of spinning and contingency reserves, conventional power sources to back up the variable resources and the need for other reactive devices for voltage control.

A consideration of replacing any generation with wind is the capacity factor. For example, if the decommissioned coal-fired generation was replaced with wind, and a conservative 33% capacity factor was assumed, then 7583 MW of wind would have to be installed to make up for the 2725 MW of coal-fired generation. Natural gas-fired generation can be configured as a one for one replacement to coal if natural gas infrastructure could be modified/expanded to accommodate new generation.

Without coal-fired generation, there are impacts to the Billings area. The coal-fired generation is an excellent source of Volt-Amp Reactive (VAR) power and the Billings area will need to replace the VARs supplied by the coal-fired generation. This replacement could be in the form of capacitors in the Billings area or by maintaining at least one high voltage line that feeds into the area. The high voltage line could be a 500 kV line or a new 230 kV line. The 500 kV line could be one of the existing 500 kV lines. A 500 kV line under light loading may actually cause too much capacitance (high voltage). Another area of interest in this scenario is the South of Great Falls cut plane. Without the 500 kV transmission system intact, reliability violations were found that would decrease the current South of Great Falls cut plane total transfer capability. If there were no 500 kV transmission system, then additional transmission from the Three Rivers area to Great Falls (likely a 230 kV line) would be needed to support current needs and obligations in that area.

Assuming a new 230 kV line between Great Falls and Three Rivers with routing along the existing 100 kV facilities, the length would be about 135 miles. A high-level estimate of $750,000 per mile yields a total line estimate of $101 million. In addition to the transmission line, a new 230 kV terminal at the Three Rivers Substation as well as a new 230 kV terminal at the Great Falls 230 kV Switchyard would be required which adds an additional $5 million to the estimate. Altogether, the total estimate for the line and associated facilities is $106 million.

The results of this analysis are high-level and should only be used for informational purposes.

Study

Questions

1. Without coal-fired generation, can NWE reliably serve its local area load?
2. Without coal-fired generation, is the 500 kV transmission system useable and needed?
3. Can NWE replace coal-fired generation with wind or a combination of wind and natural gas-fired generation?
4. What are export and import impacts to the four external transmission paths?

Considerations

Currently, Montana has more generation than load and is typically considered an export state. With the loss of approximately 2520 MW of coal-fired generation on the system, Montana would have less generation than load during medium and heavy loading and would be faced with the routine import of power to serve native load. In addition to impact to NorthWestern's customers, the large choice customers would be faced with the same situation – significantly reduced in-state resources to meet their energy intensive needs.

The 500 kV transmission system was installed with the primary purpose of exporting power from the Colstrip coal-fired generation plant and to serve Montana customers through substations along the transmission lines. The 500 kV transmission system now also serves as a strong backbone to the overall transmission system. Without generation in excess of load, there may be diminished need for the 500 kV transmission system. Currently, 675 MW of load is designated to be served by coal-fired generation in the NWE Balancing Authority.

Study Assumptions/Process

NorthWestern Energy studied the following scenarios:

1. No coal-fired generation, no 500 kV.
    a. Scenario 1 with the addition of a 250 MW natural gas-fired generation plant modeled in Billings.
2. No coal-fired generation, no other system changes.
    a. Scenario 2 with the addition of a 250 MW natural gas-fired generation plant modeled in Billings.
3. No coal-fired generation, 2520 MW of wind added to the system. The introduced wind is modeled at 100% output (very optimistic and perhaps not realistic, but required to test the technical limits of the transmission system); all existing wind on the system was dispatched according to the "Dispatch Descriptions for all Scenarios" section.
    a. Scenario 3 with the addition of a 250 MW natural gas-fired generation plant modeled in Billings; this 250 MW replaced 250 MW of the introduced wind.

For all scenarios, both heavy and light loading was considered. NWE explored a 2015 Light Summer case and a 2015 Heavy Winter case. The results are steady-state only.

First, an exploration was made to see if the transmission planning cases solved given the six different scenarios. Next, contingency analysis was performed to discover any initial reliability violations. If the case had reliability violations, then the cases were modified to see if those violations could be alleviated through generation re-dispatch or modification to the path flows. Last, the path flows were increased to see if the transmission system could reliably handle being treated as a conduit for transmission service.

For the most part, once the case was solved and initial contingency violations were alleviated, NWE was not able to increase the path flows without creating new contingency violations.

Dispatch Descriptions for all Scenarios

While there are infinitely many combinations of path flows and generation dispatch levels, the two different dispatch levels selected for study are an attempt to study the "bookends" of the many different combinations that could result from these three scenarios.

<u>Light Loading in the NorthWestern Balancing Authority (1140 MW):</u> Heavy hydro and wind to simulate a spring runoff condition.
This extreme case is to analyze the ability to export power out of Montana.

<u>Heavy Loading in the NorthWestern Balancing Authority (1750 MW):</u> Light hydro and no existing wind dispatched.
This extreme case represents the worst-case scenario for importing power to serve native load. In the Heavy Loading cases under Scenario 3; the introduced wind was fully dispatched (again an optimistic view, but required to test the system).

High-Level Results

The loss of coal-fired generation presented some challenges to the transmission system.

<u>Scenario 1, No Coal-Fired Generation, No 500 kV, Heavy System Loading:</u> The 500 kV transmission line was required to be de-energized (taken out of service) east of Garrison which is the interconnection to the BPA system. In this scenario, Path 8 imports would have to be limited to approximately 850 MW which is down from the current import limit of 1350 MW. The initial critical outage is the loss of one of the 161/100 kV transformers at Mill Creek which caused cascading voltage collapse in the Butte area. If those transformers were upgraded, then the next critical contingency is the loss of the 230 kV South Butte to Three Rivers line which causes cascading voltages. Each of these scenarios is unacceptable.

<u>Scenario 1, No Coal-Fired Generation, No 500 kV, Light System Loading:</u> In this analysis, South of Great Falls total transfer capability would have to be reduced unless a new 230 kV line between Great Falls and Three Rivers could be built. The loss of the 230 kV line between Judith Gap South and Broadview is the critical contingency that causes cascading outages in the Harlowton area. This is not only a reliability concern, but commitments made to third parties for wholesale transmission service would be significantly impacted. Currently, the southbound Total Transfer Capability (TTC) is 495 MW, of which 360 MW is designated as firm transmission. The northbound TTC is 468 MW, of which 374 MW is designated as firm transmission. Both the northbound and the southbound directions are often fully designated if both firm and non-firm designations are considered.

Scenario 2, No Coal-Fired Generation, 500 kV In Service, Heavy System Loading: Though the 500 kV transmission system was considered "in service", one of the parallel 500 kV lines between Broadview and Garrison had to be de-energized to maintain voltage limits on the transmission system; if both lines remained in service, then their combined capacitance would make it such that reactors would have to be installed to offset their capacitance (reduce voltage). This case presents a loading and generation condition that solved and maintained N-1 reliability.

Scenario 2, No Coal-Fired Generation, 500 kV In Service, Light System Loading: Though the 500 kV transmission system was considered "in service", one of the parallel 500 kV lines between Broadview and Garrison had to be de-energized to maintain voltage limits on the transmission system. This case presents a loading and generation condition that solved and maintained N-1 reliability.

Scenario 3, No Coal-Fired Generation, 500 kV In Service, 2520 MW Wind, Heavy System Loading: With 2520 MW of wind at 100% dispatch, there are no violations seen on the heavy loading condition and the system demonstrated N-1 reliability.

Scenario 3, No Coal-Fired Generation, 500 kV In Service, 2520 MW Wind, Light System Loading: With 2520 MW of wind at 100% dispatch, there were violations seen for loss of 230 kV and 161 kV segments in the Broadview/Billings areas caused by the introduction of a very large wind farm at Broadview/Billings area.

All scenarios with the addition of a 250 MW natural gas combined cycle plant in the Billings area:

- In general, the gas plant helped alleviate voltage issues in the Billings area. The gas plant was modeled at the Steam Plant Substation, but voltage support beyond the capability of the gas plant would still be necessary. If a 250 MW natural gas plant were to be built in Billings, then the Billings Steam 230 kV Substation would benefit from being re-configured to a breaker-and-a-half scheme. With the current configuration and with the addition of a 250 MW natural gas plant, a single breaker failure or stuck breaker in the Billings Steam 230 kV Substation could lead to voltage collapse in the Billings area.
    - Additional capacitor banks in Judith Gap area are approximately $1 million based on historical costs.
    - Replacement of the existing Steam Plant 230 kV bus with a new 230 kV breaker-and-a-half scheme configuration would cost approximately $25 million.

Discussion

Using wind as a resource presents complications. Wind, by its very nature, is variable and not inherently predictable. Wind is not always available when it is needed most. Every MW of wind added to any transmission system has to have corresponding balancing reserves for the inevitable time when wind generation is scheduled and then the wind dies out.

Transmission systems are often described using a "spring-mass" comparison; the transmission lines themselves are the "springs" and the generators are the "masses". A coal-fired generator has the most "mass" and as such, responds well to contingencies.

Wind farms have much less "mass" using this analogy and provide little to no response to contingencies.

Table 2 details the observed path flows for the scenarios described above. All values are in MW. A positive value indicates an export; a negative value indicates an import.

Table 2: Interchange Values for the Different Scenarios

Loading	Scenario	Path 8 (MW)	Path 18 (MW)	Path 80 (MW)	Path 83 (MW)	Total Dispatched Generation (MW)	Generation minus Load (MW)	Net Path Interchange, Pre-Contingency (MW)
Light, 1140 MW	No Coal, no 500 kV	61	27	-421	185	1056	-84	-148
	No Coal, no 500 kV, 250 MW at Billings	157	44	-325	214	1310	170	90
	No Coal, 500 kV In Service	-179	-131	128	140	1178	38	-42
	No Coal, 500 kV In Service, 250 MW at Billings	-1	-113	177	150	1428	288	213
	No Coal, 500 kV In Service, 2520 MW Wind	1785	287	325	173	3903	2763	2570
	No Coal, 500 kV In Service, 2270 MW Wind, 250 MW at Billings	1801	280	326	170	3908	2768	2577
Heavy, 1750 MW	No Coal, no 500 kV	-851	-97	-341	-300	276	-1474	-1589
	No Coal, no 500 kV, 250 MW at Billings	-851	-94	-90	-300	526	-1224	-1335
	No Coal, 500 kV In Service	-1272	-34	-49	64	557	-1193	-1291
	No Coal, 500 kV In Service, 250 MW at Billings	-1160	-28	-51	194	820	-930	-225
	No Coal, 500 kV In Service, 2520 MW Wind	631	167	123	37	2863	1113	958
	No Coal, 500 kV In Service, 2270 MW Wind, 250 MW at Billings	666	158	116	35	2871	1121	975

During heavy loading and low generation output, NWE can expect to have to import significant power in order to serve load. Because only "bookends" were studied for this analysis, NWE may expect to have to import power during light loading as well.

Discussion

These results assume no other elements out of service. Much consideration will be required of the transmission system if there are any unplanned or planned outages on the system. Transient stability was not performed because there were already reliability violations present in steady-state. A transient stability analysis will be necessary when there is a clear understanding of the landscape surrounding these issues.

Considerations

Frequency

The large mass of the coal-fired generation units allows the units to respond to transient stability events with a positive dampening effect. The coal-fired generation units effectively dampen oscillations that occur during transient stability events and that dampening helps to improve response time and to protect the transmission system. While renewables have some damping capability, they are hardly comparable with the dampening power of coal-fired generation. The transmission system will be more susceptible to oscillations during transient stability events if coal-fired generation were shut down and either not replaced or replaced with only renewable energy. If a 250 MW natural gas-fired generation plant were built in the Billings area, it would help maintain system frequency both during steady-state and during contingency.

Total Transfer Capability, Path Capacity

The capacity of a line does not decrease when a resource is removed much like a garden hose's capacity does not disappear when the water spigot is shut off. However, it is possible that the path rating/transmission capability might have to be reduced due to resource limitations depending on the possible resulting scenario.

The 500 kV transmission system is critical to Path 8. Without the 500 kV transmission system, there will be significant limitations on both the import and export capability of the path. If renewables, or a combination of renewables and natural gas-fired generation, were to replace all the coal-fired generation on the system, then analysis will have to be done to determine new values for the total transfer capability on any of the affected paths.

Local Area

Any time generation is added or removed from the system, extensive study work is required to assess any impact to loads and transmission near the generation. If the alternate generation resources are at or near Colstrip, there may be no change in the Colstrip area, but if not, system improvements may be required. While high-level impacts to the local area were analyzed, the study did not focus on load growth or future local area projects. This analysis did identify a need for VAR support in the Billings area. That VAR support may be in the form of a gas-fired generator in the Billings area or as a high-voltage transmission line into the area.

Voltage Support with the 500 kV Transmission System Intact

The Colstrip facility currently provides important voltage support to the transmission system in eastern Montana, and is vital in keeping the Montana 500 kV system within its voltage limits. Any replacement alternate generation would need to be capable of providing equal voltage support capability so that there is no negative affect to the system or stress on nearby generation. If a variable alternate generation resource such as solar or wind was chosen, additional dynamic and/or static VAR devices may be necessary to maintain adequate voltage on the 500 kV system. In general, the alternate generation resource will need to boost voltage under heavy generation output and suppress voltage under low generation output. As a side note, capital investments in devices to provide voltage support in the Billings area were planned and installed recently, in large part due to the known closure of the Corette coal-fired generation plant in Billings. That facility traditionally provided significant voltage support in the Billings area. The installation of capacitor banks in the Billings area over the last few years totaled $1.9 million (five switched banks totaling 80 MVAR).

Voltage Support without the 500 kV Transmission System

The voltage profile of the entire NWE transmission system will change without the 500 kV transmission system intact. The 500 kV transmission system supplies necessary VARs to both the Billings area and the Mill Creek area. Without the 500 kV transmission system, voltage support will be required. That voltage support may be in the form of dynamic VAR devices, capacitors or new generation that supplies the required VARs.

Remedial Action Scheme (RAS)

Currently, the Colstrip units are protected by the ATR which senses acceleration on the four coal-fired units and trips a combination of the units in order to maintain stability on the transmission system. While the ATR itself would no longer be required if all of the Colstrip facility is taken out of service, a RAS or multiple RASs will be necessary to protect the transmission system during outage and contingency events. Any RAS can only be developed once the state of the system is known.

Impact to Import Capability

The 500 kV transmission system acts as a strong “backbone” for the entire transmission system. Without it, the transmission system has lessened capability to both import and export power. The 500 kV transmission system is vital to the import capability on Path 8 as well as the capability of through flows on the South of Great Falls cut plane. Impacts to the import capability of Path 8 are of particular interest and concern. Without coal-fired generation and without the 500 kV transmission system, there is a significant need to import power to serve local load, but the import capability on Path 8 is lessened which will stress the other paths. Without building new transmission lines internal to the NWE transmission system, there will be lessened opportunities to move power through the transmission system to serve our internal customers and to meet current obligations for transmission service to wholesale customers.

South of Great Falls Cut Plane

The South of Great Falls (SOGF) cut plane is a uniquely situated portion of the NWE transmission system. Due to the mountain ranges in Montana and the location of the natural load pockets, there is a grouping of transmission lines that are sited between the north and south portions of the state, with the center-point being the city of Great Falls. Any transmission service in the north-south or south-north direction through NWE has to go through this cut plane, which makes it inherently valuable from a transmission service perspective. The SOGF Cut Plane will be impacted with the loss of the 500 kV transmission system. Without the “backbone” of the transmission system, the reliable limit through the SOGF, either north or south, will be reduced. Currently, the southbound Total Transfer Capability (TTC) is 495 MW, of which 360 MW is designated as firm transmission. The northbound TTC is 468 MW, of which 374 MW is designated as firm transmission. Both the northbound and the southbound directions are often fully designated if both firm and non-firm designations are considered. While a full-blown Total Transfer Capability analysis was not done for this report, it was shown in Scenario 1 that reductions to the SOGF are in order and that reliable flows may be in the 300 MW to 350 MW range for northbound flows – a reduction in the range of 120 to 170 MW.
Economic Impact

The analysis above does not consider the economics, viability or other infrastructure requirements associated with a large build out of wind generation or gas generation in eastern Montana as potential replacement to Colstrip generation. NWE does not take a position regarding the economics of wind generation in Montana and ability to find a customer, presumably outside of Montana, for a large wind resource. With regard to gas generation, if Colstrip generation was shut down, presumably transmission capacity would be available on the Colstrip 500 kV transmission system for replacement generation. There is multi-party ownership of this transmission capacity. However, significant consideration would be required of gas transportation and gas supply for large scale gas generation in eastern Montana.

Currently, NWE spends approximately $2.26 million on property taxes for the 500 kV transmission system between Colstrip and Garrison, of which, approximately $0.6 million is the property tax paid due to NWE's beneficial use of the portion of 500 kV transmission system owned by the Bonneville Power Administration (BPA).

The Montana Intertie Agreement between BPA and the Colstrip Transmission Owners covers the responsibilities of the parties for the facilities and transmission service across the Montana Intertie. The contract is tied to the output of the Colstrip generation. If the Colstrip generation is removed, then BPA has the option to remove the 500 kV facilities from Townsend to Garrison for its salvage value. If this happened, then the Broadview-Townsend line would not tie to anywhere and the transmission system from Colstrip to Townsend would become a stranded asset for the Colstrip Transmission Owners. The Colstrip Transmission Owners have the option to remove their transmission facilities if the Colstrip Generation Project stops production per the Colstrip Transmission Agreement. Removal of these facilities will have a significant impact on the property taxes and Beneficial Use Taxes collected on these facilities.

Conclusions

The loss of coal-fired generation would be a huge change to the planning and operation of the transmission system. With the transmission system "as-is" and the only change being the loss of coal-fired generation, the transmission systems ability to export power is drastically impacted and import capability is also greatly impacted.

NWE is uniquely situated in the Western Interconnection and currently not only serves its native/local customers, but also is a transmission conduit for other parties seeking to move power through the NWE transmission system. With a full shutdown of coal-fired generation in the state there would need to be very significant infrastructure changes.

The South of Great Falls Cut Plane would need to be reinforced to handle increased flows caused by the loss of the 500 kV system. This cut plane is heavily used to serve customers, move hydro generation and coal fired generation and also to move significant wind generation to and through the state. In the Scenario 1 study, it was found that in today's system, the South of Great Falls cut plane flows would have to be reduced down to approximately 300 to 350 MW in the northbound direction, a reduction of up to 170 MW, if the only changes are the loss of coal-fired generation and the loss of the 500 kV transmission system east of Garrison.

At the very least, a new 230 kV line between Three Rivers and Great Falls would be required to simply maintain the Total Transfer Capability rating of 495 MW under the no coal-fired generation, no 500 kV transmission scenario. Under any of the scenarios, a new 230 kV line and perhaps other significant infrastructure changes would be required to increase the capacity through the cut plane and alleviate the congestion caused by power movement through the NWE system.

The results of this analysis are high-level and should only be used for informational purposes.

ATTACHMENT C to PSE's Response to NWEC-RNW-NRDC Data Request No. 014

NTTG Study Report
for the
2016-2017 Public Policy Consideration Scenario

NTTG Study Report
for the
2016-2017 Public Policy Consideration Scenario

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1. Background

During Quarter 1 of the NTTG 2016-2017 Regional Planning Cycle, the Renewable Northwest ("RNW") and the Northwest Energy Coalition (NWEC") jointly submitted a Public Policy Consideration ("PPC"), defined in the NTTG Funders' Attachment K) request for a scenario analysis study. This request was to assess the transmission impacts and reliability implications associated with the retirement of Colstrip Power Plant ("Colstrip") units 1 and 2, the hypothetical closure of Colstrip unit 3, the integration of replacement wind resources at the Broadview substation and the inclusion of a gas plant in the Billings area. Members of the NTTG Technical Workgroup ("TWG"), and representatives from RNW and NWEC jointly reviewed the request and agreed on modifications to the requested study. These modifications, and the associated study assumptions, are documented in the NTTG 2016-2017 Study Plan, Attachment 3. The NTTG Study Plan, including the PPC Study Proposal for a Scenario Analysis, was subsequently approved by the NTTG Steering Committee on July 20, 2016. The result of this analysis is included in this report.

This study does not constitute a total transfer capability, Path Rating, Generation Interconnection Agreement or Transmission Service Request study and the results herein should be used for informational purposes only. The results of this analysis do not suggest or imply that a one-for-one substitution of wind or a combination of wind and gas for coal is feasible without further analysis or system improvements. This study does not imply or convey transmission rights in any fashion.

2. Study Assumptions

Several assumptions were made to create the scenario to retire the three Colstrip units:

- All introduced generation, wind and gas, will be exported on Path 8
- The 1494 MW of Type 4 wind was modeled on the Broadview 500 kV bus and was dispatched at 0%, 35% and 100%
- The introduced generation on the Broadview 500 kV bus is assumed to meet the voltage requirements that would be required as a result of an actual interconnection; any voltage contributions or deviations from the collector system is assumed to be mitigated at the POI
- The 250 MW gas plant was modeled onto the Alkali Creek 230 kV bus without a Remedial Action Scheme ("RAS") for 500 kV outages that would be similar to the RAS assumed for the proposed new wind at Broadview. In an actual interconnection or transmission service request, the need for a RAS would be evaluated. The gas plant was modeled in with cases that had the wind at Broadview modeled at 1244 MW; the 1244 MW was dispatched at 0%, 35% and 100%.
- A RAS to trip the new Broadview wind was assumed to be designed to act faster than the current Colstrip Acceleration Trend Relay ("ATR"). By having the RAS act faster than the ATR, it both protects the transmission system

and does not interfere with the inputs to the ATR. These changes occur by 2026

- No new transmission lines or facilities beyond those already planned for operations in the year 2026 will be considered.
- For any contingency that results in a loss of generation, generators in the northwest were assumed to be re-dispatched to accommodate for the loss of generation.

3. Base cases

NTTG used TEPPC's 2026 version 1.3, edited to incorporate fixes to load shapes, modified resource mapping by the four Western Regions, plus other adjustments that enhanced the accuracy of the database. The production cost model simulating the 2026 load and resources forecast, was used to identify stressed system conditions (i.e., load and generation dispatch conditions) to study. A production cost model uses the costs of operating a fleet of generators to minimize costs for the 8760 hours of the year while simultaneously adhering to a wide variety of operating constraints. The production cost model data for the selected system conditions were then translated into power flow base cases. A power flow model is a numerical analysis of a single condition flow (e.g., hour) of electric power in an interconnected system. There was a significant effort undertaken to ensure that the round trip produced a case that was both steady-state and dynamics capable. Additionally, it took numerous person-hours to convert selected steady-state contingencies into dynamics-ready contingencies. Without this effort, the automation of the dynamics analysis would not have been possible.

The base case used for this PPC study was a Montana to the Northwest (MT-NW) Case that had been adjusted to have high flows on WECC Path 8 coming out of Montana. The TWG prepared the following scenario cases to study the request:

- MT-NW case (case "C" in the TWG study) was used as the basis for comparison: in addition to the closure of Colstrip units 1 and 2, Colstrip unit 3 was also turned off.
- MT-NW case with Colstrip units 1, 2 and 3 offline modified to include a 1494 MW wind farm on the Broadview 500 kV bus. The new Broadview wind was modeled at the following dispatch levels:
    - 0%, 35%, 100%
- MT-NW case with Colstrip units 1, 2 and 3 offline modified to include a 1244 MW wind farm on the Broadview 500 kV bus along with a 250 MW gas plant in Billings. The 1244 MW wind farm replaces the 1494 MW wind farm. The

gas plant was kept at full output and the new Broadview wind was modeled at the following dispatch levels:
  - 0%, 35%, 100%

The TWG started with case “C” from the initial production cost model runs from the Study Plan. Case “C” has Path 8 flows from Montana to the Northwest of approximately 2189 MW and the path is rated at 2200 MW. From that case, the TWG turned off Colstrip unit 3 and modified the case to include the proposed wind at Broadview, as well as the gas plant in the Billings area. The wind was modeled directly on the Broadview 500 kV bus and assumed to have a RAS that would immediately trip the wind project for any single or double 500 kV outage between Colstrip and Garrison. The decision to trip the full output of the wind farm was based on typical ATR action that trips Colstrip generation for these outages. The gas was modeled on the Alkali Creek 230 kV bus; this bus was chosen as being a viable location from an electrical perspective. Gas transmission impacts were not considered.

Because Path 8 exports (flows from Montana to the Northwest) were of primary interest, the breakdown of each case and its associated Path 8 west-bound MW flows are provided in Table 1.

Table 1: MW flows for Montana to the Northwest on Path 8

Case Description	Montana to the Northwest (MW)
Case for Plan (Case "C")	2189
CS units 1, 2 and 3 offline, new BV wind at 100%	2203
CS units 1, 2 and 3 offline, new BV wind at 35%	1382
CS units 1, 2 and 3 offline, new BV wind at 0%	926
CS units 1, 2 and 3 offline, new BV wind at 100%, with the gas plant	2194
CS units 1, 2 and 3 offline, new BV wind at 35%, with the gas plant	1522
CS units 1, 2 and 3 offline, new BV wind at 0%, with the gas plant	1136

The TWG focused on Path 8 Montana to the Northwest flows in the development of these cases. For the base Case (Case “C”), the TWG adjusted the case until the maximum reliable export on Path 8 of 2200 MW was achieved. Then, when creating the case with the loss of Colstrip unit 3 and the inclusion of 1494 MW of wind at full dispatch at the Broadview 500 kV bus, the TWG again adjusted the case to achieve the maximum reliable export of 2200 MW. This adjustment naturally occurred when 250 MW of the wind at Broadview was replaced with a 250 MW gas turbine in Billings. From those “seed” cases, a reduction of the wind resulted in a similar MW reduction of west-bound Path 8 flows.

By focusing on the path flows for the cases with the most generation, the TWG has ensured that the outages would be comparable. The 500-kV system to which the Colstrip units are attached is a unique and critical component of the transmission system. Historically, it is the MW flow on Path 8 (i.e., Montana to the NW path) that will govern the type of transmission (and generation) response to outages on the 500-kV system from Colstrip to the west.

4. Power Flow Analysis Results; Steady State and Transient Stability

All analyses involved both steady state powerflow and transient stability runs. The TWG started by analyzing the case with Colstrip units 1and 2 offline and performing steady state and stability analyses. The results of the analyses conclude that there are no voltage violations, thermal overloads or transient stability concerns present in the case.

The TWG then modeled an additional 1494 MW of Type 4 wind on the Broadview 500 kV bus dispatched at 100%. The case was then modified so that there was approximately 2200 MW flowing on Path 8 from Montana to the Northwest. The two subsequent base cases had the new Broadview wind dispatched at 35% and 0%; both cases had fewer MW flowing westbound on Path 8 as the TWG was attempting to represent the variable nature of the wind and how that variability impacts the transmission system. The TWG then performed both steady state and transient stability studies on these three cases and for the contingencies analyzed the TWG found no thermal overloads, voltage excursions or transient stability concerns that would indicate that new equipment would be needed to supplement the wind for coal substitution.

The TWG then took the 1494 MW Broadview wind case and reduced the wind at Broadview from 1494 MW to 1244 MW while concurrently modeling 250 MW gas plant on the 230 kV Alkali Creek bus in Billings. This analysis did not include a gas transmission component; the Alkali Creek bus was selected because it is ideally situated to accommodate new generation from an electric perspective. The case with 1244 MW of new wind at Broadview dispatched at 100% and the 250 MW gas plant in Billings was also modified to have approximately 2200 MW westbound on Path 8 from Montana to the Northwest. The subsequent cases had the 1244 MW of wind at Broadview dispatched at 35% and 0% and had fewer MW flowing on Path 8 to the west. The TWG performed steady state and transient stability analyses on the three cases and found that there were no thermal overloads, voltage violations or transient stability concerns.

The TWG ensured that the results of the steady state analysis corresponded with the results from the transient stability analysis by comparing post-contingency steady state voltages with post-contingency transient voltages after they had settled. The TWG found that the two types of analyses resulted in similar voltages and therefore concluded that the modeling and analyses were performed correctly.

~~Appendix A lists all contingencies that were analyzed. Each contingency listed was analyzed as both steady state and transient stability.~~The TWG analyzed over 400 contingencies in this analysis, of which, over 30 were also analyzed dynamically.

5. Production Cost Model

As specified in the Study Plan, Production Cost Modeling (PCM) was performed on the case that was selected as being the "best" from an electrical perspective. Since none of the cases resulted in the inability for Path 8 to experience the full 2200 MW export, a case that has both wind and gas to replace the coal was selected as it will provide the largest range of options to economically operate the system. The PCM was run with and without the 250 MW gas plant in Billings to more fully ascertain the impact of the cost of running a gas plant in conjunction with a wind farm, and the result showed minor shifts in wind and thermal generation, but no change to hydro. Both scenarios with and without gas turbine (GT) showed increased dispatch in Montana wind (e.g., different level of wind penetration) and IPC, PAC and PGE thermal dispatch.

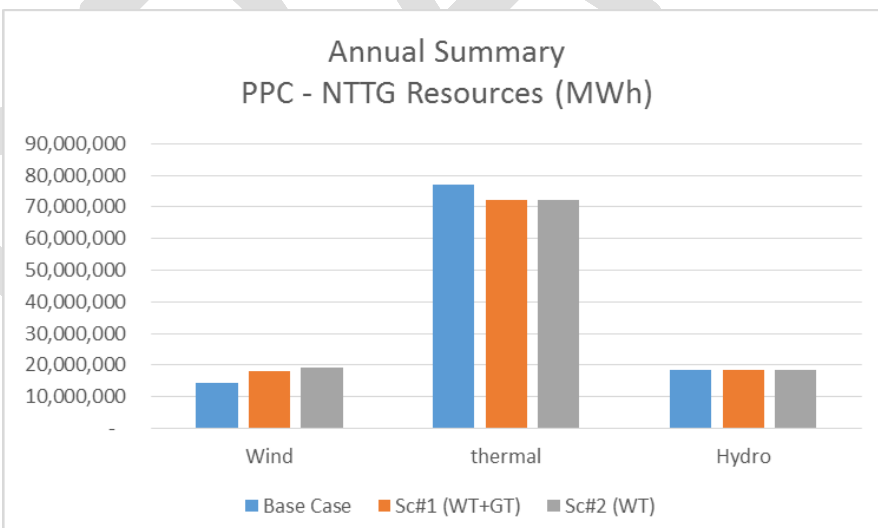

Figure 1: NTTG Generation - Annual Summary (MWh)

The results of the PCM runs are consistent with the results that would be expected when low cost wind dispatch replaces higher cost resources, see figure 2. That is, the times when there is a majority of wind and hydro available for dispatch results in a cheaper dispatch cost than when the system has more coal and gas dispatched(e.g., hourly resources have zero fuel costs). Operating costs when running a system with both wind and gas replacing coal is more expensive than running a system with just wind; but both of those scenarios are cheaper than running the system with coal (250 MW GT vs. 778 MW (net) Colstrip 3 coal). However, beyond this limited dispatch analysis, other costs and benefits are not estimated within this study (e.g. capital costs, flexibility reserves, single world dispatch, etc.). At no time did the change in generation introduce congestion on Path 8 west bound flows.

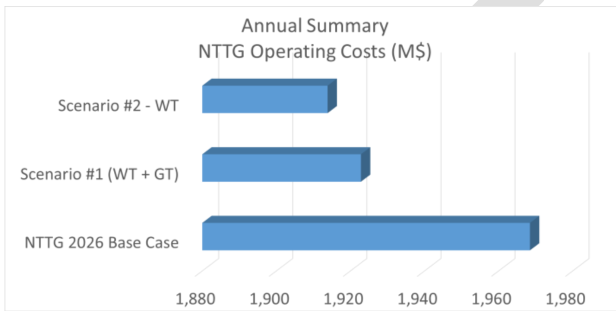

Figure 2: NTTG Annual Operating Costs (M$); based on the TEPPC 2026 CC cost assumptions

6. Conclusions

The Renewable Northwest Project (RNW) submitted a Public Policy Consideration request for a scenario analysis study for the NTTG 2016-2017 ten-year transmission planning cycle. This study report assessed an accelerated phase-out of coal plants while developing utility-scale renewable resources, replacing Colstrip units 1, 2 and 3 with either wind only or a combination of wind and gas.

The study results suggest that a replacement of wind or a combination of wind and gas for coal may be feasible, though nothing in this study constitutes a path study nor does it convey or imply transmission rights. Additional analysis such as sub-synchronous control interaction studies and fault duty analysis due to loss of significant amount of inertia would be required in order to understand the full impacts of phasing out of coal plants.

This limited technical study was comprised of both steady state and transient stability analyses; all of these demonstrated that there are no thermal overloads, voltage excursions or transient stability violations that would pre-empt the replacement of coal with wind or a combination of wind and gas. For the analysis performed, the TWG saw no need for a synchronous condenser as all the studies resulted in a stable system. No operational studies were performed to study the impacts on voltage performance due to two lightly loaded 500 kV lines out of Colstrip with only one unit online. Also impacts on the sub-synchronous resonance (SSR) due to Unit 3 offline were not part of this analysis.

This study did not model the collector system for the wind farm on the Broadview bus and, therefore, didn’t address any capacitance or reactance that could result from the collector system itself; that analysis would take place in a generation interconnection request. This study assumed that the output from the new wind farm met all the voltage requirements that would be required of a real interconnection.

The RAS for the new Broadview wind was assumed to act similarly to the ATR that protects the transmission system by tripping Colstrip generation for 500 kV outages. The timing of the RAS and the equipment necessary to produce the desired result would take place in the study work for an actual generation interconnection request. This study merely confirmed that RAS is required to maintain the stability of the transmission system.

The results of the PCM analysis showed no transmission congestion on the major path connecting Montana to the NTTG footprint (paths 8, 18 and 80). The PCM model dispatched hourly resources with zero fuel costs over gas and coal (e.g., Montana wind dispatched at high capacity factor-- annual average of 35%).

ATTACHMENT D to PSE's Response to NWEC-RNW-NRDC Data Request No. 014

Economic Planning Study

Impacts from Coal Shutdown

Final Study Report

June 18, 2015

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Executive Summary

As part of ColumbiaGrid planning process, an Economic Planning Study (EPS) was conducted to assess potential transmission system impacts on the Northwest power grid from the announced shutdown of Boardman (585 MW) and Centralia (1,340 MW). As part of this effort, a study team was formed to provide some guidance and suggestions to the study work which focused on nine scenarios. Currently there are no replacement plans for Boardman and Centralia. Given that these plants operate at a high capacity factor for two thirds of the year, it is likely that this capacity will be replaced with equivalent firm supply. For purpose of this analysis, it will be assumed that the retired capacity will be replaced with modern combined cycle resources. Carty II is assumed to be the replacement capacity for Boardman (PGE is currently evaluating supply options for Boardman). This shifts the focus of replacement capacity to Centralia which is assumed to be replaced with four modern 1x1 F-Frame combined cycles at three different locations.

Four base case scenarios were used to evaluate location impact of replacement capacity for Centralia. A reference case, Base Case 0 (B0) assumes the base assumptions are applied with the exceptions that Boardman and Centralia (Northwest coal) units are assumed to still be operating. Base scenarios B1-B3 assumed the Northwest coal is retired with Centralia replacement capacity located at three different areas consisting of four generic combined cycles. Additional coal retirement is evaluated in five additional sensitivity scenarios. Retirement of Colstrip 1 and 2 (614 MW) is used to represent this risk for additional coal retirement in the Northwest. Units 1 and 2 were replaced with two additional generic combined cycles. This additional replacement capacity is applied to each of the B1-B3 scenarios to create S1-S3. The last two sensitivity cases utilize the freed up intertie capacity from Montana to the Northwest by adding 600 MW of wind in Montana to replace the retired capacity at Colstrip 1 and 2. This creates S2w and S3w which is based on S2 and S3. Table E-1 summarizes the supply change in the eight sensitivity cases.

Table E-1: Study scenarios and key resource assumptions in the study

Base Case	Case Abbrv	Base Coal Retire	Replacement Capacity			
			Centralia	N. of Seattle	Stanfield	MT Wind
Base Case 0	B0	No	0	0	0	0
Base Case 1	B1	Centralia	1,320	0	0	0
Base Case 2	B2	Centralia	990	330	0	0
Base Case 3	B3	Centralia	660	0	660	0
Sensitivity 1	S1	B1+Colstrip	1,650	0	330	0
Sensitivity 2	S2	B2+Colstrip	990	660	330	0
Sensitivity 3	S3	B3+Colstrip	660	0	1,320	0
Sensitivity 2w	S2w	B2+Colstrip	990	660	330	600
Sensitivity 3w	S3w	B3+Colstrip	660	0	1,320	600

Two key components are required to determine likely site locations for replacement capacity; availability of fuel supply and adequate transmission to deliver generation to load. The three locations selected have direct access to a major gas transmission line and high voltage transmission. The three locations are:

- Centralia Area: The general area south of Olympia, WA to south of Longview, WA along the I-5 corridor. This includes the Grays Harbor spur south of Olympia. The existing Centralia plant is located in this area.
- North of Seattle: North of the greater Seattle area and south of the Canadian border along the I-5 corridor.
- Stanfield Area: Stanfield area is the intersection of two major natural gas pipelines. This would be in the John Day/Hermiston, OR area towards Boardman, OR and along Highway 14 towards Goldendale, WA. Note that Carty II is in the Stanfield area next to the existing Boardman plant.

Production cost simulation using GridView was used as the main tool for this study. Consequently, the scope of this study was focused on economic impacts by simulating potential hourly system conditions throughout a Base Study year. The study evaluated impacts on the Northwest transmission system such as potential congestion, how the resources may be operated differently from today or potential changes in production costs or cost to load. Reliability aspects from these scenarios such as system stability, reactive deficiencies or other related issues are outside the scope of this study and may be conducted in the future if needed.

In general, this analysis consisted of two components, the Backcast (benchmark) and Forecast (future) studies. This approach was developed from the concept that future operations are unknown but historic operations are the best indicator of future operations. A Backcast provides a means to compare simulated results with actual historical operation. This comparison process facilitates improvements to the dataset by aligning simulation results with historic operation. The resulting modeling improvements were applied to all forecast runs.

In this study, the 2010 WECC Backcast dataset was used as the starting dataset. A current year Backcast is more desirable but would require substantially more work to complete. The Backcast study results showed areas of potential improvement. ColumbiaGrid focused on improving flow on defined paths and flowgates by improving regional unit operation. Consequently, the improvements on the original dataset resulted in much better correlation between the simulated results and historical operation.

After completion of the Backcast study, the forecast study was conducted to evaluate future system conditions. The core focus of the analysis is on Coal retirement in the Northwest, which is estimated to take place by the mid 2020's. With the current changing supply mix and uncertainty in developing a supply plan for mid 2020s the study team agreed to focus on the known supply changes. The year 2017 was selected as the base year with known supply changes, post 2017, applied to the base year. These changes focus on the current wave of solar additions, announced coal retirement, and elimination of California Once through Cooling (OTC) plants. Operationally, California is in the middle of phasing in AB 32. However, full implementation of this program was assumed in the Base Case.

This study focuses on coal retirement in the Northwest and its impact on the Northwest generation. Looking at generation changes due to coal retirement from the perspective of replacement supply only does not capture the full impact to Northwest generation. Other dispatchable supply will also respond to changing supply in the system. For comparative purposes results are reviewed based on dispatchable gas and coal supply in the Northwest.

Overall, study results showed that the assumed coal retirement did not significantly impact power flow on major transmission paths or how the system is operated.

<u>Key conclusions from the study results:</u>

- Impact on Base Case for known coal retirement: Boardman and Centralia
    - Overall, the lost generation from Boardman and Centralia was made up by dispatchable generation in the Northwest
    - The location of the replacement capacity for Centralia results in a shift of Northwest flows but flows are within or on the edge of historic operation, 2010-2014.
    - Congestion hours on any of the paths did not exceed historic congestion.
- Sensitivity Cases assuming additional Northwest coal retirement represented by Colstrip Units 1 & 2:
    - As expected, flow from Montana to the Northwest dropped with the retirement of Colstrip 1&2.
    - Overall, the lost generation from Colstrip 1&2 was made up by dispatchable generation in the Northwest.
    - The internal flow in the Northwest shifts based on the location of the replacement capacity for Colstrip. Resulting Northwest flows are within or on the edge of historic operation, 2010-2014.
    - The addition of wind in Montana increased flow from Montana to the Northwest but within historic operating range while a minor reduction of dispatchable generation in the Northwest was observed.
    - Congestion hours on any of the paths did not exceed historic congestion.

Introduction

In the 2014 planning cycle, ColumbiaGrid implemented the Economic Planning Study (EPS) as part of its annual study program. In general, the scope of EPS focuses on evaluating future system performance such as potential transmission congestion or utilization, prices at specific locations or areas, potential production at generation facilities and other issues with the ability to simulate hourly or sub-hourly system behavior using Production Cost Simulation software. In general, the EPS conducted by ColumbiaGrid consists of two components, the Backcast (benchmark) and Forecast (future) studies. This approach was developed from the concept that, before studies to assess future system conditions can be conducted, a benchmark study should be conducted to assess the overall performance of the starting Production Cost Simulation dataset. This can be accomplished by comparing simulation results with historical data to see how well it mimics historical operation for the same timeframe. If the benchmark studies show major diversion between the two sets of data, adjustments are made to the starting dataset to improve the alignment of simulation results with the historical operation as much as possible. After this task was completed, the Forecast study was based on the improved Production Cost Simulation dataset.

ColumbiaGrid formed a study team in 2013 to oversee this study. Participation in this study team was open to any interested parties. Since its inception, the EPS study team has worked on refining the Backcast model and developing study assumptions, methodology, and defining the scope for future studies that focused on assessing potential impacts from coal retirement and replacement capacity alternatives in the Pacific Northwest for Boardman and Centralia. Other fundamental supply changes that are currently occurring in the Western energy market such as renewable resource additions, retirement of California Once Through Cooling (OTC) plants, and policy addition of a CO2 tax in California were included in the study assumptions. Furthermore, the study also looked at the scenarios where additional coal retirement in the Northwest is evaluated with the potential retirement of Colstrip 1&2 as sensitivity cases. More details of study scenarios, key assumptions, study results, will be provided in this report. For more information regarding this study, please refer to ColumbiaGrid's website at http://www.columbiagrid.org/CGEPS-overview.cfm.

Study Scenarios

In this section, more details of the study scenarios are described. Basically, the studies were conducted on eight study scenarios representing different assumptions of coal generation retirement, replacement capacity (the variety of location, sizes, and technologies), and other key changes that are likely to occur in the future. Among these factors, coal retirement and its associated replacement capacity are the two factors that could significantly impact the Northwest. Currently there are no replacement plans for Boardman and Centralia. Consequently, the study team agreed to use the following guidelines to develop study scenarios:

1. Replacement Technology: The Northwest coal supply operates at a high capacity factor with a seasonal dip during the spring run-off. Historical operation exceeds an 80% capacity factor during August through February (Average operation 2008-2014). Given this high utilization, replacement capacity is assumed to be Combined Cycle (CC) power plants. However, in two sensitivity scenarios (S2w and S3w), wind resources are added to the case in addition to combined cycle replacement capacity to create scenarios with higher resources.
2. Generic CC replacement for Boardman: Portland General currently operates a MHI G-Frame CC at Port Westward and is constructing a new G-Frame in the Boardman area (Carty I). Portland General is evaluating their supply options for replacing their 80% share of Boardman. For purpose of this analysis, a second G-Frame Combined Cycle is located in the Boardman area, referred to as Carty II. This is equivalent to Portland Generals share of Boardman.
3. Generic CC replacement for Centralia: The F-Frame Combined Cycle is the most common type of Combined Cycle installed in recent years. For purpose of this analysis the latest generation of F-Frame Combined Cycle is used as replacement capacity for Centralia with the following unit characteristics:
    i. A 1x1 F-Frame combined cycle 330 MW
    ii. Minimum loading of 185 MW
    iii. A full load heat rate of 6.95 MMBtu/MWh
    iv. A 50 MW duct burner with a 9.2 MMBtu/MWh heat rate

v. For a net rating of 380 MW with a full load heat rate of 7.25 MMBtu/MWh

4. Site Location: Placement of new combined cycle plants needs access to both a major gas pipeline and high voltage transmission. Three areas were selected for potential new development for the replacement combined cycles. Approximated geographical locations of these areas are shown in figure 1. Please note that gas pipelines are shown as green lines.

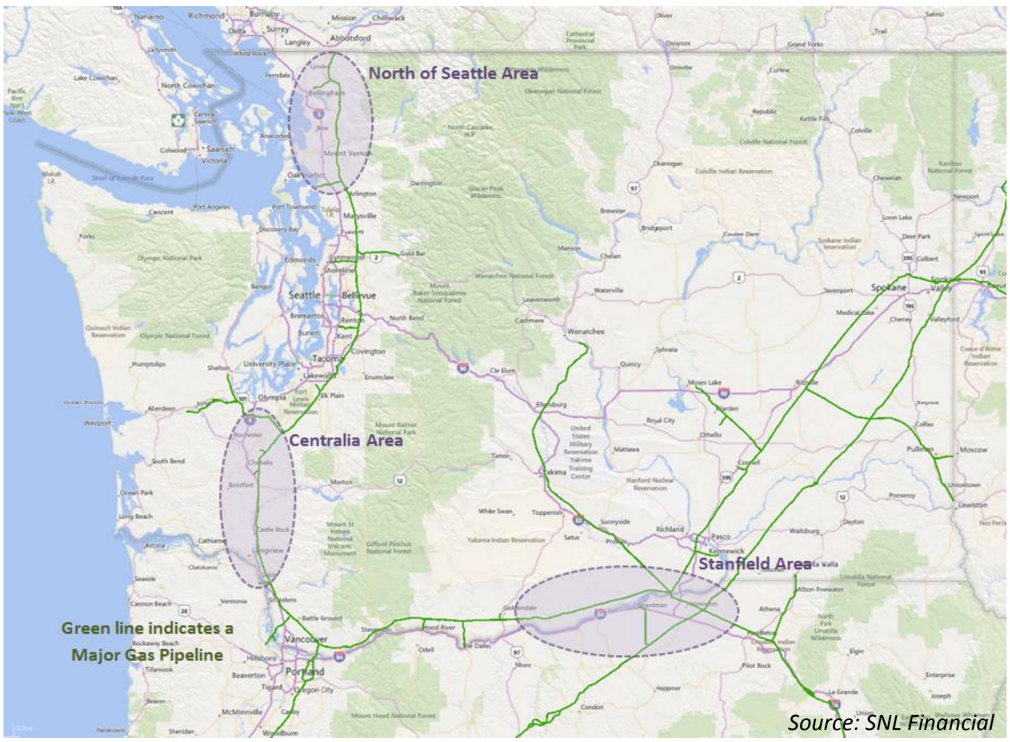

Figure 1: Approximated locations of Combined Cycle facilities that were used as replacement capacity

Centralia Area: Located along the I-5 corridor south of Olympia to the Longview area. This would also contain the pipeline spur from the Olympia area to Grays Harbor. Gas is supplied from the Northwest Pipeline. This area is west of the cascades and between the Seattle and Portland load pockets. Note the existing Centralia plant is located in this area. Buses used in the Centralia area are: Centralia G1 20 kV, Centralia G2 20 kV, and Paul 500 kV.

North of Seattle: North of the greater Seattle area to the Canadian border. Gas would be supplied off Northwest Pipeline. This is the area west of the cascades and north of the Seattle load pocket. Buses used in the North of Seattle area are: Sedro 230 kV and Custer West 500 kV

Stanfield Area: Stanfield/Hermiston area, to Boardman area in OR. This is the intersection of the Northwest and TransCanada GTN Pipelines. This would also include development along Highway 14 going toward Goldendale, WA off the Northwest Pipeline. This is the area east of the Cascades Range. Since the majority of the load centers in the northwest are located on the west side of the Cascades, electricity from the replacement capacity in this option will need to travel west through major transmission paths to serve load centers. Note the existing Boardman plant is located in this area. Buses used in the Stanfield area are: McNary S1 230 kV, McNary S2 230 kV, Coyote 500 kV and McNary S3 230 kV

The studies consisted of three main scenarios (B1-B3) and five sensitivity scenarios (S1-S3w) that were created using the Reference Case (B0) as a starting point. Year 2017 was selected by the study team as the base year of this analysis. This eliminates some uncertainty associated with developing supply assumptions for load growth into the mid 2020's. In addition, year 2017 also benefits from a higher certainty of operational power plants and transmission projects assumptions. Below are key assumptions of these scenarios:

- **Base Scenario 0 (B0 or Base 0 or the Reference Case)**: Using the 2010 dataset which included Backcast improvements as a starting point, this scenario modeled the retirement of 4,737 MW from the announced coal plant retirement throughout the west, California Once Through Cooling (OTC) units, and major retirements that already occurred since 2010 such as the shutdown of San Onofre Nuclear Power Plan in California. However, in order to create a reference case, Boardman and Centralia were assumed to be online in the base (B0) case. New generation facilities were added to the B0 case based on the latest available information of utility's Integrated Resource Plans (IRPs) and other sources. Firm transmission projects that were scheduled to be energized between 2010 and 2017 were also modeled in the study. In addition, this case also modeled the impacts from major policy such as Green House gas by assuming the full implementation of the California Green House Gas (GHG) Program (AB 32).

- **Base Scenarios 1**-3 (B1-B3 or Base 1 – Base 3): The only difference between B1-3 and B0 cases are the retirement of Boardman, Centralia and location of the replacement capacity for Centralia. Boardman is online in the B0 case but is assumed to be retired with Carty II as the replacement capacity in the B1-B3 cases (PGE is currently evaluating replacement options for Boardman). Centralia is online in B0 and offline in the B1-B3 cases. Replacement capacity assumptions for Centralia in the B1-B3 cases are as follows:
  - **Base Scenario 1 (B1)**. The replacement capacity for Centralia is located at Centralia area 1,320 MW (4 units). This is equivalent to a status quo case by maintaining the replacement capacity in the same area as the coal retirements.
  - **Base Scenario 2 (B2)**. In this case, instead of placing all replacement capacity around Centralia, gas-fired generation facilities were placed at two locations. Basically, 990 MW in the area around Centralia (3 units) and 330 MW north of Seattle respectively (1 unit).
  - **Base Scenario 3 (B3)**. In this case the replacement capacity is split equally between Centralia area (660 MW or 2 units) and Stanfield area (660 MW or 2 units)

- **Sensitivity Scenario 1-3 (S1-S3)**. Sensitivity scenarios 1-3 (S1, S2, and S3) applied additional Northwest coal retirement to B1-3 cases. Colstrip 1&2 (614 MW in total) is used to represent additional coal retirements which results in a total retired generation capacity of 2,539 MW (from Boardman, Centralia and Colstrip 1&2). Two additional generic F-Frame combined cycle units were added to the Base cases (660 MW) to replace Colstrip 1 and 2. This brings the total combined cycle replacement capacity to 2,430 MW from 7 units.
  - **Sensitivity Scenario 1 (S1).** Two replacement units for Colstrip 1&2 were added to the B1 Case. One unit was added in the Centralia area and another in the Stanfield area. This results in a net capacity at Centralia of 1,650 MW with the remaining 330 MW in the Stanfield area.

- **Sensitivity Scenario 2 (S2)**. The two replacement units for Colstrip 1&2 were added to the B2 case. One unit was added North of the Seattle area and another in the Stanfield area. In this case, replacement capacity was placed in all 3 locations (around Centralia, North of Seattle, and Stanfield) with the amount of 990, 660, and 330 MW respectively.
- **Sensitivity Scenario 3 (S2)**. The two replacement units for Colstrip 1&2 were added to the B3 in the Stanfield area. This results in a net capacity in the Centralia area of 660 MW and 1,350 MW in the Stanfield area. The net increase in capacity installed on the east side of the cascades will help to evaluate potential east to west congestion across the cascades.

- **Sensitivity Scenarios 4 & 5 (S2w & S3w)**. These sensitivity scenarios assumed additional wind resources are online. Both sensitivities assumed 600 MW of wind resources are added in Montana in addition to the replacement capacity that relies on combined cycles. Below are the summary of these two cases.
  - **Sensitivity Scenario 4 (S2w)**. Based on case S2 with the additional of 600 MW of wind resources in Montana
  - **Sensitivity Scenario 5 (S3w)**. Based on case S3 with the additional of 600 MW of wind resources in Montana

A summary of all scenarios that were studied is shown provided in table 1:

Table 1: Study scenarios and key resource assumptions in the study

Base Case	Case Abbrv	Base Coal Retire	Replacement Capacity			
			Centralia	N. of Seattle	Stanfield	MT Wind
Base Case 0	B0	No	0	0	0	0
Base Case 1	B1	Centralia	1,320	0	0	0
Base Case 2	B2	Centralia	990	330	0	0
Base Case 3	B3	Centralia	660	0	660	0
Sensitivity 1	S1	B1+Colstrip	1,650	0	330	0
Sensitivity 2	S2	B2+Colstrip	990	660	330	0
Sensitivity 3	S3	B3+Colstrip	660	0	1,320	0
Sensitivity 2w	S2w	B2+Colstrip	990	660	330	600
Sensitivity 3w	S3w	B3+Colstrip	660	0	1,320	600

Study Assumptions

This section describes key assumptions used in this analysis. These include the improvements that were identified in the Backcast and the assumptions for the future conditions. Some of these assumptions are common to all scenarios (common assumptions),which include the improvements that were identified from Backcast studies (Backcast Improvements), major addition of new resources[1], generation retirements[2], new or change in the topology of major transmission facilities, load growth, gas prices assumptions, and others. In addition, there are also other assumptions that apply to each individual case.

A. Backcast Improvements

The Backcast studies identified 17 major improvements that improved the alignment of Production Cost Simulation study results with historical operation and these improvements were applied to all cases. A production cost model optimizes the entire system whereas WECC is operated with thirty eight independent Balance Areas (BA) each optimizing their individual cost. A Backcast provides a means to apply modeling constraints to mimic historic behavior. This assumes historic operation will continue into the future. Creating and optimizing a Backcast dataset creates a benchmark that provides a better foundation for the future forecast study. In this round of the EPS, the WECC 2010 Backcast dataset was used as the starting point for Backcast studies. The significant modifications to the original dataset are summarized below:

1. **Nature Gas Price**: Natural gas prices were adjusted to reflect gas trading hub prices and local transport fees. The original dataset had the burner tip price in California less expensive than the Northwest or Southwest. This resulted in combined cycle generation in California over generating compared to its historical operations and under generation of combined cycles in the Northwest and Southwest. The new gas price corrected this behavior.
2. **Non-Dispatchable Supply**: Non-Dispatchable supply is generation that the local Balance Area (BA) has little to no control over how it’s dispatched. Non-Dispatchable supply is

[1] New resources that were added to all cases, not including replacement capacity
[2] Generation retirement that were applied to all cases, not including coal shutdown

not limited to wind and solar projects. Other types of supply fit this category: Biomass, cogeneration, Qualifying Facilities (QF), geothermal, nuclear. There are two primary issues with the original dataset: resulting generation does not match historic operation and the units have a dispatch range. The original generation from Geyser units in Northern California over states generation by 30% and it is allowed to change its generation based on economics. These units are modeled as must run units with a flat monthly shape based on historic operation.

3. **Commitment Order**: A production cost model assumes a single owner dispatch while WECC is operated via thirty eight balance areas. The starting production cost dataset (WECC 2010 Dataset) uses the same generic assumptions for all units within a generic generation class. However, in reality, each balancing area optimizes its own supply to serve its internal needs which could lead to disparity between the actual historical data and the simulation results. In order to address this issue, ColumbiaGrid applied a technique which is based on a review of publically available data like Environmental Protection Agency (EPA) Continuous Emission Monitoring System (CEMS) and Energy Information Administration Form 923 data to change the behavior of dispatchable supply to reflect historic operation. The key factors that were adjusted as part of this step are summarized below:

    3.1. Start Cost: The original start cost for combined cycles were on par with steam coal units. The start cost for combined cycle was lowered to align modeled operation with historic. Adjusting the start cost of a unit make a unit more or less attractive to commit within a region supply.

    3.2. Heat rate performance factor is used to adjust commitment order within a regional market to mimic historic operations. The performance factor works by scaling the modeled heat rate curve. This changes the units order in the regional commitment stack.

    3.3. Must Run: The single owner commits and dispatch of a production cost model does not capture individual balance area behavior. To overcome under commitment of supply must run is a tool used to mimic this historic behavior. It can be applied seasonally or annual to mimic historic behavior.

3.3.1. Must run behavior is not limited to just individual unit. For example the individual turbines at Red Hawk combined cycle is committed 50-60% of the time, while the plant is connected over 90% of the time.

3.3.2. A nomogram may be used to force commitment for minimum generation levels, i.e. megawatt amount or percent of balance area load. A nomogram was used in the EPE balance area to enforce local commitment behavior.

4. **Full load Heat Rate**: Several corrections were made to full load heat rate of peakers and combined cycles due to two issues with the original values. First, the full load heat rate didn't always match the technology used. For example a twenty year old combined cycle had a full load heat rate better than currently best available technology. Adjustments were made to align full load heat rates with turbine type and vintage of the turbine. Second, ColumbiaGrid found that duct firing was not typically modeled for most of the combined cycles that have this capability. This practice overstates operational capability of combined cycle in WECC by a couple thousand megawatts. Since duct firing occurs in a combined cycle with an oversized steam turbine, i.e. this surplus capability can only be utilized through supplement firing in the waste heat recovery boiler. This duct firing has a heat rate on par with a conventional steam gas plant, not a combined cycle therefore its incremental utilization is typically low.

5. **Splitting combined cycles into 1x1 configurations**: The commitment decisions for combined cycles are made by gas turbine but the original modeling of combined cycle was by plant. The modeling of combined cycles was split from whole plant to a 1x1 configuration to improve the commitment behavior of combined cycle. Previous modeling represented a 2x1 combined cycle as one plant, i.e. a 2x1 CC modeled as 600 MW with a min loading of 330 MW.

6. **Maintenance outage**: Maintenance event for major units have a significant impact on power flow. Maintenance outages were developed for major base load units based on the commitment status from EPA CEMS data.

7. **Seasonal Non-Operation**: Maintenance outages were also used to account for some seasonal non-operation periods. For example, maintenance events were used on combined cycles in the Northwest to limit operation during the spring run-off. GridView

had a high utilization of Northwest CC during this period while historic operation had little if any operation during a six to eight week period during the spring run-off.

8. **Supply Review**: Information from public sources was used to review how certain resources (supply) were operated in 2010. Corrections were made as needed to account for any discrepancy.

9. **Hydro modeling**: The hydro modeling used actual 2010 Hydro as modeled by WECC. Some adjustments were made to Hydro coefficient in British Columbia to Unserved Energy in that area.

10. **Phase Shifter Transformer**: Set point for phase shifter is adjusted and/or operating limits applied to mimic historic flows.

11. **Path 27**: Flow on the IPP DC line (Path 27) is limited to generation from Intermountain Power with the addition of Milford Wind project.

12. **Other Paths**: Reviewed model interface definitions and ratings and updated as needed. As part of this task, path ratings and transmission lines for modeled WECC Paths and BPA Flowgates were confirmed and corrected as needed. For example, corrections were made on the definitions of several paths such as Path 59 (WALC Blythe Sub to SCE Blythe). This limited flow on TOT 7 in Colorado to less than 218 MW on a path rated at 890 MW.

13. **Transmission Upgrades**: Added/changed transmission system model to reflect system conditions in 2010:
    13.1. Added Imperial Valley to Miguel 500 line
    13.2. Added Populus substation and associated transmission lines

14. **Modeling of DC-Tie to external regions**: WECC has eight DC-Ties connecting WECC with other regions. Following are more details of how these DC-ties were modeled:

14.1. The Alberta to Saskatchewan and Virginia Smith tie is not modeled

14.2. A fixed hourly shape is used for the Black Water and Artesia converters in NM

14.3. A high dispatchable cost unit is used for the remaining DC-Ties (DC-Ties: Mile City, Rapid City, Stegall, and Lamar). This minimizes imports while still allowing imports when system conditions warrant it.

15. **Wind Project**s: Locations of wind projects in the Northwest from the starting dataset (2010 WECC) were reviewed. Adjustments were made to the wind projects that were placed at the wrong locations in the starting dataset.

16. **TOT 3 Import**: Due to unrealistic flows on this path, a nomogram was created to limit the net imports into the Denver area across TOT 3 (Path 36 – Eastern Wyoming to Colorado) and TOT 5 (Path 39 – West to East Colorado). After the implementation of the nomogram, power flow on these paths are more in-line with the historical operation.

B. Study Year:

Year 2017 was selected as the study year for this study. Transmission and load growth is fixed to 2017. GridView has limited scenario capability to manage supply changes post 2017, 2025 was run with 2017 loads and transmission system to overcome this issue.

C. Major Resource Retirements:

This section provides a summary of generation retirement or fuel switching to natural gas that was applied to all cases. Please note that these do not include the assumptions of Boardman and Centralia retirement that can be varied for each case.

- Planned steam coal retirement and fuel conversion to natural gas: Currently 1,665 MW of steam coal has been retired. Furthermore, an additional 4,997 MW is currently slated for retirement or fuel switching to natural gas. The retirement assumptions were developed during the fall of 2014. A summary of planned retirement is shown in table 2.

Table 2: Summary of planned retirements that were included in all cases

Summary of Modeled Coal Retirements				
Unit	State	Owner	Retirement Date	Capacity (MW)
Northwest				
Boardman	OR	PGN	12/31/2020	585
Centralia 1	WA	TransAlt	12/31/2020	670
Centralia 2	WA	TransAlt	12/31/2025	670
			Northwest Total	1,925
Inland				
Osage 1-3	WY	BHP	3/1/2014	30
Neil Simpson	WY	BHP	3/1/2014	19
Ben French	SD	BHP	3/1/2014	22
J E Corette	MT	PPL	4/30/2015	153
Carbon 1-2	UT	PAC	4/30/2015	172
			Inland Total	347
Southwest				
Four Corners 1-3	NM	APS	1/1/2014	560
Cholla 2	AZ	APS	4/1/2016	260
Apache 2	AZ	AEPC	12/31/2017	175
San Juan 2&4	NM	PNM	by 2017	837
Reid Gardner 1-3	NV	NEVP	by 2015	298
Reid Gardner 4	NV	NEVP	by 2020	255
Navajo unit	AZ	NEVP	by 2017	750
H Wilson Sundt 4	AZ	TEP	12/31/2017	156
			Southwest Total	3,291
Rocky Mountain				
N W Clark 1&2	CO	BH	3/1/2013	43
Arapahoe 3	CO	PSC	12/31/2013	44
Arapahoe 4	CO	PSC	12/31/2013	112
Cherokee 1	CO	PSC	5/1/2012	107
Cherokee 2	CO	PSC	10/1/2011	106
Cherokee 3	CO	PSC	12/1/2015	152
Cherokee 4	CO	PSC	in 2017	352
Valmont	CO	PSC	12/31/2017	184
			Rocky Mountain Total	1,100
			Net Retired	6,662

- California Once Through Cooling (OTC): The California Water Resource Board has mandated that OTC unit to be retrofitted with essentially a closed loop cooling cycle or retire by a schedule date. Currently 3,660 MW of steam natural gas has been retired and an additional 12,890 MW is scheduled to retire by 2021. However, please note that Diablo Canyon is an OTC plant but its retirement is not included in the analysis.

- Early retirement of San Onofre nuclear plant in Southern California. Plant operation had ceased in Jan-2012 due to mechanical issues and was officially retired in Jun-2013.

D. Major Resource Additions:

Resources that have received regulatory approvals or planned utility replacements were modeled in all cases. These include several types of resources described below. A summary of major resource additions is shown in table 3.

- Solar projects: A significant amount of capacity is under Purchase Power Agreement (PPA) with the utilities in California to meet mandated Renewable Portfolio Standard (RPS). These Solar power plants represent a large proportion of these resources but the economics of these solar projects is highly dependent on the federal Investment Tax Credit (ITC) which currently set to expire by the end of 2016. In this study, most solar projects with a purchase power agreement and scheduled in-service date by the end of 2016 were assumed to be materialized and modeled in the study. According to current trend of solar project development, it is anticipated that the amount of total capacity from solar power plants in WECC will be double in the next two years (end of 2014 to the end of 2016)

5. Other Resources: New resources (in addition to Solar projects) that meet the following criteria were also included in the study
    a. Facilities that have been in-service after 2010
    b. Facilities that are under construction.

c. Approved or announced replacement plan for retired capacity is modeled
d. Approved or announced new additions by load serving entities projects that are schedule to operation prior to the end of 2017
e. Renewable projects with a purchase power agreement and expected to be operation by the end of 2017 were added
f. SCE and SDG&E approved capacity expansion for San Onofre is included (CPUC Track 1 and Track 4).
g. Replacement for the retired OTC units assumes in kind capacity at the same locations. Current repower projects at the California Energy Commission are used as replacement capacity. A generic LMS100 is used as replacement capacity for plant without any proposed replacement plans
    i. California is not our primary area of concern and this assumption insures adequate supply in California without impacting the Northwest.

E. State and Federal Policies:

- The Assembly Bill (AB) 32 or California Clean Air Act imposes a CO2 tax on all California generation as well as imports into the State. These rules are currently being phased in. The base case and sensitivities runs will include the full impact of these rules. The results from the 2010 Backcast run are shown in Figures 1-7. These results show the modeled average daily on-peak flow from the simulation as compared to actual 2010 operations.

  CO2 tax used in California is $24.96/ton of CO2. This translates into:
    i. A California CO2 import tax: $11.97/MWh
    ii. Import tax for Asset Control Supplier (from BPA & Powerex): $0.53/MWh
    iii. The CO2 tax converted into a fuel cost adder:
        1. Natural gas: $1.460/MWh
        2. Coal: $2.683/MWh

Table 3: Summary of resource additions that were applied to all cases

Summary of Fossil Fuel Additions 2011-2017

Area	Unit Name	Capacity (MW)	Type	Location	Start Year
Northwest					
	Langley Gulch CC	300	CC	IPC	2012
	Port Westward II	218	IC	PGE	2014
	Carty CC 1	450	CC	PGE	2016
		968			
Inland					
	Dave Gates CT1	144	LM6000	NWMT	2011
	Highwood	40	LM6000	NWMT	2011
	Dry Fork	385	ST-Coal	PACE	2011
	Lake Side II	629	CC	PACE	2014
		1,198			
Northern California					
	Almond 1-4	200	LM6000	TID	2012
	Russel City CC	616	CC	PG&E	2013
	Los Esteros CC	256	CC	PG&E	2013
	Mariposa 1-4	200	LM6000	PG&E	2012
	Lodi Energy Center	277	CC	PG&E	2012
	Marsh Landing 1-4	720	GT	PG&E	2013
	Woodland 1-6	50	IC	MID	2011
	GWF Hanford CC	120	CC	PG&E	2013
	GWF Henrietta CC	120	CC	PG&E	2013
	GWF Tracy CC	314	CC	PG&E	2012
		2,873			

Table 3: Summary of resource additions that were applied to all cases (cont)

Summary of Fossil Fuel Additions 2011-2017 (Cont)

Area	Unit Name	Capacity (MW)	Type	Location	Start Year
Southern California					
	Haynes 1-6	600	LMS100	LADWP	2013
	Scattergood LMS 1-2	200	LMS100	LADWP	2015
	Scattergood CC3	310	CC	LADWP	2015
	Canyon 1-4	200	LM6000	ANHM	2011
	Lake Hodges	40	PS	SDGE	2012
	Pio Pico 1-3	294	LMS100	SDGE	2017
	Carlsbad 1-6	588	LMS100	SDGE	2017
	McGrath	50	LM6000	SCE	2012
	El Segundo CC 1A	255	CC	SCE	2013
	El Segundo CC 1B	255	CC	SCE	2013
	Sentinel 1-8	768	LMS100	SCE	2013
	Wallnut 1-5	480	LMS100	SCE	2013
	El Centro 3	142	CC	IID	2012
		4,182			
Southwest					
	Harry Allen CC1_A	524	CC	NEVP	2011
	Coolidge Peaker	575	LM6000	SRP	2011
	Newmen	288	CC	EPE	2011
	Rio Grande GT	95	LMS100	EPE	2013
	Montana 1-3	300	LMS100	EPE	2015
	Montana 4	100	LMS100	EPE	2017
		1,882			
Rocky Mountain					
	Pueblo Airport CC	100	CC	Pueblo	2012
	Pueblo Airport LMS	98	LMS100	Pueblo	2012
	Cheyenne CC	100	CC	Cheyenne	2014
	Cheyenne GT	120	LM6000	Cheyenne	2014
	Cherokee CC1	588	CC	EXCEL (PSC)	2015
		1,006			

Table 3: Summary of resource additions that were applied to all cases (cont)

Summary of Fossil Fuel Additions 2011-2017 (Cont)

Area	Unit Name	Capacity (MW)	Type	Location	Start Year
Alberta					
	Keephills 3	450	ST-Coal	AESO	2011
	Firebag 3	160	GT	AESO	2011
	Cold Lake 1-2	170	GT	AESO	2013
	Bonnybrook CC	200	CG	AESO	2013
	Firebag 4	160	GT	AESO	2015
	Shepard EC 1-2	800	CC	AESO	2015
		1,940			
CFE (Mexico)					
	Baja Calif II 1-3	120	GT	CFE	2013
	Baja CA III CC	320	CC	CFE	2016
		440			
	Net	14,489			

F. Hydro and Pump Storage Modeling:

- Fixed hourly shapes inform WECC 2010 Backcast were not changed.
- Hydro coefficients ware not changed from ColumbiaGrid's Backcast.
- Dispatchable Hydro in the Northwest and Inland was changed to 2008 monthly values
- Dispatchable Hydro in California, the Southwest and Rocky Mountain used changed 2005 monthly generation (WECC current normal year).
- Pump Storage parameters were adjusted to backcast

G. Balance Area Definitions:

6. Defined balance area in the dataset ware not changed. Note that BANC and LADWP balance areas were not extracted from the CAISO balancing areas.

H. **Wheeling Charges:**

7. An exit fee from CAISO of $/10 MWh is used.

I. Transmission Upgrades:

Using 2010 WECC dataset as the starting point, transmission upgrades were modeled in the study are shown in table 4.

Table 4: List of transmission projects that were modeled in all scenarios

Transmission Upgrades proposed to be modeled in 2014			
No	**Project Name**	**In-Service Date**	**Source***
1	Montana Alberta Tie - Line (MATL) Project	Operational	CG Biennial Plan
2	Sunrise Powerlink	Operational	CCTA
3	Pawnee-Smoky Hill	Operational	CCTA
4	WOM Group 1 (McNary - John Day)	Operational	CCTA
5	Midway-Waterton	Operational	CCTA
6	TRTP	Operational	CCTA
7	Gateway Central: Mona to Oquirrh 500 kV	2013	CCTA
8	Ponderosa 500/230 kV #2 Transformer Addition	Operational	CG Biennial Plan
9	Douglas - Rapids 230 kV line and Rapids 230/115 kV Substation	2014	CG Biennial Plan
10	Salem - Chemawa 230 kV Line Upgrade	2014-15	CG Biennial Plan
11	Desert Basin - Pinal Central 230 kV	2014	CCTA
12	Northwest Transmission Line 287kV	2014	CCTA
13	One Nevada Line (ON Line) 500 kV	2013-2014	CCTA
14	Pinal West-Pinal Central-Browning (SEV)	2014	CCTA
15	Columbia - Larson 230 kV line	2014	CG Biennial Plan
16	Big Eddy - Knight 500 kV line and Knight Substation	2015	CG Biennial Plan
17	Rapids - Columbia 230 kV line and Columbia Terminal	2015	CG Biennial Plan
18	Devers - Colorado River 500 kV (DCR) Project	2014-2015	CCTA
19	Gateway Central: Sigurd - Red Butte 345kV Line	2015	CCTA
20	Hassayampa - North Gila 500 kV #2	2015	CCTA
21	Interior to Lower Mainland Transmission (ILM) Project 500 kV	2015	CCTA
22	Walla Walla to McNary 230kV	2014-2015	CCTA
23	West of McNary Reinforcement Project Group 2 (Big Eddy-Knight) 500kV	2015	CCTA
24	Raver 500/230 kV Transformer, 230 kV line to Covington	2016	CG Biennial Plan
25	John Day - Big Eddy 500 kV #1 line reconductor	2016	CG Biennial Plan
26	Celilo Terminal Replacement (PDCI upgrade 3220 MW)	2016	CG Biennial Plan
27	Bothell - SnoKing 230 kV Double Circuit Line Reconductor	2016	CG Biennial Plan
28	Delridge - Duwamish 230 kV Line Reconductor	2016	CG Biennial Plan
29	Central Ferry - Lower Monumental (Little Goose Area) 500 kV	2015-2016	CCTA
30	Delaney - Palo Verde 500 kV	2016	CCTA
31	Delaney - Sun Valley 500 kV	2016	CCTA

J. Load:

Assumptions regarding load modeled in all scenarios are summarized below:

- 2017 load forecast is based on linear interpolation between 2010 and TEPPC 2024 preliminary
- Monthly load shapes was normalized to reflect historical trends

K. Gas Price:

ColumbiaGrid participated in the WECC technical group that recommended a market based approach in developing burner-tip gas price. From this effort the 2017 dataset was modified to better reflect the actual conditions. As a result, the following gas prices on major hubs were used in this study.

- Henry Hub: $4.205/MMBtu
- AECO: $3.600/MMBtu
- San Juan: $4.092/MMBtu
- SoCal Boarder: $4.393/MMBtu

Study Results

Two sets of study results are presented in this report. First, results from Backcast study are shown in items 1.1-1.7. Mainly, these results show the comparison between the simulation results using the original datasets and the improved datasets which incorporated the changes that were identified from the Backcast study using the 2010 historical data as a reference. The comparison focuses on average power flow on 6 major transmission paths that connect the Pacific Northwest to the rest of the Western Interconnection and other major paths. Second, the results from the simulation on future system conditions using the improved results from the Backcast study are summarized in section 2. Based on discussions with Study Team participants, this report will focus on the impacts of generation dispatch, and power flow on major paths. However, different type of results can be provided based on the input from interested parties.

1. Backcast Study Results

The Backcast study results are presented by comparing power flow on seven major paths as shown in sections 1.1 through 1.7. For each path, a summary of average On-Peak flow is shown in a chart containing three lines representing three set of results. The green lines represent 2010 historical flow which will be used as reference. The dotted lines show the original WECC 2010 Backcast without any modification and the ruby red line shows the results from the ColumbiaGrid Backcast which incorporates the improvements that were identified in the Backcast study. Generally, performance of the Backcast can be measured by the ability to mimic the historical data. Below are the comparison results:

1.1. Montana to Northwest (Path 8)

Contractual supply from Colstrip located in Montana is a significant energy source for the Pacific Northwest. In 2010, historical data shows an average of 1,250 MW was imported to Northwest throughout the year. Figure 1 shows actual flow on Path 8 (green line) compared to the two sets of simulation data showing that simulation with the improved ColumbiaGrid Backcast study models (solid purple line) has tracked the historical data better than the original dataset (dotted line). As shown below, at the starting point, both the simulation from

ColumbiaGrid Backcast and original dataset produced similar results with the same range of errors within 5% of the actual flow. However, for the remaining results, it is clear that Backcast study has better performance than the original data. Basically, the Backcast has reduced the errors from 9.4% to 5.2%. A summary of the study results for Path 8 is shown in figure 1:

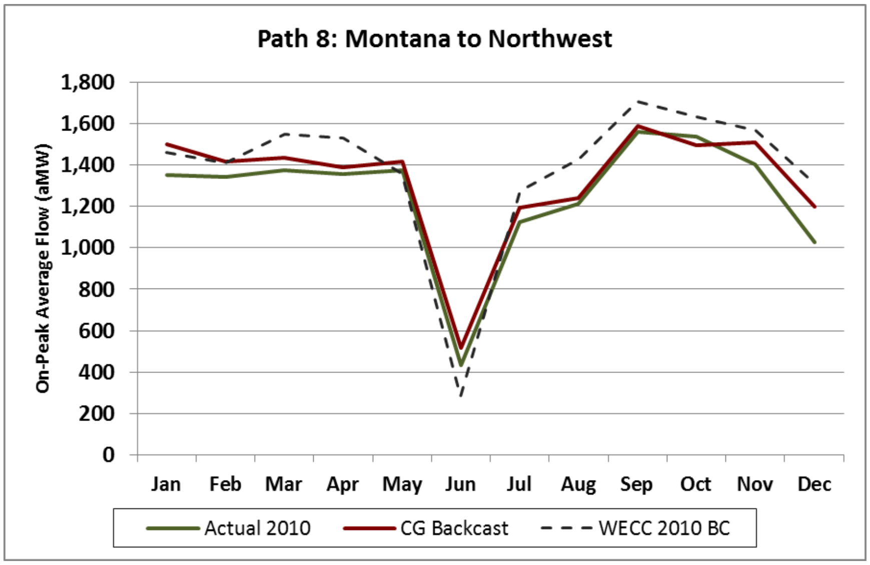

Figure 1: Comparison of power flow on Path 8 with/without Backcast improvements

1.2. West of Cascades (Combined North and South, Paths 4 and 5)

Being major transfer paths between supply-rich areas on the east side of the Cascade Mountains and load centers on the west side, the West of Cascades North and South paths can be an internal constraint within the Pacific Northwest that cannot be ignored. In this case, as shown in figure 2, the results from both ColumbiaGrid Backcast and original dataset are within 5% of actual flow at the starting point. On annual basis both the Backcast and starting point are within +/-1%. Some improvement can be made in the seasonal shape. Backcast results are on the high side (22%) compared to a starting point of -24% low. A summary of the study results for Path 4 and 5 is shown in figure 2.

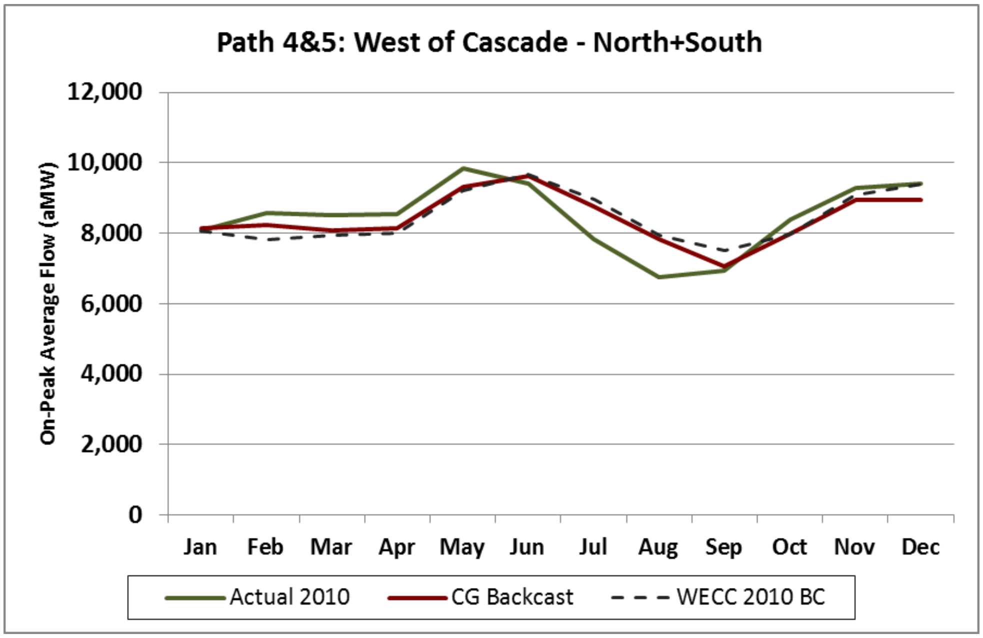

Figure 2: Comparison of power flow on Paths 4&5 with/without Backcast improvements

1.3. North of John Day (Path 73)

North of John Day divides West of Cascades North and South paths. It measures flow moving from north to south across this cut plan. Generation at Centralia will reduce flow on this path while generation north of John Day along the Columbia River will increase its flow. The results from original WECC dataset was approximately 24% lower than historical operation while ColumbiaGrid simulation is approximately 21.5% higher than actual data. However, a 12% decrease in the standard deviation represents an improvement in the ColumbiaGrid Backcast. A summary of the study results for Path 73 is shown in figure 3.

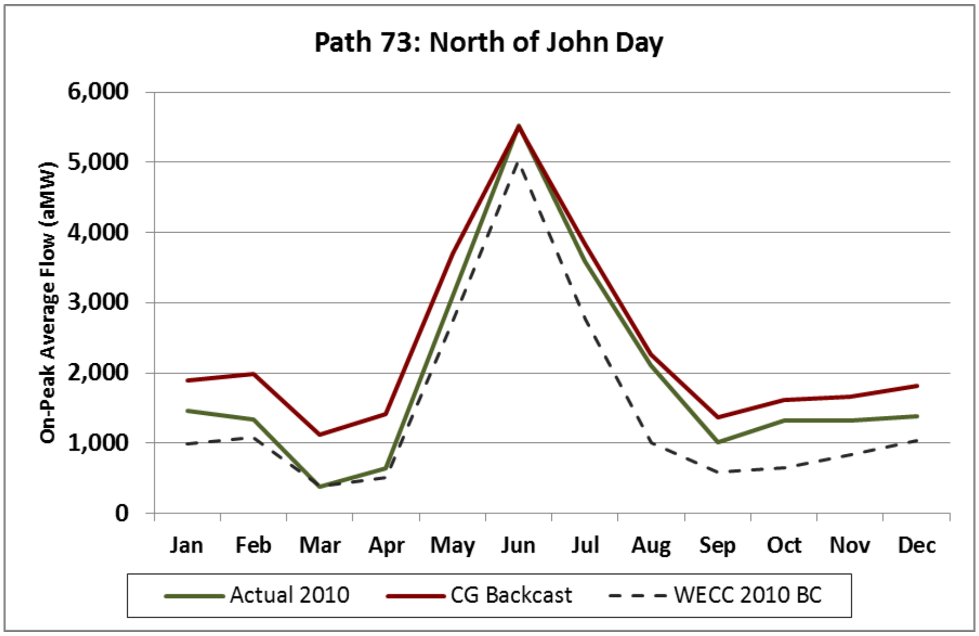

Figure 3: Comparison of power flow on Path 73 with/without Backcast improvements

1.4. South of Allston (Path 71)

Typical power flow on this path is normally north to south, along the I-5 corridor, from Longview, WA to the Portland area. Flow along this path is driven by generation at Centralia and flow across West of Cascades South (Path 5). The annual difference from WECC original dataset was approximately -13% lower than the historical operation while ColumbiaGrid Backcast is approximately 19% higher. ColumbiaGrid Backcast captures the seasonal spike in flow at a lower average standard deviation from actual than the original dataset by -29%. In addition, Backcast results for the winter and fall months are generally higher than the historical operation (on the high side) while peak flows in the summer are in line with actual flow. A summary of the study results for Path 71 is shown in figure 4.

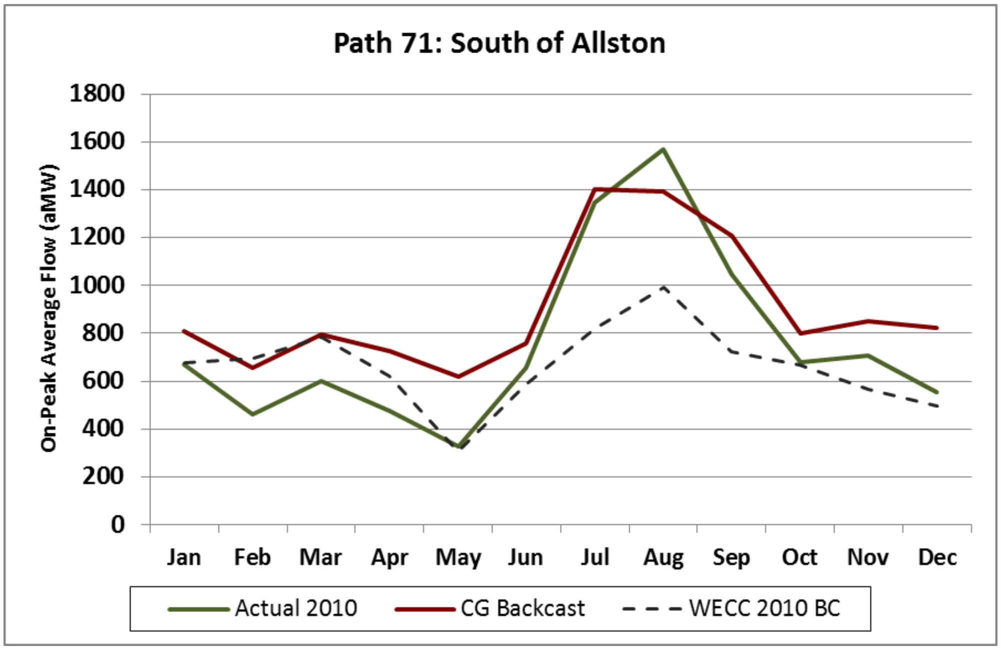

Figure 4: Comparison of power flow on Path 71 with/without Backcast improvements

1.5. Combined Pacific Direct Current Intertie (PDCI or Path 65) and California Oregon Intertie (COI or Path 66)

PDCI and COI are two major paths connecting Pacific Northwest and California. As shown in Figure 5, significant amount of power is exported to California from the Pacific Northwest (with an average flow of 2,895 MW in 2010) mainly due to spring runoff. The historical data shows the seasonal shape with the peak export of 5,900 aMW in June and a low of 1,700 aMW in April. The ColumbiaGrid Backcast improved the simulation performance from the original dataset with an error of -59% (below the actual value) to 4.8% (above the actual value). This brings the Backcast results in-line with historic operation. A summary of the study results for Path 65 and 66 is shown in figure 5.

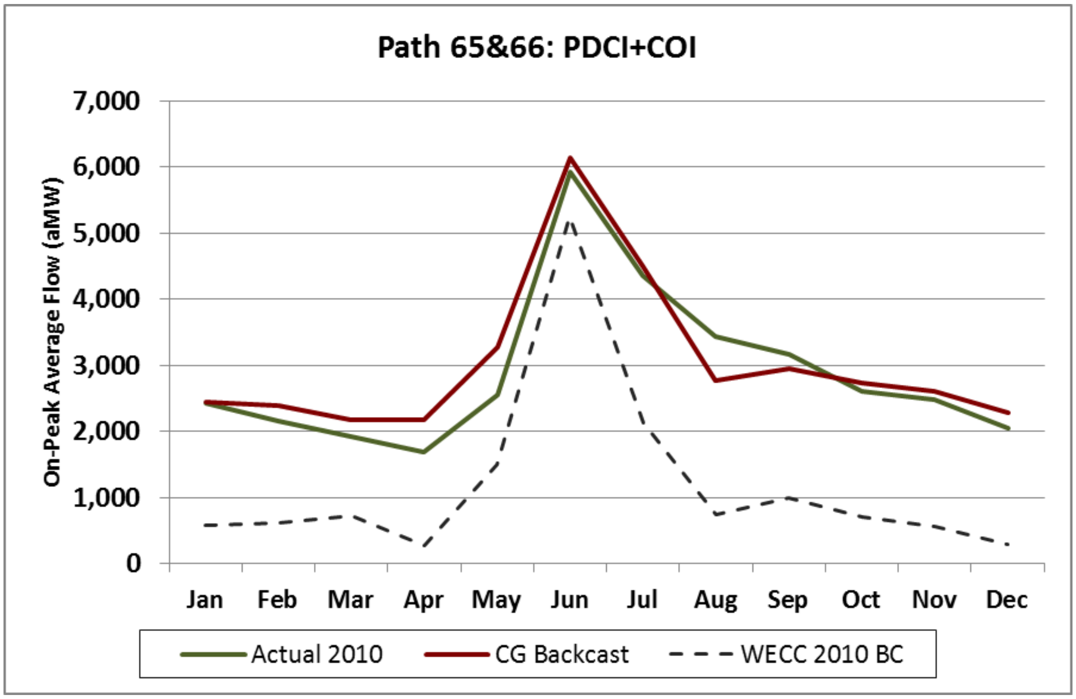

Figure 5: Comparison of power flow on Paths 65&66 with/without Backcast improvements

1.6. West of Colorado River (WOR of Path 46)

California is the largest importer of electric power in the west. Surplus power from the Northwest and Southwest are competing for market share in California. Consequently, WOR is the major gateway to California from the Southwest. As shown in figure 6, results from original dataset did not provide a good tracking between the historical data and simulation results. However, results from the Backcast show significant improvement as seen from the simulated flow on West of Colorado River (Path 46 - WOR) are closely tracked with approximately 5% error (256 MW on average) while the error from the original data set is approximately 48% (2,480 MW on average) at the starting point. A summary of the study results for Path 46 is shown in figure 6.

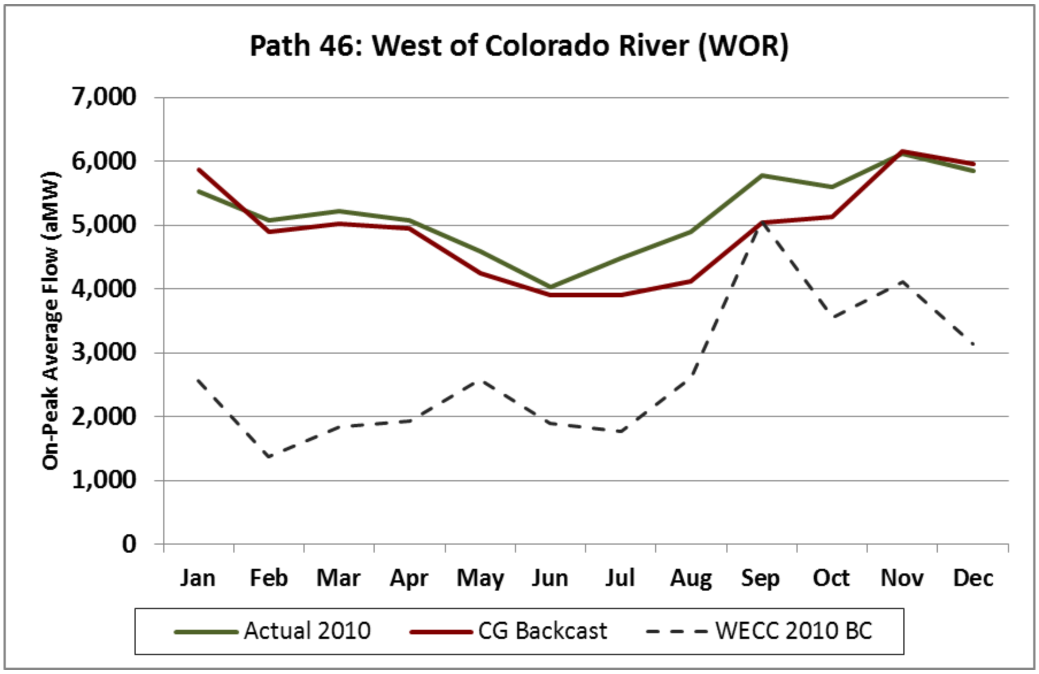

Figure 6: Comparison of power flow on Path 46 with/without Backcast improvements

1.7. Net California Import (Combination of Paths 46, 65, and 66)

In order to provide more complete picture of California imports, a comparison of the net Northwest and Southwest imports are compared. This is the combined Path 46, 65, and 66 with an average flow of 8,080 aMW in 2010. It is also important to note that since the Northwest and Southwest are two major competing resources for California import, it is critical to maintain accurate and proper balance among the three regions. In this case, as shown in figure, the errors from simulation results using the original dataset can be as high as -52% or -4,177 MW (as observed at the starting point). However, the Backcast study has significantly improved the simulation results by reducing the errors to approximately -1.4% or -117 MW. A summary of the study results for Path 46, 65 and 66 is shown in figure 7.

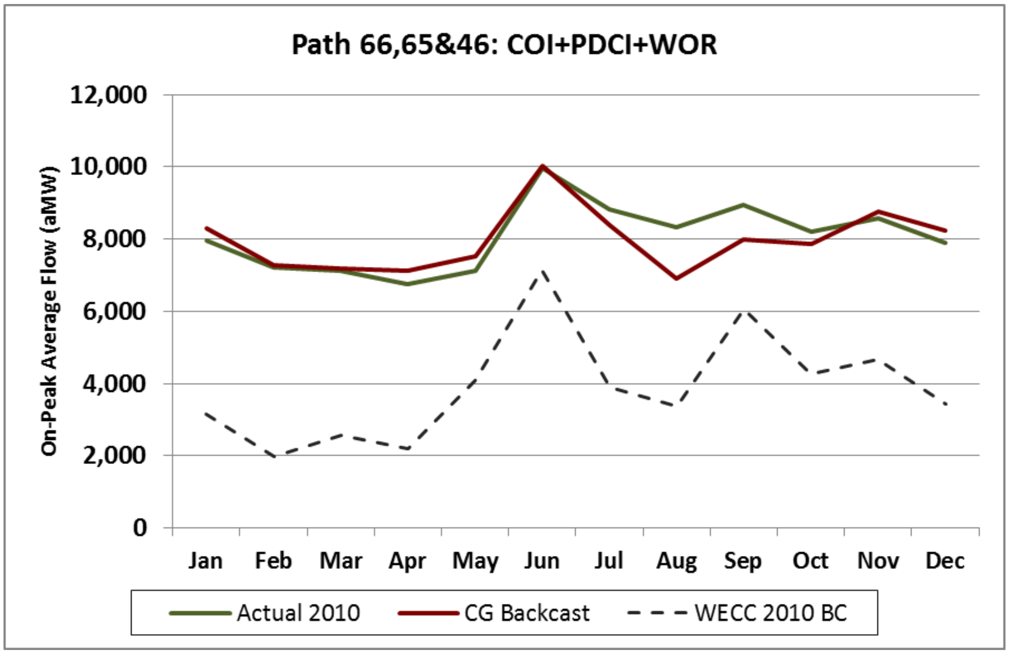

Figure 7: Comparison of power flow on Paths 46, 65 and 66 with/without Backcast improvements

2. <u>Forecast Results</u>

Simulation results from the improved dataset assessing future system conditions (2017) are presented in this part of the report. Since the study has produced a large amount and wide range of data, it will be impractical to include all aspects of study results in the report. Consequently, three types of comparison are provided which includes the behavior of dispatchable generation, net Northwest import, and individual major paths will be presented in this report.

2.1 **Change in dispatchable generation within the Northwest**.

This type of result compares how the core dispatchable generation in the Northwest responds to the changing supply in the scenarios. This provides insights on how the system may respond to the changes in the scenario. In this study, dispatchable generation consists of combined cycle and internal combustion engine (Port Westward II) with total capacity more than 10,869 MW in the Northwest Base. The foot print includes dispatchable supply in Washington, Oregon, Avista (in Northern Idaho) and Colstrip share to the Northwest. Cogeneration and peaker power plants are not considered as this type of resources.

For the base scenarios as shown in figure 8, the results show that the location of replacement capacity for Centralia has no impact on the net dispatchable generation (Base 1 – Base 3). As seen from the chart, behaviors of Northwest dispatchable generation are almost identical for the three cases, they are within 0.3% of its annual average. The net dispatchable generation from B0 to B1-3 drops -5.2%. This is due to the dispatchable gas does not make up for all the lost generation from the retired coal supply. It makes up 78% of this lost generation.

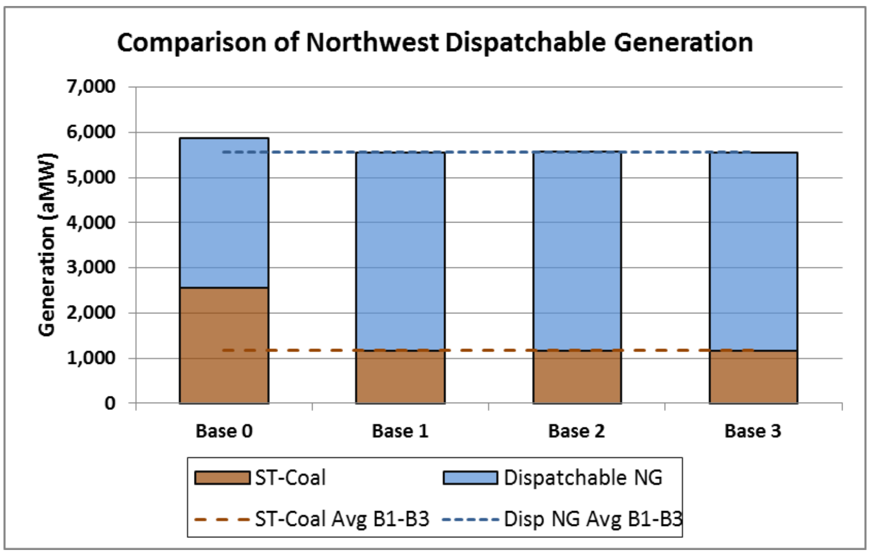

Figure 8: Comparison of output from Dispatchable generation among base cases (B0-B3)

For sensitivity cases, a similar pattern of results were observed from the simulation. The Northwest dispatchable generation is almost identical for cases with the same amount of generation retirement even though the locations of replacement capacity are different. The net dispatchable generation remains constant across all Base and Sensitivity cases as shown in figure 9. In Sensitivity case S1-S3 the dispatchable generation makes up 94% of the lost generation from Colstrip 1 and 2. The net dispatchable generation in the Northwest increases in the Sensitivity cases because 100% of the replacement capacity for Colstrip 1 and 2 is located in the Northwest while the Northwest share is 50%. In the two Sensitivity cases with additional wind in Montana, there was a slight decrease in Northwest dispatchable generation.

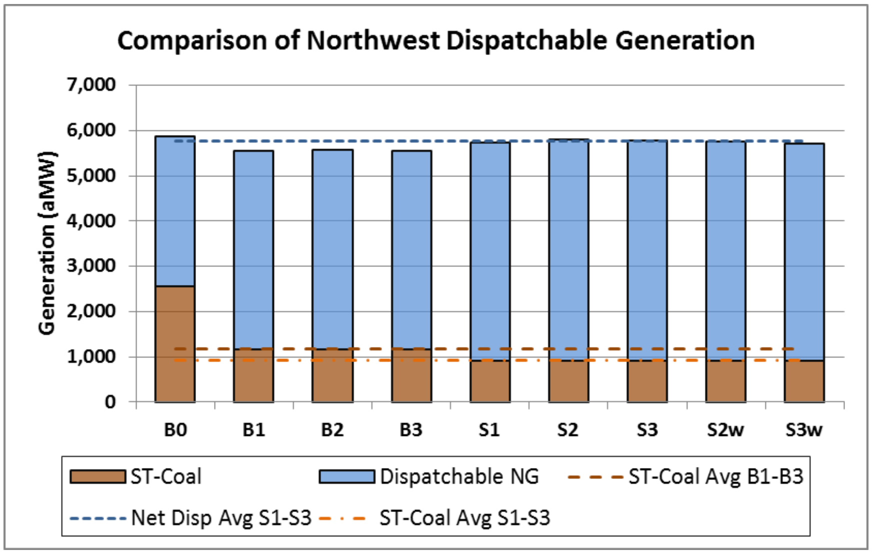

Figure 9: Comparison of output from Dispatchable generation among sensitivity cases (B0-B3)

2.2 **Annual Change in net Northwest exports**.

The objective of reviewing these results is to understand how changes in Northwest coal retirement and replacement capacity impacts Northwest power exports to neighboring areas. Consequently, in this context, the Northwest export is defined by the combining flow on the following six WECC paths using the following formula:

Northwest Export = Path 3 + Path 66 + Path 65 + Path 76 - Path 8 - Path 14

For this comparison the Northwest share of Colstrip is considered internal to the Northwest and does not impact Northwest imports. For the base scenarios, as seen in figure 10, the net exports were similar for the cases with similar retirement assumptions. The plot shows a slight drop from Base Case 0 where no retirement was assumed, while remaining constant in all three Base Cases (B1-B3) with the same assumptions on retirements but different location for replacement capacity. On average, the net

Northwest exports drop 318 MW with almost half of that amount contributed by a drop in exports to California (144 MW).

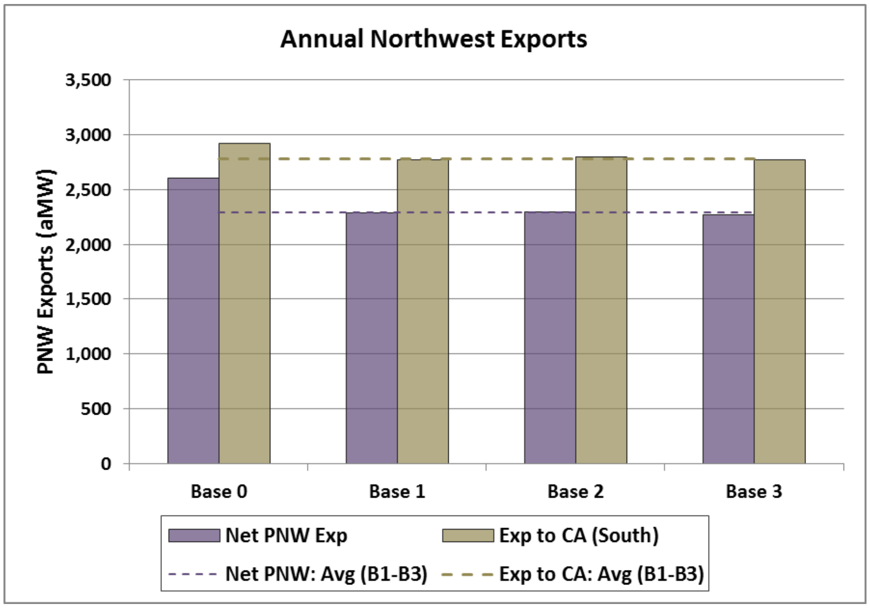

Figure 10: Comparison of Annual Northwest Export among base scenarios

In the sensitivity cases, the same patterns that net exports were similar for the cases with similar retirement assumptions were also observed. As shown in figure 11, net PNW exports increase in S1-S3 by the average of 196 MW and exports to California by 31 MW. Note that 50% of Colstrip is owned by entities in Montana but the replacement capacity is located in the Northwest. This resulted in a 165 MW increase of exports to Montana.

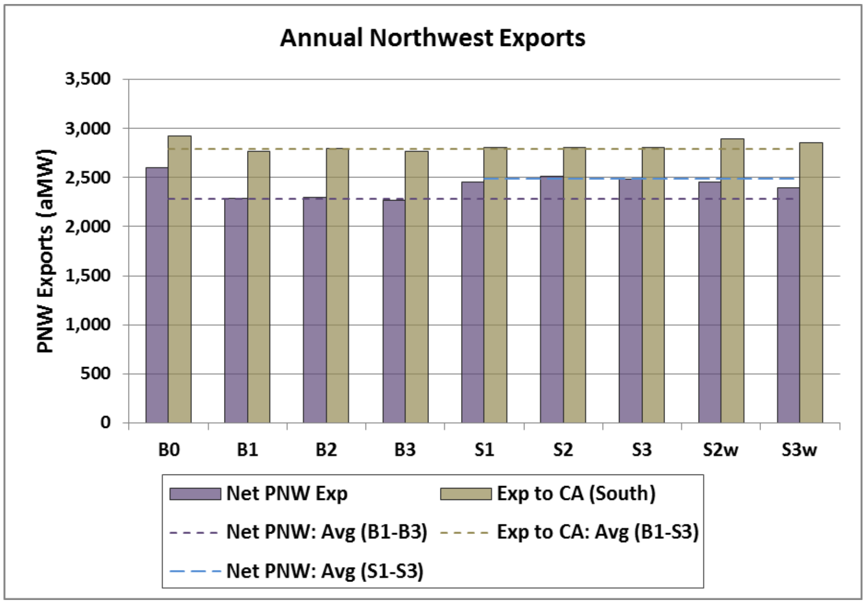

Figure 11: Comparison of output from Dispatchable generation among sensitivity cases (B0-B3)

2.3 **Monthly Change in net Northwest export**

As shown in figure 12, net Northwest exports are highly dependent on spring run-off peaking at an average export of 7,576 MW in June of the Base Cases. During the winter months (Nov-Feb) the average net Northwest exports drops below 500 MW (463 MW for Base 0 case and 45 MW for the average of Base 1-3 cases).

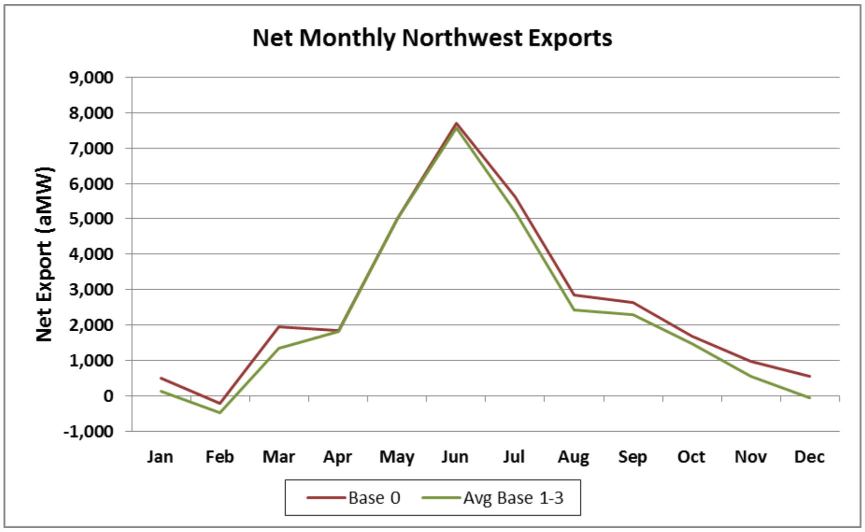

Figure 12: Comparison of Net Monthly Northwest Export among base cases

Similar pattern regarding the Net Monthly Northwest Export has been observed for the sensitivity cases where the fundamental shape in the Sensitivity case remains the same as the Base cases. The Sensitivity cases show an average increase of 196 MW. This is driven by all the replacement capacity for Colstrip 1 and 2 being located in the Northwest. During the winter months the average net exports see additional increase of 220 MW. Figure 13 shows these trends of higher export

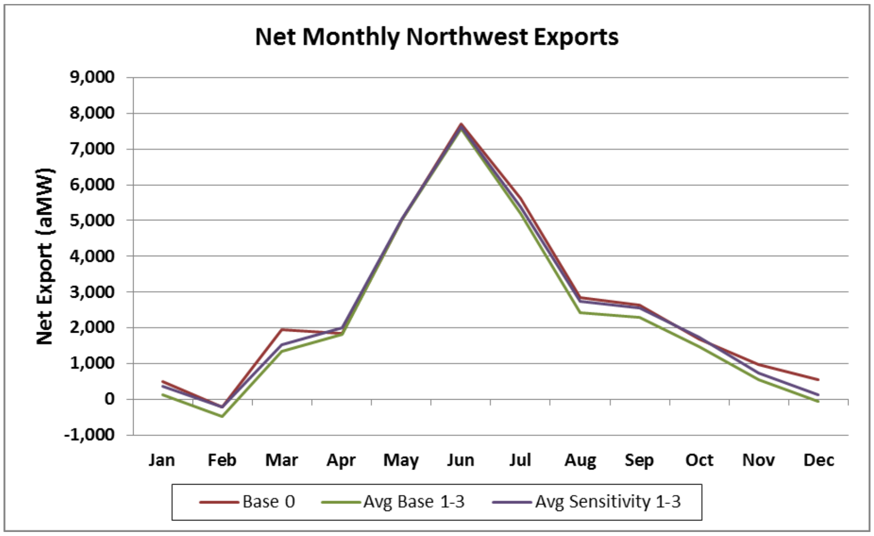

Figure 13: Comparison of Net Monthly Northwest Export among sensitivity cases

2.4 Monthly Net Northwest Export without Replacement Capacity

As shown in Figure 14, without any replacement capacity in the Base Case the Northwest becomes a net importer of an average 942 MW during the winter months (Nov-Feb). This suggests some form of firm replacement supply is needed to replace the retired coal capacity (Boardman and Centralia). The addition of a dry or critical water year would increase the Northwest needs for additional power.

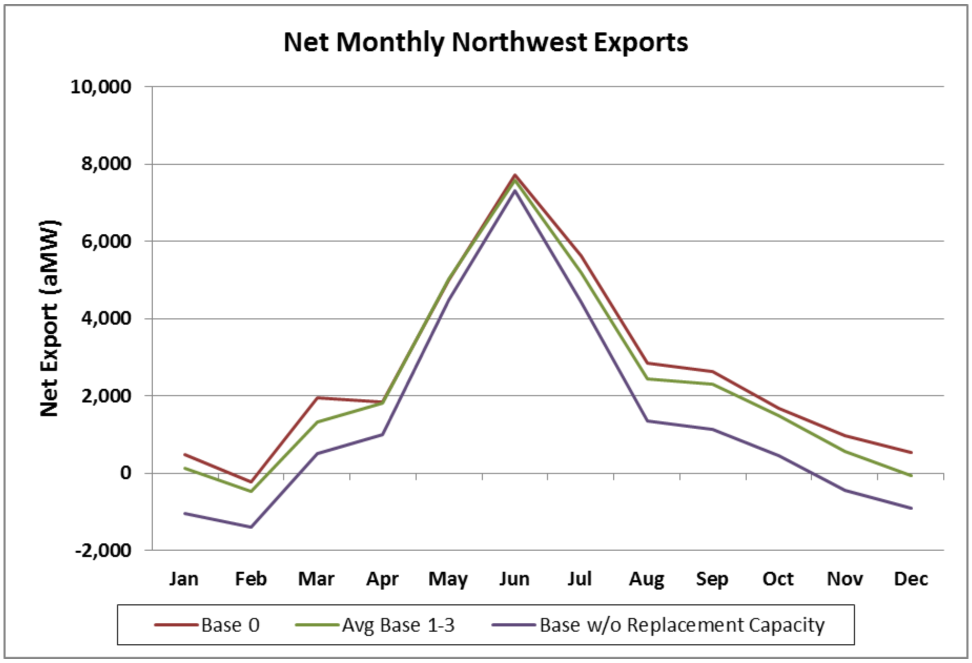

Figure 14: Net Monthly Exports without Replacement Capacity

2.5 **Individual path power flow comparison**

In this section, comparison of power flow on each major path and flowgate from the simulation will be discussed. Among many transmission paths in the Western Interconnection, this study focused on major transmission paths that are internal to the Northwest or major paths that connected Northwest with neighboring areas. Due to a large number of study scenarios and the information produced by this study, for each path, only a plot showing the comparison of flows among base cases and a table summarizing the changes among sensitivity cases will be provided in this section. Please refer to appendix A for more details of the plots showing the comparison of flows among sensitivity cases.

West of Cascade – North (Path 4)

Minor movement in power flow was observed in S2 with the addition of a second Combined Cycle (CC) north of the Seattle area as well as a slight increase in the case with the addition of wind generation in Montana. For comparison purposes, forecasted flow is compared to five years of historic flow from 2010 to 2014. The historic flow data is developed from publicly available BPA hourly or sub-hourly Flowgate data. To align historic and forecasted flow a Flow Duration Curve (FDC) is used. A FDC sorts hourly flow for each year of data in descending order. This FDC data is used to create a historic operation range (minimum and maximum flow) and the average flow. The area encompassing the historic operating range is shaded light green. The average historic flow is the darker dashed green line.

Flow in B1 and B2 dropped from the reference case by approximately -4.2% and -5.7%. The replacement generation North of Seattle in B2 results in an additional -1.5% reduction on West of Cascades – North versus all replacement generation at Centralia in B1. An additional -4.4% reduction on the West of Cascades – North path is observed when a second CC North of Seattle is added in case S2. A slight increase in flow is observed with the additional of wind generation in Montana. In addition, a summary of deviation from historical operation from each case is summarized in table 3.

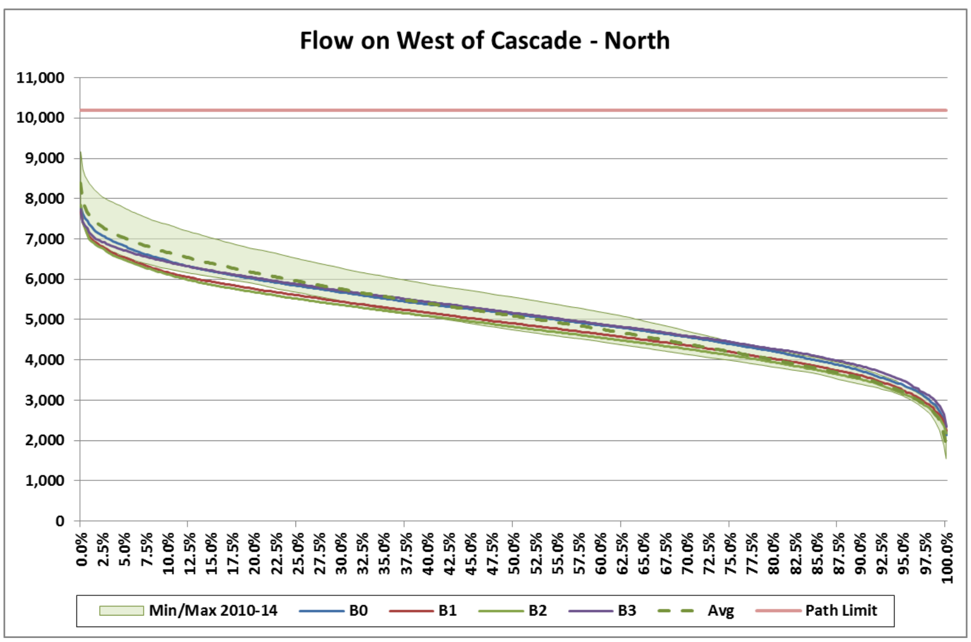

Figure 15: Comparison of power flow on Path 4 among base cases

Table 3: A summary of the changes in average Path 4 flow between the cases

From Case	To Case	Change aMW	% Change
B0	B1	-213	-4.2%
B0	B2	-292	-5.7%
B0	B3	35	0.7%
B1	S1	-69	-1.4%
B2	S2	-211	-4.4%
B3	S3	-15	-0.3%
S2	S2w	51	1.1%
S3	S3w	15	0.3%

West of Cascade – South (Path 5)

All Base Cases are on the high side of historic operation range by 18% while peak flow remains 18% under path limit. Flows on B0-B2 are all comparable while flow increases on average of 203 MW in B3 due to the increased generation in the Stanfield area. In addition, a summary of incremental change in simulation results is summarized in table 4.

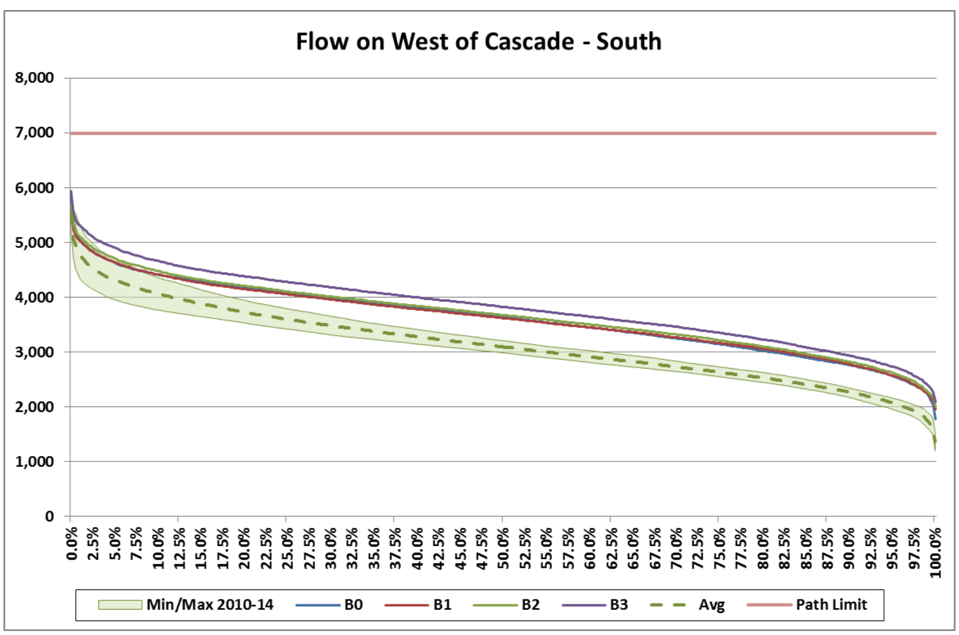

Figure 16: Comparison of power flow on Path 5 for base cases

Table 4: A summary of the changes in average Path 5 flow between the cases

From Case	To Case	Change aMW	% Change
B0	B1	-3	-0.1%
B0	B2	51	1.4%
B0	B3	203	5.6%
B1	S1	-3	-0.1%
B2	S2	4	0.1%
B3	S3	43	1.1%
S2	S2w	15	0.4%
S3	S3w	14	0.4%

West of Cascade – North/South Combined (Paths 4&5)

The combined West of Cascade North and South measure the net flow across the Cascades (East to West). In B1 and B2 the flow across the Cascades drops an average -228 MW. The replacement capacity for Boardman and Centralia is located on the same side of the Cascades as the original units. The reduction in flow across the Cascades shows slight preferences for generation on the west side of the Cascades. In B3, where half of Centralia replacement capacity is located on the east side of the Cascades, flow across the Cascades increases. As previously discussed the dispatchable generation in B1-B3 remains constant, therefore the location of the replacement capacity shifts what interfaces are loaded. A summary of incremental change in simulation results is summarized in table 5.

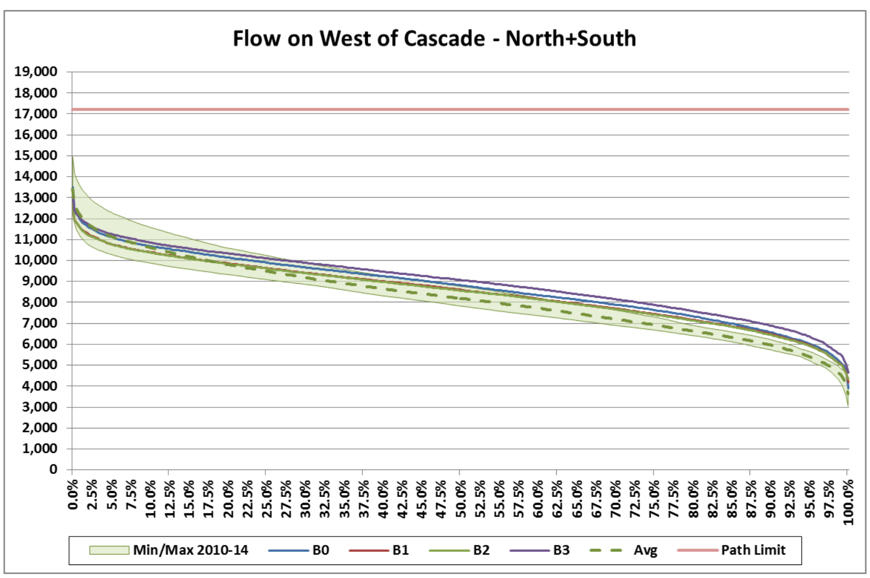

Figure 17: Comparison of power flow on Paths 4&5 for base cases

Table 5: A summary of the changes in average Paths 4&5 flow between the cases

From Case	To Case	Change aMW	% Change
B0	B1	-216	-2.5%
B0	B2	-241	-2.8%
B0	B3	238	2.7%
B1	S1	-72	-0.8%
B2	S2	-207	-2.4%
B3	S3	28	0.3%
S2	S2w	67	0.8%
S3	S3w	30	0.3%

North of John Day (Path 73)

The path limit is reached for one hour in the B0 case. B1-B3 peak flow falls within historic operating range. The highest flow occurs in B2 with replacement capacity installed North of Seattle area. Flow in B1 and B3 are comparable while B0 is the lowest. A summary of incremental change in simulation results is summarized in table 6.

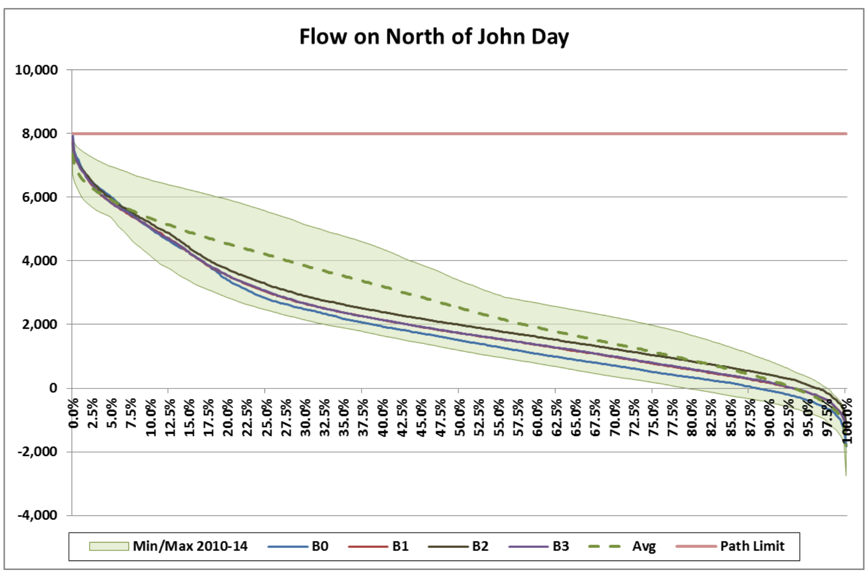

Figure 18: Comparison of power flow on Path 73 for base cases

Table 6: A summary of the changes in average Path 73 flow between the cases

From Case	To Case	Change aMW	% Change
B0	B1	179	9.2%
B0	B2	405	20.8%
B0	B3	189	9.7%
B1	S1	-250	-11.7%
B2	S2	-124	-5.3%
B3	S3	-312	-14.6%
S2	S2w	102	4.6%
S3	S3w	107	5.8%

<u>South of Allston (Path 71)</u>

All cases fall within historic operating range except for B3. With the shift of replacement capacity to the Stanfield area in the B3 case, flow increases on West of Cascade – South resulting in a decrease of flow on South of Allston. Flow in S3 is lower by approximately -6.6% with the addition of two additional CC in the Stanfield area. A summary of incremental change in simulation results is summarized in table 7.

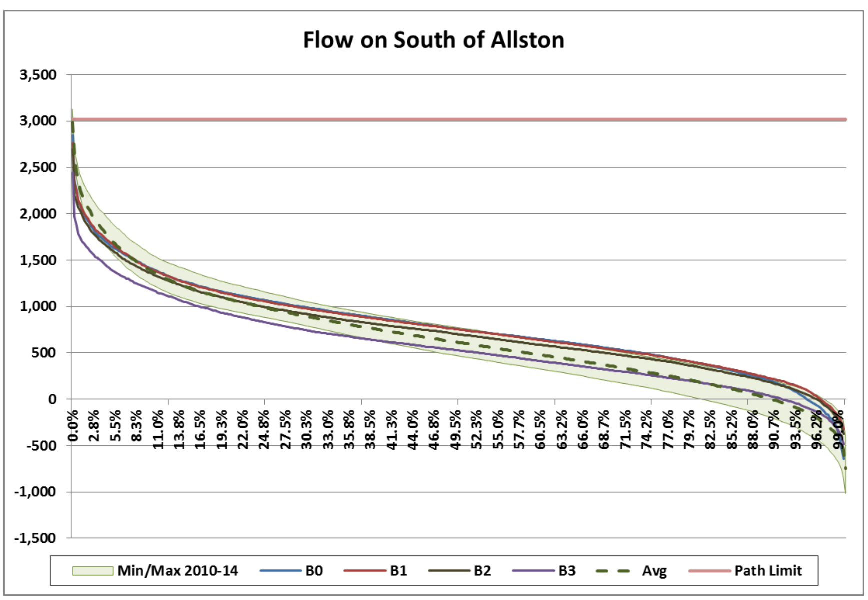

Figure 19: Comparison of power flow on Path 71 for base cases

Table 7: A summary of the changes in average Path 71 flow between the cases

From Case	To Case	Change aMW	% Change
B0	B1	6	0.8%
B0	B2	-46	-5.8%
B0	B3	-217	-27.6%
B1	S1	-7	-0.9%
B2	S2	4	0.6%
B3	S3	-38	-6.6%
S2	S2w	-3	-0.4%
S3	S3w	-6	-1.2%

West of Slatt (BPA Flowgate)

Overall, the simulation results show peak flow is lower than historic operating range while minimum flows are higher than the historic operation. In B3, the addition of supply in the Stanfield area increases flow 74 MW on average over B1 and B2. Flow in S3 also increase 5.1% with the addition of two additional CC in the Stanfield area. A summary of incremental change in simulation results is summarized in table 8.

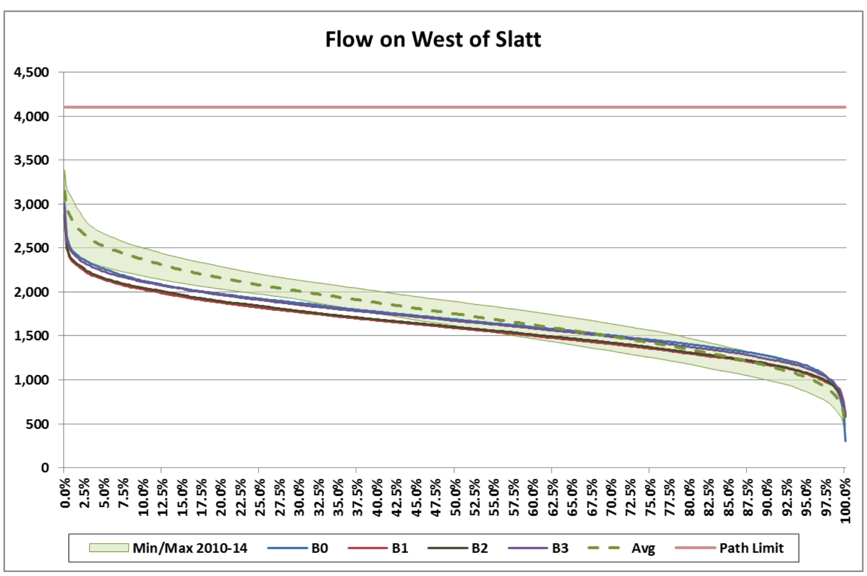

Figure 20: Comparison of power flow on West of Slatt Path for base cases

Table 8: A summary of the changes in average West of Slatt flow between the cases

From Case	To Case	Change aMW	% Change
B0	B1	-99	-5.8%
B0	B2	-83	-4.9%
B0	B3	-17	-1.0%
B1	S1	8	0.5%
B2	S2	11	0.7%
B3	S3	85	5.1%
S2	S2w	22	1.4%
S3	S3w	16	0.9%

<u>Montana to Northwest (Path 8)</u>

According to WECC, rating of this path is 2,200 MW which includes a 200 MW import on the Mile-City DC Tie. Therefore, 2,000 MW limited was used in the model in the study. The study results showed power flow were within historic operation.

Note that the BPA flowgate for Montana to Northwest is located on the west side of Garrison substation while the modeled WECC definition is on the east side of Garrison. The average reduction in flow for 2010 through 2012 is -13 MW (Historic flow from WECC is not available after 2012). Consequently, the use of the BPA Flowgate is reasonable given the magnitude of the flow.

Flows on Montana to the Northwest are directly impacted with the retirement of Colstrip 1&2 (614 MW). The average reduction in flow from B1-B3 to S1-S3 is -378 MW, and the addition of 600 MW of wind in Montana increase the flow 170 MW. A summary of incremental change in simulation results is summarized in table 9.

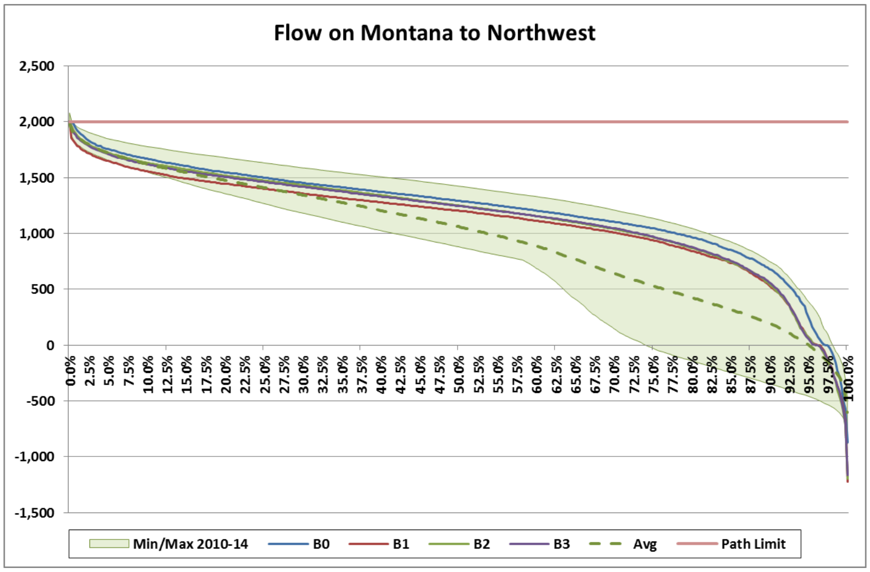

Figure 21: Comparison of power flow on Path 8 for base cases

Table 9: A summary of the changes in average Path 8 flow between the cases

From Case	To Case	Change aMW	% Change
B0	B1	-108	-8.9%
B0	B2	-61	-5.0%
B0	B3	-64	-5.3%
B1	S1	-344	-31.2%
B2	S2	-403	-35.0%
B3	S3	-388	-33.9%
S2	S2w	174	23.3%
S3	S3w	165	21.7%

West of Hatwai (Path 6)

Generally, flows on West of Hatwai are directly impacted by the retirement of Colstrip 1&2 (614 MW). For base scenarios S1-S3, the results showed an average reduction in flow of 349 MW from B1-B3. However, with an addition of 600 MW of wind in Montana, the flow in S2w and S3w has increased approximately 131 MW compare to S2 and S3 cases. A summary of incremental change in simulation results is summarized in table 10.

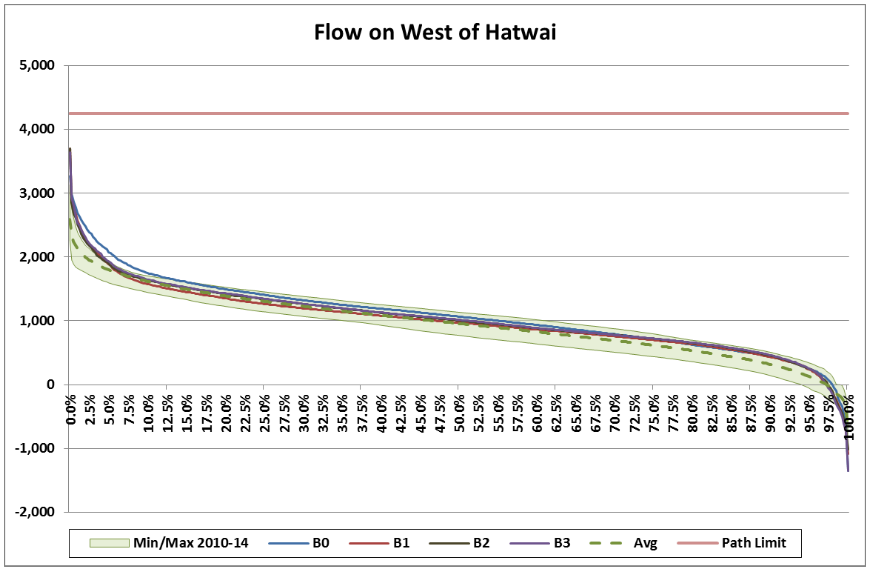

Figure 22: Comparison of power flow on Path 6 for base cases

Table 10: A summary of the changes in average Path 6 flow between the cases

From Case	To Case	Change aMW	% Change
B0	B1	-86	-7.9%
B0	B2	-52	-4.8%
B0	B3	-46	-4.2%
B1	S1	-312	-31.3%
B2	S2	-385	-37.3%
B3	S3	-351	-33.8%
S2	S2w	153	23.6%
S3	S3w	110	16.0%

Pacific DC Intertie and California Oregon Intertie and (Paths 65&66)

Average flow in B1-B3 drops over 1,132 MW from the average historic flow (2010-2014). Peak flow on this path is reached 3% of the time. This is a modeling issue due to the a high level of Hydro flexibility. ColumbiaGrid is working on developing input parameters to improve Hydro operation.

As shown in Figure 23, significant amount of power is exported to California from the Pacific Northwest, with an average flow in 2010 of 2,640 MW, mainly due to spring runoff. The historical data shows the seasonal shape with the peak export at 5,700 MW and a low of 1,500 MW. The ColumbiaGrid Backcast has improved the simulation performance from the original dataset from an error of -35% (below the actual value) to 4% (above the actual value) with an average of 2,740 MW compared to the starting point of 1,710 MW. A summary of incremental change in simulation results is summarized in table 11.

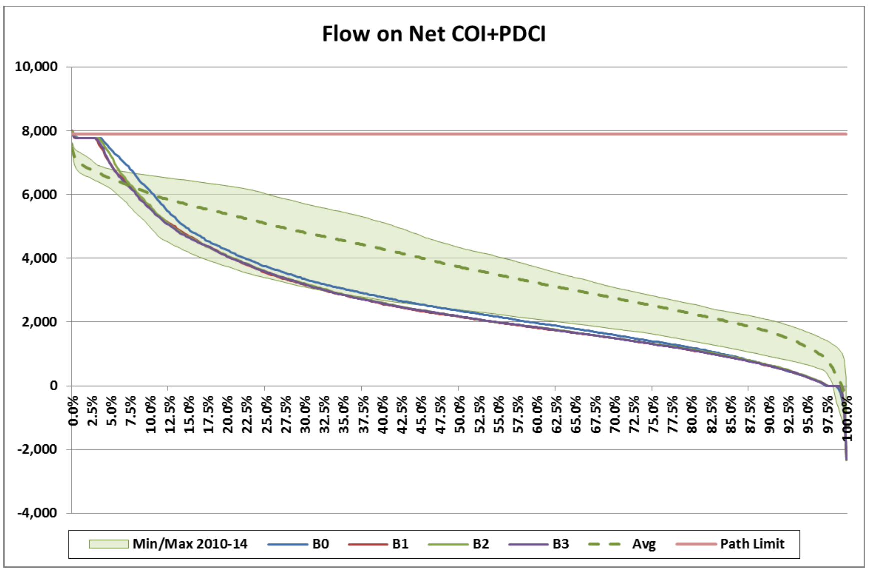

Figure 23: Comparison of power flow on Paths 65&66 for base cases

Table 11: A summary of the changes in average Path 6 flow between the cases

From Case	To Case	Change aMW	% Change
B0	B1	-161	-5.7%
B0	B2	-137	-4.9%
B0	B3	-160	-5.7%
B1	S1	-83	-3.1%
B2	S2	16	0.6%
B3	S3	36	1.4%
S2	S2w	83	3.1%
S3	S3w	49	1.8%

Conclusions

The following are key conclusions from the results of this study which focuses on coal retirement in the Northwest and its impact on Northwest generation and transmission facilities.

- Impact on Base Case for known coal retirement: Boardman and Centralia
  - Overall, the lost generation from Boardman and Centralia was made up by dispatchable generation in the Northwest
  - The location of the replacement capacity for Centralia results in a shift of Northwest flows but flows are within or on the edge of historic operation, 2010-2014.
- Sensitivity Cases assumed additional Northwest coal retirement which is represented by retiring Colstrip 1 & 2:
  - As expected, flow from Montana to the Northwest dropped with the retirement of Colstrip 1&2.
  - Overall, the lost generation from Colstrip 1&2 was made up by dispatchable generation in the Northwest.
  - The internal flow in the Northwest shifts based on the location of the replacement capacity for Colstrip. Resulting Northwest flows are within or on the edge of historic operation, 2010-2014.
  - The addition of wind in Montana increased flow from Montana to the Northwest but within historic operating range while a minor reduction of dispatchable generation in the Northwest.

Appendix A

The comparison of sensitivity study results of each major paths are shown in Figures A1-A27

West of Cascade – North (Path 4)

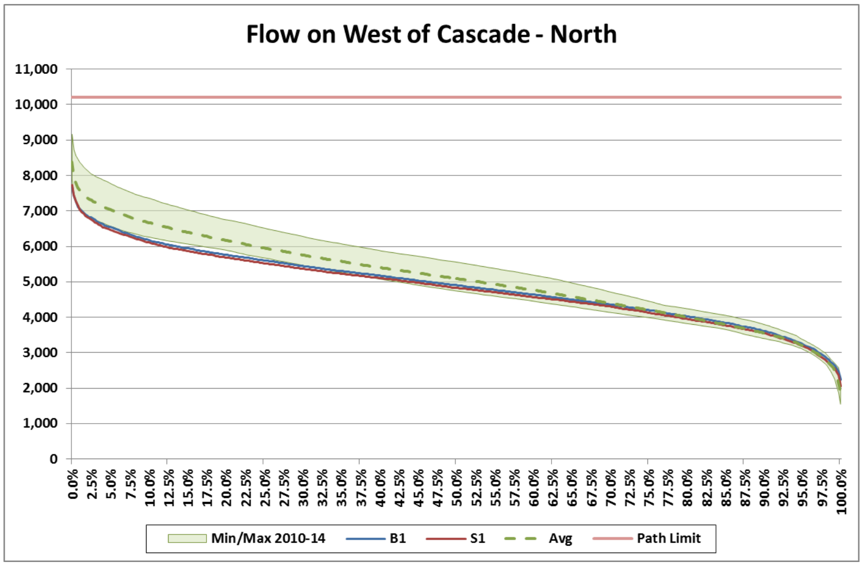

Figure A1: Comparison of results from B1 and S1 scenarios on Path 4

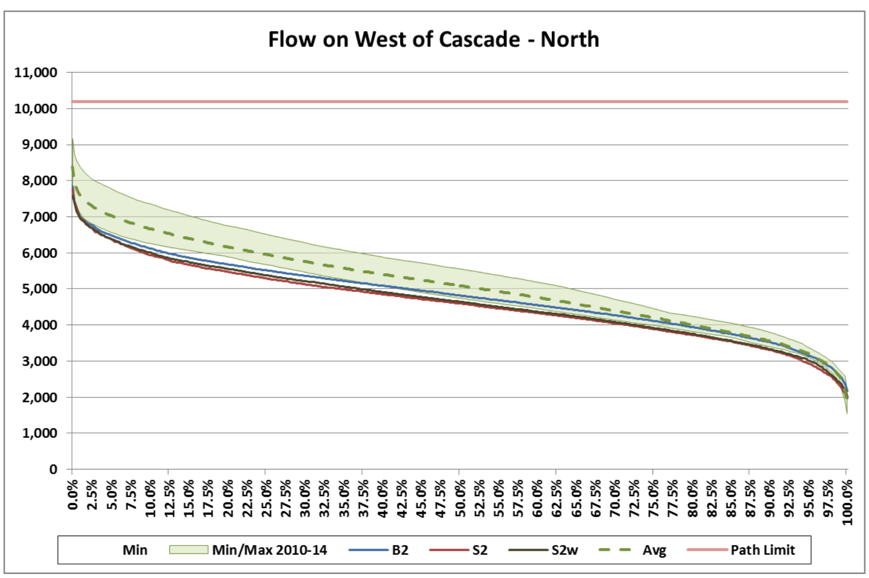

Figure A2: Comparison of results from B2, S2 and S2w scenarios on Path 4

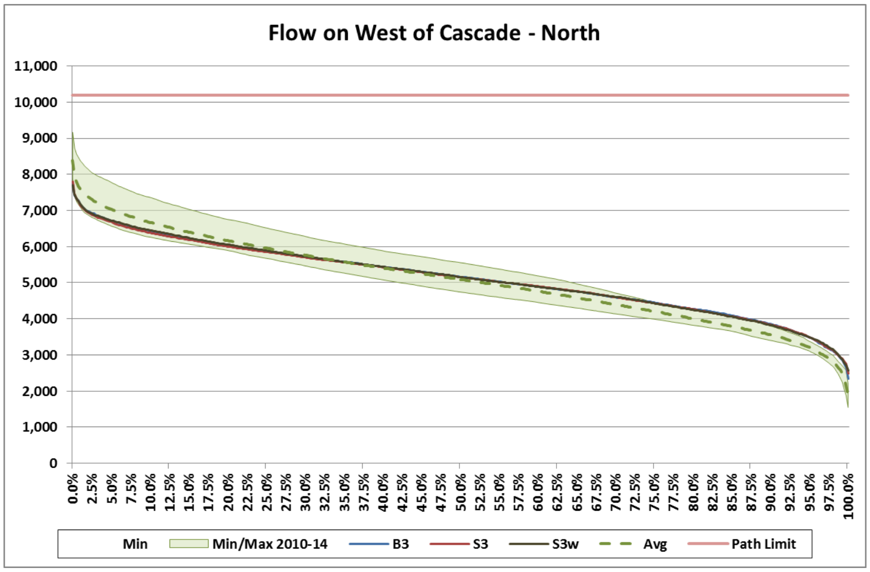

Figure A3: Comparison of results from B3, S3 and S3w scenarios on Path 4

Table A1: A summary of the changes in average Path 4 flow between the cases

From Case	To Case	Change aMW	% Change
B1	S1	-69	-1.4%
B2	S2	-211	-4.4%
B3	S3	-15	-0.3%
S2	S2w	51	1.1%
S3	S3w	15	0.3%

The retirement of Colstrip 1 and 2 with replacement capacity in the Northwest has no significant impact of West of Cascades North. In S2 with the replacement capacity installed North of the Seattle area the average flow drops by -4.4%

<u>West of Cascade – South (Path 5)</u>

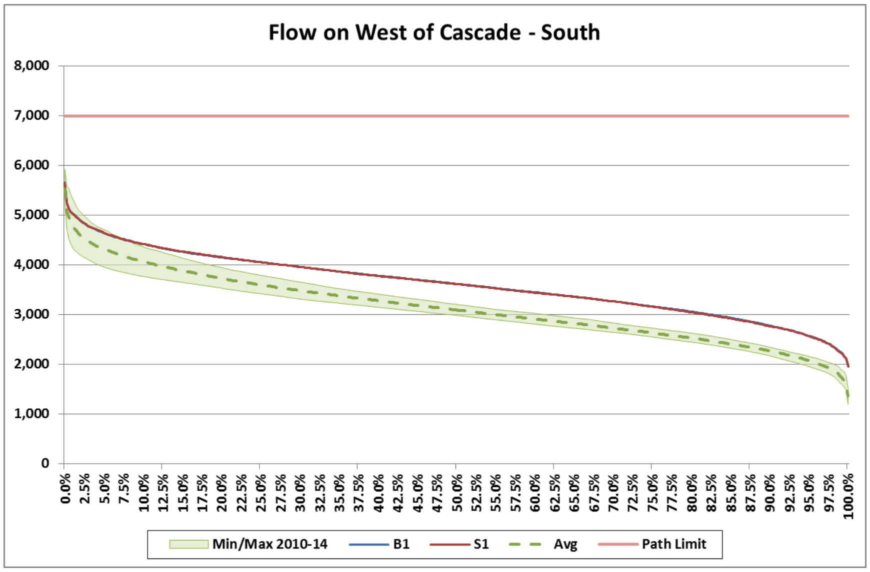

Figure A4: Comparison of results from B1 and S1 scenarios on Path 5

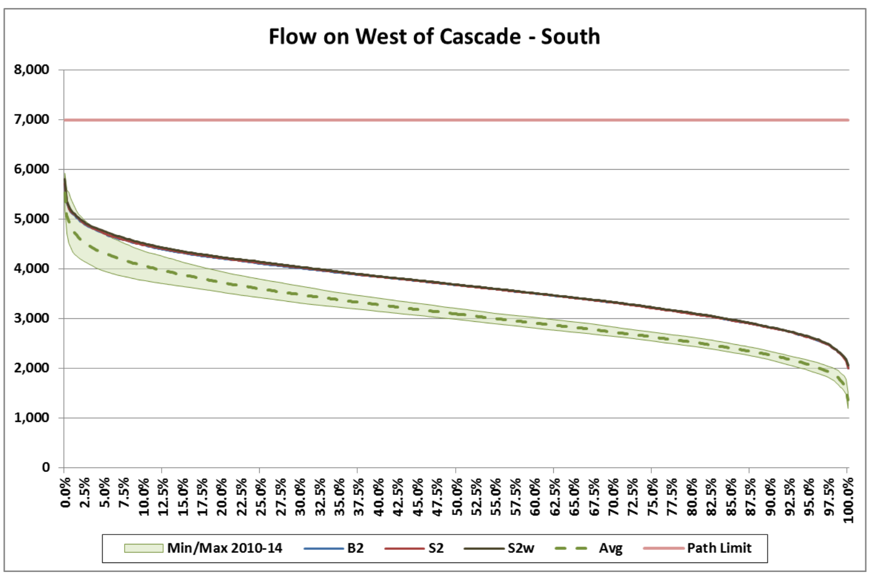

Figure A5: Comparison of results from B2, S2 and S2w scenarios on Path 5

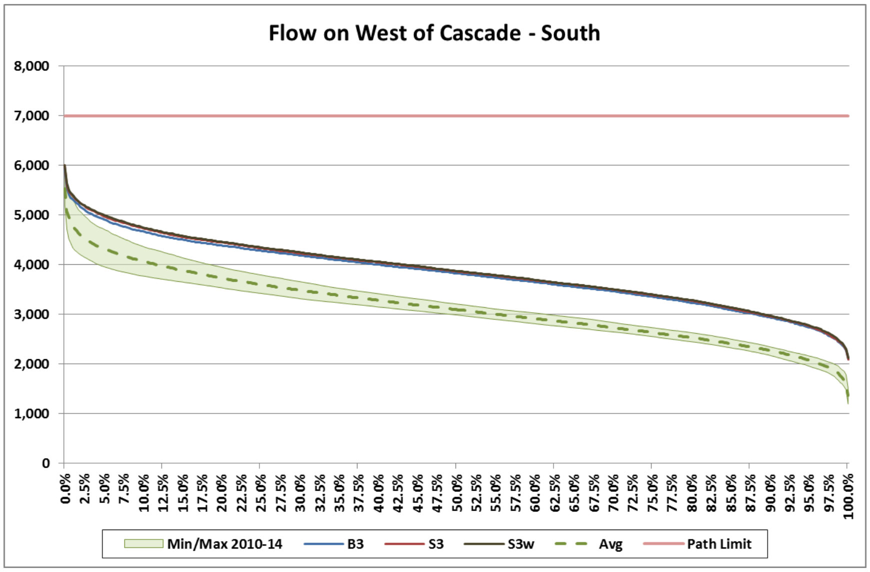

Figure A6: Comparison of results from B3, S3 and S3w scenarios on Path 5

Table A2: A summary of the changes in average Path 5 flow between the cases

From Case	To Case	Change aMW	% Change
B1	S1	-3	-0.1%
B2	S2	4	0.1%
B3	S3	43	1.1%
S2	S2w	15	0.4%
S3	S3w	14	0.4%

The retirement of Colstrip 1 and 2 with replacement capacity in the Northwest has no significant impact of West of Cascades South

West of Cascade – North/South Combined (Paths 4&5)

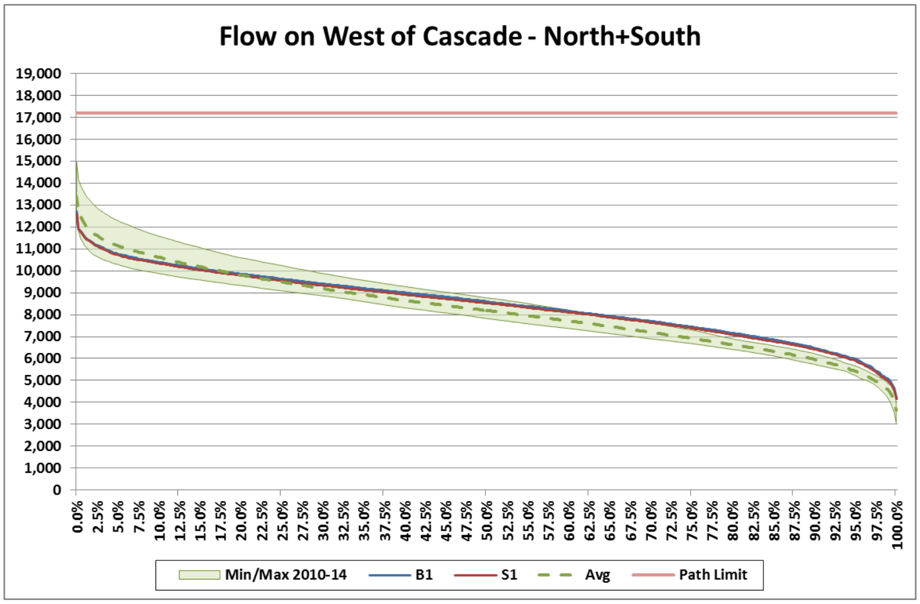

Figure A7: Comparison of results from B1 and S1 scenarios on combined Paths 4&5

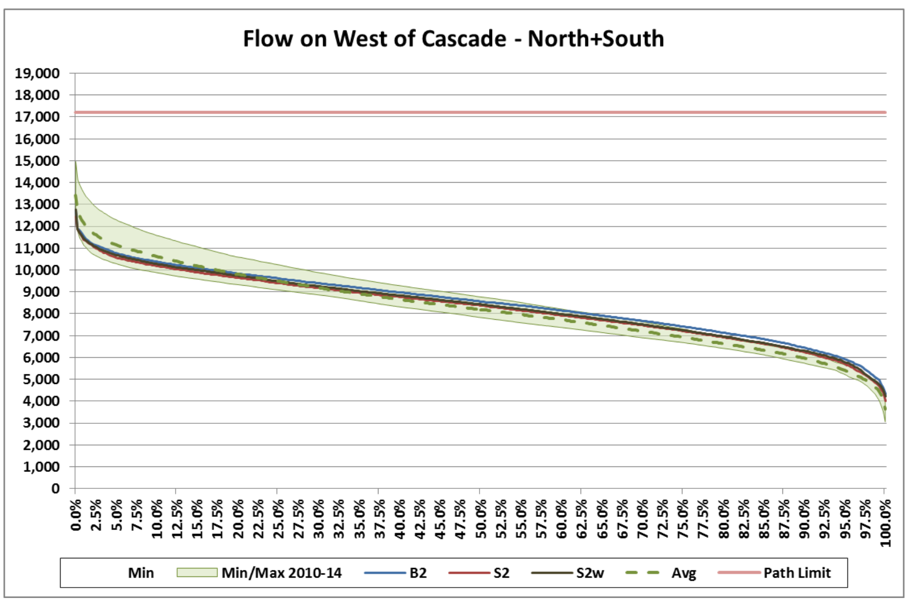

Figure A8: Comparison of results from B2, S2 and S2w scenarios on combined Paths 4&5

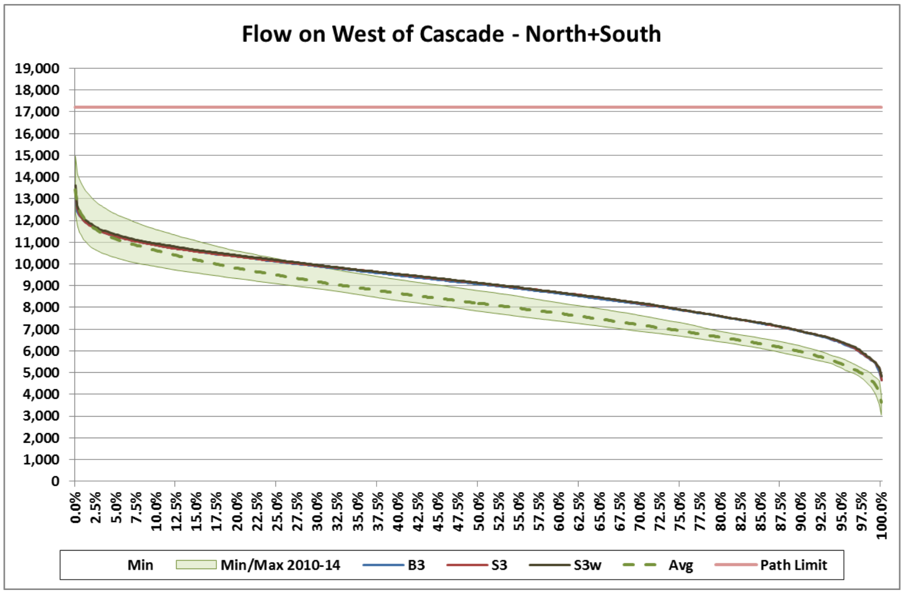

Figure A9: Comparison of results from B3, S3, and S3w scenarios on combined Paths 4&5

Table A3: A summary of the changes in average Paths 4&5 flow between the cases

From Case	To Case	Change aMW	% Change
B1	S1	-72	-0.8%
B2	S2	-207	-2.4%
B3	S3	28	0.3%
S2	S2w	67	0.8%
S3	S3w	30	0.3%

The retirement of Colstrip 1 and 2 with replacement capacity in the Northwest has no significant impact of West of Cascades North/South. In S2 with the replacement capacity installed North of the Seattle area the average flow drops by -2.7%.

North of John Day (Path 73)

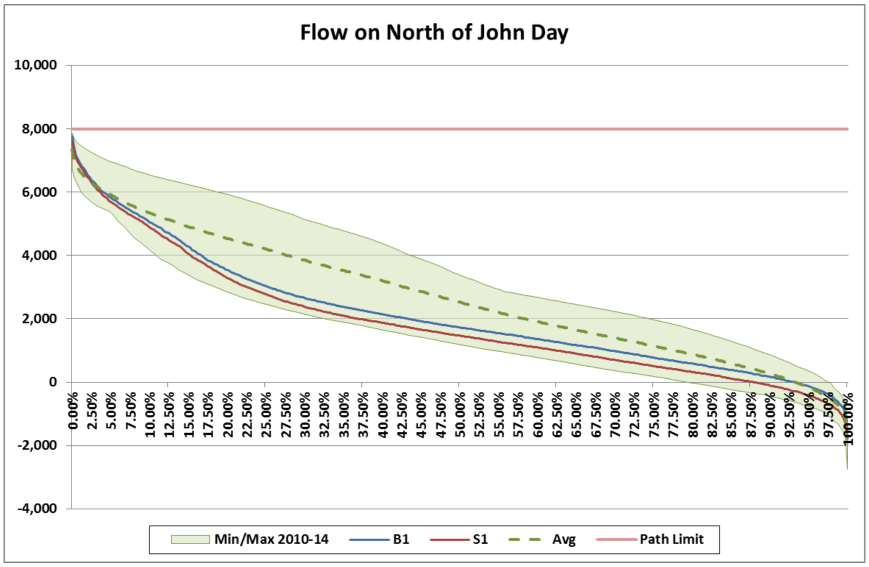

Figure A10: Comparison of results from B1, and S1 scenarios on Path 73

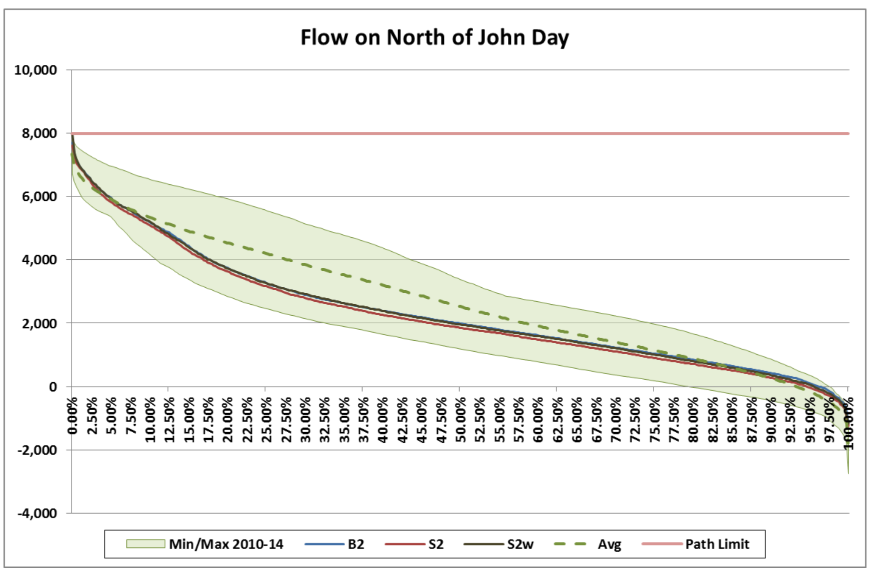

Figure A11: Comparison of results from B2, S2, and S2w scenarios on Path 73

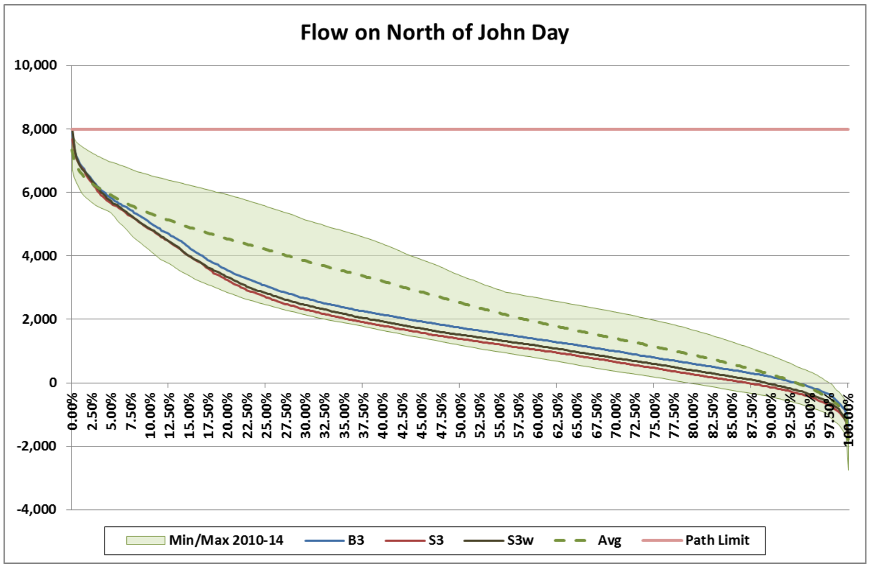

Figure A12: Comparison of results from B3, S3, and S3w scenarios on Path 73

Table A4: A summary of the changes in average Path 73 flow between the cases

From Case	To Case	Change aMW	% Change
B1	S1	-250	-11.7%
B2	S2	-124	-5.3%
B3	S3	-312	-14.6%
S2	S2w	102	4.6%
S3	S3w	107	5.8%

The retirement of Colstrip 1 and 2 with replacement capacity in the Northwest results in a drop of north to south flow. The generation from the dispatchable generation in the Northwest remains relative constant in S1-S3. The difference in flow in S1-S3 is driven by the location of the replacement capacity. The addition of 600 MW of wind in Montana increase flow by ~100 aMW.

South of Allston (Path 71)

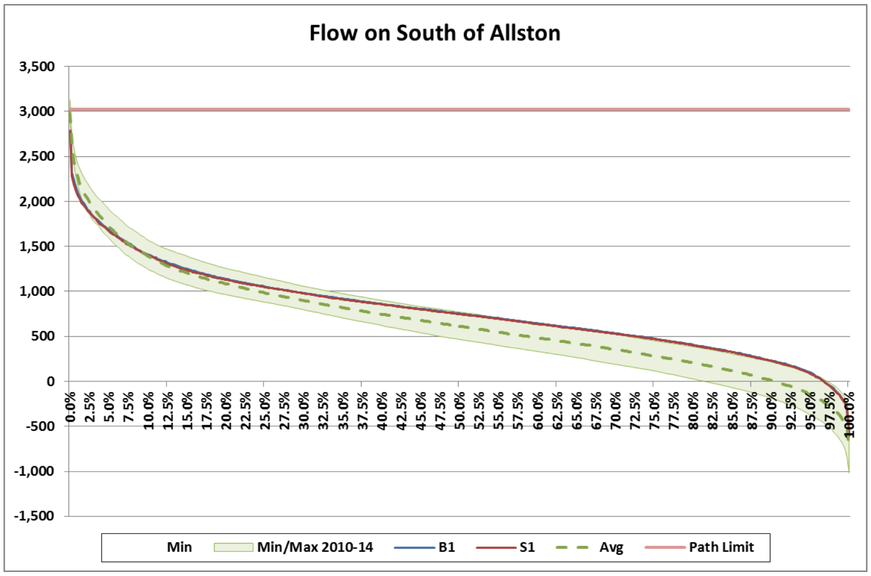

Figure A13: Comparison of results from B1 and S1 on Path 71

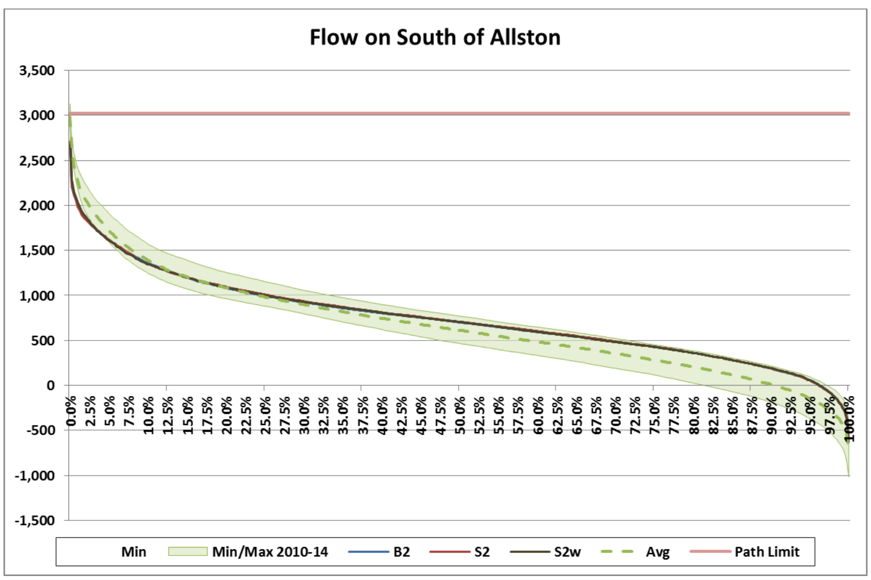

Figure A14: Comparison of results from B2, S2, and S2w scenarios on Path 71

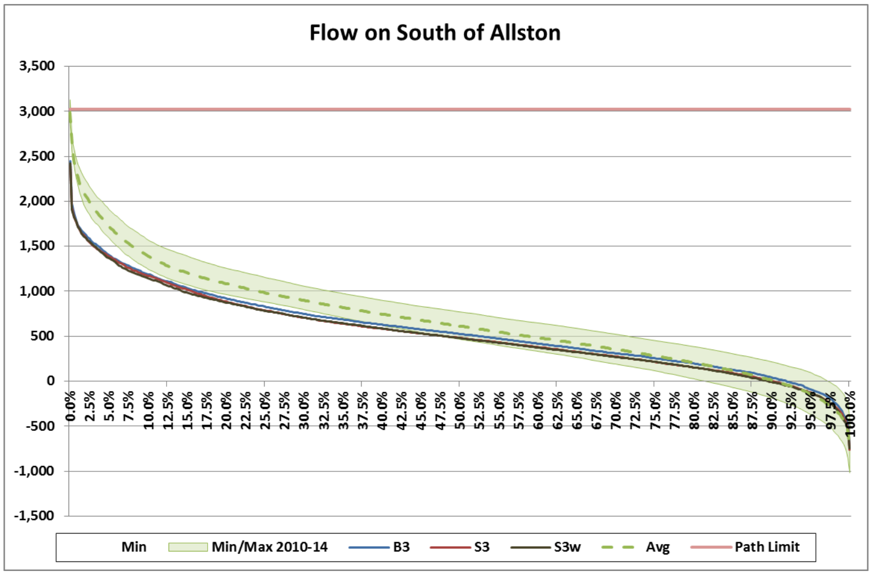

Figure A15: Comparison of results from B3, S3, and S3w scenarios on Path 71

Table A5: A summary of the changes in average Path 71 flow between the cases

From Case	To Case	Change aMW	% Change
B1	S1	-7	-0.9%
B2	S2	4	0.6%
B3	S3	-38	-6.6%
S2	S2w	-3	-0.4%
S3	S3w	-6	-1.2%

The Sensitivity Cases show minor change in flow from the corresponding Base Case except for S3. The additional generation in the Stanfield area in S3 increase flow on West of Cascade – South which off loads South of Allston.

West of Slatt (BPA Flowgate)

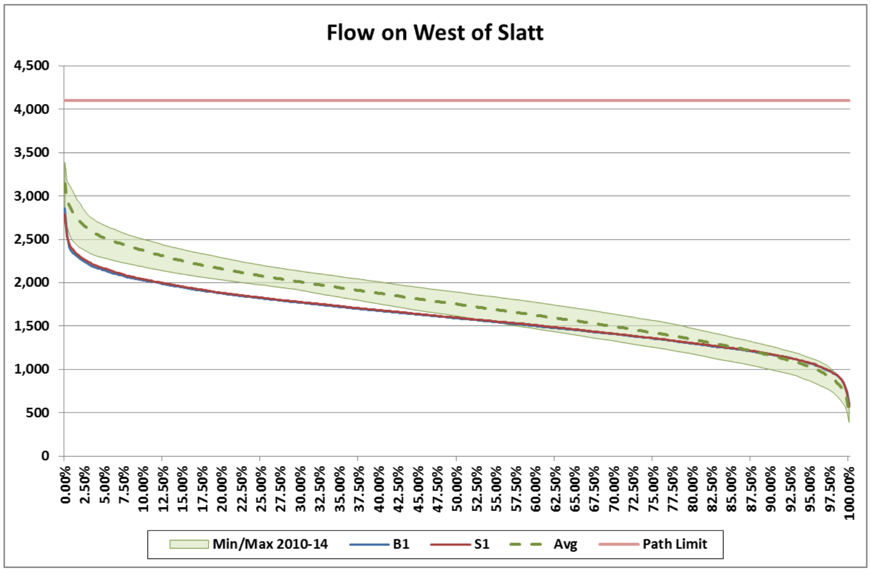

Figure A16: Comparison of results from B1 and S1 scenarios on West of Slatt Flowgate

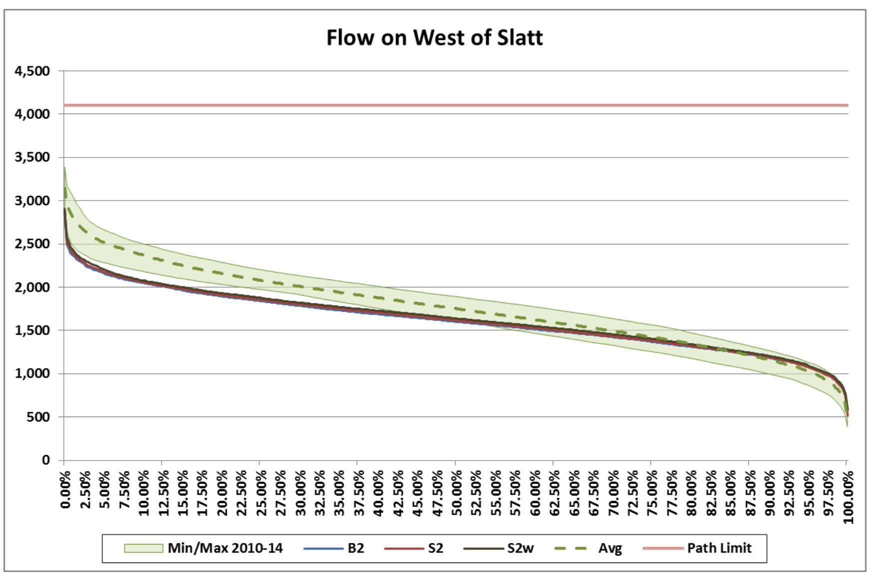

Figure A17: Comparison of results from B2, S2, and S2w scenarios on West of Slatt Flowgate

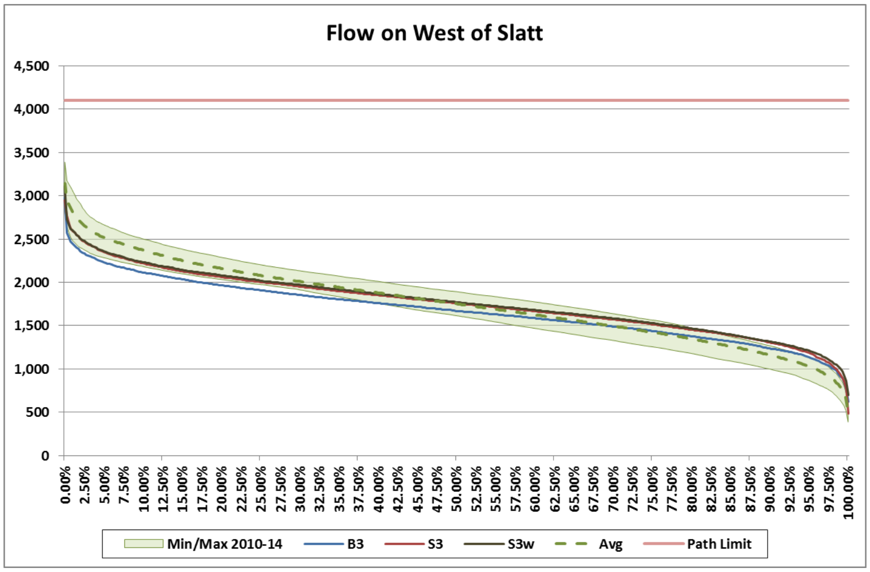

Figure A18: Comparison of results from B3, S3, and S3w scenarios on West of Slatt Flowgate

Table A6: A summary of the changes in average West of Slatt flow between the cases

From Case	To Case	Change aMW	% Change
B1	S1	8	0.5%
B2	S2	11	0.7%
B3	S3	85	5.1%
S2	S2w	22	1.4%
S3	S3w	16	0.9%

The Sensitivity Cases show minor change in flow from the corresponding Base Case except for S3. The additional generation in the Stanfield area increase flow on this path by 5.1%.

Montana to Northwest (Path 8)

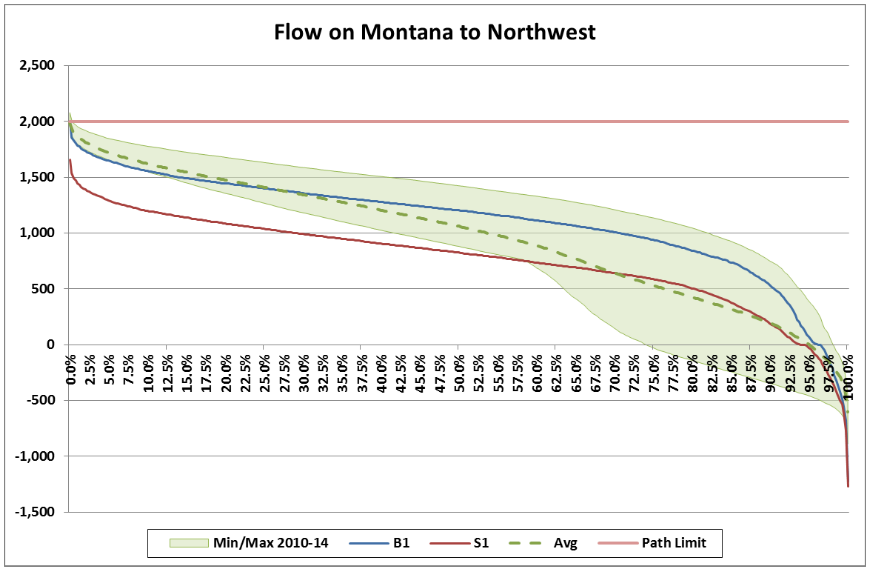

Figure A19: Comparison of results from B1 and S1 scenarios on Path 8

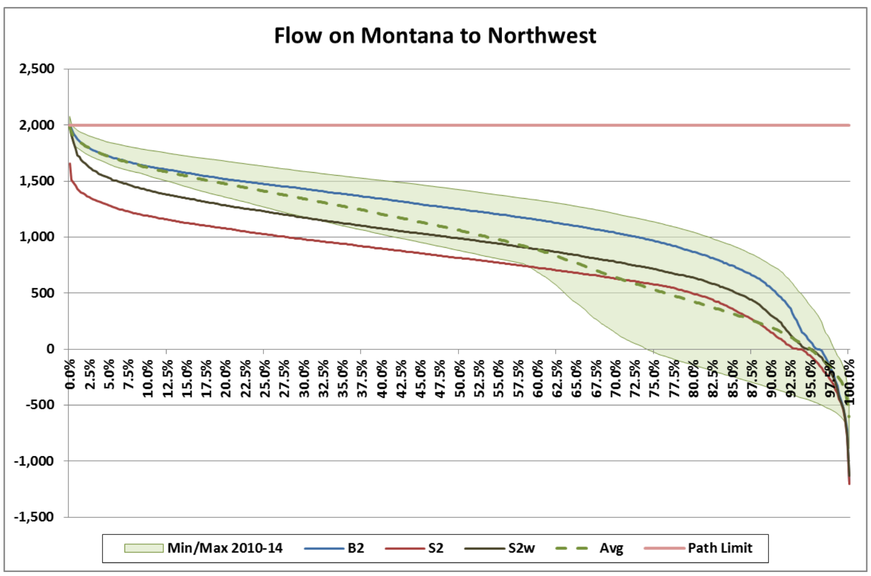

Figure A20: Comparison of results from B2, S2, and S2w scenarios on Path 8

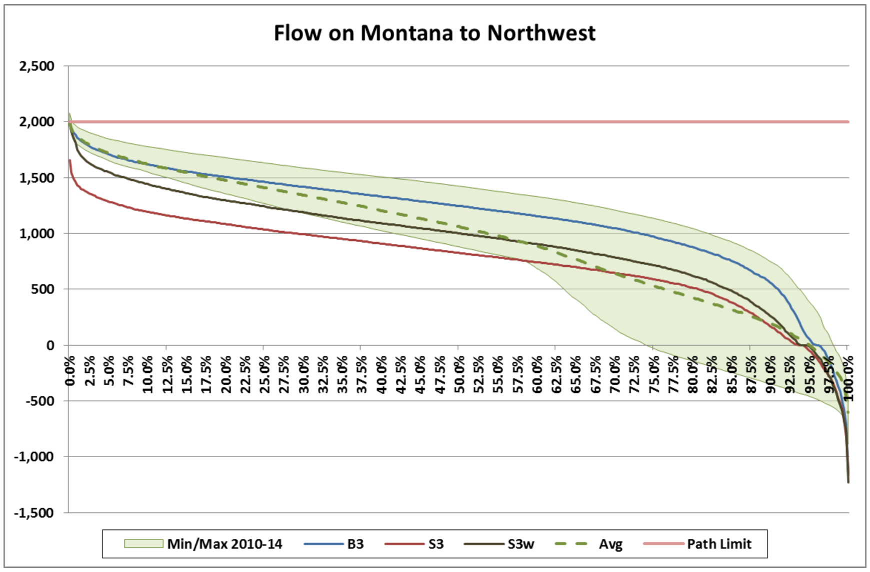

Figure A21: Comparison of results from B3, S3, and S3w scenarios on Path 8

Table A7: A summary of the changes in average Path 8 flow between the cases

From Case	To Case	Change aMW	% Change
B1	S1	-344	-31.2%
B2	S2	-403	-35.0%
B3	S3	-388	-33.9%
S2	S2w	174	23.3%
S3	S3w	165	21.7%

The retirement of Colstrip 1 and 2 has a direct impact on flow from Montana to the Northwest. The retirement of 614 MW at Colstrip results in a reduction of flow by -378 aMW, the equivalent of a 62% CF.

West of Hatwai (Path 6)

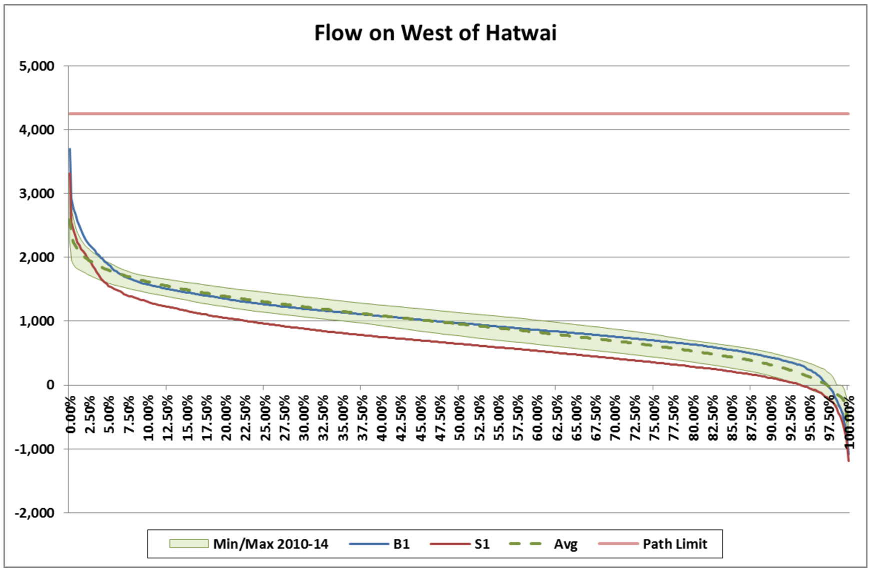

Figure A22: Comparison of results from B1 and S1 scenarios on Path 6

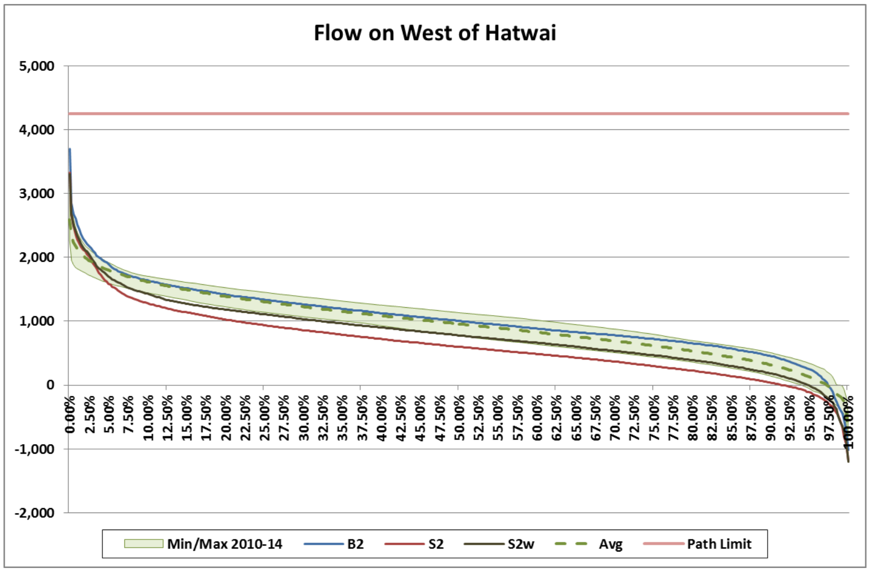

Figure A23: Comparison of results from B2, S2, and S2w scenarios on Path 6

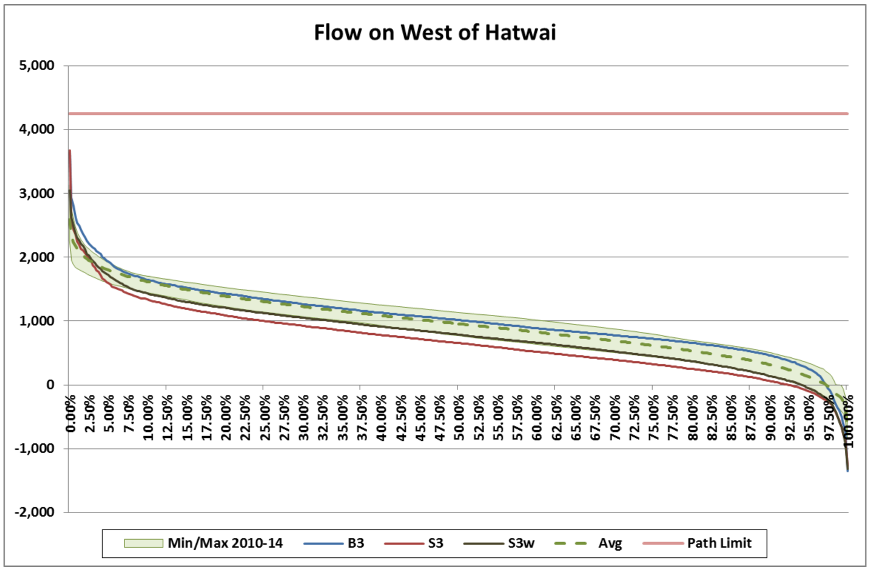

Figure A24: Comparison of results from B3, S3, and S3w scenarios on Path 6

Table A8: A summary of the changes in average Path 6 flow between the cases

From Case	To Case	Change aMW	% Change
B1	S1	-312	-31.3%
B2	S2	-385	-37.3%
B3	S3	-351	-33.8%
S2	S2w	153	23.6%
S3	S3w	110	16.0%

The retirement of Colstrip 1 and 2 has a direct impact on flow from Montana to the Northwest. Hatwai is the second interface Montana generation uses to get to Washington. The retirement of 614 MW at Colstrip results in a reduction of flow on this path by -349 aMW, which is 29 aMW more than Montana to Northwest (Path 8) with -379 aMW.

Pacific DC Intertie and California Oregon Intertie and (Paths 65&66)

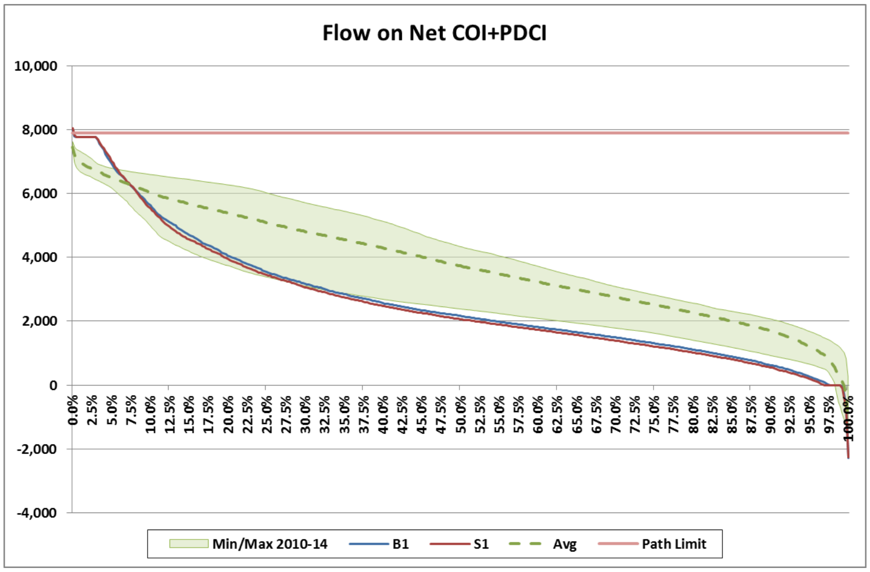

Figure A25: Comparison of results from B1 and S1 scenarios on combined Paths 65&66

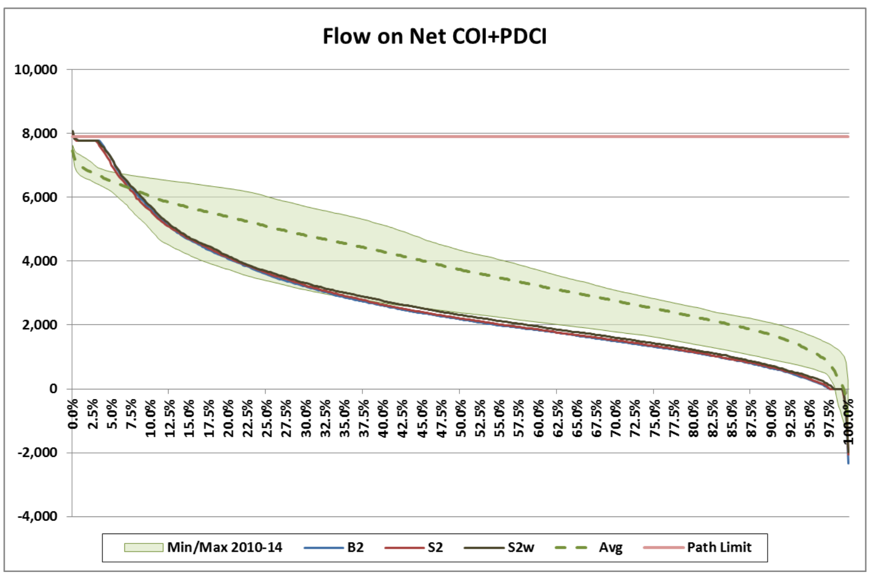

Figure A26: Comparison of results from B2, S2, and S2w scenarios on combined Paths 65&66

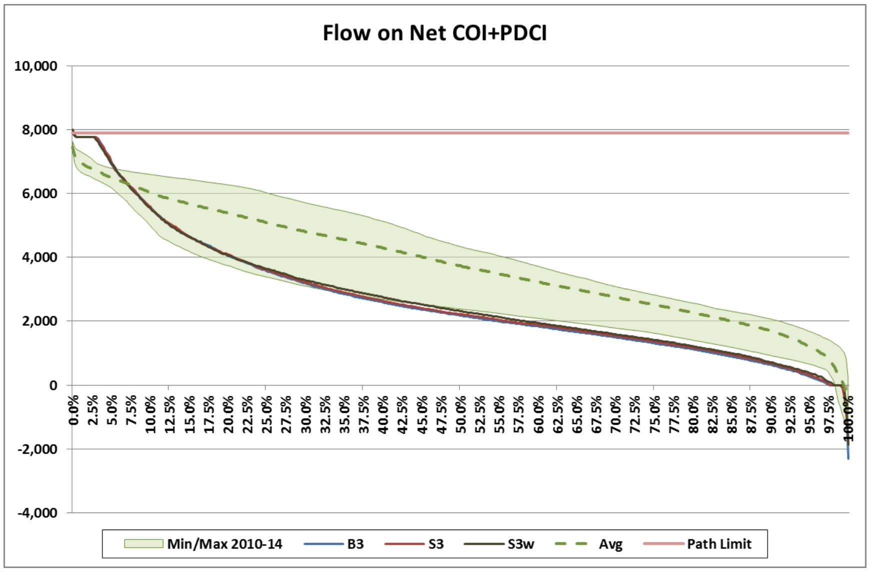

Figure A27: Comparison of results from B3, S3, and S3w scenarios on combined Paths 65&66

Table A9: A summary of the changes in average Path 65+66 flow between the cases

From Case	To Case	Change aMW	% Change
B1	S1	-83	-3.1%
B2	S2	16	0.6%
B3	S3	36	1.4%
S2	S2w	83	3.1%
S3	S3w	49	1.8%

The Sensitivity Cases show minor change in flow from the corresponding Base Case within +/- 3%.