NTTG 2016-2017 draft FINAL REGIONAL TRANSMISSION PLAN

June 30, 2017

I. Executive Summary

The objective of the Northern Tier Transmission Group ("NTTG") Regional Transmission Plan ("RTP") is to evaluate from a regional perspective whether NTTG's transmission needs may be satisfied on a regional or interregional basis more efficiently or cost effectively than through local planning processes. An important element of this biennial planning cycle was to implement the FERC Order 1000 interregional provisions for the regional and Interregional Transmission Projects ("ITP" or "ITPs") that were submitted to NTTG during its Quarter one (January-March 2016) and Quarter five (January-March 2017) data collection processes. The development of NTTG's 2016-2017 Regional Transmission Plan ("RTP") by the end of December 2017 is preceded by the development of a draft Regional Transmission Plan ("dRTP") by the end of Quarter 4 (12/2016) and, if appropriate, a Draft Final Regional Transmission Plan ("dfRTP") in by the end of Quarter 6 (6/2017). Stakeholder comments on the dRTP, Quarter 5 updated data or new information required the dRTP to be reevaluated in Quarter 5 and 6 and a dfRTP to be posted for stakeholder by the end of Quarter 6. NTTG's 2016-2017 Regional Transmission Plan will finalized and posted by the end of Quarter 8 (12/2017).

During the first year of the NTTG 2016-2017 biennial planning cycle, the Technical Work Group ("TWG") of the NTTG Planning Committee evaluated the prior Regional Transmission Plan (pRTP) developed in the 2014-2015 planning cycle, the Initial Regional Transmission Plan ("IRTP")[1] and a number of Change Case[2] plans that included non-committed regional projects[3] and Interregional Transmission Projects to determine a more efficient or cost effective plan which became the dRTP. The evaluation considered the facilities submitted by the Transmission Providers as well as the Interregional Transmission Projects submitted in Q1. This dRTP selection was made by conducting power flow studies to perform a reliability analysis of the pRTP case, the IRTP case and each Change Case under seven stressed conditions and by performing an economic analysis of the pRTP, the IRTP and those Change Case plans that reliably meet NTTG's transmission needs. The power flow stressed conditions consisted of the following: NTTG summer peak, NTTG winter peak, high flows on the Idaho to Northwest path for both southern Idaho imports and exports, Montana to the Northwest path westbound transfers, north to south flows across TOT2, and a high Wyoming Wind scenario. The economic analysis examined three key metrics -- capital related costs, NTTG area loss benefits, and reserve sharing benefits. The dRTP was posted for stakeholder comment at the end of Q4 (Dec 2016). Following receiving stakeholder comments and additional studies in Quarters 5 and 6, the dRTP is evaluated to determine if the dRTP should become the dfRTP or if changes to dRTP would be necessary.

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[1] The IRTP includes projects in the prior Regional Transmission Plan, projects in the Funders Local Transmission Plans, and accounts for future generation additions and deletions (e.g., announced coal retirements).

[2] A Change Case is where one or more of the Alternative Projects is added to or replaces one or more non-Committed Projects in the IRTP. The deletion or deferral of a non-Committed Project in the IRTP without including an Alternative Project can also be a Change Case.

[3] A Committed project is a planned project whose right-of-way has been fully secured.

TWG discovered at the end of Quarter 4 that the 887 MW of incremental wind resources in Wyoming that was submitted by PacifiCorp in Q1 as part of their L&R were inadvertently omitted from the NTTG analysis. To address the issue, additional analysis was conducted in Quarter 6 to determine the extent of its impact on system performance. The dRTP reliability issues identified in the Wyoming area were exacerbated by the increase of Wyoming incremental wind without the addition of new transmission infrastructure in Q5. The analysis performed with the additional wind resources confirms the need for transmission projects identified in the dRTP in Quarter 4.

The Change Case plans were created by removing the non-committed projects from the IRTP and adding one or more of the Alternative Projects[4] to be evaluated through technical evaluation. The TWG determined, given the study assumptions, that four non-committed regional projects from the IRTP must be included in the dRTP when considering all of the modelled existing wind (that is, without the addition of future WY wind) generation is simultaneously dispatched to 95% or more in Wyoming and scheduled to the west - the Boardman to Hemingway (“B2H”) project, the Energy Gateway (“EG”) projects (both Gateway West and Gateway South) and the Antelope Transmission Projects. The addition of these four projects are necessary to achieve acceptable system performance when considering all the modelled existing Wyoming wind (network resources) generation is simultaneously dispatched to 95% or more and scheduled to the west to meet NTTG’s loads. The Null Change Case[5] power flow study results showed that system performance was acceptable in only one of the seven stress conditions studied, the Heavy Winter case, without any future transmission additions. The high southern Idaho import case showed the need for the B2H project to transfer up to 1000 MW of load service obligations. The southern Idaho export coupled with increased future Wyoming wind (needed to deliver to future network load) further reinforces the need for the EG projects when Wyoming wind is simultaneously dispatched to 90% or more and scheduled proportionally to PacifiCorp’s network load in the west. The 540 MW (net) nuclear resource[6] when developed at the Idaho National Lab also showed acceptable system performance with the non-committed Antelope Transmission Projects included.

The TWG technical study discovered that the 2014-2015 pRTP that included two non-committed projects (B2H project and a portion of the EG project) was not reliable. The study also

[4] Alternative Projects collectively refers to Sponsored Projects, projects submitted by stakeholders, projects submitted by Merchant Transmission Developers, and unsponsored projects identified by the Planning Committee (if any).

[5] To develop the null case, TWG took the 2026 production cost model and removed all significant future transmission facilities (i.e., the CCTA list plus any other significant future BES transmission facilities). The purpose of the null case is to test the NTTG footprint with the present (2016/2017) transmission system with 2026/2027 future loads and resources.

[6] It is assumed that interconnection of the nuclear generation to the transmission system includes two new 345 kV lines from Antelope to Goshen and from Antelope to Borah (previously referred to as the Antelope Transmission Projects).

established that the amount of new Wyoming wind that is added over time impacts the transmission system reliability west of Wyoming. To arrive at this conclusion the TWG evaluated 23 Change Cases that fully explored the need for the non-committed projects in the IRTP, pRTP and the three proposed Interregional Transmission Projects. Stepping through its reliability study process the TWG winnowed the number of potential dRTP cases to three – the IRTP and two the variants of the IRTP (Change Cases 21 and 23[7]). These Change Cases were created to explore the relationship of the Wyoming wind buildout and its impact to transmission system reliability west of Wyoming and a potential incremental buildout of the Gateway West project.

Three Interregional Transmission Projects (ITP or ITPs) were studied in Change Cases 5 through 20-- the SWIP-North Project (Midpoint to Robinson Summit), the Cross-Tie Project (Clover to Robinson Summit) and the TransWest Express Project (Aeolus area to southern Nevada). As described in NTTG 2016-17 Study Plan, the evaluation of the three ITPs was conducted in the context of ITP joint interregional coordination with the other Regional Planning entities and NTTG's regional planning process as Alternative Projects. NTTG coordinated its planning data with the other Relevant Regional Planning entities and will also coordinate its dRTP ITP study results with the other Regional Planning entities. Each ITP, in combination with other ITPs and/or non-committed regional projects, were analyzed through Changes Cases as a possible replacement for one or more of the IRTP non-committed projects (e.g., B2H and/or EG). It was determined that none of the ITPs could replace or augment the non-committed Projects such that NTTG's regional transmission needs were satisfied from a regional perspective on a more efficient or cost-effective basis.

An economic analysis of the IRTP and Change Cases 21 and 23 was conducted after completing the reliability analysis. The economic analysis compared the annualized incremental costs of the IRTP and the two Change Cases[8]. The annual incremental cost was computed as the sum of three metrics - the capital related costs, monetized energy loss benefit and monetized reserve benefit. Figure 1 below displays the results of the incremental cost analysis.

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[7] Change Case 21 is similar to the IRTP but excludes the Midpoint-Hemingway #2 and the Midpoint-Cedar Hill 500 kV lines. Change Case 23 was taken from Change Case 21 and also excludes the Populus-Borah 500 kV line. Both Change Case 21 and Change Case 23 are staged versions of the IRTP, for the transfers studied, these lines segments did not significantly improve system performance. At higher transfer levels, these additional segments or an alternative would be necessary.

[8] Note, the Antelope Transmission Project was not considered in the economic analysis due to the local nature of the project.

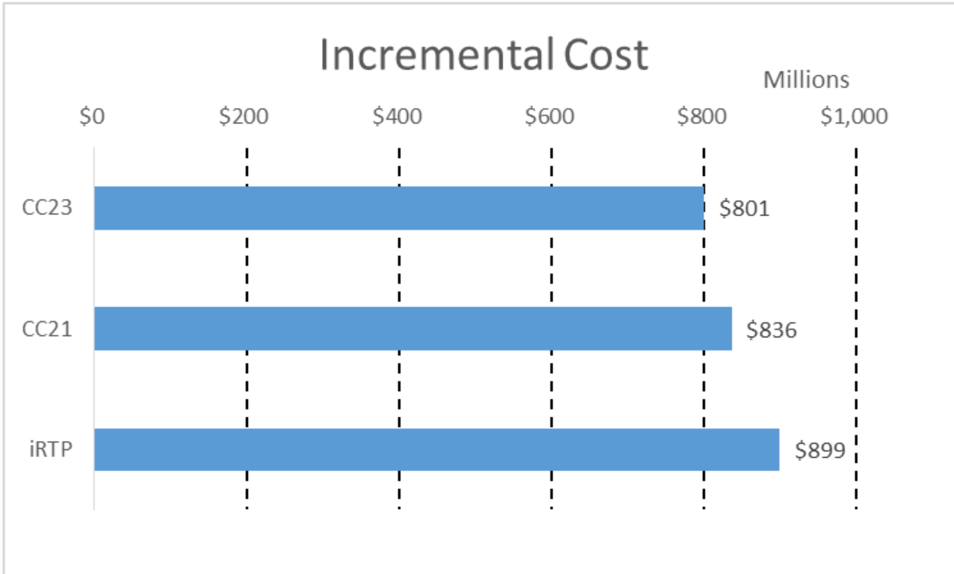

Figure 1 – Summary of Incremental Costs for 2026 NTTG Study Cases

Based on the reliability and economic considerations for the transfers studied, the more efficient and cost-effective draft plan is the Change Case (CC23), which is comprised of the IRTP with the following non-committed projects removed:

- Midpoint-Hemingway #2 500 kV
- Midpoint-Cedar Hill 500 kV
- Populus-Borah 500 kV

II. Introduction

The NTTG 2016-2017 Draft Regional Transmission Plan was developed in accordance with the NTTG's Transmission Providers' Attachment K that included FERC Order 1000 regional and interregional transmission planning requirements[9]. The dRTP is a result of reliability and economic studies and activities outlined in the NTTG Biennial Study Plan for the 2016-17 Regional Planning Cycle[10] and carried out by the NTTG Technical Work Group[11].

A. Load Forecast

The forecasted loads for Balancing Authority Areas internal to the NTTG footprint were provided in response to the Quarter 1 data request. These loads are generally those in the participating

[9] Link to Full Funder Attachment Ks

[10] Link to the 2016-2017 NTTG Study Plan Quarter 6 Update

[11] This work group was established by the NTTG Planning Committee chair to create the study plan and perform the technical evaluations necessary to develop the Regional Transmission Plan. The TWG is comprised of the NTTG Planning Committee or their representatives who have access to and expertise in power system power flow analysis or production cost modeling, are committed to participating in the entirety of the planning process (not just a single study or phase), and will ensure completion of those assignments in a cooperative and timely manner.

load serving entities' official load forecasts (such as those in integrated resource plans) to serve network load and are similar to those provided to the Load and Resource Subcommittee of the WECC Planning Coordination Committee. In Quarter 5 NTTG requested that Transmission Providers and Stakeholders provide updates to the data provided in Quarter 1 if there have been any material changes. Table 1 summarizes the load forecast used in the 2016-2017 planning cycle.

SUBMITTED BY:	2015 Actual Peak Demand (MW)	2024 Summer Load Data Submitted in 2014-15 (MW)	2026 Summer Load Data Submitted in Q1 2016 (MW)	2026 Summer Load Data Submitted in Q5 2017 (MW)	Difference (MW) 2024-2026
Idaho Power	3,730	4,193	4,346	4,340	147
NorthWestern	1,790	1,774	1,992	1,992	218
PacifiCorp	12,634	14,002	13,414	13,414	-588
Portland General	3,958	3,933	3,885	3,874	-59
TOTAL*	22,947	23,902	23,637	23,231	-282

* | * Loads for Deseret G&T and UAMPS are included in PacifiCorp East

Table 1: January 2016-2017 Data Submittal – Load Comparison

B. Resource submissions

Resources provided in response to the Quarter 1 and Quarter 5 data requests are incremental to existing resources within the NTTG footprint and are summarized in Figure 2 and Table 2 below.

State	Resource Additions (MW)
Arizona[12]	-414
California	-59
Idaho	860
Montana	874
Nevada	-262
Oregon	22
Utah	872
Washington	3
Wyoming[12]	777

Table 2: Location of 2026 Forecasted Resources

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[12] Reflects PacifiCorp's retirement of Cholla 4, a coal resource outside the NTTG footprint. Naughton 3 has been modeled as retiring at the end of 2018. PacifiCorp will be continuing to re-access alternatives to repower the unit if proven to be cost effective for customers.

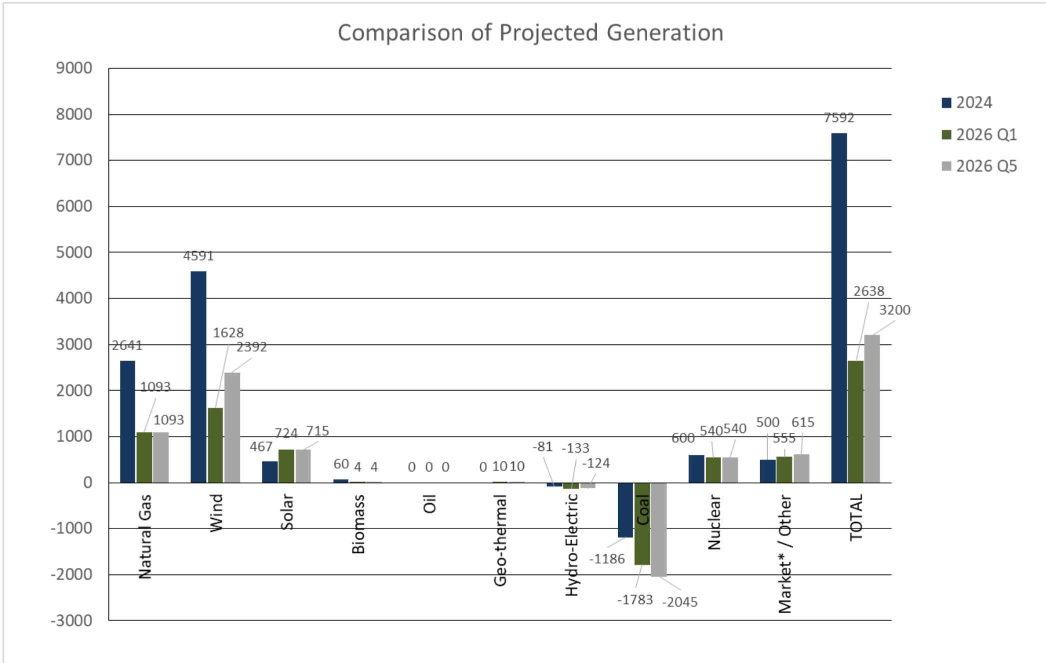


Figure 2: Comparison of Forecasted Resources

In Quarter 5, 550 MW of new Montana wind was submitted and PacifiCorp indicated that their recently submitted IRP increased the amount of Wyoming Wind from 887 MW to 1100 MW. As shown in this figure, the total resource forecast of 3200 MW submitted this cycle is reduced (-392 MW or -12.25%) from the 3592 MW forecast in 2024. Following the Quarter 1 data submittal it was announced that Colstrip 1 and 2 would be retired prior to 2026. There was also a high likelihood that the Valmy 1 and 2 would also be decommissioned. Both sets of retirements were assumed in the 2016-2017 studies and are reflected in Quarter 5 values shown in Figure 2.

In the 2014-15 study cycle, the 3000 MW wind of wind resources were submitted by Power Company of Wyoming (PCW) associated with the TransWest Express Project, PCW asked that those resources not be included in the NTTG 2014-15 Regional Plan. Those resources have been submitted with an Interregional Transmission Project in the 2016-17 study cycle.

C. Transmission Facilities and Service submissions

Listed below in Table 3 are the regional transmission projects that were submitted in Quarter 1. The project types may be either prior Regional Transmission Plan (pRTP), Full Funder Local Transmission Plan (LTP), Sponsored Project, unsponsored Project, or Merchant Transmission Developer. The Initial Regional Transmission Plan was derived from projects included in the prior Regional Transmission Plan and projects included in the Full Funders local transmission plans.

JANUARY 2016 DATA SUBMITTAL – TRANSMISSION ADDITIONS BY 2026

Sponsor	From	To	Voltage	Circuit	Type	Regionally Significant[13]	Committed	Projects
Deseret G&T	Bonanza	Upalco	138 kV	2	LTP	No	No	New Line
Idaho Power	Hemingway	Boardman/ Longhorn	500 kV	1	LTP & pRTP	Yes	No	B2H Project
	Hemingway	Bowmont	230 kV	2	LTP	Yes	No	New Line (associated with Boardman to Hemingway)
	Bowmont	Hubbard	230 kV	1	LTP	Yes	No	New Line (associated with Boardman to Hemingway)
	Cedar Hill	Hemingway	500 kV	1	LTP	Yes	No	Gateway West Segment #9 (joint with PacifiCorp East)
	Cedar Hill	Midpoint	500 kV	1	LTP	Yes	No	Gateway West Segment #10
	Midpoint	Borah	500 kV	1	LTP	Yes	No	(convert existing from 345 kV operation)
	King	Wood River	138 kV	1	LTP	No	No	Line Reconductor
	Willis	Star	138 kV	1	LTP	No	No	New Line
Enbridge	SE Alberta		DC	1	LTP	Yes	No	MATL 600 MW Back to Back DC Converter
PacifiCorp East	Aeolus	Clover	500 kV	1	LTP & pRTP	Yes	No	Gateway South Project – Segment #2
	Aeolus	Anticline	500 kV	1	LTP & pRTP	Yes	No	Gateway West Segments 2&3
	Anticline	Jim Bridger	500 kV	1	LTP & pRTP	Yes	No	345/500 kV Tie
	Anticline	Populus	500 kV	1	LTP & pRTP	Yes	No	Gateway West Segment #4
	Populus	Borah	500 kV	1	LTP	Yes	No	Gateway West Segment #5
	Populus	Cedar Hill	500 kV	1	LTP	Yes	No	Gateway West Segment #7
	Antelope	Goshen	345 kV	1	LTP	Yes	No	Nuclear Resource Integration
	Antelope	Borah	345 kV	1	LTP	Yes	No	Nuclear Resource Integration
	Windstar	Aeolus	230 kV	1	LTP & pRTP	Yes	No	Gateway West Segment #1W
	Oquirrh	Terminal	345 kV	2	LTP	Yes	Yes	Gateway Central
	Cedar Hill	Hemingway	500 kV	1	LTP	Yes	No	Gateway West Segment #9 (joint with Idaho Power)
PacifiCorp West	Wallula	McNary	230 kV	1	LTP	Yes	Yes	Gateway West Segment A
Portland General	Blue Lake	Gresham	230 kV	1	LTP	No	No	New Line
	Blue Lake	Troutdale	230 kV	1	LTP	No	No	Rebuild
	Blue Lake	Troutdale	230 kV	2	LTP	No	No	New Line
	Horizon	Springville Jct	230 kV	1	LTP	No	No	New Line (Trojan-St Marys-Horizon)
	Horizon	Harborton	230 kV	1	LTP	No	No	New Line (re-terminates Horizon Line)
	Trojan	Harborton	230 kV	1	LTP	No	No	Re-termination to Harborton
	St Marys	Harborton	230 kV	1	LTP	No	No	Re-termination to Harborton
	Rivergate	Harborton	230 kV	1	LTP	No	No	Re-termination to Harborton
	Trojan	Harborton	230 kV	2	LTP	No	No	Re-termination to Harborton

Table 3

[13] Regionally significant transmission projects are generally those that effect transfer capability between areas of NTTG. Projects that are mainly for local load service are not regionally significant. Projects that are not regionally significant will be placed into all change cases and not tested for impact on the Regional Transmission Plan. The facilities submitted in the LTP's will be removed in the Null Case

Transmission Service Obligations: Listed below, in Table 4, are the transmission obligations that were submitted in for the 2016-2017 planning cycle.

Submitted by	MW	Start Date	POR	POD
Idaho Power	500/200	2021	Northwest	IPCo
	250/550	2022	LGBP	BPASEID
PacifiCorp East	540	2024	Antelope	Network
	1100	2026	Miners / Point of Rocks	Network

Table 4 – Transmission Service Obligations

Available Transfer Capability (ATC): Listed in Table 5 is a summary of the transmission path ratings and Available Transfer Capability (ATC) on the designated transmission path(s).

Path Name	Existing Path Rating (MW)	Available Transfer Capability (*2015*)
8 – Montana to Northwest	E-W: 2200 W-E: 1350	E-W: 698 W-E: 652*
14 - Idaho to Northwest	W-E: 1200 E-W: 2175	W-E: 0 E-W: 399▪ E-W: 0▪▪
16 – Idaho - Sierra	N-S: 500 S-N: 360	N-S: 263 S-N: 0
17 – Borah West	E-W: 2557 W-E: 1600	E-W: 26 W-E: 1350
19 – Bridger West	E-W: 2400 MW W-E: 1250 MW	E-W: 86* W-E: 0* E-W: 0** W-E: 0**
20 – Path C	N-S: 1600 S-N: 1250	N-S: 0 S-N: 0
37 - TOT 4A	NE-SW: 950	NE-SW: 0 SW-NE: 0
38 - TOT 4B	SE-NW: 880	SE-NW: 0 NW-SE: 0
75 - Hemingway-Summer Lake	E-W: 1500 W-E: 550	E-W: 0▪▪ W-E: 0▪▪

Path 8 Notes:

* This number is the ATC on the NorthWestern or Eastern side of the meter points. West of the meter points belongs to BPA and Avista and will have different values.

Path 14, 19 and 75 Notes:

- ▪ IPCo Share.
- ▪▪ PAC Share

Table 5 – Transmission Path Capacity and Available Transfer Capability

Table 6 below provides a list of the Interregional Transmission Projects (ITPs) received in Q1.

SUMMARY OF Q1-2016 INTERREGIONAL PROJECTS SUBMITTED TO NTTG						
Project Name	Company	Relevant Planning Region(s)	Termination From	Termination to	Status	In Service Date
Cross-Tie Transmission Project	TransCanyon, LLC	NTTG, WC	Clover, UT	Robinson Summit, NV	Conceptual	2024
SWIP-North[14]	Great Basin Transmission LLC	NTTG, WC	Midpoint, ID	Robinson Summit, NV	Permitted	2021
TransWest Express Transmission Project	TransWest Express, LLC	NTTG, WC and CAISO	Sinclair, WY	Boulder City, NV	Conceptual	2020

Table 6 – Interregional Transmission Projects

D. Transmission Needs Driven by Public Policy Requirements

Public Policy Requirements are those requirements that are established by local, state, or federal laws or regulations.

Local transmission needs driven by Public Policy Requirements are included in the NTTG Initial Regional Plan[15] through the Local Transmission Plans of the NTTG Transmission Providers. Additionally, during Quarter 1, stakeholders may submit regional transmission needs and associated facilities driven by Public Policy Requirements to be evaluated as part of the preparation of the Draft Regional Transmission plan. During the Regional Planning Cycle, the Planning Committee will determine if there is a more efficient or cost-effective regional solution to meet these transmission needs.

The selection process and criteria for regional projects meeting transmission needs driven by Public Policy Requirements are the same as those used for any other regional project chosen for the Regional Transmission Plan. All transmission needs identified as driven by Public Policy Requirements, and available at the time this revised NTTG Biennial Study Plan was developed, will be included in the study plan.

During this planning cycle, no additional transmission needs, beyond those submitted by the transmission providers, were submitted to satisfy Public Policy Requirements. A full listing of applicable Public Policy Requirements for the NTTG footprint is included in Appendix A. The following RPS values will be used in its modeling:

[14] The SWIP-North project submitted by Great Basin Transmission (GBT) requires a new physical connection at Robinson Summit, at the southern end of the Project. To transmit power beyond the Project, ~1,000 MW of capacity rights on the already in-service ON Line Project from Robinson Summit to Harry Allen 500 kV, as well as, completion of CAISO's Harry Allen to Eldorado Project in 2020, those GBT capacity rights will provide a CAISO access to SWIP-North.

[15] See Attachment K, Local Planning process

	TEPPC 2026 case
California	33%
Oregon	27%
Washington	15%
Idaho	-
Montana	15%
Wyoming	-
Utah	20%
Nevada	25%

Table 7 – RPS Assumptions in Production Cost Model Dataset

E. Development of Initial Regional Transmission Plan

The planning process started by developing the Initial Regional Transmission Plan through a bottom up approach by aggregating the Funding Transmission Providers' (TPs') local transmission plans into a single regional transmission plan. Next the IRTP non-committed projects within the NTTG geographical area were analyzed through Change Case plans to determine whether Alternative Projects could be added or substituted and/or one or more non-committed projects could be deferred so as to yield a regional transmission plan that would be more efficient or cost effective than the IRTP. It is the result of this analysis that formulated the dRTP presented herein. This dRTP document discusses in detail the activities and studies completed and how the dRTP was developed.

III. Study Methodology

To determine the more efficient or cost-effective transmission plan that would become the dRTP, both reliability and economic studies were performed in accordance with the 2016-2017 Study Plan. The reliability studies utilized production cost modeling and power flow studies. The production cost model results (the base case input data derived from the WECC 2026 Common Case[16]) were used to identify seven stressed hours. These seven hours were subjected to reliability analysis using a power flow model. The input and output data for these selected hours were transferred, using the round trip process, from the production cost model (i.e., GridView) to a power flow model (i.e., PowerWorld) to perform the technical reliability analysis. The economic studies that were performed next utilized the Attachment K's three metrics (i.e., capital related costs, energy losses, and reserves) to analyze those Change Case plans that were

[16] See Appendix B lists the resource additions and removals made to the production cost model and power flow Change Cases.

reliable to further determine the cost effectiveness of the NTTG transmission plan. The reliability study process and the economic evaluations will be described in more detail below.

A. Production-Cost Modeling

GridView[17] production cost software was used to look at 8760 hours of data to determine stressed conditions within the NTTG footprint. The production cost dataset representing the year 2026 was obtained from the Transmission Expansion Planning Policy Committee ("TEPPC") of the Western Electricity Coordinating Council ("WECC"). This case included a representation of the load, generation and transmission topology of the WECC interconnection-wide transmission system ten years into the future. The TEPPC dataset was released on July 1st. Members of the TWG reviewed the loads, resources, and transmission data for their transmission planning area to ensure that the representations in this case were reasonably close to the data they had submitted in the first Quarter ("Q1") of the biennial cycle. TWG identified the need to incorporate a significant number of corrections prior to use by NTTG. In early September, NTTG shared these changes with the other Regional Planning entities and WECC for inclusion in their future studies. The TWG then agreed to use this modified TEPPC case in creating the stressed cases discussed below.

TWG determined that there were seven stressed conditions which impact the NTTG area that should be studied:

- high NTTG summer peak;
- high NTTG winter peak;
- high Montana-Northwest (Path 8) flows;
- high southern Idaho import (Idaho-Northwest Eastbound);
- high southern Idaho-Northwest export (Idaho-Northwest westbound);
- high NE-SE (Path Tot2) flows; and
- high Wyoming Wind production.

After running all 8760 hours using the GridView production-cost program, the data was analyzed and the hours representative of the seven stressed conditions were identified. The hours are shown in Table 8 below.

[17] GridView is a registered ABB product

Stressed Condition	Date	Hour	TWG Label
Max. NTTG Summer Peak	July 22, 2026	16:00	A
Max. NTTG Winter Peak	December 8, 2026	19:00	B
Max. MT to NW	September 10, 2026	Midnight	C
High Southern Idaho Import	June 11,2026	14:00	D1
High Southern Idaho Export	September 17, 2026	2:00	D2
High Tot2 Flows	November 11, 2026	17:00	E
High Wyoming Wind	September 17, 2026	2:00	F

Table 8 – Hours Selected from 2026 WECC TEPPC Case to Represent Different NTTG System Stresses

B. Power Flow Cases

The next step in the process was developing the power flow stressed condition cases by converting (i.e., a "round-trip process") the production cost model for the above seven hours into the Power World power flow cases. Even though the TWG has used a conversion process (i.e., export the production cost database to a power flow readable format) for the past four cycles, this process continues to require effort to manipulate the resultant power flow base cases so the power flow model will run. It should be noted that this conversion process has improved with each cycle from months to weeks to now hours once the initial dataset has been adjusted.

The TWG determined that power flow model loads extracted from the production cost model did not stress the transmission system as much as historical conditions would suggest. Further exploration found that the production cost database uses a 1 in 2 load forecast and when extracting a single hour from the production cost model to the power flow model this single hour may not represent a coincident peak hour between the balancing areas as has been experienced in the past. TWG recognized that these differences result in a lower than expected peak loads in the extracted power flow for a number of the balancing areas within NTTG. To better reflect possible highly stressed conditions for the selected peak loads within the NTTG footprint, the balancing area loads were adjusted to get peak loads that represent 1 in 5 to 1 in 10 peak load conditions. Each of the stressed cases was then reviewed by the TWG to ensure that the case met steady state system performance criteria (no voltage issues or thermal overloads). Bubble diagrams showing the inter-area flows for each of the stressed cases are included in the results sections below.

In Quarter 5, the TWG developed dynamic data and contingency files that was utilized in the Public Policy Consideration study in Appendix D.

C. System Performance Criteria

The details of the system performance criteria can be found in the Study Plan (see footnote 10). An abbreviated summary of the NERC reliability criteria state that lines and transformers must not exceed their normal and emergency thermal ratings and bus voltages must remain within certain ranges. For steady-state conditions the voltages must be between 95% and 105% for buses 345 kV and below and between 100% and 110% for 500 kV buses and above. Post contingency voltages must be > 90% and < 110% for 345 kV and below and between 95% and 115% for 500 kV and above.

For dynamic studies, the criteria are based on TPL-001-WECC-CRT-3, following fault clearing, the voltage shall recover to 80% of the pre-contingency voltage within 20 seconds for each BES bus serving load and shall not dip below 70% for more than 30 cycles nor remain below 80% for more than 2 seconds once the voltage has recovered above 80% post fault. All oscillations shall be positively damped within 30 seconds or the contingency will be considered unstable.

D. Simultaneous Wind Production in Wyoming

In first half of the study cycle, the wind production for the high wind case was assumed to be at 95% of the nameplate capacity for the existing wind resources. It was discovered in late Q4 that the 887 MW of incremental wind resources in Wyoming that were submitted by PacifiCorp in Q1 were inadvertently omitted from the NTTG analysis. Coincident with Q5 data submittal, PacifiCorp's newly published IRP calls for 1,100 MW of incremental wind in Wyoming.

With the additional wind in Wyoming submitted in Quarter 5, the TWG reviewed the hourly simultaneous production of the wind resources in Wyoming. Figure 3 shows a peak duration curve of those expected resources. In studies for the dRTP, the Wyoming wind was studied at about 1300 total MW and excluded the proposed wind submitted by PacifiCorp. In Quarter 6, TWG reviewed the duration curve in Figure 3 and performed a number of change case runs at 2175 MW.

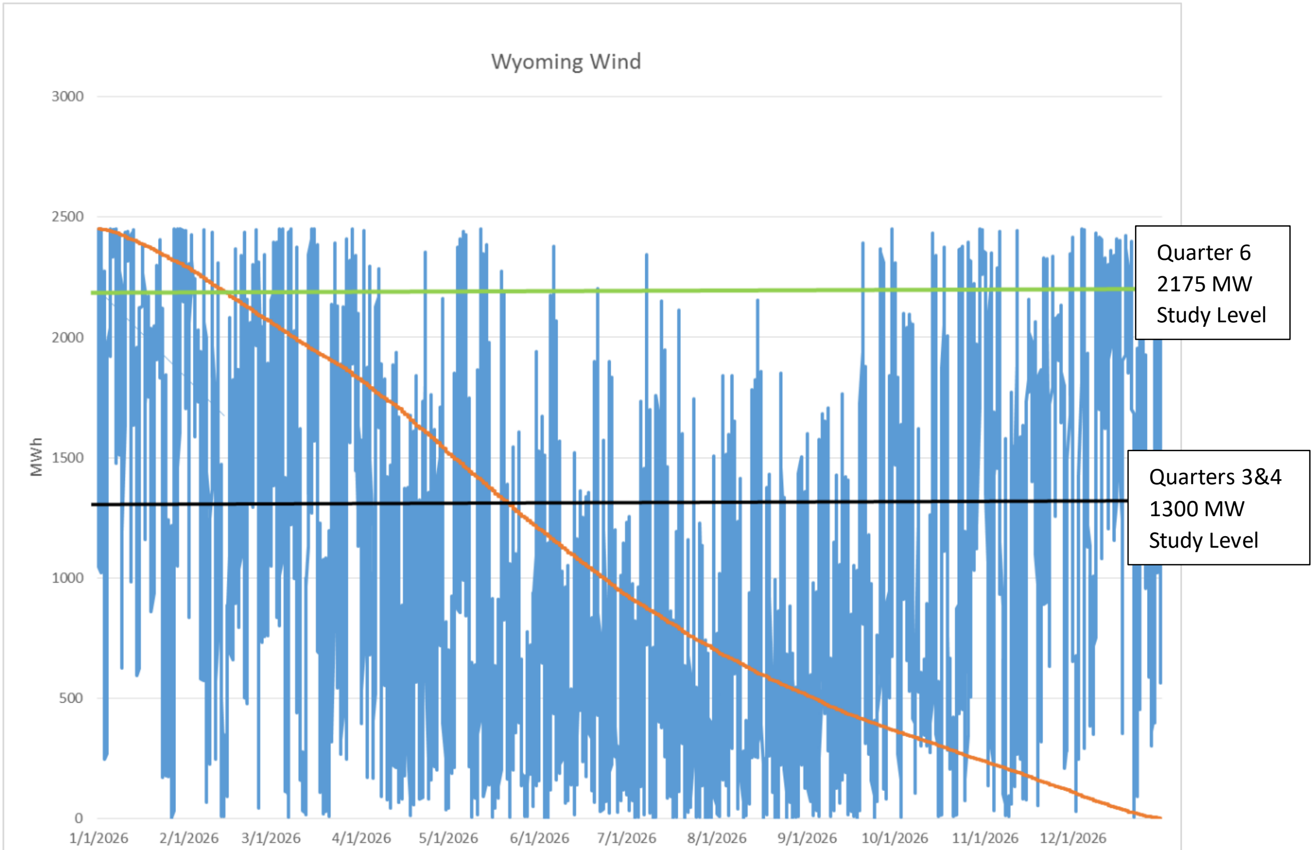


Figure 3: Chronologic and Duration curve of forecasted Wyoming wind production for 2026

IV. Stress Conditioned Case Study Results

After analyzing the steady-state performance of each of the seven stress conditioned cases, a rigorous contingency analysis commenced. This contingency analysis consisted of over 375 single contingencies and 39 credible double contingencies, to determine if each contingency meets the system performance criteria. If there were reported reliability violations by the power flow program, TWG determined if these violations were legitimate and needed mitigation to correct the violation or if modeling problems (e.g., corrections to the modeled contingency actions) caused the reliability violation. For the legitimate violations, TWG determined what additional facilities would be needed to meet the criteria and adjust the IRTP to include the additional facilities. If no violations, then the facilities in the IRTP are deemed adequate for serving the NTTG loads and resources in the year 2026. The results of each of the seven stressed cases are discussed below:

A. NTTG Summer Peak Case

This case has an NTTG summer peak load of 24,100 MW with 17,851 MW of generation. The sum of the NTTG boundary flows in the case is approximated by taking the difference between generation and load, which equated to -6,250 MW (import). A bubble diagram of the case is shown below.

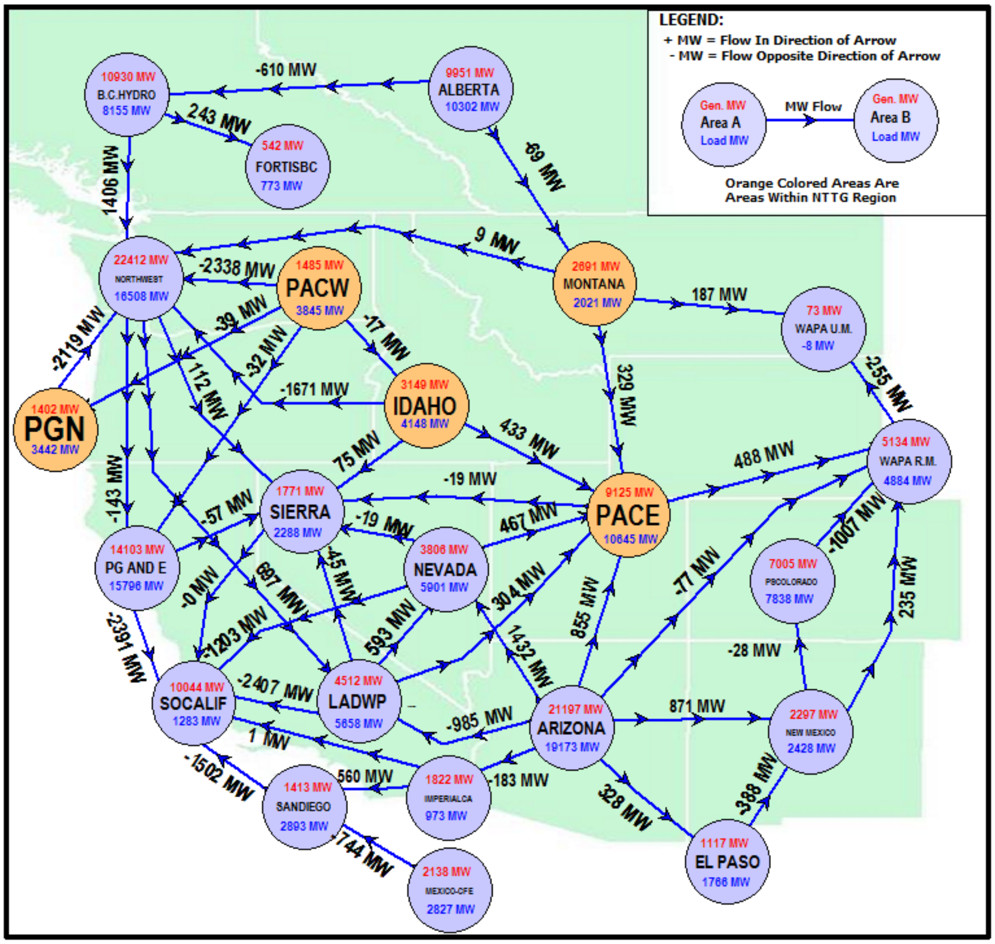


Figure 4 - Tie-line flows for Summer Peak Case
(July 22, 2026 Hour 16 - NTTG Case A)

In this case, the IRTP performed reasonably well with a few local areas having known existing issues that have not risen to the level of justifying expenditures to resolve them. The Null Change Case topology indicates, although to a lesser extent than some of the other stressed flow conditions (cases D1, D2, E and F), that system performance is inadequate without transmission system additions by 2026 to meet NTTG's requirements. The Case A was also studied at the 2175 MW wind level to check the performance of the DRTP.

B. NTTG Winter Peak Case

The NTTG winter peak load in this case is 22,468 MW with a total of 19,261 MW of generation. The difference of generation and load approximates the boundary flow which is equal to -3,208 MW (import). A few local system violations occur in the IRTP case. It is apparent that the heavy winter condition is less stressful than the heavy summer condition, as very few additional violations occur in the Null case compared to the IRTP case.

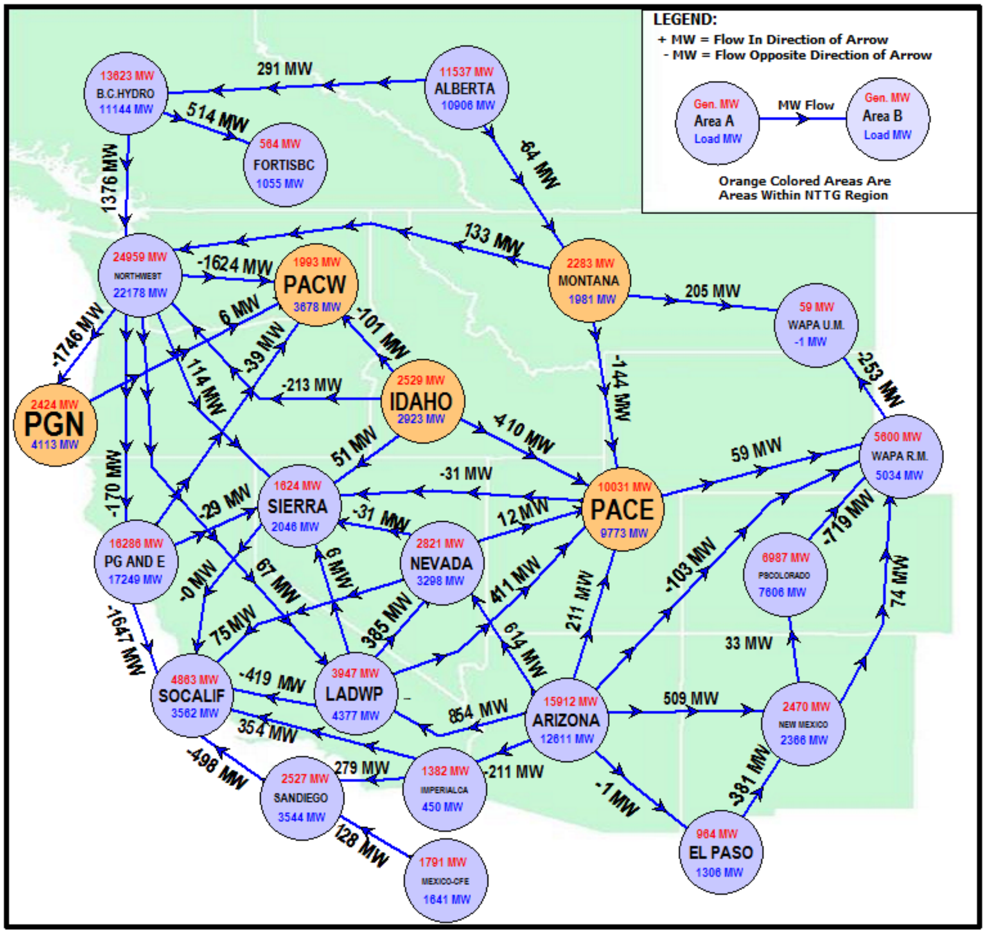


Figure 5 - Tie-line flows for Winter Peak Case
(Dec 8, 2026 Hour 19 - NTTG Case B)

The Case B was also studied at the 2175 MW wind level to check the performance of the DRTP.

C. Maximum Path 8 Case

This case has a Path 8 flow of 2,042 MW. The NTTG total is approximately 959 MW import. The NTTG load and generation in this case are 13,097 MW and 12,138 MW respectively. The bubble diagram follows. This case was used for the Public Policy Consideration study; see Appendix D for results of that study.

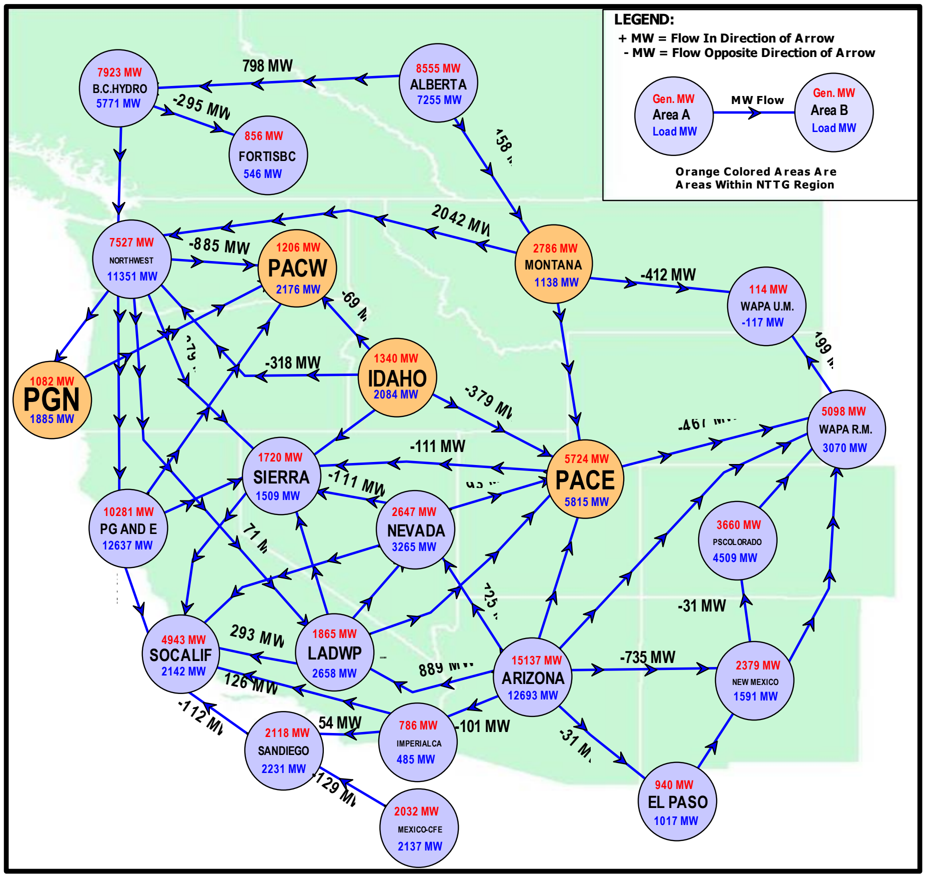


Figure 6 - Tie-line flows for Montana-Northwest Case
(Sept 10, 2026 Hour 24 - NTTG Case C)

D1. High Southern Idaho Import Case

This case has the ID-NW Path flow at -2,244 MW. The NTTG load and generation in this case are 16,382 MW and 9,159 MW respectively. The NTTG footprint is importing 7,223 MW. The bubble diagram follows. The IRTP performs well with a few local violations. The Null case is another matter, as it is clear that the existing system topology is incapable of importing power to this level and load service obligations in southern Idaho would not be met.

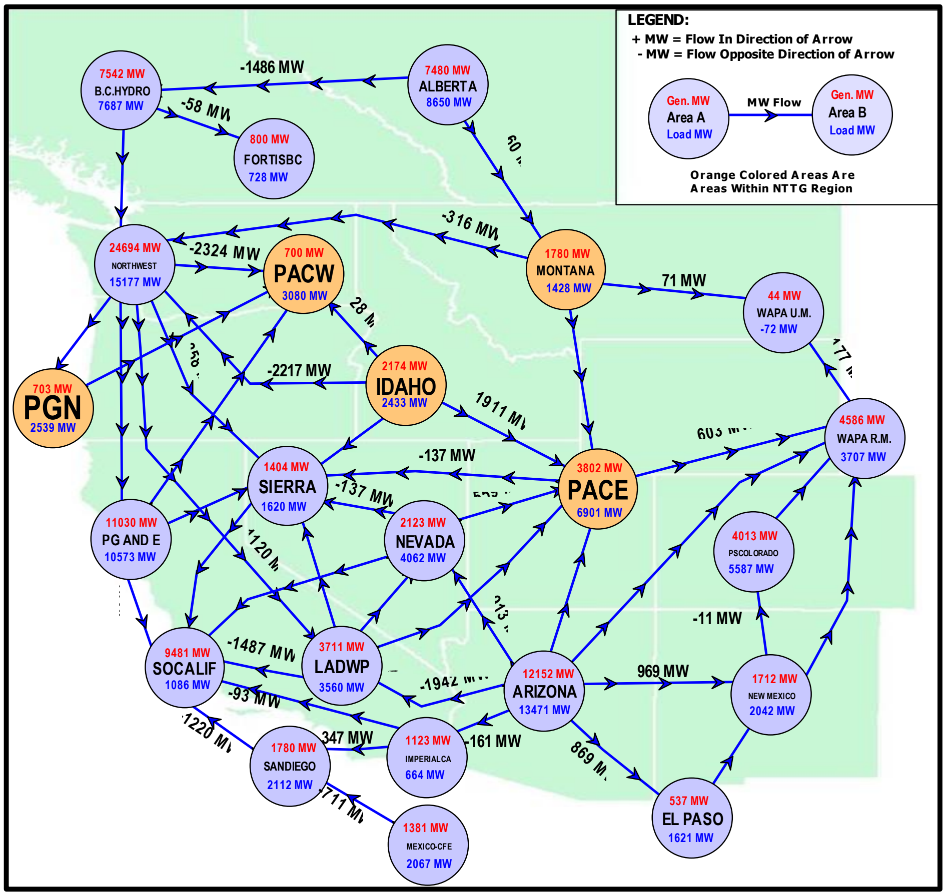


Figure 7 - Tie-line flows for High Southern Idaho Import Case
(June 11, 2026 Hour 14 - NTTG Case D1)

D2. High Southern Idaho Export Case

This case has the ID-NW Path 8 flow at 3,391 MW. The NTTG load and generation in this case are 11,935 MW and 14,683 MW respectively, with NTTG exporting 2,748 MW. Similar to the D1 flow condition, the IRTP performs well with just one contingency that causes a series cap bank to overload; however, that bank has reached the end of its useful life and is likely to be replaced before 2026. The bank rating will be reviewed prior to its replacement to insure it does not inhibit transfers across the system. The Null Case topology again demonstrated that without reinforcement, the system would not be able to support the expected transfers and would not satisfy NTTG's requirements for 2026.

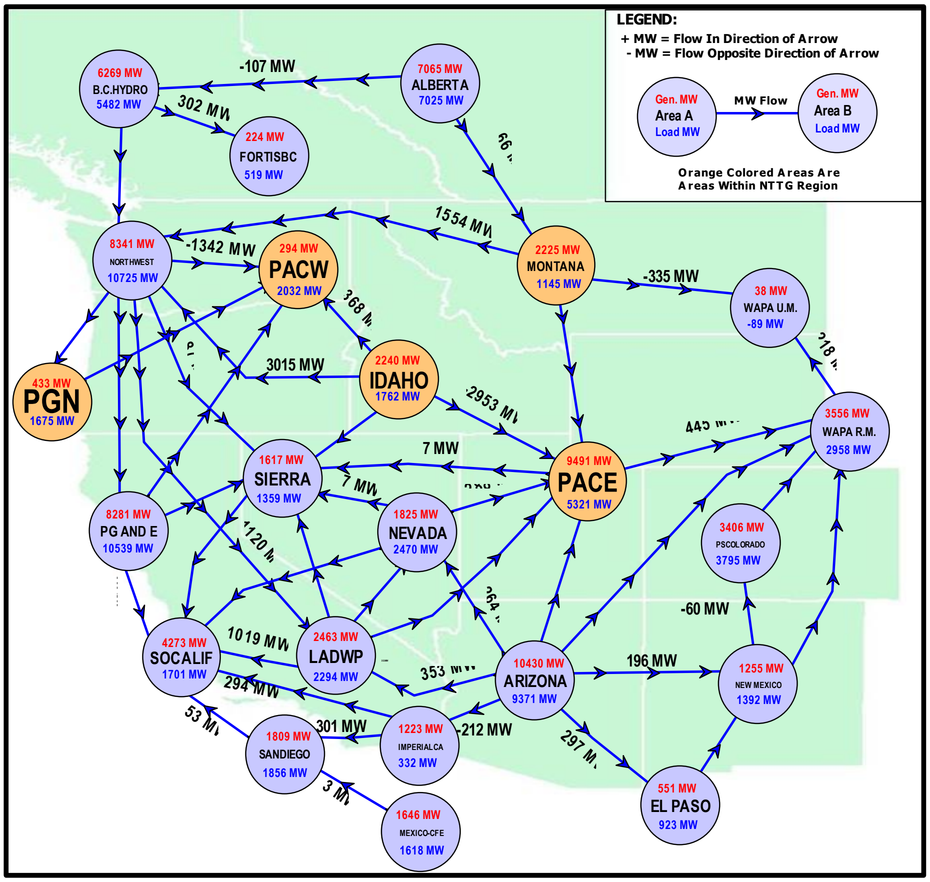


Figure 8 - Tie-line flows for High Southern Idaho Export Case
(Sept 17, 2026 Hour 2 - NTTG Case D2)

E. High Tot2 Case

This case has a Tot2 flow of 1,566 MW. The NTTG load and generation are 16,625 MW and 16,620 MW respectively, with the NTTG footprint nearly balanced with a 5 MW import. The bubble diagram follows. The focus of this case is to evaluate the performance of the ITPs in supporting interregional transfers. These additional interregional transfers were not identified in Q1 to meet or defer NTTG's 2026 footprint resource requirements.

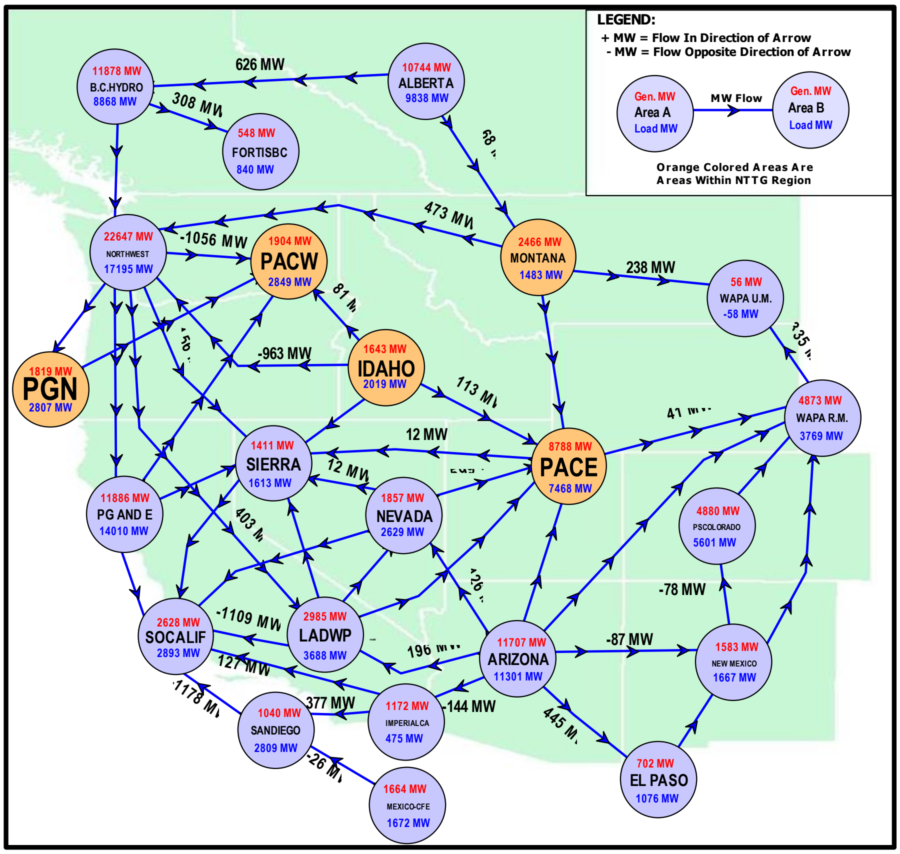


Figure 9 - Tie-line flows for High Tot2 Case
(Nov 11, 2026 Hour 17 - NTTG Case E)

The Case E was also studied at the 2175 MW wind level to check the performance of the DRTP.

F. High Wyoming Wind Case

The NTTG load and generation in this case are 11,935 MW and 15,015 MW respectively with a NTTG export of 3,081 MW. The existing Wyoming wind was increased from 630 MW to 1,303 MW. The bubble diagram follows. This case was developed from the D2 case by adjusting the production level of the planned Wyoming wind generation. The main focus was to check the performance of the Wyoming system to support this level of resource. With the additional transfers across southern Idaho, the pRTP performed poorly and failed to meet NTTG's reliability criteria. Adding a number of Gateway West segments not included in the pRTP, resolved the performance issues for this case. The prior planning cycle failed to study this level of transfer across southern Idaho.

As described earlier, for the resources modeled in the area, NTTG's footprint performed poorly and failed to meet NTTG's reliability criteria without any system improvements.

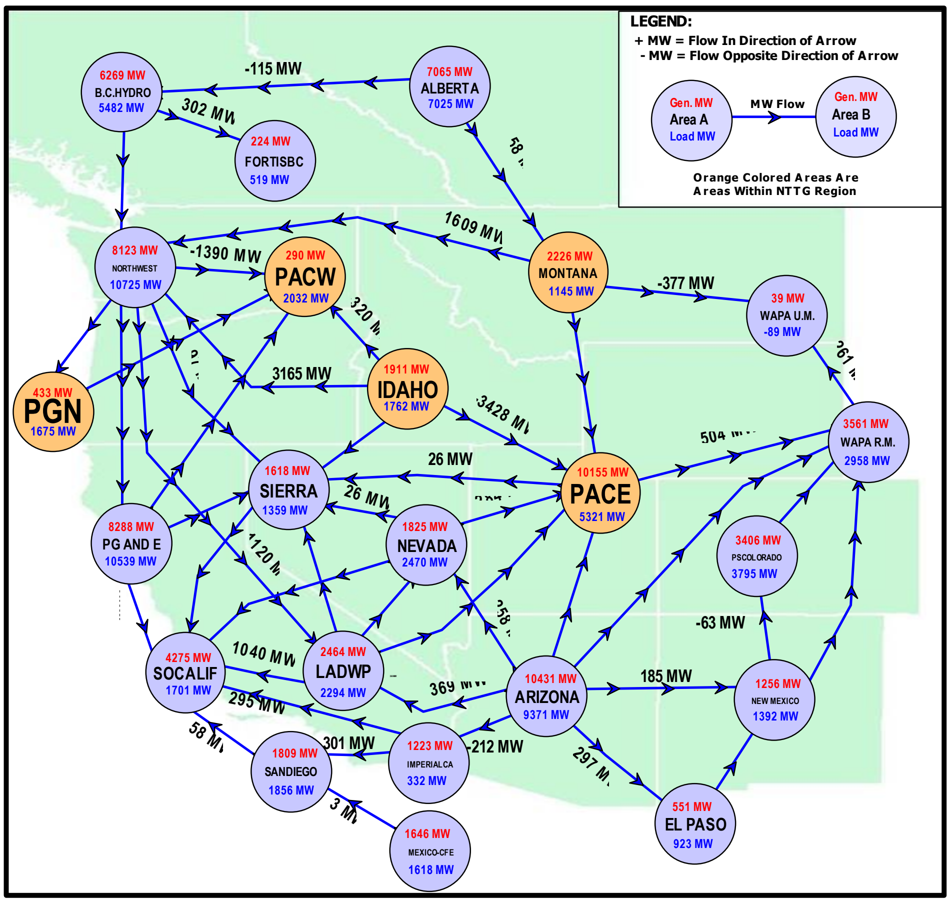


Figure 10 - Tie-line flows for High Wyoming Wind Case
(Sept 17, 2026 Hour 2 - NTTG Case F)

The Case F was also studied at the 2175 MW wind level. The area-to-area transfers of the Case F studied in Quarter 6 (Fq6) where remarkably similar to those in Figure 10. The additional incremental wind resulted in intra-area transfers within the PACE bubble. The additional wind in the Wyoming area exacerbated the reliability issues observed in Wyoming and confirmed the need for additional transmission to use these resources to its fullest extent. The dRTP identified in Q4 addresses the reliability concern and alleviates the transmission constraints observed previously.

V. Change Case Results

For each of these stress conditioned cases, a "Null" Change Case was prepared and reliability results were analyzed. The Null case represents roughly today's transmission topology with 2026 Loads and Resource requirements. Only the Heavy Winter case (B) had acceptable performance. All the other conditions had performance issues that require correction, in increasing order: the Heavy Summer case (A); the High Tot2 case (E); the B2H import case (D1); the Heavy Export case (D2); and, finally, the High Wyoming wind case (F) being the worst.

The IRTP as submitted in Quarter 1 includes the following non-committed projects:

- The Boardman to Hemingway Project (Longhorn-Hemingway)
- The Gateway West Project which contains a number of sub-sections:
  - Windstar-Aeolus 230 kV
  - Aeolus-Anticline (Jim Bridger) 500 kV
  - Anticline-Populus 500 kV
  - Populus-Borah 500 kV
  - Populus- Cedar Hill 500 kV
  - Cedar Hill-Hemingway 500 kV
  - Cedar Hill- Midpoint 500 kV
  - Borah-Midpoint 345 to 500 kV conversion
  - Midpoint-Hemingway #2 500 kV
- The Gateway South Project:
  - Aeolus-Clover 500 kV
- The Antelope Projects:
  - Goshen-Antelope 345 kV
  - Antelope-Borah 345 kV

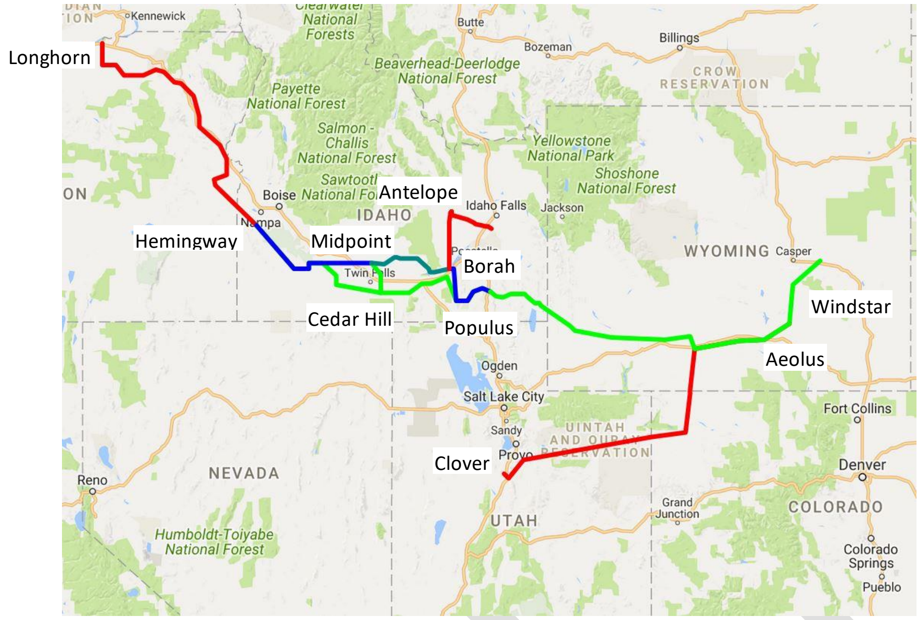


Figure 11 - IRTP Projects

The prior Regional Transmission Plan from last planning cycle included a subset of the projects submitted in the current Quarter 1:

- The Boardman to Hemingway Project (Longhorn-Hemingway)
- The Gateway West Project which contains several sub-sections:
  - Windstar-Aeolus 230 kV
  - Aeolus-Anticline (Jim Bridger) 500 kV
  - Anticline-Populus 500 kV
- The Gateway South Project:
  - Aeolus-Clover 500 kV

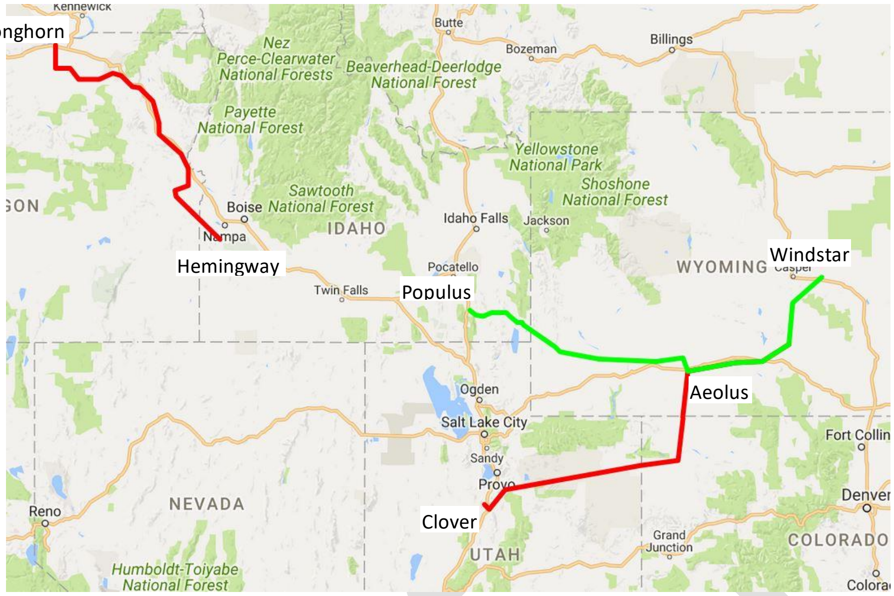


Figure 12 - pRTP Projects

To efficiently study the wide range of potential combinations of non-committed projects, the TWG formulated a Change Case matrix, an initial formulation of which was included in the Biennial Study Plan[18]. Once the stressed power flow cases had been selected and developed, the TWG modified the matrix to better reflect the recommended analysis. During the month of October 2016, stakeholder comments were solicited on the draft set of projects selected for analysis in the Change Case matrix. No comments were submitted. The matrix was also presented to the Planning Committee at the October and November meetings. Table 9 below, is the Change Case matrix that was used by the TWG:

[18] The Biennial Study Plan is the study plan used to produce the Regional Transmission Plan, as approved by the NTTG Steering Committee.

Case	B2H*	Gateway S*	Gateway W*	Antelope Projects	SWIP N	Cross-Tie	TWE	Case(s):
null								A B D1 D2 F
pRTP	X	X	D					A B D1 D2 F
iRTP	X	X	X	X				A B D1 D2 E F
CC1	X							A B D1 D2 F
CC2		X		X				A D2 E F
CC3		X	X					A D1 D2 E F
CC4	X		X	X				A D1 D2 E F
CC5							X	A B D1 D2 F
CC6						X		A B D1 D2 F
CC7					X			A B D1 D2 F
CC8							X	E+RPS
CC9		X					X	E+RPS
CC20		X	X				X	E+RPS
CC10						X		E+RPS
CC11		X				X		E+RPS
CC18		X	X			X		E+RPS
CC12					X			E+RPS
CC13			X		X			E+RPS
CC19		X	X		X			E+RPS
CC14		X	X		X	X		E+RPS
CC15			X		X		X	E+RPS
CC16		X				X	X	E+RPS
CC17		X	X		X	X	X	E+RPS
CC21	X	X	A	X				D2 F
CC22	X	X	B	X				D2 F
CC23	X	X	C	X				F

* B2H and Alternate P in the pRTP are similar to B2H, Gateway S and Gateway W in the 2016-17 Q1 data submittals

(dark green)	The change case does not include the non-Committed Project
X	The change case includes the non-Committed Project
A	Gateway West without Midpoint-Hemingway #2 and Cedar Hill-Midpoint
B	Gateway West without Borah-Midpoint Uprate and Populus-Borah
C	Gateway West without Midpoint-Hemingway #2, Cedar Hill-Midpoint and Populus-Borah
D	Gateway West without Midpoint-Hemingway #2, Cedar Hill-Midpoint, Populus-Cedar Hill-Hemingway, Populus-Borah and Midpoint-Borah Uprate
(light blue)	The change case was run with and without B2H

Table 9 - Change Case matrix used in the development of this report

In all, over 100 reliability studies were performed with the previously mentioned 410+ contingencies. Appendix C lists a selected path flows from a subset of the cases developed. A summary of the performance of these cases is described below. To better communicate the results of these studies, the TWG created heat maps which present a weighted[19] graphical performance of a Change Case on a specific flow condition. In these heat maps, performance issues were accumulated for each powerflow zone, for example, the D2a-Null[20] case performance looks like:

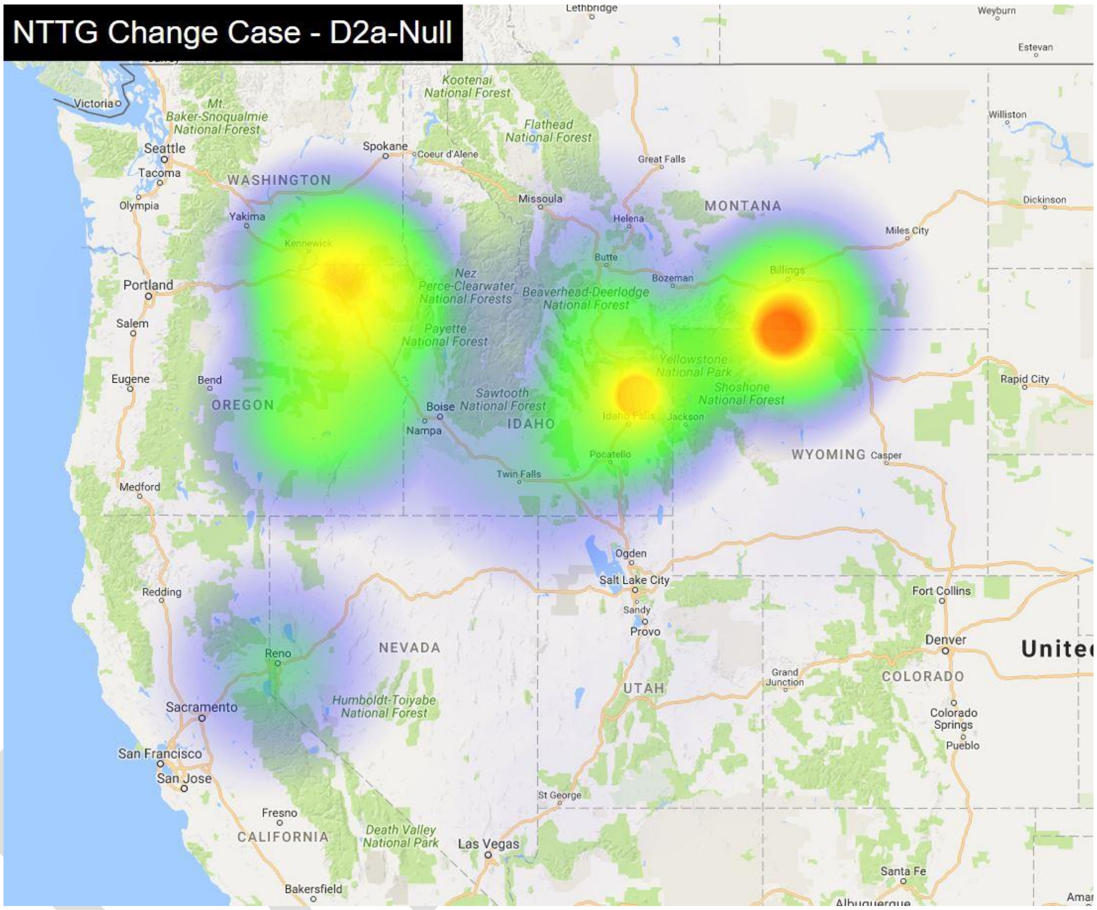


Figure 13 – Example Heat Map of the D2-Null Case

This map does not indicate where the contingency occurred but the general location where the performance (e.g., overloaded transmission line) issues occurred for the contingency which may be 300 or 400 miles away. In the above heat diagram the accumulation of overloads and

[19] High voltage conditions had a weighting of 1; Low voltage conditions had a weighting of 3; and overloads of branches had a weighting of 5. For example, a zone in which 10 contingencies caused an overload of one branch in that zone would receive a total weight of 50 (i.e., 10 x 5), which would then be translated into a color on the map. A blue color represents a weighted total of about 10, green is a count up to 30, yellow is a count up to 50 and red is for a weighted count exceeding about 70.

[20] This particular heatmap does not have any incremental Wyoming wind and with the existing wind modeled in Wyoming is operating at about a 50% capacity factor.

voltage issues are represented by the various colors. The map shows three general areas of reliability violations – NW Wyoming/SE Montana, southern Idaho and SE Washington/Central Oregon. These violations are occurring because the transmission systems are incapable of handling anticipated transfers across that area's transmission system. This particular heatmap using the existing Wyoming Wind resources dispatched at about 600 MW indicates that addition transmission enforcements are necessary to integrate the projected wind resources.

The same map for the D2-IRTP case looks like:

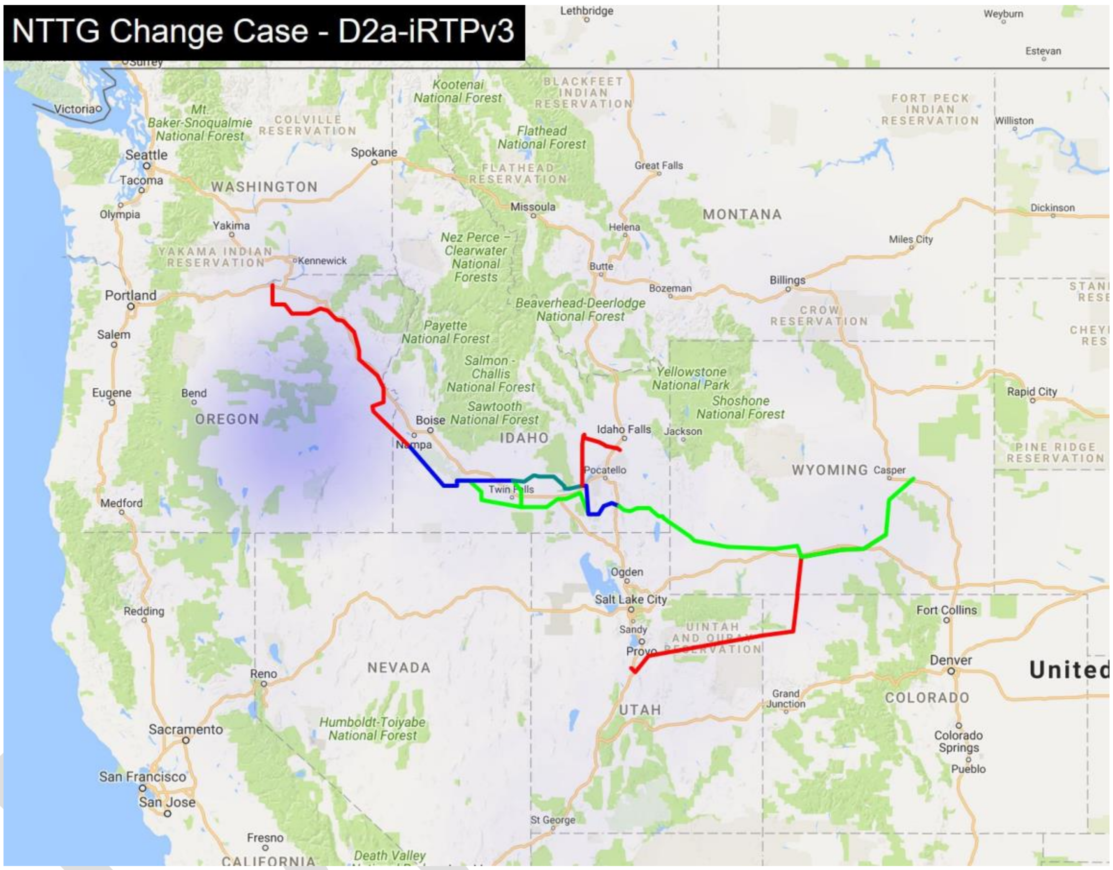
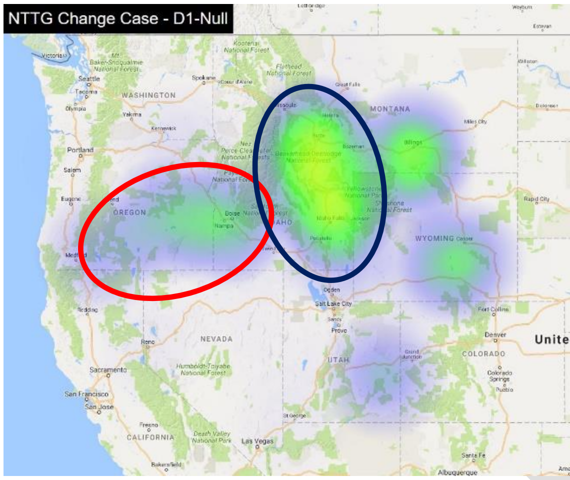


Figure 14 – Heat Map of the D2 Case with the IRTP facilities included

In this case, the map points to an overload in Oregon area on the Burns Series capacitor that is likely to be replaced prior to 2026. The rating of the bank will be re-evaluated to avoid it becoming a bottleneck to system performance. This map shows the dramatic improvement of the IRTP Change Case has when compared to the Null case.

A. Heavy Southern Idaho Import Case results

Similarly, comparing the Heavy Import Null Case (D1-Null) with a case where the B2H project (inserted as a red line in the right heat map) is added is shown below:



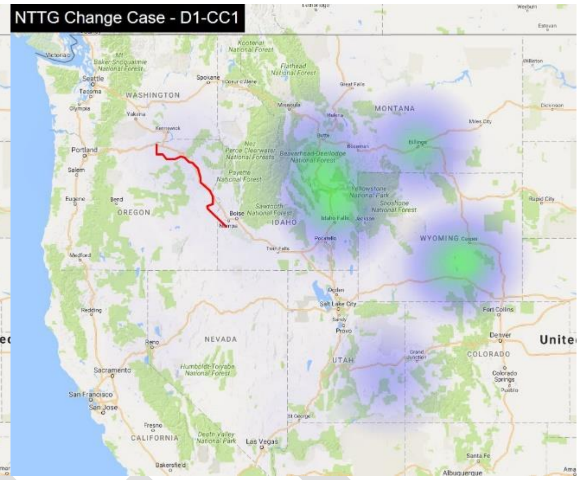


Figure 15 **Figure 16**

The stress across the Idaho-Northwest path, shown within the red oval, has been relieved when B2H is added, as well as, stress across the Montana-Idaho path (WECC Path 18), shown in the blue oval. The heat map in Figure 16 still has issues along the Continental Divide that demonstrates B2H does not resolve all the performance problems for the D1 case. Including the other non-committed projects (Gateway West and Gateway South transmission lines shown in the blue oval) with the B2H project, the violations in Figure 17 for the D1 flow condition are eliminated.

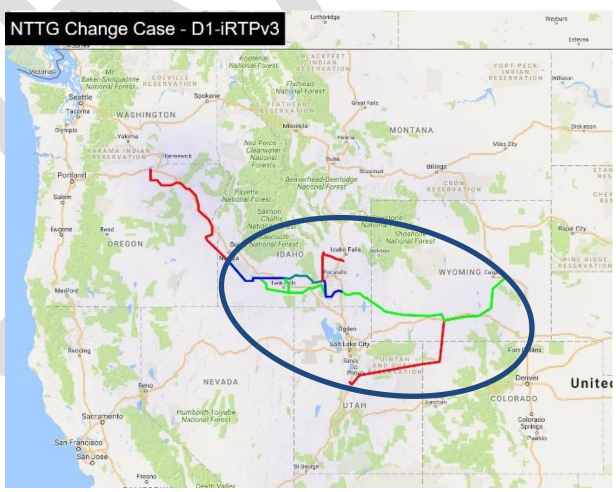
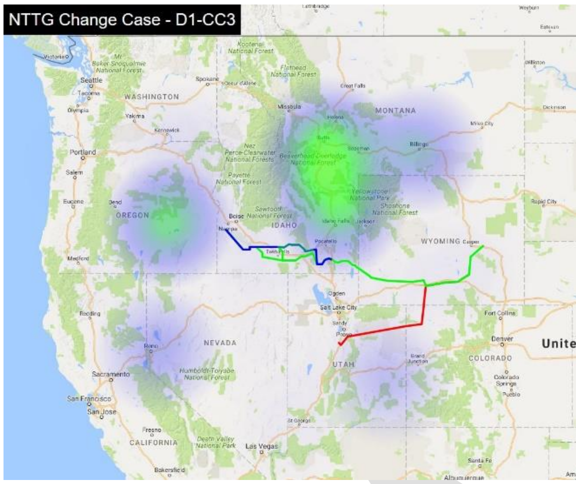


Figure 17

Change Case CC3, in the heat map Figure 18 below, tests to see if the Gateway West and/or Gateway South projects shown in the blue oval above can replace or be comparable to the B2H project. As can be seen below, a number of performance issues without the B2H project included in the D1-Null case have not been alleviated. The Figure 19 heat map shows that NTTG's prior Regional Transmission Plan (pRTP[21]) proposed non-committed transmission facilities do not alleviate the violations.



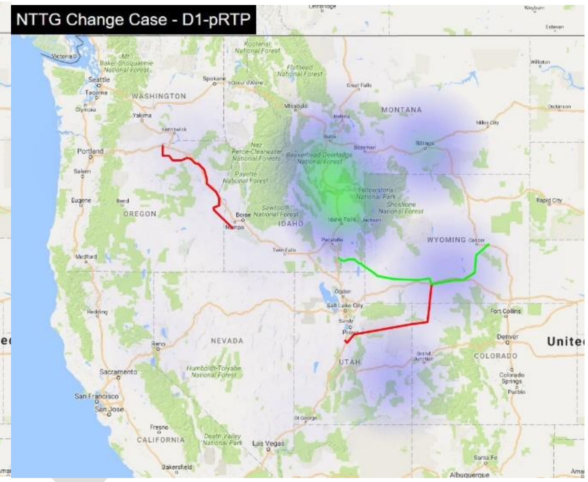
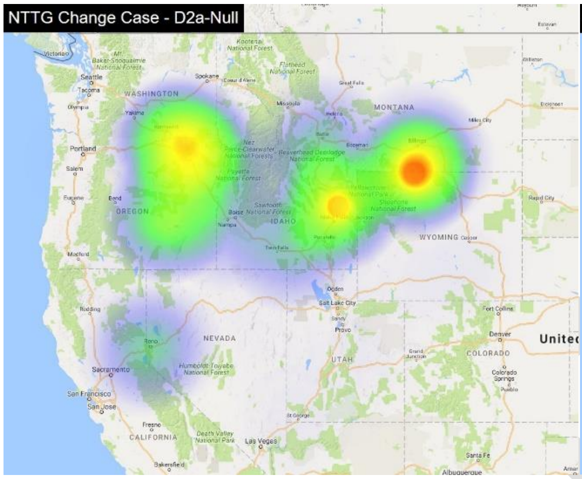


Figure 18 **Figure 19**

[21] The pRTP excludes the western portion of the Gateway west project west of the Populus substation in eastern Idaho.

B. Heavy Southern Idaho Export Case results

The D2-Null case is shown again in Figure 20 to compare the performance improvement of adding the B2H project. As can be seen in Figure 21, again the stress across the Idaho-Northwest cutplane is relieved, but significant issues remain east of Hemingway.



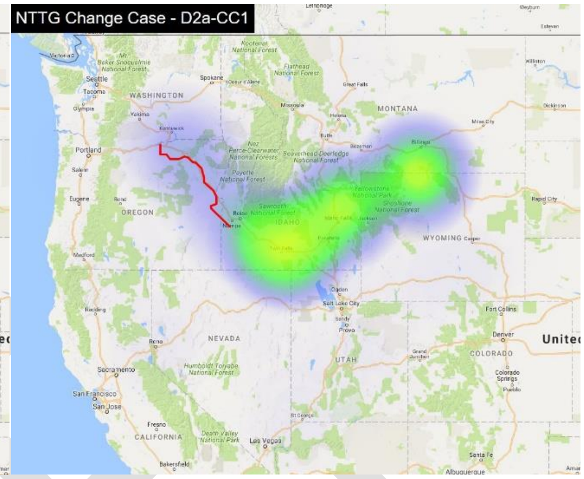


Figure 20 **Figure 21**

C. High Wyoming Wind Case results

As mentioned in the text following Figure 11, the Wyoming transmission system is incapable handling the existing wind resources without significant future reinforcements. The F-Null case results depicted in Figure 22[22] with the wind production at the 1300 MW level, indicate that its performance is worse than the heavy southern Idaho export case. When the IRTP facilities are added in Figure 23, the only remaining problems are with the rating of the Burns series capacitor bank. This bank is due for replacement since it has reached the end of its use full life. Its future rating has not been determined but the parties will consider these studies in establishing its new rating.

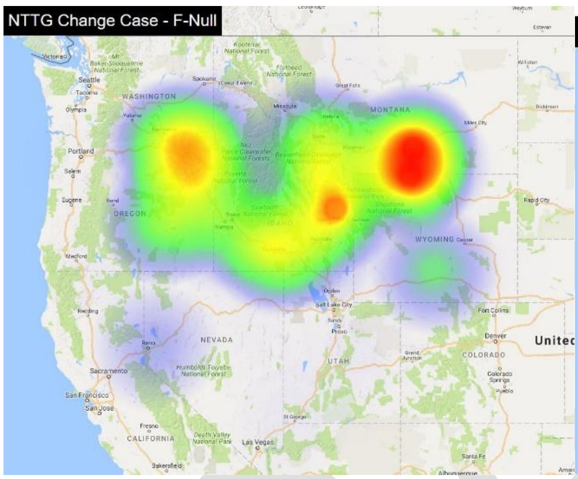


Figure 22[22]

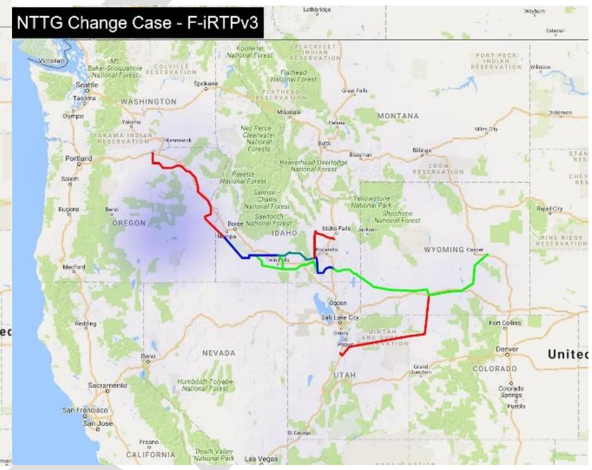


Figure 23

The prior Regional Transmission Plan, shown in Figure 24, does not perform as well as the IRTP, in fact it missed a significant issue related to the transfers across the eastern portion of southern Idaho.

[22] Heatmap without incremental wind in Wyoming and existing wind modeled at 1300 MW, see Figure 25 for Case Fq6 with 2175 MW of Wyoming wind modeled.

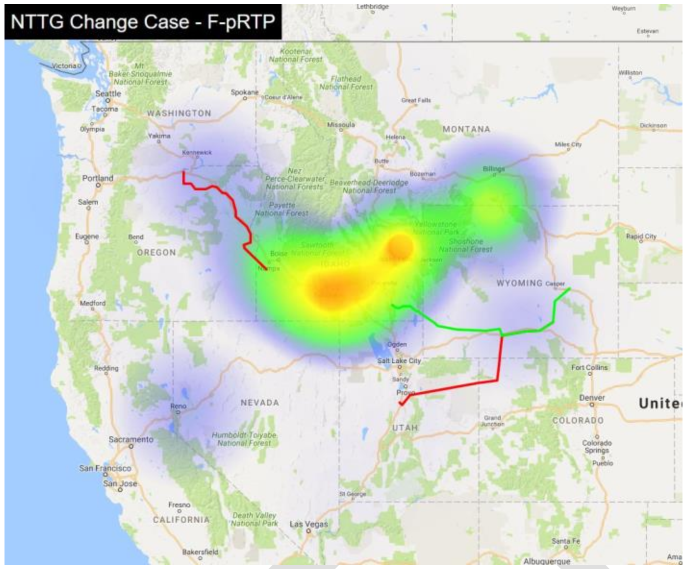


Figure 24

In Quarter 6, Case F was tested to see if CC1 through CC4 would support the increased level of Wyoming Wind, see Figure 25. The Null case on Case Fq6 was unable to be solved with wind above 1800 MW, even at that level, performance was unacceptable. This means that the existing transmission system is not sufficient to reliably serve the Transmission Provider's transmission needs and additional upgrades are needed to resolve these issues.

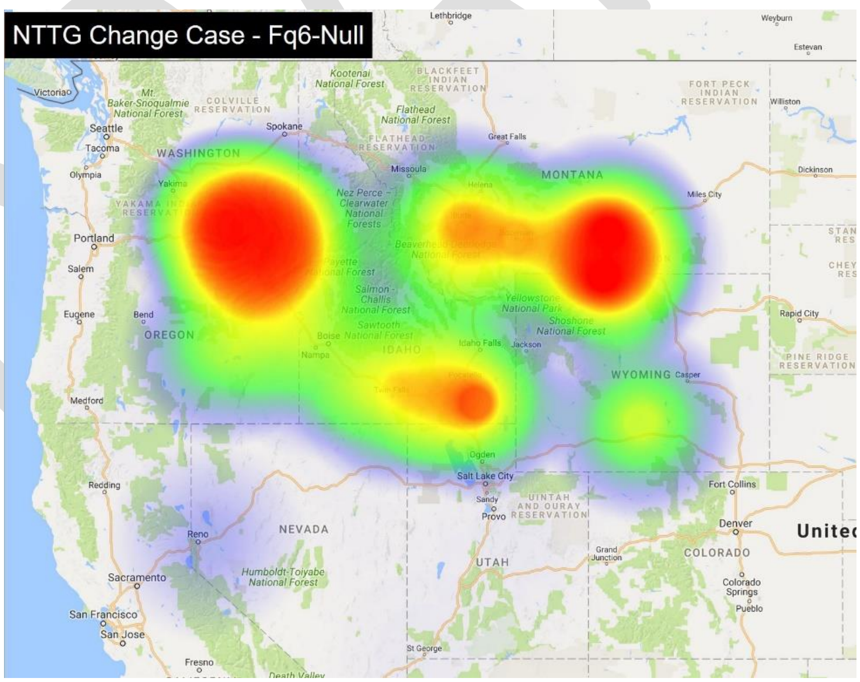
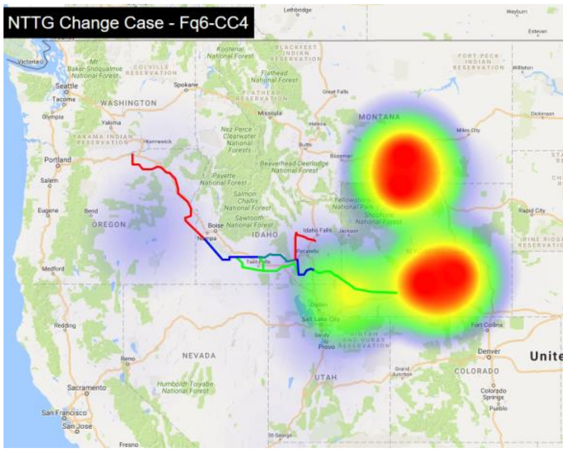


Figure 25

Testing CC4 required adding the Aeolus-Anticline 500 kV line to eliminate a number of contingencies that failed to solve in Wyoming



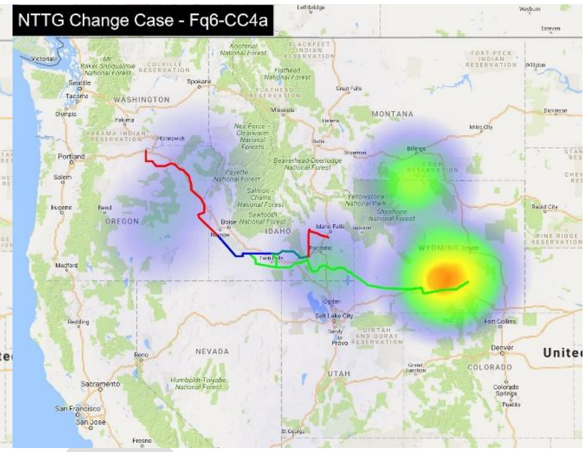


Figure 26 **Figure 27**

The main difference between CC4a and CC23 in Case Fq6 is the addition of Gateway South. As shown below in Figure 28, Case Fq6 modeled with the CC23 configuration and the Wyoming wind at 2175 MW performed well. The highlighted area in eastern Oregon is Burns Series capacitor rating issue already discussed and the region in southeastern Idaho is the result of high voltage following a line outage that can be easily mitigated by switching off a portion of a shunt capacitor bank post contingency.

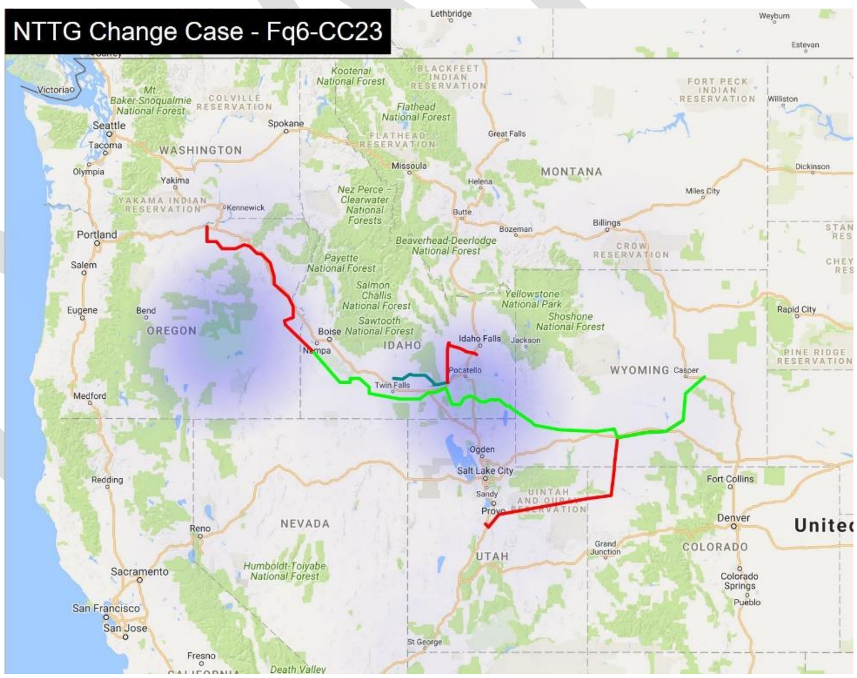


Figure 28

D. Interregional Transmission Projects

The Interregional Transmission Projects were analyzed to determine whether an ITP alone or in combination with the other ITPs and/or the non-committed projects could, from a regional perspective, satisfy NTTG's transmission needs on a regional or interregional basis more efficiently or cost effectively than through local planning processes. The ITPs were added to the Null cases without any additional resources to serve NTTG load beyond those resources identified in the Quarter 1 data submittals. The heavy southern Idaho export case results are shown graphically below in Figures 29 through 32.

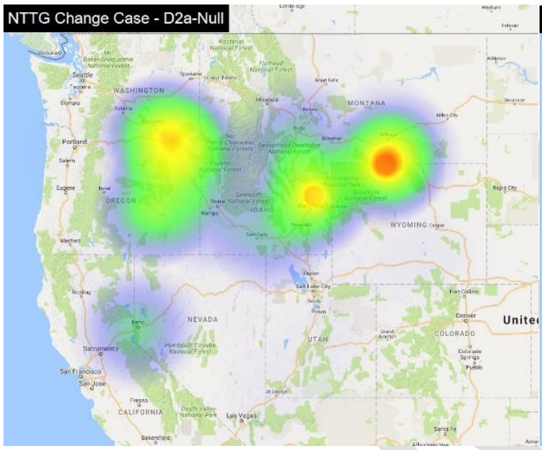


Figure 29

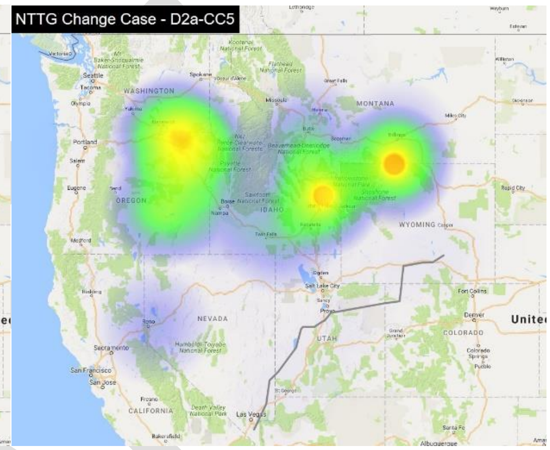


Figure 30

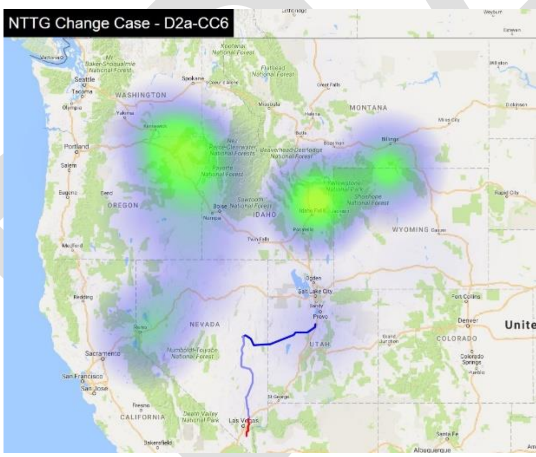


Figure 31

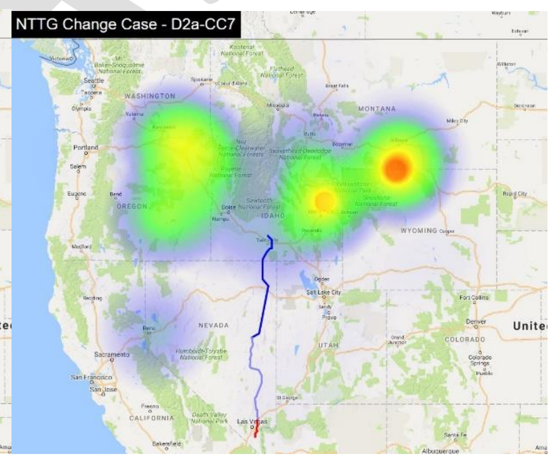
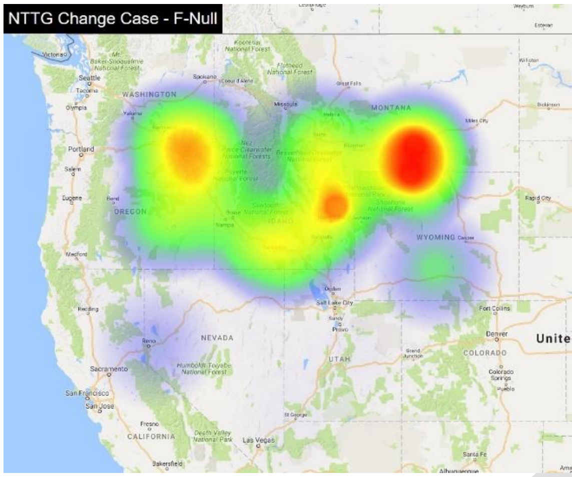


Figure 32

For the High Wyoming Wind case:



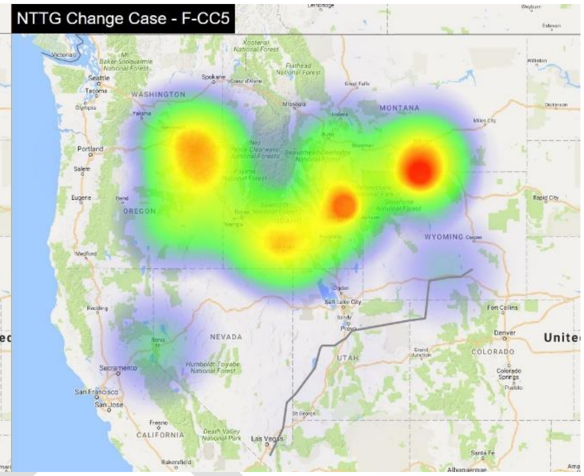
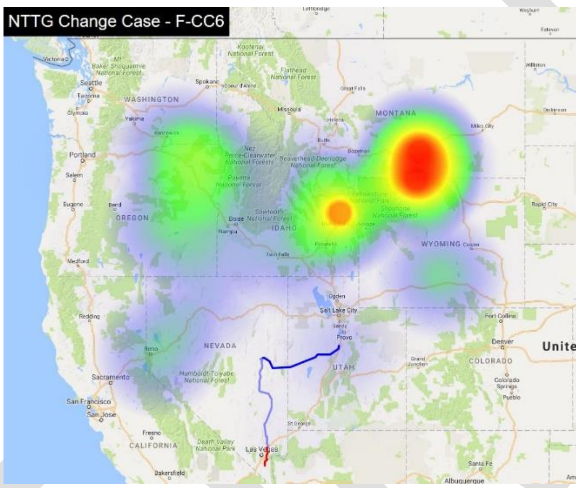


Figure 33 **Figure 34**



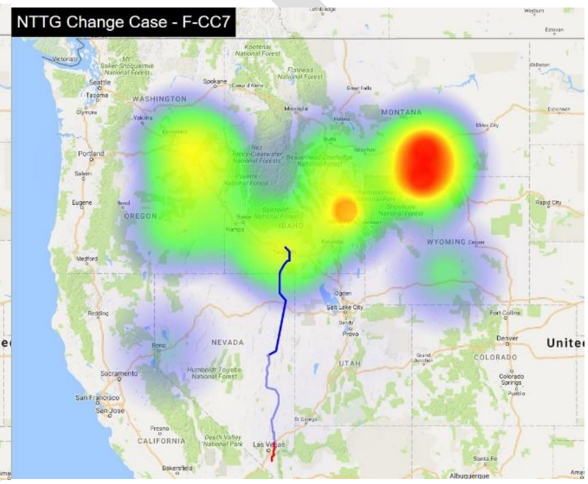


Figure 35 **Figure 36**

It does not appear that the ITPs provide the NTTG footprint with regional benefits by significantly reducing performance issues or displacing NTTG non-committed projects.

The IRTP was also analyzed to determine whether it is capable of supporting the interregional resource transfers proposed by the ITPs:

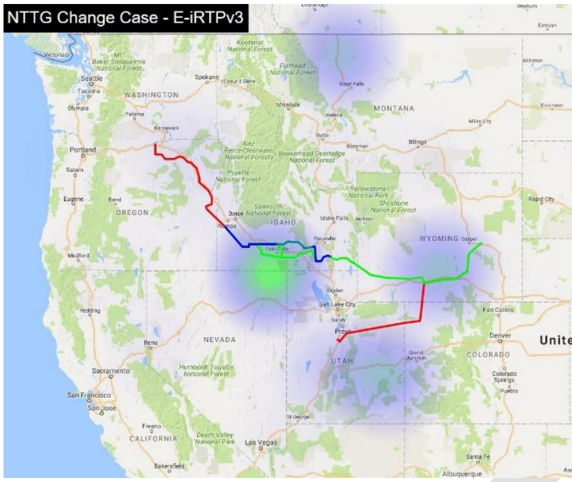


Figure 37

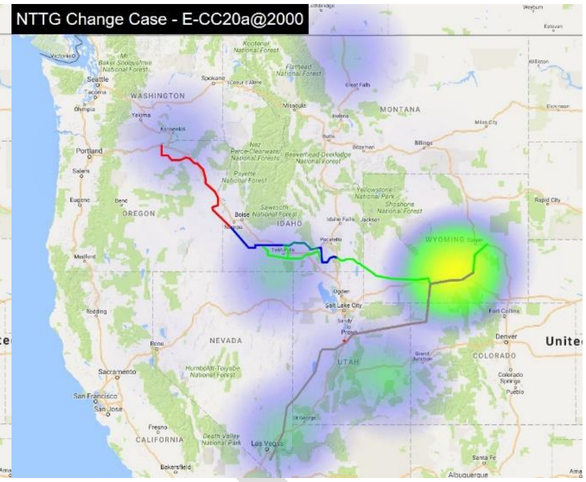


Figure 38

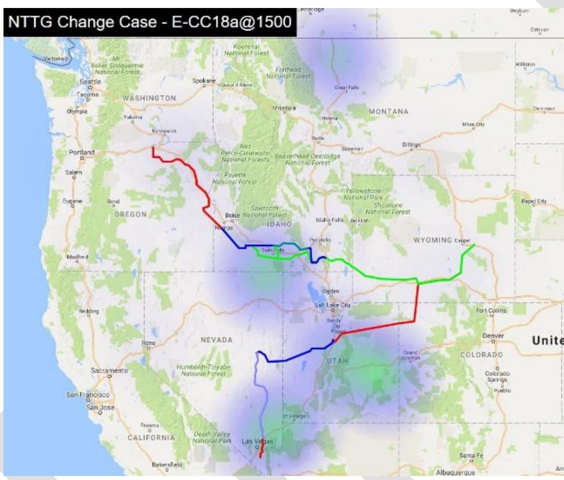


Figure 39

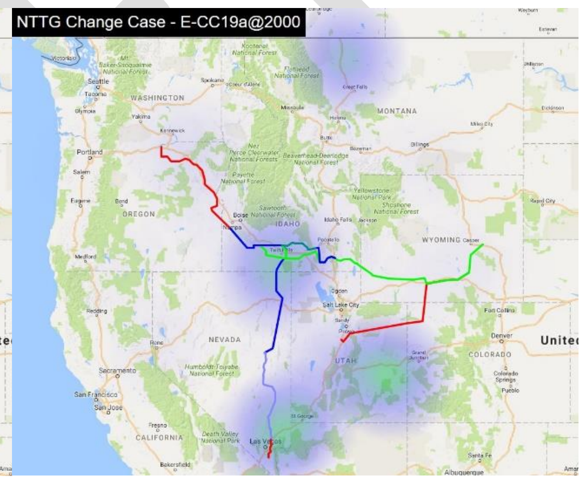


Figure 40

Each of the ITPs interfaces differently with the additional wind resources in Wyoming. In the TWE E-CC20a case (Figure 38), the case was run just tripping the wind resource and not tripping the balancing combustion turbine resources for DC line outages. In order to avoid performance issues, the entire 2,000 MW of resources would need to be tripped. Additionally, in these studies, the DC terminal was modeled just connecting to the existing 230 kV system, even when the Gateway West and South 500 kV projects were represented in the case. Adding a 500 kV interface to the DC terminal would likely eliminate the Wyoming performance issue. Combinations of the ITPs projects were also studied with resource additions up to 5,500 MW.

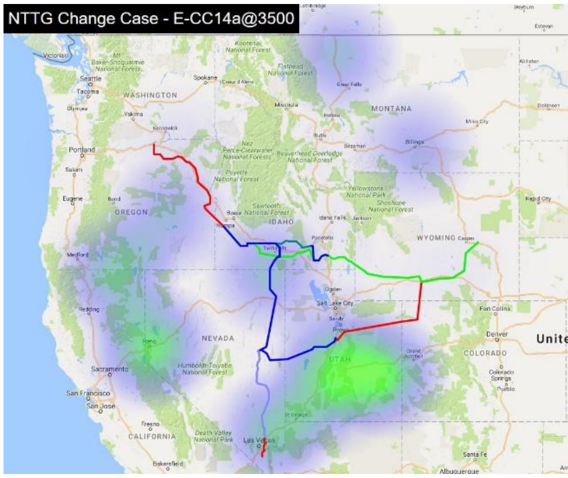


Figure 41

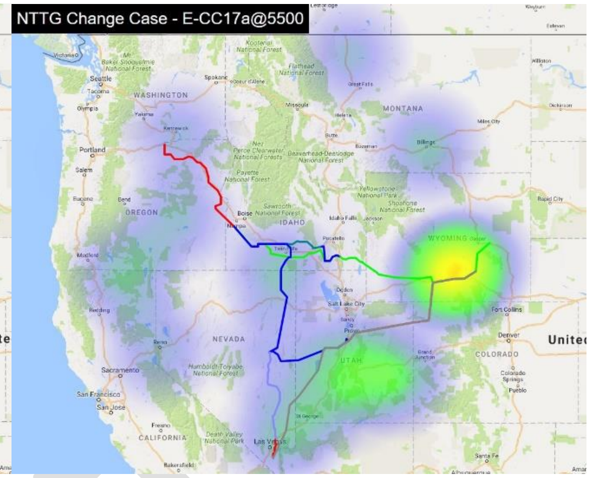


Figure 42

Again, Change Case E-CC17a in Figure 42 has the same issue as Change Case E-CC20a in Figure 38. Given the relatively long distances of the ITPs, the local integration performance issues in Wyoming are solvable.

VI. Impacts on Neighboring Regions

The TWG monitored the impacts of projects under consideration for the Draft Regional Transmission Plan on neighboring Planning Regions through each Change Case. TWG found that the IRTP or the alternative Change Case plans did not impact neighboring Planning Regions.

VII. Reliability Conclusions

Based on the above study results, the TWG concludes that Change Cases CC21, CC23, and the IRTP satisfy the NTTG reliability criteria. In Quarter 5, Change Case 23 and the wind resource additions were tested by TWG at various load and flow levels on the Heavy Summer, the Heavy Winter, High Tot2 and High Wyoming wind cases, the NTTG area is not reliably served in the year 2026 without including the following non-committed regional projects:

- Boardman to Longhorn (formerly Hemingway)
- The Energy Gateway projects including segments:
  - Windstar-Aeolus 230 kV
  - Aeolus-Clover 500 kV
  - Aeolus-Anticline 500 kV
  - Anticline-Populus 500 kV
  - Populus-Cedar Hill-Hemingway 500 kV
- Antelope Transmission Project including:
  - Antelope – Borah 345 kV
  - Antelope – Goshen 345 kV
  - Antelope 345/230 kV transformers and interconnection facilities

The ITPs were evaluated to determine whether one or more ITP would defer or replace NTTG's non-committed projects. It was determined that none of the ITPs solve NTTG's reliability performance issues and, as such, have not been included the NTTG fRTP.

VIII. Economic Evaluations

To determine whether the IRTP or a Change Case transmission plan was more cost effective, the calculation and evaluation of certain economic metrics in the IRTP and in the various Change Cases were required. The transmission plan, incorporating some or all of the non-committed projects and Alternative Projects as may be necessary to satisfy NTTG's reliability performance criteria, that is determined as the more "efficient or cost effective" will comprise in the Draft Regional Transmission Plan. From the Biennial Study Plan, the economic metrics to be evaluated are the capital related costs, power flow losses, and reserves. The economic evaluations for the IRTP and the Change Cases are discussed below.

A. Capital Related Cost Metric

Development of the capital related cost metric required three steps to complete. The first step was to validate the Project Sponsor's Q1 submitted project capital cost. The validation was completed by comparing the Project Sponsor's submitted capital cost to the output results of the TEPPC Transmission Capital Cost Calculator, an MS Excel spreadsheet. If the submitted capital costs varied from the Calculator output by 20% or more, the TWG worked with the Project Sponsor and seek to resolve the cost difference. If the difference could not be resolved, the TWG determined the appropriate cost to apply in the study process. If the Project Sponsor did not submit project capital cost, then the TWG developed the project's capital cost using the TEPPC Transmission Capital Cost Calculator output. The analysis results from this first step are shown in Table 10.

Project Capital Cost Estimates

Validate Cost Estimate

	Acceptable	iRTP non-Committed			
Million 2016$	Range	B2H	EG	CC21	CC23
	80%	$911	$3,922	$3,564	$3,368
TEPPC Calculator Estimate	100%	$1,139	$4,903	$4,455	$4,210
	120%	$1,367	$5,884	$5,346	$5,052
Sponsor Capital Cost Estimate	2016$	$1,221	Not Provided	Not Provided	Not Provided
Validation		Sponsor	TEPPC Calc	TEPPC Calc	TEPPC Calc
Capital Cost Estimate Used	2016$	$1,221	$4,903	$4,455	$4,210

Table 10 Validated Cost Estimates

The second step to develop the capital related cost metric used the results of the first step to estimate the annual capital related costs. The annual capital related cost was computed as the sum of annual return, depreciation, taxes other than income, operation and maintenance expense, and income taxes. A future escalation rate of 2% was applied to future construction costs and a weighted cost of capital of 8.5% was estimated for all projects assuming 50% debt (@6%) and 50% equity (@11%) structure. The depreciation period was assumed to be 40 years for all projects. Next, the total present value of annual capital related costs was computed using a discount rate of 8.5% for all projects. Table 11 provides the result of this analysis.

Annual Capital Related Costs

Millions of Dollars

Expressed in 2016$	B2H	EGW	iRTP	CC21	CC23
Capital Cost Estimate Used	$1,221	$4,903	$6,124	$5,675	$5,431
NPV Capital Related Costs	$2,028	$8,145	$10,173	$9,428	$9,022
Difference from iRTP				-7.3%	-12.2%

Table 11 Estimated Capital Related Cost Estimates

The third step was to levelize[23] the net present value annual capital related costs for the IRTP and the Change Case plans. Table 12 provides that levelized capital related cost for the IRTP and the Change Case plans.

Levelized Capital Related Costs

Millions of Dollars

Expressed in 2016$

Levelized Capital Related Cost	$179	$720	$899	$833	$797
Difference from iRTP				($66)	($102)

Table 12 Levelized Capital Related Costs

B. Energy Loss Metric

1. Background and Method

The Energy Loss Metric is used to capture the change in energy generated, based on system topology, to serve a given amount of load. Using power flow software, the NTTG footprint losses were evaluated. A reduction in losses for a Change Case represents a benefit because less energy is required to serve the same load.

Six of the seven NTTG Stressed Cases (excluding Case C) were analyzed. The losses for the six cases were then averaged to determine an average MW loss value. The average MW loss value was then annualized and multiplied by a 2026 nodal energy price extracted from the

[23] Using the same economic parameters described above.

WECC 2026 TEPPC production cost model to produce an annualized energy loss benefit in dollars.

Note that the TWG also evaluated the use of production cost analysis software to evaluate annual energy losses. The production cost method of calculating losses resulted in lower annual losses when compared to power flow software method described above. The Technical Workgroup will continue to review the differences between the two methods in the following Quarters.

2. Results

The Table 13 summarizes the energy loss benefit analysis for each of the affected NTTG balancing areas.

Balancing Area	IRTP	CC21	CC23	Ave MW
PacifiCorp	3,342,000	3,354,000	3,377,000	383.29
PGE	279,000	279,000	279,000	31.87
Northwestern	575,000	587,000	588,000	66.54
Idaho Power	1,245,000	1,313,000	1,308,000	147.11

Table 13: Average Energy Loss of Powerflow cases

Balancing Area	IRTP	CC21	CC23	Ave MW
PacifiCorp	1,816,000	1,818,000	1,817,000	207.4
PGE	605,000	606,000	606,000	69.1
Northwestern	74,000	74,000	74,000	8.4
Idaho Power	546,000	546,000	546,000	62.3

Table 14: Average Energy Loss from Production Cost
Model Summary and Conclusions for Loss Analysis

Table 13 above shows that the two change cases with fewer Gateway West transmission segments causes them to have equal to or higher losses. From a loss perspective, the IRTP case has less losses and as such is the more efficient case. Losses are higher in the two change cases case because the electrical flows in the IRTP case were redistributed to fewer lines as a result of eliminating some of the proposed IRTP transmission additions in the change cases. Table 14 shows the loss results from the Production Cost Model, although a similar result, the difference between the cases was much smaller.

Several factors may be leading to the different results; in the powerflow approach, the peak load cases were scaled to reflect a more stressed 1 in 5 or 1 in 10 condition of higher loads, whereas, the PCM database reflects a 1 in 2 condition; the flows in the hours selected in the powerflow approach may be of higher stress than the average stress of the PCM model, the area accounting in the models are not aligned, etc.

The Technical Workgroup will continue to investigate these results.

From Table 13, the loss change between the IRTP case and cases CC21/CC23 can be calculated and monetized into an annual benefit as shown in Tables 15 and 16 below:

Balancing Area	Annual Energy (MWh)	Locational Marginal Cost ($/MWh)	Annualized Benefit ($)
PacifiCorp	-12,322	$30.21	($372,286)
PGE	-15	$33.07	($482)
Northwestern	-12,060	$25.16	($303,401)
Idaho Power	-67,992	$31.76	($2,154,433)
		Total NTTG Benefit	($2,830,603)

Table 15 – Energy Loss Metric Annual NTTG Benefit for Change Case 21

Balancing Area	Annual Energy (MWh)	Locational Marginal Cost ($/MWh)	Annualized Benefit ($)
PacifiCorp	-34,982	$30.21	($1,056,869)
PGE	0	$33.07	$0
Northwestern	-12,994	$25.16	($326,929)
Idaho Power	-63,145	$31.76	($2,005,579)
		Total NTTG Benefit	($3,389,357)

Table 16 – Energy Loss Metric Annual NTTG Benefit for Change Case 23

C. Reserve Metric

The reserve metric evaluates the opportunities for two or more parties to economically share a generation resource that would be enabled by transmission. The metric is a 10-year incremental look at the increased load and generation additions in the NTTG footprint and the incremental transmission additions that may be included in the dRTP.

In the study cycle, Gateway West, Gateway South, B2H, SWIP North and the Cross-Tie projects were included in the analysis. To evaluate these projects, the NTTG footprint was segmented into five zones and a sixth external zone was included to study the SWIP North and the Cross-Tie projects.

The metric assumes that the parties share a pro-rata portion of a simple cycle combustion turbine (priced at $800/kw). The calculation is spreadsheet based. The six zones could potentially create 180 different sharing combinations including 30 two-party, 54 three-party, 60 four-party, 30 five-party and 6 six-party combinations. However, the transmission additions above do not enable all combinations, when the un-committed transmission is overlaid on the six zones, those 180 combinations drop to 122 viable ones (22, 36, 40, 20, 4). The uncommitted transmission segments are shown in Figure 43 below.

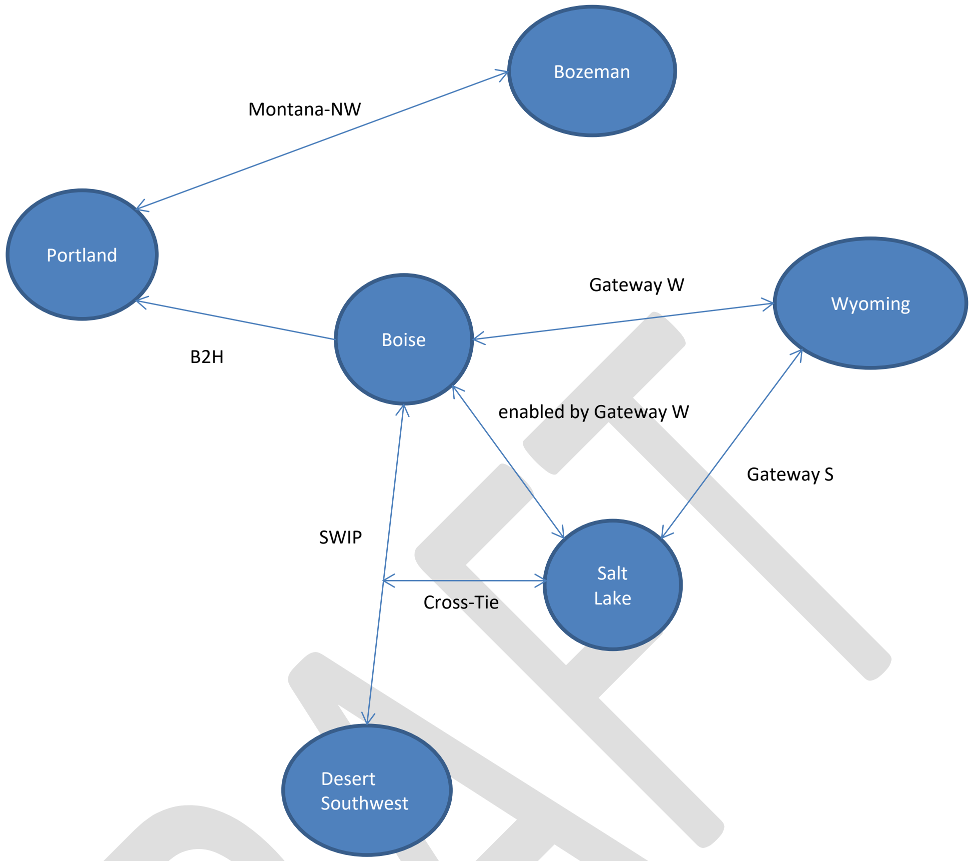


Figure 43

Of these 122 viable combinations, the analysis of the Annual Net Savings over the party's standalone alternative suggests that only 34 viable combinations are economic. The most economic combination for each zone are listed in Table 17 below:

Reserve location	Receiving parties	Net Annual Savings	Source Party	Receiving Party
Boise	Bozeman Portland Desert Southwest	$2,896,974	$3,340,315	($518,088) $34,198 $40,549
Portland	Bozeman	$891,190	$265,373	$625,818
Bozeman	Portland	$891,774	$626,227	$265,546
Wyoming	Bozeman	$487,683	$1,154,121	($666,438)
Desert Southwest	Boise, Bozeman, Portland, Salt Lake	$2,351,315	$2,480,116	$676,876 ($314,778) ($37,271) ($153,629)
Salt Lake	Desert Southwest	$756,086	$1,576,050	($819,964)

Table 17 – Distribution of savings sharing reserve capacity with the Desert Southwest via an ITP

The Table 17 assumes that the SWIP North and/or Cross-Tie projects are constructed to enable a reserve transaction with the Desert Southwest. Without the ITP projects, the number of viable combinations drop to seven, the top five are listed in Table 18:

Reserve location	Receiving parties	Net Annual Savings	Source Party	Receiving Party
Boise	Bozeman Portland	$946,473	$2,039,780	($946,120) ($147,187)
Portland	Bozeman	$891,190	$265,373	$625,818
Bozeman	Portland	$891,774	$626,227	$265,546
Wyoming	Bozeman	$487,683	$1,154,121	($666,438)
Salt Lake	Bozeman	$483,710	$1,302,563	($818,853)

Table 18 – Distribution of savings sharing reserve capacity within the NTTG footprint

It should be noted that this metric includes generation capital costs in its evaluation and, as such, may only be appropriate for cost allocation purposes and should not be a driving factor in the selection of a dRTP. Whether these cost savings warrant jointly sharing the costs of reserve capacity is up to the parties to decide. The sharing of the estimated annual net savings between the parties is expected to be difficult as typically the receiving zone is exposed to transmission costs to enjoy the reserve benefit and the source zone does not. The source zone generally enjoys the greater positive benefit.

For the NTTG metric analysis, the IRTP and the two alternative Change Cases each support the viable economic combinations. Since these change cases could contain the same benefit value, the Change in Reserve metric does not factor into the dRTP selection decision.

D. Metric Analysis Conclusion – Incremental Cost Comparison

The sum of the annual capital related cost metric, loss metric (monetized) and reserve metric (monetized) calculated an incremental cost for the IRTP and the Change Case plans (see Table 19 and 20). The set of projects (either the IRTP or a Change Case plan) with the lowest incremental cost, after adjustment by the plans effects on neighboring regions will then be incorporated within the dRTP. Note that the incremental cost is computed as the levelized annual capital related cost minus NTTG loss benefit minus monetized reserve benefit.

Change Case Metric Difference from IRTP

	Negative is a Benefit	
Metric	CC21 - IRTP	CC23 - IRTP
Levelized Cap. Related Cost	($65.81)	($101.70)
NTTG Losses - Monetized	$2.83	$3.39
NTTG Reserve - Monetized	$0.00	$0.00
Total Difference	($62.98)	($98.31)

Table 19 Change Case Metric Estimate Difference from IRTP

Incremental Cost
2016 $

Case	Difference from IRTP	Incremental Cost
IRTP		$899.12
CC21	($62.98)	$836.13
CC23	($98.31)	$800.81

Table 20 Incremental Cost Estimates

IX. Final Regional Transmission Plan

Based on the reliability and economic conclusions discussed above, the more efficient or cost effective plan, based on the studies in this report, is Change Case 23 which is a staged variant of the IRTP. For the transfers submitted in Quarter 1 and Quarter 5, the facility segments shown in Figure 44 were not necessary for the transfers studied in the change cases. These segments would likely be necessary at higher transfer levels.

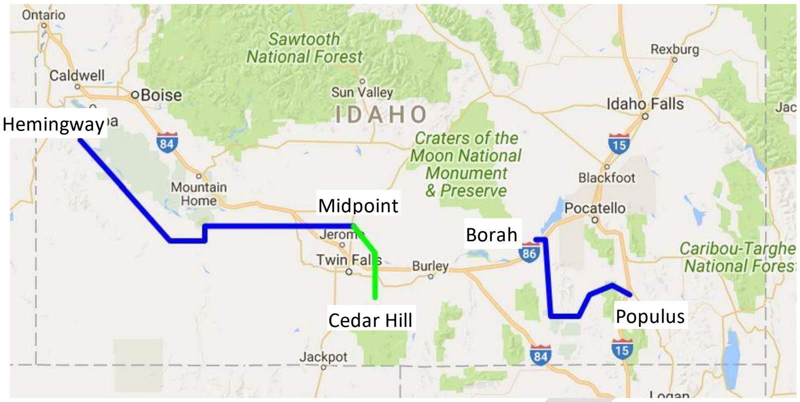


Figure 44 - IRTP segments not included in fRTP

NTTG's fRTP is shown in Figure 45 was selected after a rigorous technical Change Case reliability analysis of NTTG TP's rollup of their local area plans, assumption and non-committed regional transmission projects augmented with stakeholder interregional transmission projects. This technical analysis was followed by an economic metric analysis that selected NTTG's more efficient and cost effective Regional Transmission Plan

Figure 45 - fRTP Projects

X. Lessons learned in Q1 through Q4

A. Study Plan changes

Other than the changes made to the 2016-17 Regional Study Plan (see footnote 10) in Quarter 6 necessary to incorporate the analysis of the Quarter 5 data submittals, none were noted.

B. Data submittals in Q1 and Q5

During this study cycle, the data submittal deadline for Quarters 1 and 5 were moved from end of January to the end of March to align with other WECC data submittal deadlines. One outcome of that delay is in the second half of the study cycle the timeline for the completion of the draft final Regional Transmission Plan did not change from the end of Quarter 6, so the result is all reliability and cost allocation analysis must be completed in a very short period. For this study cycle, there was not a requirement to perform cost allocation analysis, but if there was, this report would not likely have been completed on time. A review of the Quarters 6 and 7 timelines should be undertaken to allow more analysis time following the Quarter 5 data submittals.

XI. Robustness sensitivity studies - Q5, Q6

No robustness sensitivity studies were performed in Quarter 5 and due to the compress timeline following the Quarter 5 data submittal none were performed in Quarter 6.

XII. Public Policy Consideration - Q5, Q6

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. The results of that Public Policy Consideration study have been included in Appendix D of this report.

XIII. Cost Allocation Evaluation - Q5, Q6

No projects qualified for Cost Allocation, so no evaluation was performed.

XIV. Loss Analysis using PCM vs Powerflow

Consistent with the NTTG compliance filing under FERC Order 1000, a commitment was made to explore using the production cost model (PCM) as extremely beneficial for technical analysis, including in the determination of energy losses. In addition to reduction in capital costs, NTTG uses reduction in reserves and energy losses as measures to evaluate benefits. Both PCM and Power flow software were used to compare system loss calculation.

- Power flow losses are estimated from the discrepancy between power produced and power delivered. The total energy losses for the year are calculated by multiplying the one hour losses X 8760 X Load Factor, where the Load Factor = Average load in a specified time period / peak load during that time period.
- GridView, a PCM used by NTTG, calculates area or regional losses using the following equation: (Generation + Import) – (Export – Load) = Losses, where import/export is calculated by inter-tie flow. Losses are calculated hourly and summed for the year.

GridView is using incremental losses to calculate the loss impacts on generation cost. The loss factor is the function of generation dispatch and loads. The generation dispatch will affect system total losses and individual area losses. Change in transmission topology (for example, the building of a new line) will impact the loss matrix, and will therefor impact the loss factor and area losses. HVDC losses are modeled as a quadratic function with the parameter of loss factor at full loading. The HVDC losses are subtracted from sending end flow to calculate the receiving end flow.

Figure 46 shows the variation in the calculated NTTG losses using the GridView program. It shows that it would be difficult to select a small number of hours to export in order to estimate the annual losses using the powerflow tools.

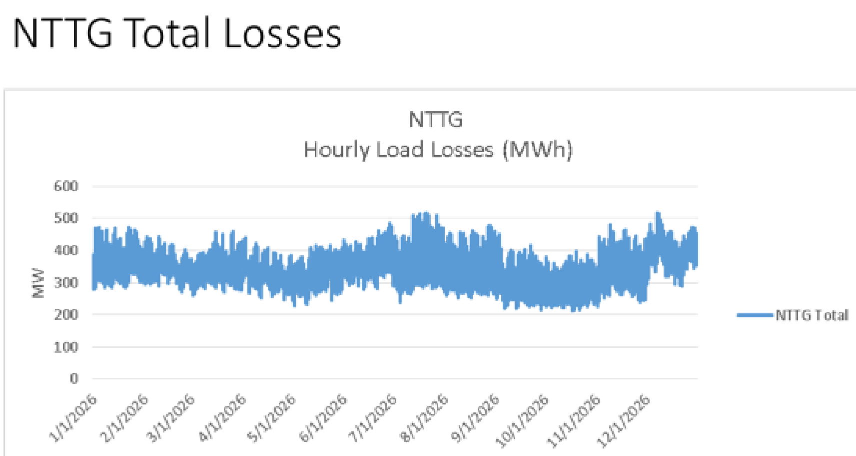


Figure 46 – Losses for the NTTG Footprint calculated by the PCM software

An effort was made to synchronize the topology in both PCM and power flow case leading to consistent power flow on lines and interfaces. However, Path C flows were higher in the power flow case, causing some discrepancies. The Table 20 below shows the area losses comparing the modified power flow case with the PCM.

Losses (7/30/26 11 am)	PF Case (MW)	PCM (MW)	Diff (PF - PCM) (MW)
IPC	52.6	67.9	-15.2
NWMT	27.1	9.2	17.9
PAC	267.4	225.9	41.5
PGE	36.8	75.3	-38.5
NTTG	383.9	378.3	5.6

Table 20 – Loss comparison between the PCM and Power Flow models

While there are some notable differences, it is more likely the PCM would result in a more accurately and repeatable estimate of the change in losses between cases than the previously used power flow estimation method.

NTTG requires calculating energy losses to determine savings when evaluating project cost benefits. Using the PCM approach with distributed bus election allows for more accuracy as the calculation is done hourly for the specified time period. The power flow methodology uses a single hour calculation adjusted by using average flows for remaining hours divided by a one-hour peak. The NTTG footprint is geographically diverse and with non-simultaneous winter and summer peaks; choosing a single hour to represent all has proven to produce higher loss calculation results than the calculation by the PCM. TWG recommends that the PCM method be considered in future planning cycles.

Appendix A

Public Policy Requirements

This attachment includes all Public Policy Requirements information that was available at the time the revised NTTG Biennial Study Plan was developed:

NTTG Member Utility	State	Applicable Entities	Applicable Energy	RPS % requirements	Energy Preference / Credits	In-state /delivery restrictions	Cost Cap
IPC	**Idaho**	No RPS Requirement					
Northwestern	**Montana**	Utilities-IOUs; Retail supplier Applies to: NWE	Wind Solar electric Geothermal Biomass *Wood, treated (SB 325 2013)* Landfill gas Anaerobic dig. Hydro (existing 10 MW or less; 15 MW new after Apr. 2009; *expansion of existing dam capacity (SB 45 2013)* Fuel Cells (RE)	2008-09 5% 2010-14 10% 2015+ 15%		Utilities must purchase RECs & output of community projects 50 MW in 2010-14 and 75 MW in 2015+	Includes cost caps utilities must pay on RE
PacifiCorp	**California**	Utilities -- IOUs; POUs Electric service providers; Community choice aggregators	Solar electric; Wind; Geothermal; Biomass; Landfill gas; MSW; Anaerobic dig.; Small Hydro (30MW or less); Tidal, wave, ocean thermal; Fuel Cells-RE	2013-Dec 20% 2016-Dec 25% 2020-Dec 33% 2030-Dec 50% SBX1-2 approved Apr. 2011 In April 2015, Governor Brown issued an executive order to establish a mid-	Product Category % Allocation: Contracts executed after June 2010 and in 3rd compliance period (2017 forward): Category (1):75% interconnected to grid within, scheduled for direct delivery into or dynamically transferred to CA Category (2): 0-25% firmed and shaped, scheduled into CA BA Category (3): 0-10% other/unbundled RECs		

NTTG Member Utility	State	Applicable Entities	Applicable Energy	RPS % requirements	Energy Preference / Credits	In-state /delivery restrictions	Cost Cap
				term reduction target for California of 40 percent below 1990 levels by 2030. CARB has subsequently been directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously-established 2050 target.			
	Oregon	<u>Large Utilities</u> -- selling more than 3% of retail electricity in OR Applies to: PGE, PacifiCorp, and Eugene Water & Electric Board	"Qualifying electricity" Electricity generated by facility operational on or after Jan. 1, 1995, except if: Non-hydro facility before 1995 upgraded, or Hydro facility upgraded on or after 1995 "Renewable energy" a) Wind; b) Solar PV or thermal; c) Wave, tidal, ocean energy; d) Geothermal e) Biomass (specified types)	5% by 2011 15% by 2015 20% by 2020 25% by 2025 50% by 2040 On March 8, 2016, Governor Kate Brown signed Senate Bill 1547-B (SB 1547-B), the Clean Electricity and Coal Transition			If costs to consumer increase more than 4%, utilities do not have to comply with RPS

NTTG Member Utility	State	Applicable Entities	Applicable Energy	RPS % requirements	Energy Preference / Credits	In-state /delivery restrictions	Cost Cap
			Hydrogen-RE Resource must be operational on or after 1995	Plan, into law. Senate Bill 1547-B extends and expands the Oregon RPS requirement to 50 percent of electricity from renewable resources by 2040 and requires that coal-fired resources are eliminated from Oregon's allocation of electricity by January 1, 2030. The increase in the RPS requirements under SB 1547-B is staged: 27% by 2025, 35% by 2030, 45% by 2035 and 50% by 2040.			
	Utah	Applicable to IOUs, Municipals, and Coops Applies to PacifiCorp (Rocky Mtn Power), UAMPS,	Wind, solar, biomass, geothermal, hydro under conditions, wave or tidal	Renewable Portfolio Goal: 20% by 2025 No interim requirements, first compliance year are 2025. Applies to "adjusted retailed sales" (=sales less power			

NTTG Member Utility	State	Applicable Entities	Applicable Energy	RPS % requirements	Energy Preference / Credits	In-state /delivery restrictions	Cost Cap
		UMPA, Deseret Power		from nuclear, effective" demand-side mgt, fossil fuel with CCS) Utilities must pursue renewables to the extent that it is "cost			
	Washington	Utilities serving more than 25,000 customers; Based on Form 861 filed with EIA Of WA's 62 utilities, applies to 17 utilities that make up about 84% of the WA load.	Renewable resource: a) Water b) Wind; c) Solar energy; d) Geothermal; e) Landfill gas; f) wave, ocean or tidal; g) gas from sewage; h) Biodiesel; i) Biomass (animal waste, organic fuels from wood, forest or field residue, and dedicated energy crops "Eligible renewable resource" – a) Located in Pacific Northwest; Electricity delivered into WA on real-time basis without shaping, storage, or integration services; b) Hydropower result of efficiency improvements completed after March 31, 1999 in PNW, or hydro generation in irrigation pipes	2012-15 3% 2016-19 9% 2020+ 15% Energy efficiency (EE) requirements: (1) By 2010 must identify achievable cost-effective potential thru 2019; (2) Meet biennial EE targets.	Distributed generation = 200% credit, if utility owns facility, contracted for DG and RECs, or contracted to purchase RECs.	"Eligible renewable resource" – a) Located in Pacific Northwest; Electricity delivered into WA on real-time basis without shaping, storage, or integration services;	
	Wyoming	No RPS Requirement					

NTTG Member Utility	State	Applicable Entities	Applicable Energy	RPS % requirements	Energy Preference / Credits	In-state /delivery restrictions	Cost Cap
PGE	**Oregon**	See Oregon above.					

Appendix B

Resource Additions and Removals to the TEPPC 2026 Common Case

Changes to the TEPPC Common Case include:

- Colstrip 1 & 2 (714 MW) was removed from all cases
- Southern Idaho Nuclear Resource (540 MW) was added to IRTP, CC2, CC4, CC21, CC22, and CC23 cases. Scheduled to displace coal resources in southern Utah
- 2000 MW of wind resources were added near the TransWest DC terminal in CC8, CC9, CC15, CC16, CC17 and CC20 cases. Scheduled to California to displace generation there.
- 1500 MW of wind resources were added at Aeolus, Point of Rocks, Difficulty, Freezeout, North Cody and Windstar in CC10, CC11, CC14, CC16, CC17 and CC18 cases. Scheduled to California to displace generation there.
- 2000 MW of Wind resources were added at Aeolus and Anticline in CC12, CC13, CC14, CC15, CC17 and CC19 cases. Scheduled to California to displace generation there.

Appendix C

Path Flows in a selected number of Power Flow Change Cases

WECC Path Number	Name	MW Forward Limit	MW Reverse Limit	Heavy Summer - Case A-iRPTv3	Heavy Winter - Case B-iRPTv3	High Path 8 - Case C-iRTPv3	High Idaho-NW Import - Case D1-iRPTv3	High Idaho-NW Export - Case D2-iRPTv3	High Wyoming Wind - Case F-iRPTv3	High Wyoming Wind - Case F-CC23
1	ALBERTA - BRITISH COLUMBIA	1000	-1200	-610	291	1365	-1486	-107	-115	-112
2	ALBERTA - SASKATCHEWAN	150	-150	0	0	0	0	0	0	0
3	NORTHWEST - CANADA	3000	-3150	1407	-1376	1196	1397	-178	-170	-174
4	WEST OF CASCADES - NORTH	10200	-10200	4183	5652	587	7106	2387	2349	2351
5	WEST OF CASCADES - SOUTH	7200	-7200	4520	5697	1892	4745	2436	2445	2436
6	WEST OF HATWAI	4277		32	-624	1995	447	1002	1044	1080
8	MONTANA - NORTHWEST	2200	-1350	6	133	2114	-319	1554	1609	1642
9	WEST OF BROADVIEW	2573		516	791	1239	111	1357	1436	1455
10	WEST OF COLSTRIP	2598		1282	1284	1123	776	1173	1175	1177
11	WEST OF CROSSOVER	2598		1199	1203	1601	691	1596	1637	1646
14	IDAHO - NORTHWEST	3400	-2250	-784	-112	8	-2244	3391	3491	3383
15	MIDWAY - LOS BANOS	4800	-2000	2915	2095	3488	1640	4104	4164	4226
16	IDAHO - SIERRA	500	-360	75	52	-146	-91	-114	-105	-100
17	BORAH WEST	3600		-207	139	442	-2088	2885	3363	3262
18	MONTANA - IDAHO	337	-256	-177	43	-99	-282	209	166	184
19	BRIDGER WEST	2400	-600	799	1587	759	-640	1482	1601	1617
20	PATH C	2250	-2250	-1812	-1445	-1048	-1858	410	585	554
25	PACIFICORP/PG&E 115 KV INTERCON.	100	-45	-33	-40	-27	-39	-33	-34	-34
26	NORTHERN - SOUTHERN CALIFORNIA	4000	-3000	-2382	-1644	-3939	-1321	-4224	-4290	-4357
27	IPP DC LINE	2400	-1400	553	652	286	193	419	419	419
28	INTERMOUNTAIN - MONA 345 KV	1400	-1200	305	414	-416	445	117	92	84
29	INTERMOUNTAIN - GONDER 230 KV	200		-44	6	-171	-165	52	78	85
30	TOT 1A	650		26	-133	-184	61	22	0	4
31	TOT 2A	690		-80	-54	31	-97	52	57	61
32	PAVANT, INTRMTN - GONDER 230 KV	440	-235	-64	-26	-313	-315	59	102	114
33	BONANZA WEST	785		55	341	427	-233	146	178	174
34	TOT 2B	780	-850	-855	-211	-440	-446	71	89	109
35	TOT 2C	600	-580	468	12	165	559	-288	-284	-303
36	TOT 3	1680		1198	1045	921	1787	1081	1133	1141
37	TOT 4A	810		-94	-26	135	136	46	85	76
38	TOT 4B	680		149	52	-95	-180	79	110	120
39	TOT 5	1680		609	655	431	702	440	422	421
40	TOT 7	890		304	223	266	524	225	230	232
41	SYLMAR - SCE	1600	-1600	-1173	-455	106	-587	-465	-455	-445
65	PACIFIC DC INTERTIE (PDCI)	3100	-3100	698	67	71	1120	1120	1120	1120
66	COI	4800	-3675	-143	-170	-1347	-1263	-1629	-1701	-1763
71	SOUTH OF ALLSTON	3980	-1115	496	222	-24	-616	-439	-465	-460
73	NORTH OF JOHN DAY	7700	-7700	2271	297	143	2330	-519	-691	-657
75	MIDPOINT - SUMMER LAKE	1500	-550	-581	50	-96	-986	1330	1421	1346
76	ALTURAS PROJECT	300	-300	113	114	-286	258	-87	-97	-106
77	CRYSTAL - ALLEN	950		245	250	243	249	249	250	246
80	MONTANA SOUTHEAST	600	-600	-230	43	-331	232	-411	-501	-519
83	MATL	325	-300	-69	-63	286	-60	-65	-58	-60
NR	West of McNary	4400		714	1046	433	-174	792	803	778
NR	West of Slatt	4760		383	430	261	106	389	389	382
NR	North of Hanford	4925		137	1409	1125	1267	1615	1693	1684
NR	West of John Day	4530		2122	2452	1320	2687	2263	2302	2293
NR	AEOLUS-CLOVER	1700		143	244	473	278	64	149	167
NR	MIDPOINT-ROBINSON									
NR	CLOVER-ROBINSON									
NR	ROBINSON-H ALLEN	2000		-562	-399	-679	-318	-46	-12	1

					TWE	TWE	TWE	Cross-Tie	Cross-Tie	Cross-Tie
WECC Path Number	Name	MW Forward Limit	MW Reverse Limit	High Tot2 - Case E-iRPTv3	High Tot2-Case E-CC8a	High Tot2-Case E-CC9a	High Tot2-Case E-CC20a	High Tot2-Case E-CC10a	High Tot2-Case E-CC11a	High Tot2-Case E-CC18a
1	ALBERTA - BRITISH COLUMBIA	1000	-1200	626	622	626	627	619	626	625
2	ALBERTA - SASKATCHEWAN	150	-150	0	0	0	0	0	0	0
3	NORTHWEST - CANADA	3000	-3150	-2576	-2568	-2575	-2577	-2567	-2572	-2571
4	WEST OF CASCADES - NORTH	10200	-10200	4165	4196	4178	4178	4242	4203	4202
5	WEST OF CASCADES - SOUTH	7200	-7200	4498	4527	4530	4527	4519	4517	4517
6	WEST OF HATWAI	4277		-479	-393	-487	-471	-114	-321	-336
8	MONTANA - NORTHWEST	2200	-1350	472	568	464	475	854	632	608
9	WEST OF BROADVIEW	2573		664	807	694	693	1078	851	819
10	WEST OF COLSTRIP	2598		1173	1182	1178	1176	1189	1179	1178
11	WEST OF CROSSOVER	2598		1001	1066	1017	1015	1183	1081	1067
14	IDAHO - NORTHWEST	3400	-2250	-1044	-984	-903	-921	-863	-832	-773
15	MIDWAY - LOS BANOS	4800	-2000	-1621	-1202	-1191	-1187	-1601	-1428	-1463
16	IDAHO - SIERRA	500	-360	453	405	404	415	442	435	435
17	BORAH WEST	3600		-310	-203	-141	-172	-139	-115	-56
18	MONTANA - IDAHO	337	-256	-180	-239	-219	-208	-240	-217	-209
19	BRIDGER WEST	2400	-600	1020	1835	1606	1046	2325	1870	1276
20	PATH C	2250	-2250	-1965	-1735	-1423	-1519	-2032	-1566	-1791
25	PACIFICORP/PG&E 115 KV INTERCON.	100	-45	5	7	7	7	11	9	9
26	NORTHERN - SOUTHERN CALIFORNIA	4000	-3000	1640	1110	1100	1095	1619	1442	1478
27	IPP DC LINE	2400	-1400	652	652	652	652	652	652	652
28	INTERMOUNTAIN - MONA 345 KV	1400	-1200	360	387	358	352	442	430	432
29	INTERMOUNTAIN - GONDER 230 KV	200		139	108	138	143	53	65	63
30	TOT 1A	650		-139	-229	-132	-123	-316	-150	-140
31	TOT 2A	690		109	111	115	116	121	119	111
32	PAVANT, INTRMTN - GONDER 230 KV	440	-235	146	114	156	166	19	39	35
33	BONANZA WEST	785		345	489	333	309	647	379	356
34	TOT 2B	780	-850	858	852	865	857	858	866	865
35	TOT 2C	600	-580	599	595	605	592	609	601	598
36	TOT 3	1680		1507	1692	1487	1485	1956	1533	1505
37	TOT 4A	810		154	279	135	167	456	199	207
38	TOT 4B	680		-96	-81	-81	-89	-117	-127	-139
39	TOT 5	1680		475	403	486	489	289	444	460
40	TOT 7	890		385	402	384	384	435	391	389
41	SYLMAR - SCE	1600	-1600	-845	-630	-625	-623	-631	-601	-607
65	PACIFIC DC INTERTIE (PDCI)	3100	-3100	403	403	403	403	403	403	403
66	COI	4800	-3675	4411	4571	4561	4558	4981	4801	4844
71	SOUTH OF ALLSTON	3980	-1115	634	611	600	600	694	665	663
73	NORTH OF JOHN DAY	7700	-7700	3326	3393	3319	3335	3663	3481	3472
75	MIDPOINT - SUMMER LAKE	1500	-550	153	212	244	221	313	304	322
76	ALTURAS PROJECT	300	-300	-156	-167	-172	-178	-175	-176	-186
77	CRYSTAL - ALLEN	950		247	247	243	248	246	245	247
80	MONTANA SOUTHEAST	600	-600	164	12	132	133	-280	-38	-3
83	MATL	325	-300	-68	-63	-68	-68	-60	-68	-67
NR	West of McNary	4400		994	1019	1028	1028	1109	1082	1101
NR	West of Slatt	4760		656	669	669	667	703	689	693
NR	North of Hanford	4925		78	69	85	81	-5	39	41
NR	West of John Day	4530		1708	1714	1728	1722	1644	1681	1679
NR	AEOLUS-CLOVER	1700		783		699	676		1351	1195
NR	MIDPOINT-ROBINSON									
NR	CLOVER-ROBINSON							872	1205	1194
NR	ROBINSON-H ALLEN	2000		165	65	100	118	860	1185	1171

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				SWIP N	SWIP N	SWIP N	Cross-Tie, SWIP N	TWE, SWIP N	TWE, Cross-Tie	TWE, Cross-Tie, SWIP N
WECC Path Number	Name	MW Forward Limit	MW Reverse Limit	High Tot2-Case E-CC12a	High Tot2-Case E-CC13a	High Tot2-Case E-CC19a	High Tot2-Case E-CC14a	High Tot2-Case E-CC15a	High Tot2-Case E-CC16a	High Tot2-Case E-CC17a
1	ALBERTA - BRITISH COLUMBIA	1000	-1200	621	618	626	626	619	618	627
2	ALBERTA - SASKATCHEWAN	150	-150	0	0	0	0	0	0	0
3	NORTHWEST - CANADA	3000	-3150	-2567	-2565	-2572	-2575	-2567	-2565	-2576
4	WEST OF CASCADES - NORTH	10200	-10200	4243	4216	4203	4255	4233	4220	4264
5	WEST OF CASCADES - SOUTH	7200	-7200	4499	4512	4512	4567	4551	4530	4589
6	WEST OF HATWAI	4277		-81	-267	-316	-157	-245	-274	-129
8	MONTANA - NORTHWEST	2200	-1350	892	680	627	779	695	672	799
9	WEST OF BROADVIEW	2573		1075	860	810	945	867	870	958
10	WEST OF COLSTRIP	2598		1183	1177	1174	1176	1176	1179	1175
11	WEST OF CROSSOVER	2598		1176	1082	1060	1117	1084	1089	1121
14	IDAHO - NORTHWEST	3400	-2250	-1053	-852	-827	-452	-689	-671	-273
15	MIDWAY - LOS BANOS	4800	-2000	-1316	-1306	-1292	-1581	-1315	-1041	-1525
16	IDAHO - SIERRA	500	-360	387	400	394	432	415	443	418
17	BORAH WEST	3600		1087	1450	1479	1603	1537	59	1646
18	MONTANA - IDAHO	337	-256	-199	-186	-179	-171	-178	-205	-162
19	BRIDGER WEST	2400	-600	3019	1589	1226	1464	1542	1919	1464
20	PATH C	2250	-2250	-1387	-1842	-1104	-1387	-1732	-1433	-1337
25	PACIFICORP/PG&E 115 KV INTERCON.	100	-45	9	9	9	13	11	11	15
26	NORTHERN - SOUTHERN CALIFORNIA	4000	-3000	1395	1384	1370	1300	870	945	728
27	IPP DC LINE	2400	-1400	652	652	652	652	652	652	652
28	INTERMOUNTAIN - MONA 345 KV	1400	-1200	426	427	414	447	424	422	422
29	INTERMOUNTAIN - GONDER 230 KV	200		69	68	81	49	71	73	73
30	TOT 1A	650		-297	-202	-107	-124	-187	-154	-119
31	TOT 2A	690		110	106	117	112	116	113	111
32	PAVANT, INTRMTN - GONDER 230 KV	440	-235	37	35	58	13	52	44	52
33	BONANZA WEST	785		606	448	273	321	416	392	306
34	TOT 2B	780	-850	872	868	871	853	863	873	851
35	TOT 2C	600	-580	600	610	590	595	590	593	599
36	TOT 3	1680		2039	1734	1602	1624	1720	1527	1611
37	TOT 4A	810		384	262	221	260	264	184	263
38	TOT 4B	680		-7	-57	-63	-110	-55	-117	-106
39	TOT 5	1680		282	392	449	419	401	451	424
40	TOT 7	890		442	410	398	404	409	391	402
41	SYLMAR - SCE	1600	-1600	-660	-657	-654	-503	-497	-480	-230
65	PACIFIC DC INTERTIE (PDCI)	3100	-3100	403	403	403	403	403	403	403
66	COI	4800	-3675	4852	4845	4835	5356	5027	4998	5580
71	SOUTH OF ALLSTON	3980	-1115	696	670	665	667	641	674	673
73	NORTH OF JOHN DAY	7700	-7700	3688	3527	3493	3656	3553	3527	3700
75	MIDPOINT - SUMMER LAKE	1500	-550	200	278	289	515	375	391	621
76	ALTURAS PROJECT	300	-300	-194	-201	-209	-210	-205	-184	-235
77	CRYSTAL - ALLEN	950		242	247	249	246	251	246	250
80	MONTANA SOUTHEAST	600	-600	-280	-47	7	-140	-55	-57	-154
83	MATL	325	-300	-63	-60	-68	-67	-61	-59	-69
NR	West of McNary	4400		1061	1090	1087	1225	1135	1142	1280
NR	West of Slatt	4760		689	692	689	737	707	708	755
NR	North of Hanford	4925		-10	30	36	1	29	29	-14
NR	West of John Day	4530		1635	1668	1674	1662	1683	1671	1659
NR	AEOLUS-CLOVER	1700				1078	1585		1358	1544
NR	MIDPOINT-ROBINSON			1471	1618	1626	1338	1525		1217
NR	CLOVER-ROBINSON						1265		1104	1266
NR	ROBINSON-H ALLEN	2000		1413	1567	1588	2520	1500	1092	2396

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Appendix D

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

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

Table of Contents

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

  - This assumption was driven by the fact that the RAS for the new Broadview wind was intended to mimic the action of the ATR. For 500 kV outages, the ATR decides how many Colstrip units need to be tripped to maintain stability. The assumption is that a new generator on the 500 kV system would have a RAS that acts similarly to the ATR because generation will still need to be tripped for 500 kV outages and that tripping should occur before the ATR acts. To coordinate with the ATR, the wind tripping needs to be much faster than the ATR to avoid multiple trips. This coordination has yet to be determined.

- 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 0%, 35% and 100% dispatch levels. The three levels of wind dispatch were chosen to reflect the inherent variability in a renewable resource. 0% and 100% were chosen to represent the extreme ends of the output spectrum. 35% was chosen as an acceptable mid-spectrum value as 35% is often used as the default output on a wind facility in WECC base cases.
- 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 power flow 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.

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.

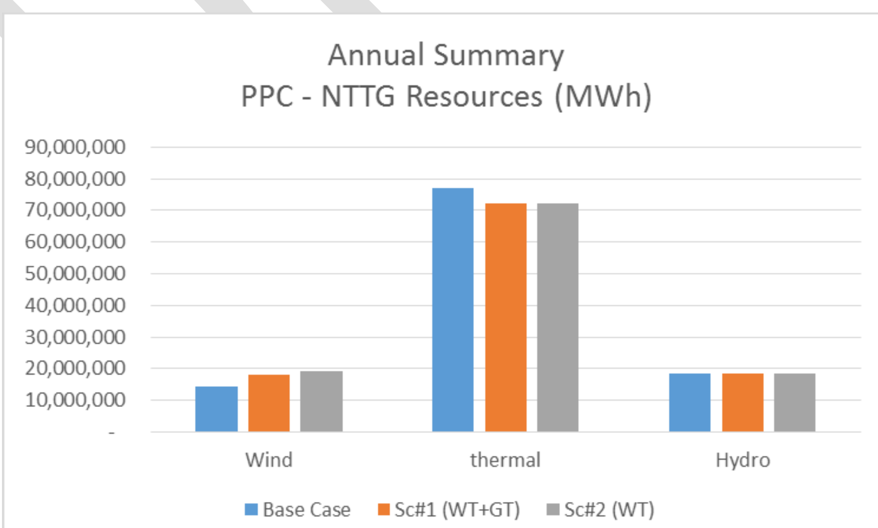

Figure 1: NTTG Generation - Annual Summary (MWh)

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.

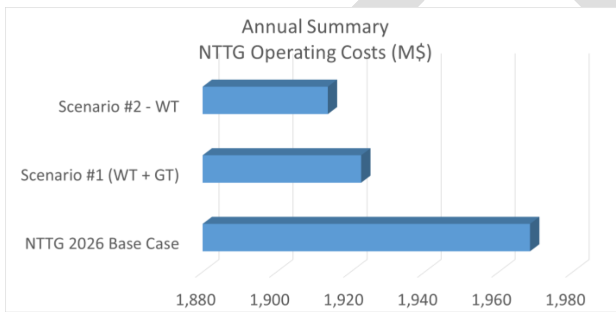

Figure 2: NTTG Annual Operating Costs (M$); based on the TEPPC 2026 CC cost assumptions

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%).

Revision History

Version	Date	Comment	Author
Version 1	5-30-17	Version for internal review prior to public review and comment	R Schellberg
Version 1.6	6-9-17	Version distributed for Planning Committee presentation	TWG
Version 1.7	6-27-17	Version for Stakeholder Meeting Presentation	A Wachsnicht and Sharon Helms
Version 2	6-30-17	Version posted for open stakeholder comment window	A Wachsnicht