NORTHERN TIER TRANSMISSION GROUP

2012-2013 Biennial Transmission Plan

Final Report

November 26, 2013

Approved by the NTTG Planning Committee: September 11, 2013
Approved by the NTTG Steering Committee: December 3, 2013

Chairman's Message

Dear Stakeholders:

We're pleased to present our third biennial regional transmission plan for the Northern Tier Transmission Group.

Much dedicated work went into this report, and it's my pleasure to recognize the efforts of all who contributed. In particular, I'd like to acknowledge the Northern Tier transmission-provider engineers and Comprehensive Power Solutions staff for soliciting and collecting the data, running the analyses, listening to and incorporating feedback, and preparing the studies. We appreciate their efforts.

We'd also like to thank you, our stakeholders, for your continued interest and participation in NTTG public processes. Your involvement improved this plan.

As with the 2011-2012 report, the Planning Committee approached the planning process by generating the study cases though production cost simulation. Planners identified the hours of significance and exported the production cost data to the power-flow simulation tool to test transmission system reliability.

If you are familiar with the prior biennium's report, you may notice this report's reduced size. Three reasons accounted for the slimming down. One, project proposers submitted fewer transmission projects and associated generating plants. Two, we saw reduced interest in building multiple scenarios – perhaps as a result of an industry shift away from Montana and Wyoming as potential wind-power sites. And three was the deferral and/or cancelation of proposed regional transmission projects considered in our prior biennial plan. For that reason, for example, we only analyzed the MSTI transmission project for the economic study. And while we studied the 500-kV Cascade Crossing transmission project, the developer canceled the project by the time the study was completed.

Overall, transmission providers forecasted greatly reduced loads and generation this biennium compared with the prior two-year period.

Nevertheless, we did conduct a Montana wind study and a 3,000-MW scenario for Wyoming.

We'd enjoy hearing your comments or suggestions. Our contact information is on the back page.

Thanks again for your interest, not only in this report, but in the larger mission of energy system reliability. Through your participation, you help ensure a more reliable transmission system for the more than 3 million people in the NTTG subregion who depend on us for safe, dependable, least-cost electricity.

Please stay involved as we begin work on the 2014-2015 planning process.

Sincerely,

Dave Angell, 2012 Chair

John Leland, 2013 Chair

NTTG Planning Committee

Disclaimer

This report was prepared by the members of the Northern Tier Transmission Group (Northern Tier) and other stakeholders participating in the effort to provide coordinated, efficient and effective planning for expansion of transmission within the Northern Tier footprint. While Northern Tier cannot assure the plan will be implemented as designed, it represents the best information available during the current planning cycle. Changing needs or new information will be accommodated through appropriate data submittals during the next planning cycle.

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Approved by the NTTG Planning Committee: September 11, 2013
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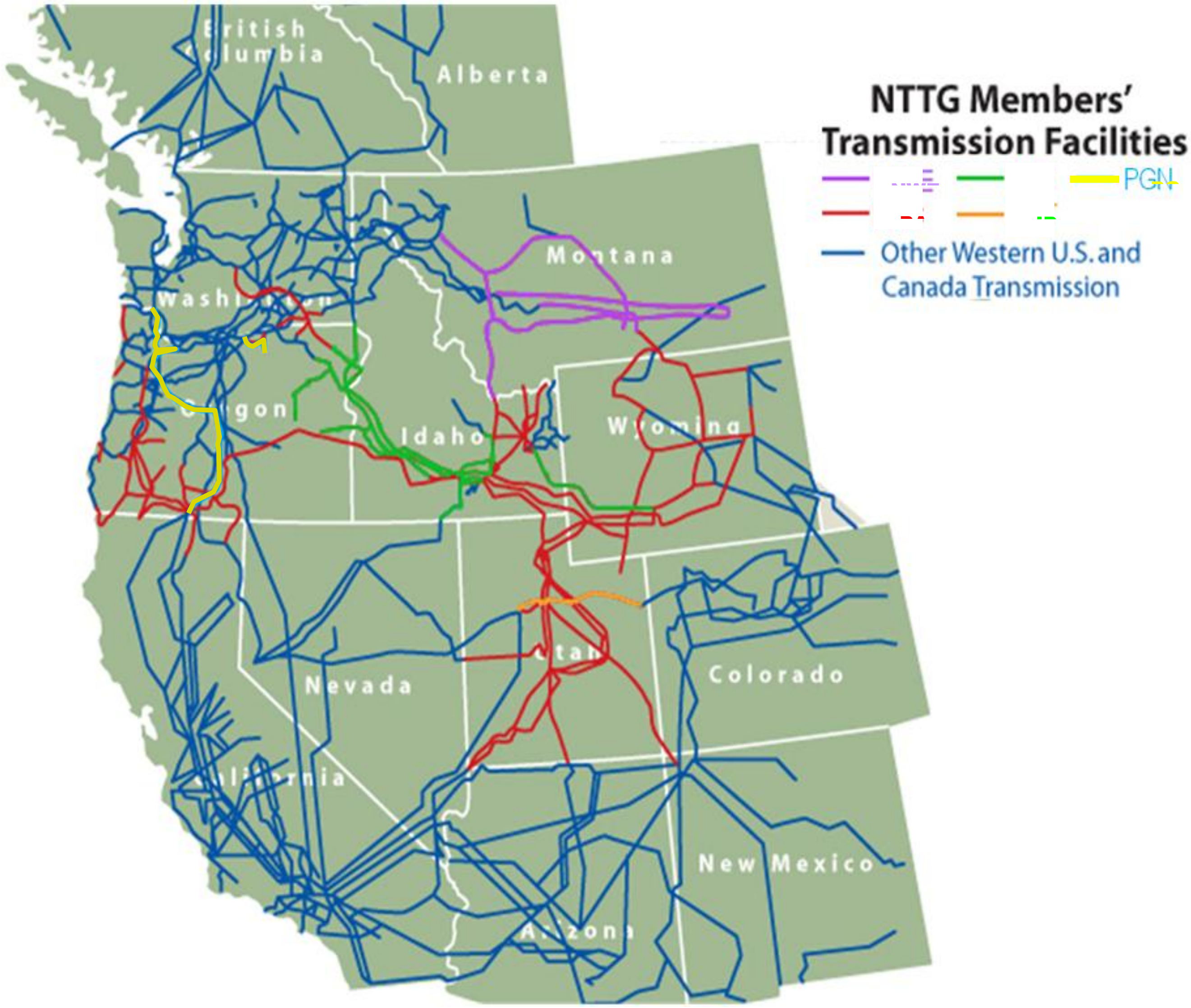
Northern Tier Transmission Group Mission: To ensure efficient, effective, coordinated use and expansion of the members' transmission systems in the Western Interconnection to best meet the needs of customers and stakeholders.



Map Illustrating Northern Tier Members' Principal Transmission Lines

The extensive high-voltage transmission network of the Northern Tier Transmission Group's transmission providers reaches to all states of the U.S. Western Interconnection

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Abstract

The 2012-2013 Northern Tier Transmission Plan uses power-flow reliability analysis to establish whether proposed transmission additions can reliably meet forecasted load and resource portfolios at stress times expected during 2022. The report reviews and summarizes the results of an economic-congestion study along with the results of null, core and scenario case studies performed by the Northern Tier Transmission Group (NTTG) during the biennium. The economic study demonstrates that the addition of a 500 kV line from Great Falls to Townsend to Midpoint and series capacitor upgrades at Burns, Malin and Midpoint would allow the transfer of 1,500 MW of power from Great Falls to Malin. The Null Case concludes that the existing NTTG transmission system cannot reliably serve 2022 forecasted loads and resources and will require additional transmission capacity. The five core cases demonstrate, however, that the NTTG transmission system can accommodate projected 2022 loads and resources without additional transmission facilities beyond the 30 proposed projects listed in the Common Case Transmission Assumptions (CCTA) for 2022.[1] Lastly, a Scenario Case finds the need to remedy the loss of both poles of a proposed 600-kV, direct-current electric transmission line to accommodate a 3,000-MW wind resource projected for southwest Wyoming. By reducing DC line flow to 2,650 MW at the receiving end, however, the loss of the DC bipole would be less severe, with few or no violations, depending on whether Fast Alternating Current Reactive Insertion (FACRI) action was employed.

Executive Summary

The 2012-2013 Northern Tier Transmission Plan describes the components of a reliable transmission system in 2022. The plan uses power-flow reliability analysis to establish whether proposed transmission additions can dependably meet forecasted load and resource portfolios at stress times expected that year.

This is the third biennial plan developed by the Northern Tier Transmission Group (NTTG or Northern Tier).

The report explains the study methodology, assumptions, data and analyses underlying the planning effort. The plan's components – the economic study and the null, core and scenario case studies – are reviewed and their results summarized.

Planning and preparation of the report spanned two years. Two planning cycles ran on parallel tracks during that time. One track comprised the biennial transmission planning cycle. The other track included two annual economic-congestion study cycles. Both tracks began in January 2012 and concluded with the final approval and publication of this report in December 2013.

[1] The developer of the 500-kV Cascade Crossing transmission line canceled its project after completion of the transmission plan. Thus, the report includes this project in its assumptions.

An introductory chapter outlines, in addition to the biennial planning process, the structure of NTTG and its various planning entities, and the local, sub-regional and regional planning process in the Western Interconnection. The relationship between Northern Tier and other subregional and regional entities is outlined, and their synchronized planning cycles are described.

Next, the report expands on study methodology, looking at the process used to create study plans, core cases, power-flow analysis and reliability criteria. Another chapter describes how the study case was developed from load forecasts, resources and expected transmission additions.[2] Notably, it points out, NTTG transmission providers' current 10-year load and resource forecast changed significantly from the prior two-year cycle, prompting NTTG to assess future transmission requirements.

The economic study demonstrates that the addition of a 500 kV line from Great Falls to Townsend to Midpoint, along with series capacitor upgrades at Burns, Malin and Midpoint, would allow 1,500 MW of power to be transferred from Great Falls to Malin. Under the maximum export case, some combination of capacitor upgrades and transmission improvements would be needed beyond the 30 projects included in the Western Electricity Coordinating Council (WECC) Common Case Transmission Assumptions (CCTA) for 2022.

The Null Case seeks to discover whether the near-term transmission system can meet the demands of the load forecasted for the NTTG footprint in 2022. The case concludes that the existing NTTG transmission system cannot reliably serve 2022 forecasted loads and resources and will require additional transmission capacity.

The core cases analyze future system reliability under five different stressed conditions within the NTTG footprint. The committee selected peak-load hours as well as high-import and high-export conditions that produced those stress points.

The five core cases demonstrate that the NTTG transmission system can accommodate projected 2022 loads and resources without additional transmission facilities beyond the 30 proposed projects listed in the 2022 CCTA.

Lastly, a Scenario Case combines a 3,000 MW wind resource projected for southwest Wyoming with a proposal for a 600 kV, direct-current electric transmission line with 3,000 MW capacity. The study finds the need to remedy the loss of both poles of the new DC line, if transferring 3,000 MW. If DC line flow were reduced to 2,650 MW at the receiving end, the loss of the DC bipole would be less severe, with few or no violations, depending on whether Fast Alternating Current Reactive Insertion (FACRI) action was employed.

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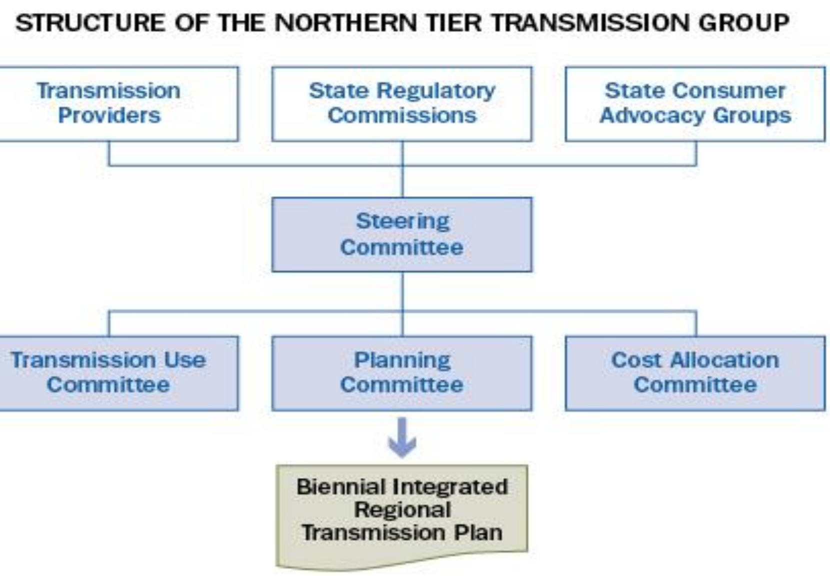
[2] The developer of the 500 kV Cascade Crossing transmission line canceled this project after NTTG completed this biennial transmission plan. Thus, the report continues to include this project in its assumptions.

Chapter 1 – Background

The Northern Tier Transmission Group

The Northern Tier Transmission Group (Northern Tier or NTTG) was formed voluntarily in 2007 to promote effective planning and use of the multi-state electric transmission system within the Northern Tier footprint.[3] NTTG fulfills Federal Energy Regulatory Commission (FERC) Order No. 890 requirements that local transmission providers participate in regional and subregional planning. Northern Tier provides a forum where all interested stakeholders, including transmission providers, customers and state regulators, can participate in planning, coordinating and implementing a robust transmission system.

Figure 1-1: Structure of the Northern Tier Transmission Group



NTTG focuses on evaluating transmission projects that move power across the subregional bulk-electric transmission system, serving load in its footprint and delivering electricity to external markets. The transmission providers belonging to Northern Tier serve over 4 million retail customers with more than

[3] The Northern Tier footprint means the geographical area comprised of the retail electric service territories of the entities enrolled in NTTG as Full Funders. Currently, these Full Funders are (i) Portland General Electric Company (Portland General), (ii) PacifiCorp, (iii) Idaho Power Company, (iv) Deseret Generation & Transmission Co-operative, and (v) NorthWestern Corporation.

29,000 miles of high-voltage transmission lines. These members provide service across much of Utah, Wyoming, Montana, Idaho and Oregon, along with parts of Washington and California.

Northern Tier Members

The Northern Tier Transmission Group's organizational structure has multiple levels, as shown in Figure 1-1 above. Overall planning direction is provided by the Steering Committee, whose membership at publication was as follows:

- Deseret Power Electric Cooperative
- Idaho Power Company
- Idaho Public Utilities Commission
- Montana Consumer Counsel
- Montana Public Service Commission
- NorthWestern Energy
- Oregon Public Utility Commission
- PacifiCorp
- Portland General Electric
- Utah Associated Municipal Power Systems
- Utah Office of Consumer Affairs
- Utah Public Service Commission
- Wyoming Public Service Commission

Transmission Planning Committee

The NTTG Transmission Planning Committee (Planning Committee or committee) coordinates transmission planning for the Northern Tier footprint. It also coordinates with other subregional planning groups and the Western Electricity Coordinating Council's planning committees. Execution of the committee's charter occurs through the biennial planning process. Northern Tier designs its planning process to be open, transparent and participatory. Transmission providers, regulators, customers and other stakeholders are encouraged to join the committee's activities and meetings, including semi-annual stakeholder meetings.

NTTG's 2012-2013 biennial plan was produced through its public processes in conjunction with related activities of the NTTG Cost Allocation Committee and NTTG Transmission Use Committee.

At publication, the Transmission Planning Committee had members from the following organizations:

- Avista Corporation
- Basin Electric
- Black Hills Power
- Deseret Power Electric Cooperative

- Gaelectric, LLC
- Grasslands Renewable Energy
- Idaho Office of Energy Resources
- Idaho Power
- Idaho Public Utilities Commission
- Montana Public Service Commission
- NextEra Energy Resources
- NorthWestern Energy
- PacifiCorp
- Portland General Electric
- Sea Breeze Pacific
- TransCanada
- Utah Associated Municipal Power Systems
- Utah Public Service Commission
- Wyoming Public Service Commission

Coordination Within the Northern Tier Footprint

Planning is an iterative process that must work in concert with local transmission plans and integrated resource plans, where they exist. This Northern Tier transmission plan uses a bottom-up load-service process, employing stakeholder data and input to ensure that the transmission system planned for the Northern Tier footprint can reliably serve forecasted load growth and conditions. While this plan addresses transmission issues and solutions within the Northern Tier footprint, it is informational only. It neither requires construction nor seeks to accommodate broader regional needs.

Each of the Northern Tier transmission providers is also responsible for transmission planning and implementation in its own service area and for any balancing authority areas it administers. This local transmission planning process is designed to parallel and interact with the planning done at Northern Tier.

The local planning process digs deeper than the subregional process, in terms of its analysis both of finer detail (lower voltages and system dynamics) and more extensive construction detail. The transmission provider's responsibilities include path ratings, project financing, permitting and approvals, and construction.

The NTTG planning process provides a mechanism for coordinating stakeholder load and resource data, as well as for considering potential non-transmission-provider transmission projects. Additionally, this process coordinates analysis of the existing subregional transmission system and the proposed projects that affect the transmission of electricity throughout the NTTG footprint.

Coordination with Others in the Western Interconnection

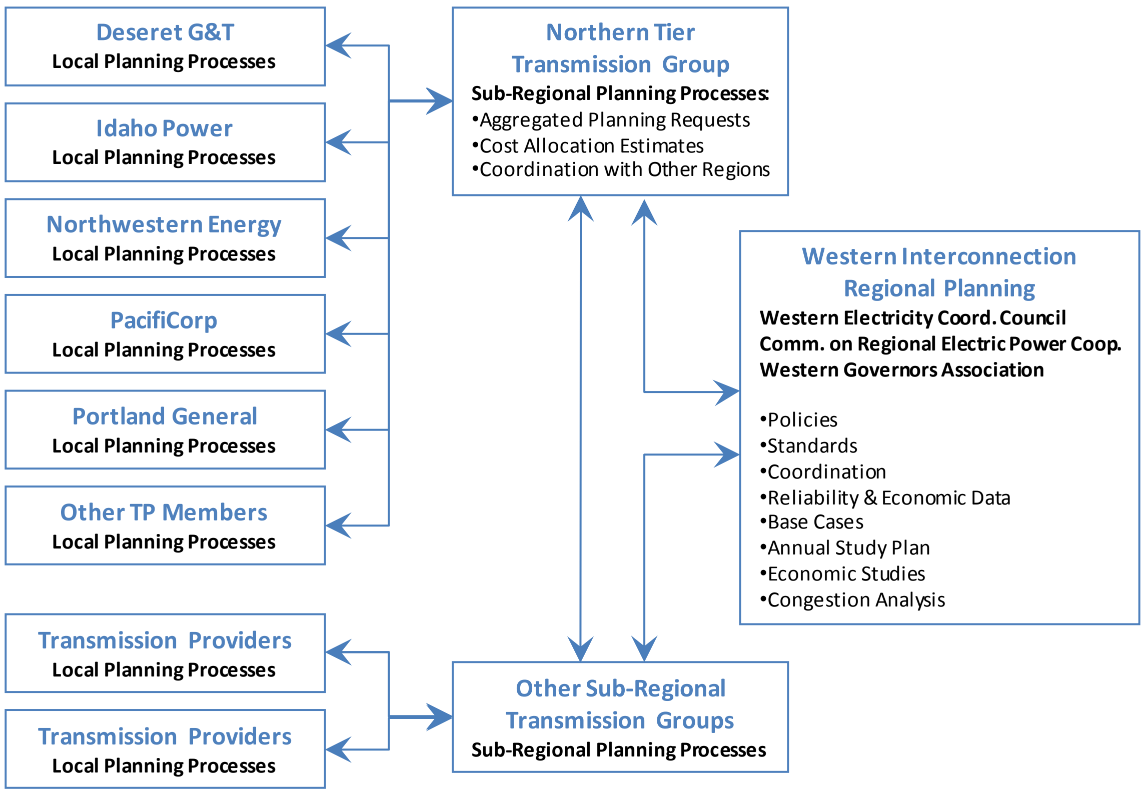
NTTG is committed to coordinating subregional planning efforts with adjacent subregional groups and other planning entities. In addition to working directly with the ColumbiaGrid and WestConnect subregional planning groups, Northern Tier relies on the data collection, validation and transmission modeling work done by the Western Electricity Coordinating Council (WECC), the regional reliability organization. This Northern Tier transmission plan is consistent with the work of WECC.

WECC provides valuable services to transmission planners across the Western Interconnection. WECC's services include providing regional reliability planning and facility rating, and supplying economic planning data and analysis to its members through its Transmission Expansion Planning Policy Committee (TEPPC).

Relationships Among Planning Entities in the West

Transmission planning in the Western Interconnection has evolved to incorporate three distinct organizational levels: transmission providers, subregional transmission groups and regional planning entities. The relationships among regional, subregional and individual transmission entities are illustrated in Figure 1-2 below.

Figure 1-2: Three-level Planning Process in the Western Interconnection



Each of the transmission providers develops and maintains an Open Access Transmission Tariff process, which receives and acts on requests for transmission service in accord with a well-defined procedure. The transmission providers also assess future load and resource developments to plan the evolution of an efficient transmission system, and undertake reliability analysis and improvements.

Planning and analysis of improvements are coordinated at the subregional level. This occurs when service requests and other identified needs call for the development of transmission requiring participation of multiple providers within a subregional transmission group's footprint.

At the regional level, the WECC TEPPC provides a forum for wider coordination and completes the three-level framework that addresses regional, subregional and local issues.

The Northern Tier Transmission Group's planning timelines are designed to coordinate with those of WECC. Those timelines include a two-year cycle for transmission expansion and reliability and a one-year economic study cycle. The economic study process examines preliminary plans during the first year of the biennial cycle and draft plans during the second year of the cycle.

Review of NTTG 2012-2013 Planning Activities

Stakeholder participation is important to the processes of the Northern Tier Transmission Group. All interested parties are encouraged to attend and contribute to the many stakeholder meetings conducted by the Transmission Use, Planning and Cost Allocation committees, and to help in preparing, developing and analyzing planning studies. A chronology of activities in the 2012-2013 biennial planning cycle is provided in Table 1.1 below.

The Northern Tier Planning Committee conducted open conference calls on a frequent basis during the 2012-2013 biennium. The planning process was developed and managed in these conferences. Participants discussed and reached agreement on assumptions, data and methodologies.

The Planning Committee decided to perform studies using the staff of member transmission providers, taking advantage of their internal expertise and software tools. The committee formed a Technical Work Group (TWG), to separate detailed technical and model discussions from the policy-level Planning Committee and to provide proper control of confidential information.

An Economic Studies Team was similarly formed to plan and perform any needed economic studies resulting from NTTG's economic-study request solicitation during the biennium.

Table 1-1: Biennial Planning Activities

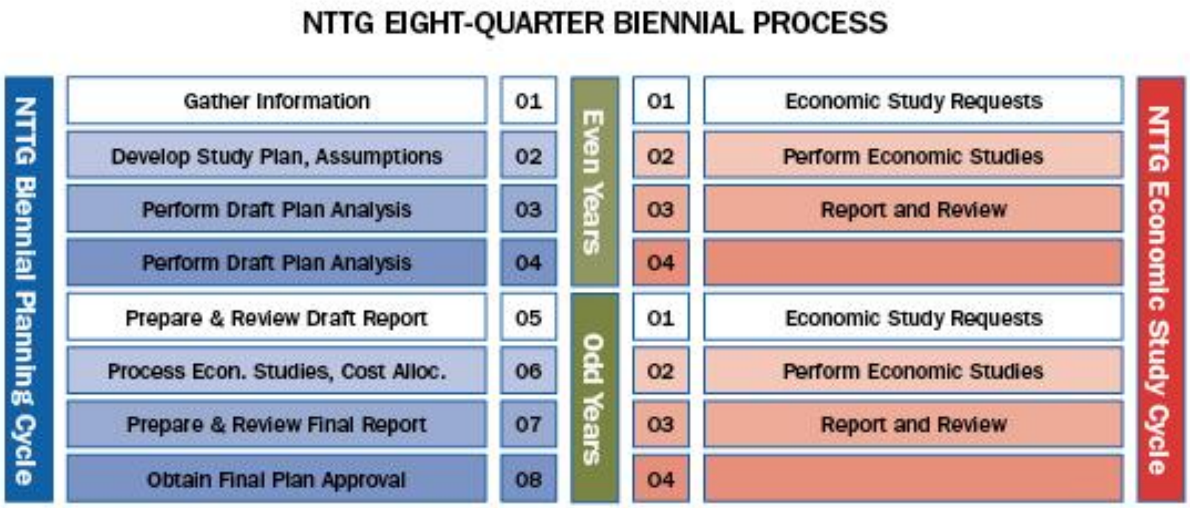
Year	Month	Day	Activity
2012	Jan	9	Planning Committee Meeting discussion of data and economic study requests
	Feb	3	2012 Public Semi-Annual Stakeholder Meeting
	Apr	4	Planning Committee Meeting selection of economic study requests
	May	2	Planning Committee Meeting review of Transmission and Economic Study Plans
	June	6	Planning Committee Meeting Transmission and Economic Study Plans Approved and Posted
	Aug	4	2012 Public Semi-Annual Stakeholder Meeting
	Sep	5	Planning Committee Meeting discussed scenario case
	Oct	3	Planning Committee Meeting review of study progress
	Nov	14	Planning Committee Meeting review of economic study results
	Dec	12	Planning Committee Meeting review of economic study results
2013	Jan	9	Planning Committee Meeting discussion of draft Biennial Transmission Plan, data and economic study requests
	Feb	7	2013 NTTG Semi-Annual Public Stakeholder Meeting
	Mar	13	Planning Committee Meeting
	Apr	17	Planning Committee Meeting discussion of economic study requests
	May	8	Planning Committee Meeting
	Jul	25	2013 NTTG Semi-Annual Public Stakeholder Meeting
	Aug		Stakeholder input to the Biennial Plan
	Nov		Biennial Plan Approval by NTTG Steering Committee
	Dec		Biennial Plan publication

Details of the Eight-Quarter Northern Tier Planning Process

The biennial transmission planning process at Northern Tier is broken down into eight quarters and two tracks. Figure 1.3 diagrams this process for the 2012-2013 cycle. The planning process during this biennial cycle is described in further detail in the Northern Tier Transmission Group's Planning Committee Order No. 890 Charter[4].

[4] In the respective compliance filings by the Full Funders of NTTG regarding the FERC Order No. 1000, the NTTG committee charters were substantially revised. Pursuant to these revisions, as of October 2013, the Planning Committee Charters have been revised such that the details of the planning process have been removed from the charter and are now found in each of the Full Funders' respective Attachment K. Although the current biennial cycle ends on December 31, 2013, for purposes of preparation and consideration of this report, the planning procedures of the Planning Committee are based on the prior Planning Committee Charter established under Order No. 890.

Figure 1-3: NTTG Eight-Quarter Biennial Planning Process



The current biennial cycle began in January 2012 with a three-month window of opportunity for stakeholders to submit data for loads, resources and transmission projects to be studied, and to submit requests for economic congestion studies.

The second quarter was dedicated to developing a study plan based on the data collected, along with the appropriate study assumptions. Additionally, development of the economic study plan ensued during this quarter.

The Economic Studies Team presented its economic-congestion study results for the biennium in the fourth quarter of 2012.

The TWG developed and exported the production cost cases to the power-flow simulation program during the second quarter. This allowed the TWG to analyze the null and core cases during the third and fourth quarters. It further allowed the TWG to share the draft Transmission Plan with the Planning Committee in the first quarter of 2013. The biennial planning process concluded with the preparation, review and acceptance of this report.

In October 2013, the fourth biennial planning cycle will begin, with data, models and processes enhanced by prior experiences and in accordance with FERC Order 1000. FERC found the NTTG transmission providers' compliance filings to be partially compliant, accepted the filing subject to further compliance filings, and set an October 2013 effective date. Based on this FERC action, NTTG's 2014-2015 biennial planning process will analyze the NTTG footprint to select a more cost-effective or efficient transmission plan.

Chapter 2 – Study Methodology

The objective of the 2010-2011 Northern Tier Transmission Plan is to determine what a reliable transmission system may look like in 2022. The plan used power-flow reliability analysis to establish whether the proposed transmission additions can reliably meet the forecasted load and resource portfolios at anticipated stress times in 10 years.

Creation of the Study Plans

As described in Chapter 1, NTTG begins the biennial transmission planning and economic study processes through a solicitation of data and study requests. This is followed by the creation of their respective study plans. During this planning cycle, the biennial transmission plan was revised several times in order to correct information and incorporate the approved scenario study. The final NTTG 2012/2013 Biennial Transmission Study Plan and Economic Study Plan are included as Appendix A and B, respectively.

Creation of the Study Core Cases

NTTG creates the power-flow core cases from a chronological, security-constrained generator-commitment-and-dispatch program to identify and select specific conditions, e.g., peak load and maximum export, to perform reliability analysis of the NTTG transmission system. The use of this technique goes beyond the traditional focus of power-flow analyses on WECC winter and summer peaks. NTTG examines all hours of the year for situations where available resources and forecasted loads across the Western Interconnection cause the highest stress on the transmission system in the Northern Tier footprint, as described in Chapter 3.

Power-Flow Analysis

Power-flow analysis is performed on the developed cases to determine if any voltage- or thermal-overload violations exist under two conditions: system normal (N-0 pre-disturbance analysis with all lines in service) and one transmission element out of service at a time (N-1 contingency analysis). The contingency analysis includes a comprehensive set of 420 single-element outages of NTTG footprint elements with an operating voltage of 230 kV and above. During this analysis, autotransformer taps and phase-shifting transformers are not allowed to adjust (locked), and the switching of shunts and tie lines is disabled. Remedial Action Schemes (RAS) are executed for contingencies that normally utilize RAS. Transient stability, reactive margin and N-2 (or more) contingency analyses are not performed for this study.

Criteria

The power-flow simulation results are measured against North American Electric Reliability Council (NERC) and WECC reliability criteria. Specifically, the NERC Reliability Standards TPL-001 and TPL-002 b require that transmission facilities maintain operation within normal and emergency limits. The WECC business practice TPL-001-WECC-RBP-2 establishes the voltage-violation threshold for N-1 contingency analysis at 5% for other systems. Thus, the software application's reporting threshold for a thermal-overload violation is based on the normal ratings for system normal and emergency summer ratings for N-1 contingency analysis. Additionally, the voltage violation threshold is set at 5%. However, only voltage deviations greater than 5% on other transmission systems and substations busses constitute a violation. Thus, the TWG carefully analyzes software-tabulated violations to cull any reported violations on local transmission-provider (within the same transmission system where contingency applied), series-capacitor and non-bulk-electric-system busses.

Path Constraints

Path constraints, also referred to as interface limits, are included in the power-flow cases. They are based on the WECC Path Rating Catalog. The TWG may modify the interface limit if transmission additions impact the limit.

Chapter 3 – Study Case Development

Comparison of NTTG 10-Year Forecast

In the first quarter of the two-year study process, stakeholders submitted loads, resources and expected transmission additions for the next 10 years. The following comparison of the 2012 and 2010 submittals led to the decision to proceed with the 2012-2013 study process.

1. Balancing authorities provided their 10-year load forecasts to NTTG in response to the first-quarter data request. The loads are generally the official load forecasts of the load-serving entities and are also provided to the WECC Loads and Resources Committee. Table 3-1 shows a load comparison from data submitted during the first quarter of 2012 compared with the same quarter of 2010.

Table 3-1: 10-Year Forecasted Load Comparison

Submitting Entity		10-yr. Summer Load Data submitted in Q1 2012	10-yr. Summer Load Data submitted in Q1 2010	Difference
Basin Electric		476	None submitted	n/a
Black Hills Energy		465	None submitted	n/a
Idaho Power		4383	4161	222
NorthWestern Energy		1680	1618	62
PacifiCorp East		9842	10105	-263
PacifiCorp West		3795	3730	65
Portland General Electric		4119	4421	-302
TOTAL		*24760*	*24035*	*-216**

** Note: The total difference in the load comparison does not include Basin Electric or Black Hills, since the 2010 data was incomplete.*

2. Resources provided in response to the first quarter data request add to existing resources within the Northern Tier footprint and are summarized in Table 3-2 (2010 Q1 data submittal) and Table 3-3 (2012 Q1 data submittal). Resource data come from integrated resource plans, interconnection queues, resource developers and transmission providers who provide indications of expected resource additions.

Table 3-2: Resource Additions Identified in 2010 Q1 Data Submittals

Submitting Entity	*Natural Gas*	*Wind*	*Geo-thermal*	*Hydro-electric*	*Coal*	*Market*	*TOTAL*
Basin Electric	*0*	*0*	*0*	*0*	*385*	*0*	*385*
Grasslands Renewable Energy	0	0	0	350	0	0	*350*
Idaho Power	300	150	40	49	0	425	*964*
NorthWestern Energy	890	2195	0	50	290	0	*3425*
PacifiCorp	1574	1156	0	39	0	1870	*4639*
Power Company of Wyoming	0	3000	0	0	0	0	*3000*
Portland General Electric	450	700	0	0	0	0	*1150*
TransWest Express	325	2900	0	0	0	0	*3225*
TransCanada	0	3000	0	0	0	0	*3000*
TOTAL	*3539*	*13101*	*40*	*488*	*675*	*2295*	*20138*

Table 3-3: Resource Additions Identified in 2012 Q1 Data Submittals

Contributing Utility	*Natural Gas*	*Wind*	*Solar*	*Biomass*	*Oil*	*Geo-thermal*	*Hydro-electric*	*Coal*	*Market*	*TOTAL*
Avista		*100*								*100*
Black Hills Energy	55									*55*
Idaho Power	300	201	20	43		52	49		470	*1135*
NorthWestern Energy	46	709					23			*778*
PacifiCorp	1627	1240	17	92	47	65	10	20	961	*4079*
Power Company of Wyoming		3000								*3000*
Portland General Electric	650	1301								*1951*
TOTAL	*2678*	*6551*	*37*	*135*	*47*	*117*	*82*	*20*	*1431*	*11098*

3. Transmission

A number of transmission projects were submitted in response to the first-quarter data request. Table 3-4 below summarizes those transmission projects. The table also denotes if a transmission project was submitted in the previous biennial cycle or if it was included in the Common Case Transmission Assumptions (CCTA) by Transmission Expansion Planning Policy Committee (TEPPC), or both. Absent from the 2012 data submittal are the Grasslands Renewable Energy project and the TransCanada project.

Table 3-4: Transmission Projects Identified in 2012 Q1 Data Submittal

Utility	Voltage	Project
Black Hills	230 kV	Teckla-Osage-Lange [WY]
Idaho Power Co.	500 kV	Boardman-Hemingway [ID-OR][*,†]
	500 kV	Gateway West (with PacifiCorp) [WY-ID][*,†]
NorthWestern Energy	500 kV	MSTI Project [MT-ID][*]
	500 kV	Montana Intertie (Path 8) Upgrade [MT-WA][*,†]
	230 kV	AMPS line (Path 18) Upgrade [MT-ID][*]
	230 kV	MSTI Collector (up to 5 segments) [MT][*]
PacifiCorp	500 kV	Gateway Central [ID-UT][*,†]
	345 kV	Gateway Central – Sigurd to Red Butte [UT] [*,†]
	500 kV	Gateway South [WY-UT][*,†]
	500 kV	Gateway West (with Idaho Power) [WY-ID][*,†]
	500 kV	Hemingway-Captain Jack [ID-OR][*]
	230 kV	Walla Walla-McNary [WA-OR][*,†]
Portland General Electric	500 kV	Cascade Crossing (Boardman-Salem) [OR][*,†]
	230 kV	Horizon-Keeler [OR][*]
	230 kV	Blue Lake-Gresham [OR]
	230 kV	Pearl-Sherwood [OR]
TransWest Express	600 kV	DC line [WY-NV][*]
Facilities from Last Cycle not submitted in current cycle:		
Grasslands Renewable	230 kV	Collector System [MT]
	500 kV	DC line, Colstrip to Bismarck {MT-ND]
TransCanada	500 kV	Chinook Project (AC+DC) [MT-ID-NV]
	500 kV	Zephyr Project (AC+DC) [WY-ID-NV]

[*] indicates that this facility was submitted in the last biennial cycle

[†] indicates that this project was included in the CCTA

4. First Quarter Data Submittal Comparison Conclusions:

> The comparison tables show that, in this biennial cycle, the total 10-year load forecast (for the balancing authorities that submitted load data during both biennial cycles) has actually decreased by 216 MW from the prior cycle. However, the amount of new resources submitted in the current cycle is down significantly. Of the total, 3,000 MW was double-counted in the last cycle and 3,000 MW from the TransCanada project was not submitted this cycle. Also, NorthWestern Energy reduced its latest resource forecast by 2,647 MW to represent only committed projects. Another 350 MW of resource was canceled with the Grasslands Renewable Energy project. Finally, Basin Electric's coal plant (385 MW) submitted last cycle is now in service.

The NTTG transmission providers' current 10-year load and resource forecast has changed significantly from the prior cycle. This change prompted NTTG to assess future transmission requirements. During the study plan development phase, members of the NTTG TWG reviewed the TEPPC 2022 PC1 model to determine its suitability for the assessment. The members found it to adequately represent the NTTG first quarter load, resource and transmission submission. The TEPPC PC1 model is described in detail in the next section.

Development of the System Model

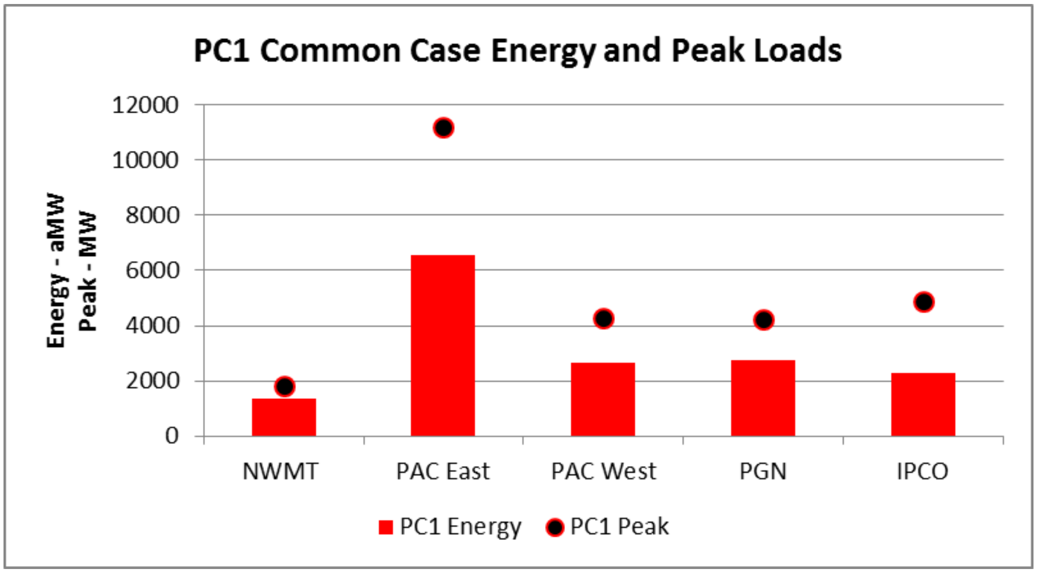
Northern Tier relies on the region-wide data collection and model-development work of TEPPC's Technical Advisory Subcommittee (TAS) for the chronological, security-constrained generator-commitment-and-dispatch model. The subcommittee's extensive efforts to acquire, review and agree on the many datasets needed in these studies not only saves considerable work by Northern Tier but also provides a widely accepted and well-vetted starting point. TEPPC in turn relies on the load-and-resource and transmission-network modeling of WECC's Planning Coordination Committee Loads and Resources Subcommittee (LRS) and Technical Studies Subcommittee (TSS). The TAS and TSS develop reference base cases used for subsequent WECC studies and for the use of WECC members in their own work. A flow chart showing the NTTG study case process is in Appendix A.

For security-constrained economic-commitment-and-dispatch modeling, TEPPC developed a production-cost case, known as the 2022 production-cost model (PC1). This case is based on the TEPPC 2020 power-flow base case, where the WECC transmission system has been modified to reflect known or highly likely future changes. These transmission additions comprise the CCTAs, discussed below. The power-flow cases used in the biennial study process were derived from the TEPPC 2022 PC1. From this model, five core cases were generated based on NTTG transmission providers' coincident: 1) peak summer load, 2) peak winter load, 3) maximum export and 4) maximum import/minimum export; and, additionally, 5) high California-Oregon Intertie (COI) plus Pacific DC Intertie (PDCI) southbound flow coincident with low NTTG export.

TEPPC 2022 PC1 Model

The TEPPC 2022 PC1 model is based on forecasted loads and resources for the year 2022 that were submitted to the LRS from all WECC balancing authorities. The balancing authorities supply monthly peak and energy forecasts. The forecasts are then dispersed into hourly load demands. The coincident WECC peak load for the 2022 Common Case is 173,161 MW and occurs on Thursday, July 21 at 16:00 hours. The table below details the average energy and peak loads in the PC1 case for each transmission provider within the NTTG footprint.

Figure 3-1: Loads in TEPPC PC1 Case



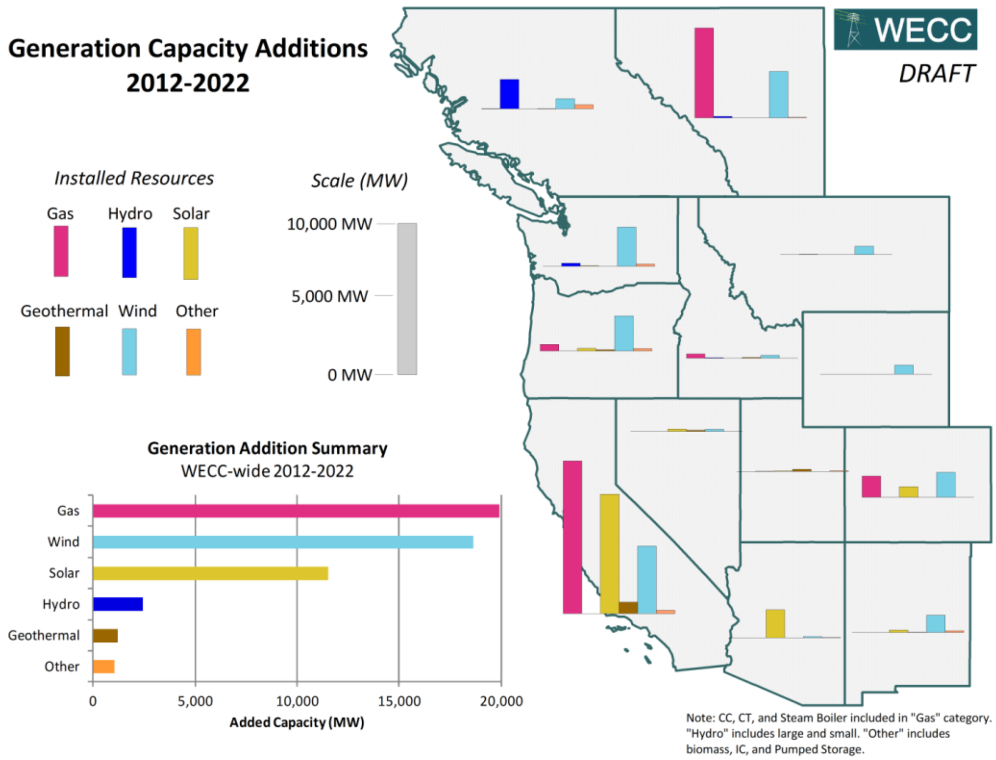
The PC1 case assumes that all state-enacted Renewable Portfolio Standards (RPS) and targets will be met in 2022. Table 3-5 details the RPS requirements by state or province. To meet these requirements, significant amounts of incremental renewable resources are added to the case. Based on the TEPPC data, this equates to an increase of 148% of existing renewable capacity.

Table 3-5: Renewable Standards for 2022

RPS Percentages in 2022 by State/Province					
State/Province	IOU	Public	Federal	Cooperative	Other
Alberta	Renewable resources, no requirement				
Arizona	12%		12%	12%	
British Columbia	Renewable resources, no requirement				
California	33%	33%	33%	33%	33%
Colorado	30%	10%		10%	
Idaho	Renewable resources, no requirement				
Montana	15%				
Nevada	23.5%				
New Mexico	20%			10%	
Texas-EPE	5%				
Utah	16%	16%		16%	
State	Utilities > 3% state load	Utilities < 3% and > 1.5%	Utilities < 1.5% state load		
Oregon	22%	8%	4%		
State	Utilities > 25k customers	Utilities < 25k customers			
Washington	15%				

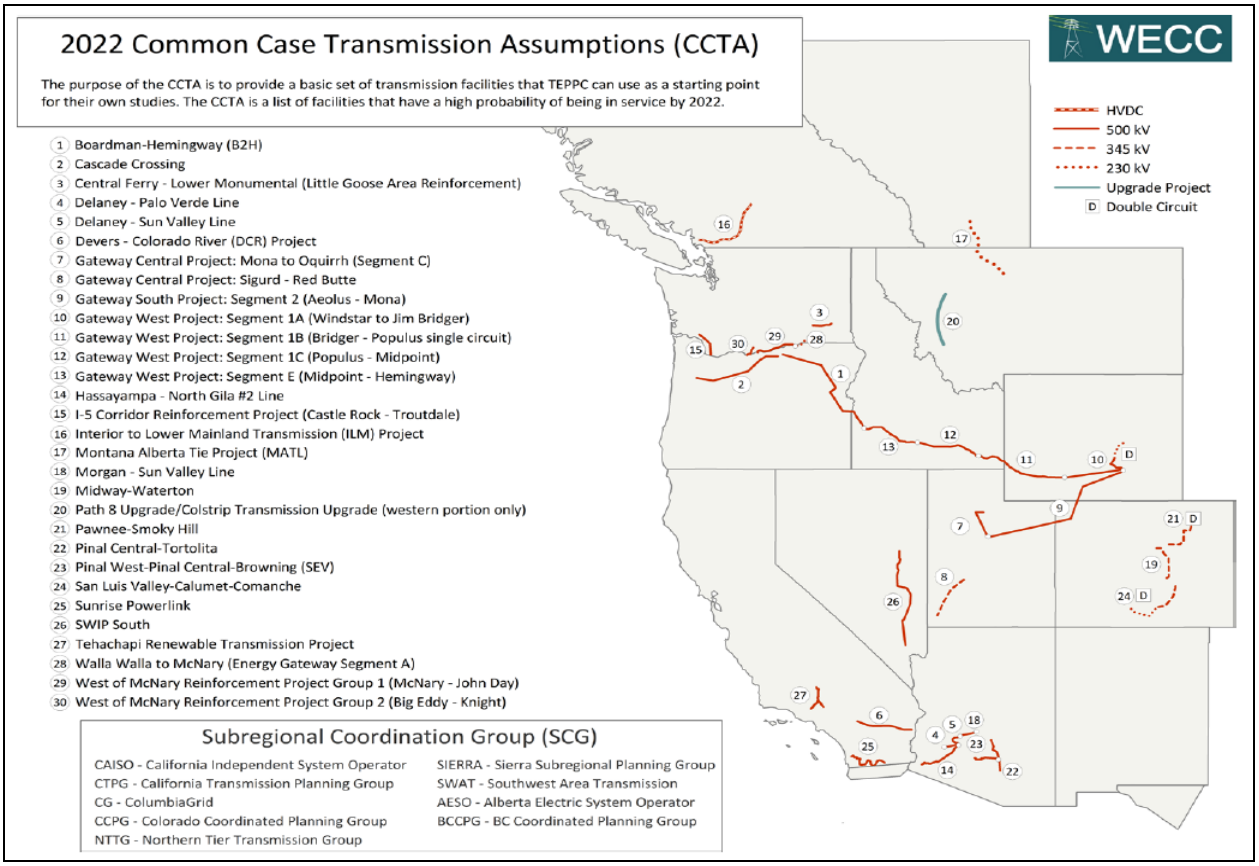
The generation additions in the PC1 case, detailed by state, can be found in Figure 3-2**Error! Reference source not found.**. The majority of generation resources added between 2012 and 2022 are gas, wind and solar. Most of the incremental gas resources are located in California and Alberta. It is worth noting that a large number of the gas resources in Alberta were implemented by TEPPC due to insufficient resources within that province.

Figure 3-2: Generation Capacity Additions by State



The model also includes transmission modifications to reflect the CCTAs, shown in Figure 3-3. Several of the transmission projects submitted in quarter 1 of the NTTG biennial process were included in the CCTA.

Figure 3-3: 2022 Common Case Transmission Assumptions (CCTA)



Selecting Hours for Power-Flow Analysis

The NTTG TWG examined the PC1 hourly loads and interface flows for the NTTG footprint. Examining hourly flows on the NTTG interface paths, the TWG reached consensus to study transmission congestion that would likely occur during peak loads and high-transfer hours. These hours represented times when local load-serving transmission could be stressed and when transmission used to export from or import into the NTTG footprint could be stressed. High-transfer hours were selected representing hours with maximum flows, resulting in paths at or near their limits. NTTG peak load and high-transfer hours selected were:

Peak Hours:

July 21 16:00 –Coincident NTTG summer peak load (Fig. 3-4)

Jan. 5 08:00 – Coincident NTTG winter peak load (Fig. 3-5)

High-Transfer Hours:

Nov. 6 10:00 – Maximum coincident NTTG footprint export (Fig. 3-6)

Sept. 8 17:00 – Minimum coincident NTTG footprint export (or maximum import) (Fig. 3-7)

June 6 12:00 – Highest COI/PDCI flow coincident with low NTTG footprint exports (Fig. 3-8)

Figures 3-4 through 3-8, below, show the load and transmission flows for specific months of the year 2022 and indicate the date and time for the selected core cases.

Figure 3-4: NTTG Summer Peak-Load Hour Selection

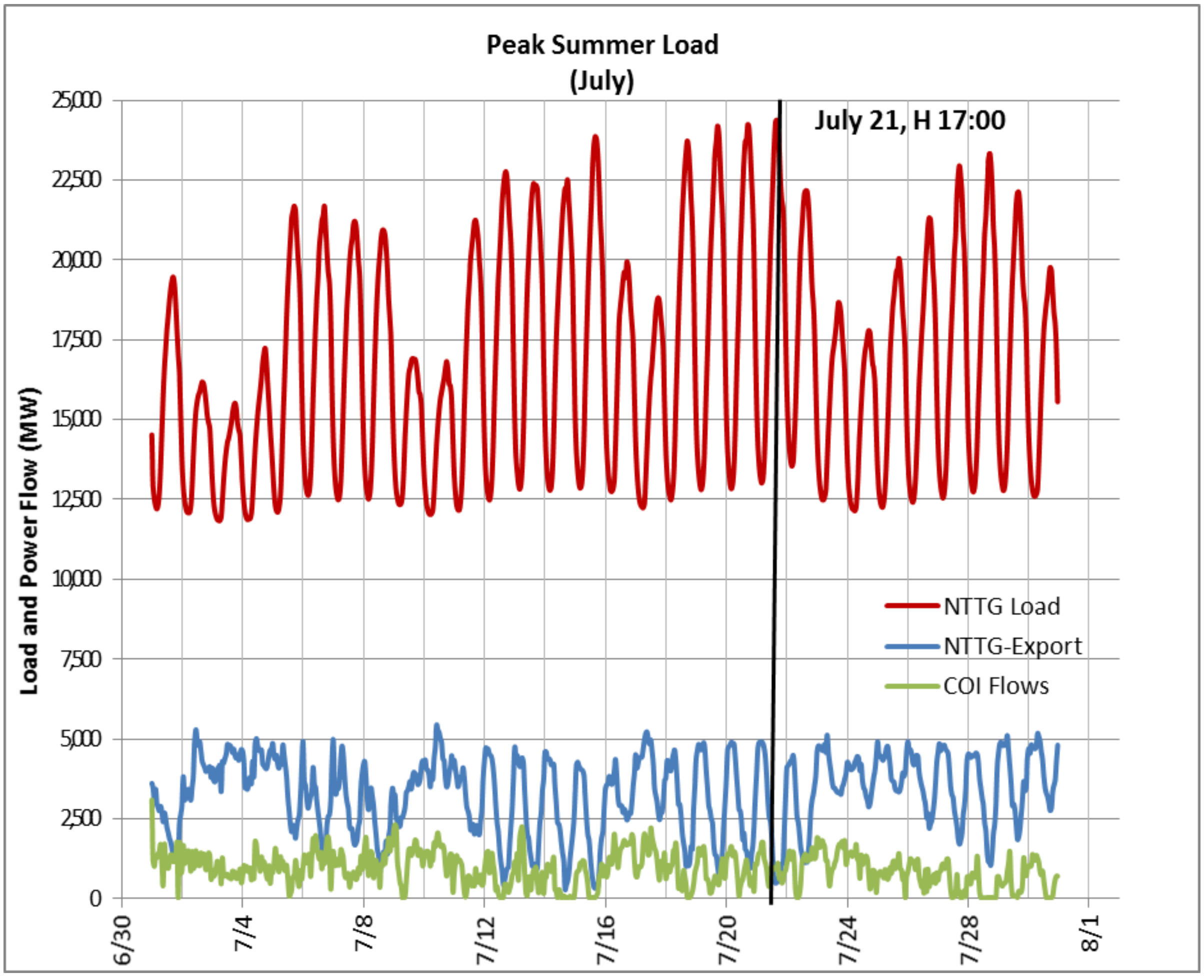


Figure 3-5: NTTG Winter Peak-Load Hour Selection

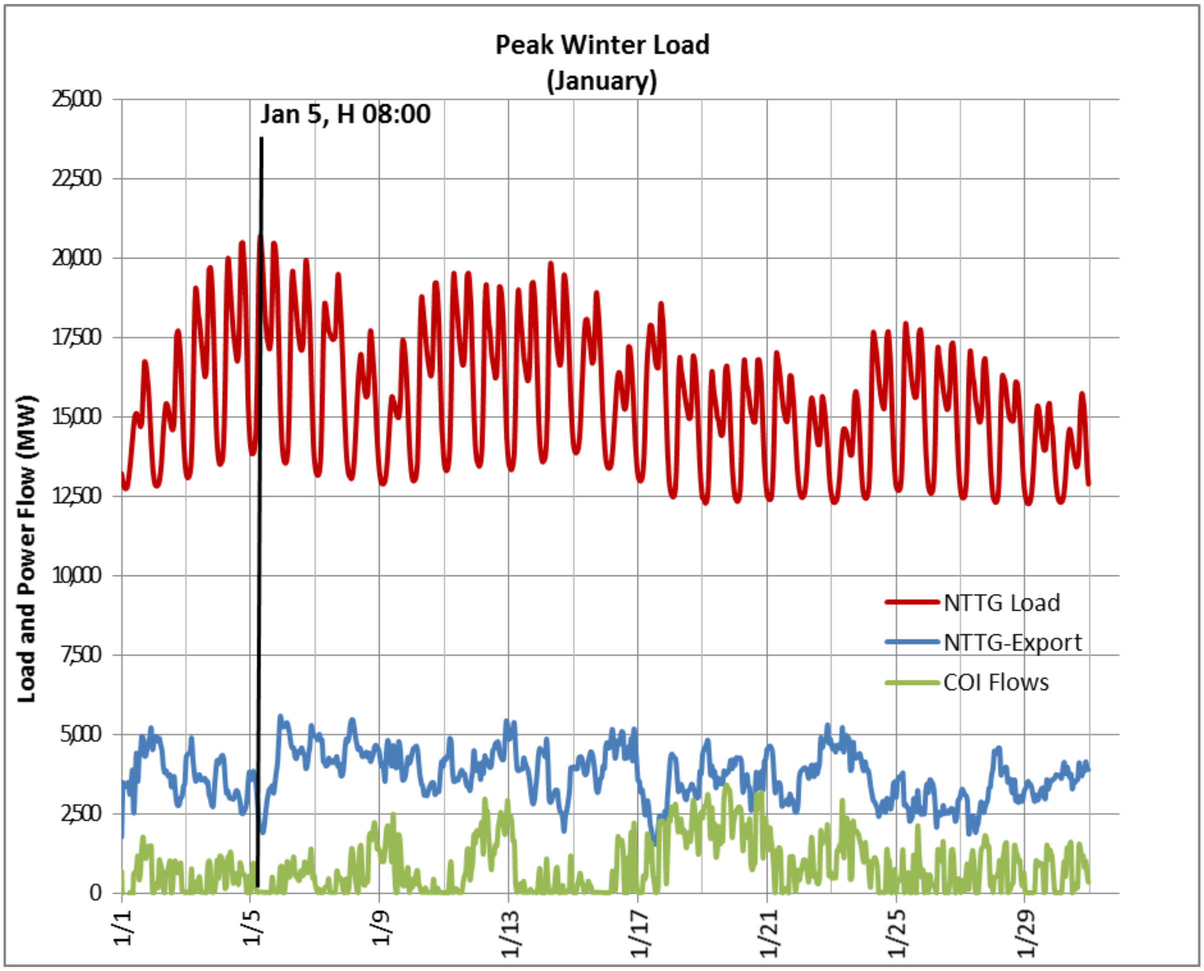


Figure 3-6: NTTG Maximum-Export Hour Selection

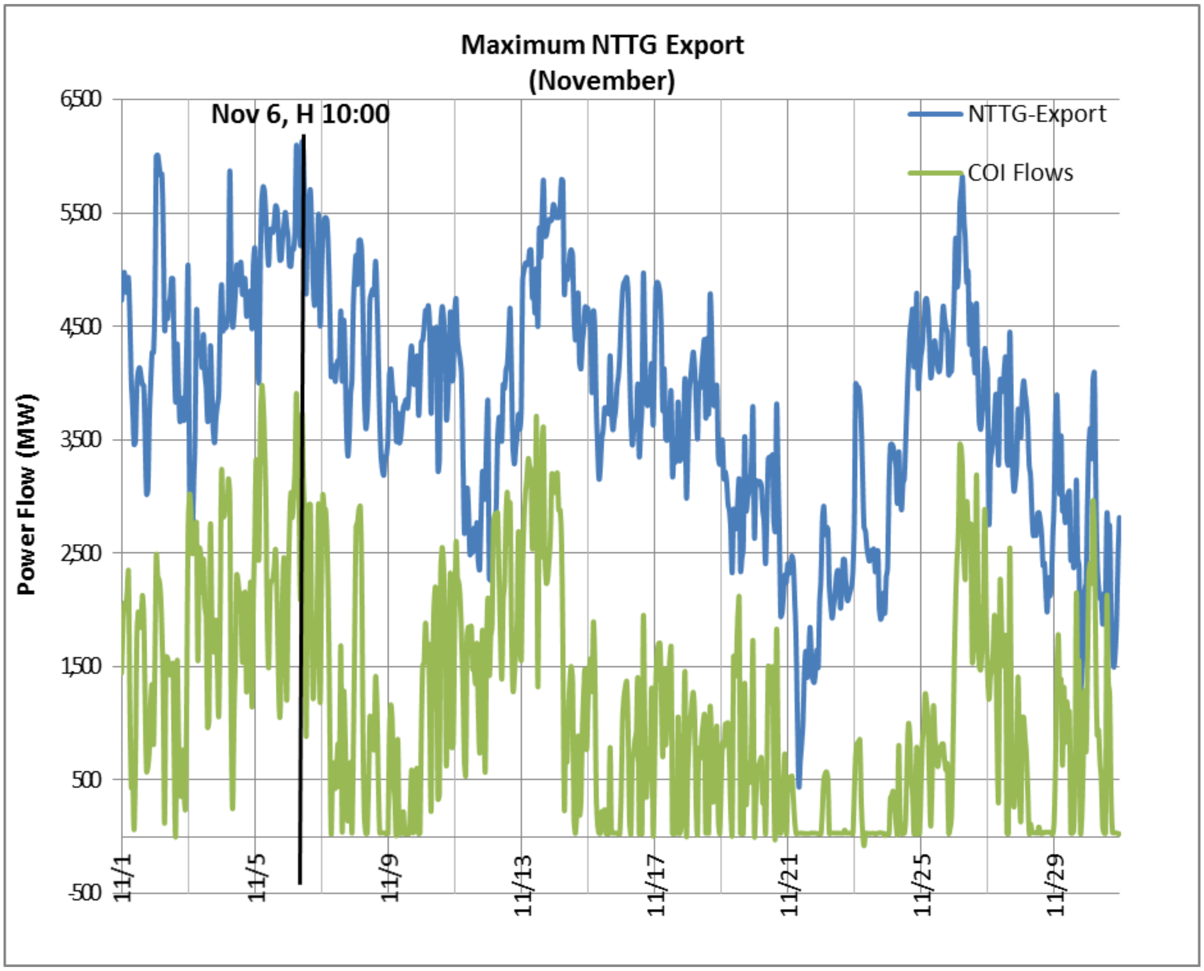


Figure 3-7: NTTG Maximum Import Hour Selection

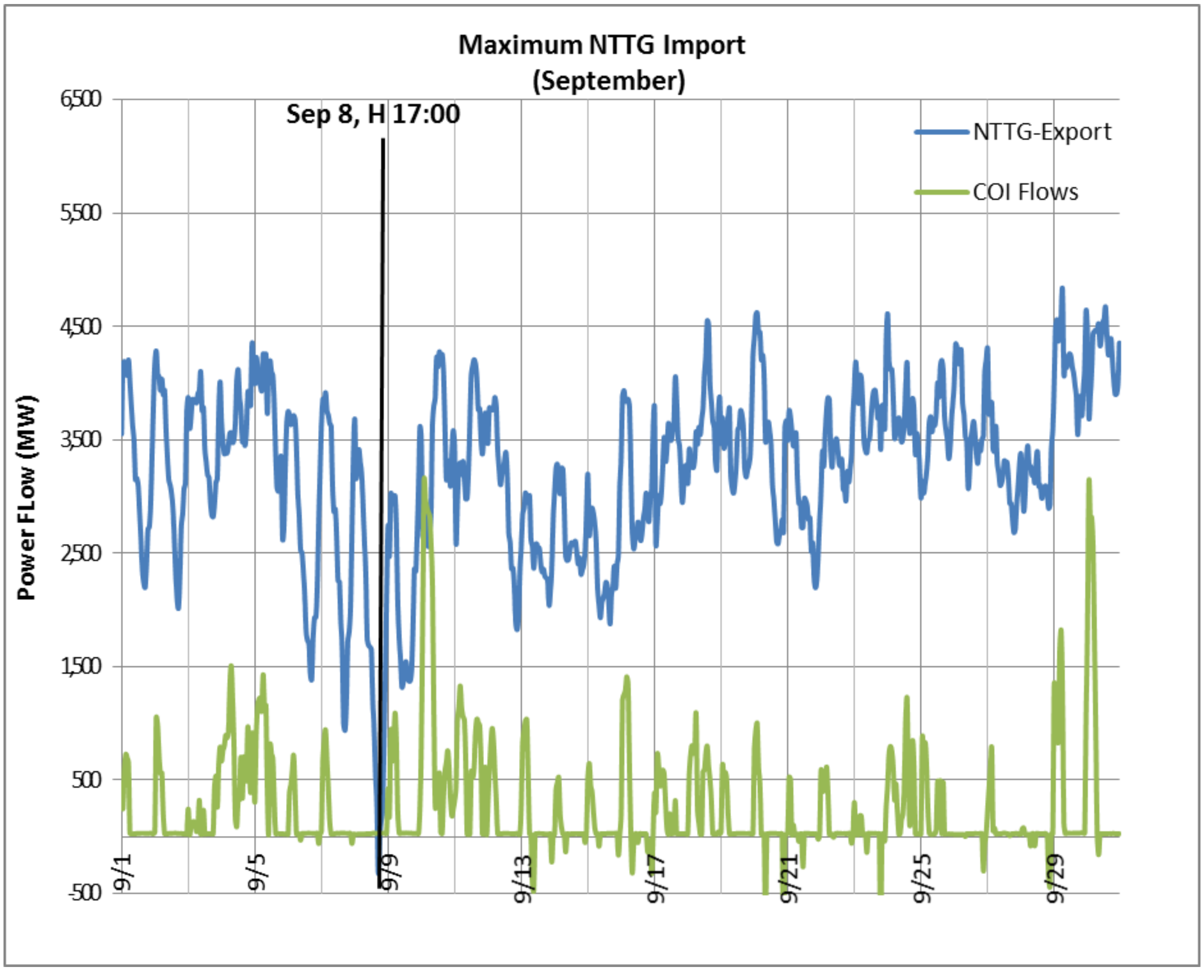
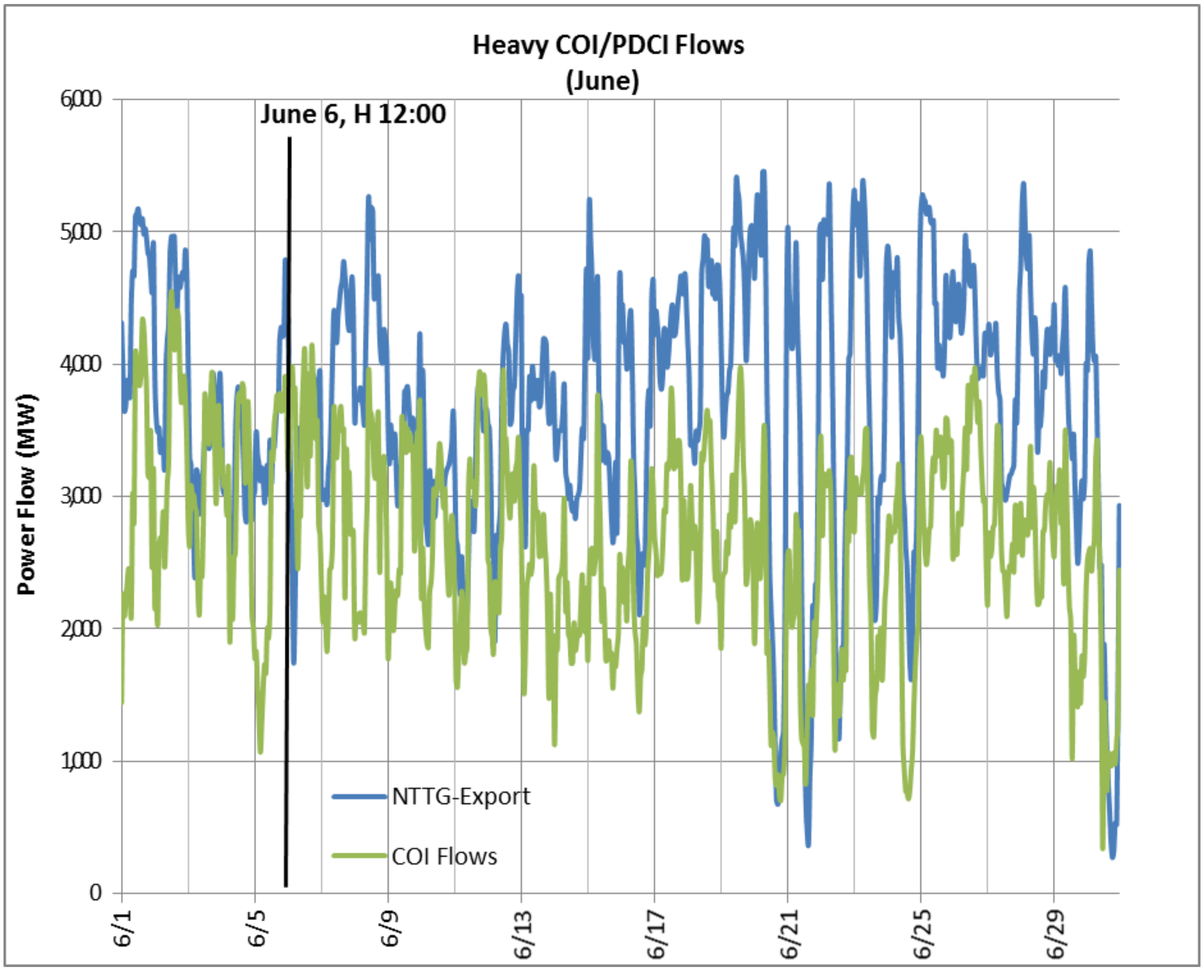


Figure 3-8: High COI/PDCI and low NTTG Export Hour Selection



Transferring Load and Resource Data and Solving Cases

Once the hours of interest were selected, the economic model was re-run and the data for those specific hours were exported to the power-flow program. Initially, data issues arose when trying to find a successful power-flow solution, resulting in specific network elements prohibiting a solution. Each issue was addressed until a successful solution was achieved.

Even after a successful solution was achieved, some generator units exceeded their reactive power limits. This was likely because the PC1 case didn't account for reactive power output requirements of generators. Additionally, because some generator output was altered as part of the process to find a successful power solution, some of the path flows differed from the PC1 data analysis. Therefore, further manipulation of the generation dispatch and loads was done to achieve the desired stressed conditions with generators operating within proper limits. Through these adjustments, NTTG assured that the cases represent real-time operating configurations and thus are more representative of the system than cases based on superficial loading and generation profiles. The cases were also minimally modified to ensure that there were no system normal overloads.

The Core Cases

Table 3-6 below presents the major path flows for each core case. Additional path flow details are provided in Appendix C. Note that a path generally consists of several lines, not just a single line. Flows shown in red text indicate an overload on the specified path.

Table 3-6: Path Flows in Core Cases

Path (Rating)	COI	PDCI	NORTH OF JOHN DAY	TOT2A	TOT2B	TOT2C	ID-NW	MT-NW	PATH C
	N-S 4800 MW	N-S 3220 MW	N-S 8400 MW	N-S 690 MW	N-S 865 MW	N-S 600 MW	E-W 3400 MW	E-W 2200 MW	N-S 1600 MW
Case	S-N -3675 MW	S-N -3220 MW	S-N N/A	S-N N/A	S-N -900 MW	S-N -580 MW	W-E -2250 MW	W-E -1350 MW	S-N -1250 MW
JUL21 16:00 – Summer	781	1235	6222	79	-148	1	-2238	484	1306
JAN5 8:00 - Winter	-2352	2600	3827	-594	-518	-8	-956	375	281
NOV6 10:00 – Export	4710	3440	4814	662	765	369	3031	2197	-905
SEP8 17:00 Import	-415	851	3544	363	21	8	-1505	158	281
JUN6 12:00 - COI	4478	2946	6234	453	328	-4	-1210	-215	1047

As seen in the table above, the PDCI flows in the Maximum Export Core Case exceed the indicated ratings. At the time the core cases were created and evaluated, the NTTG TWG assumed that planned upgrades would increase the PDCI path rating to 3,600 MW by 2022. Thus, the 3,440 MW flow level fell within the assumed future rating. However, the proposed upgrades were cancelled after the analysis was performed.

The Western Interconnection can be represented by balancing areas (e.g., areas where a transmission provider or several transmission providers balance the generation to the load) that are connected by paths. The flows across these paths (or tie-line flows) between balancing areas for each core case are shown in Figures 3-9 through 3-13. Megawatt values for the total area generation, total area load and total area interchange are shown on each diagram. Area losses can be determined from the diagram by taking the sum of the area total interchange and area total generation, then subtracting the total area load.

Figure 3-9: Tie-line Flows for Summer Peak-Load Core Case – July 21 16:00

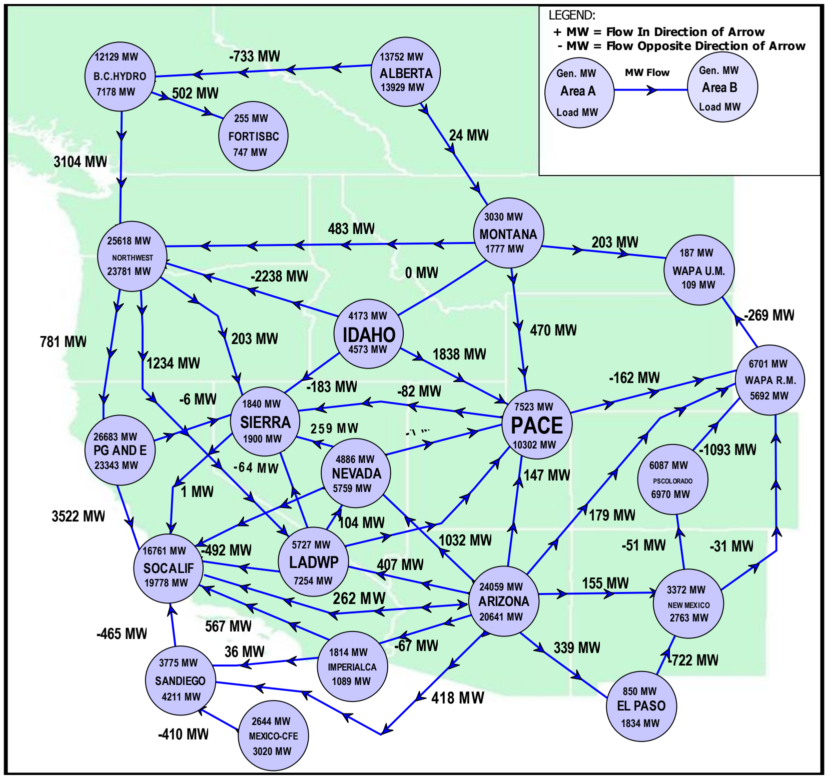


Figure 3-10: Tie-line Flows for Winter Peak-Load Core Case – Jan. 5 08:00

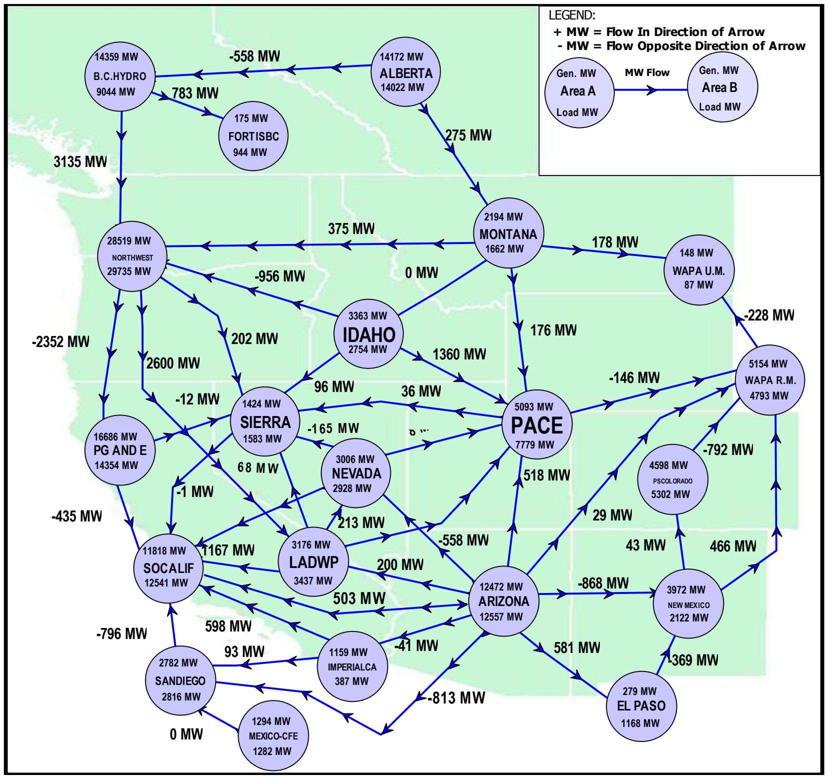


Figure 3-11: Tie-line Flows for Maximum Export Core Case – Nov. 6 10:00

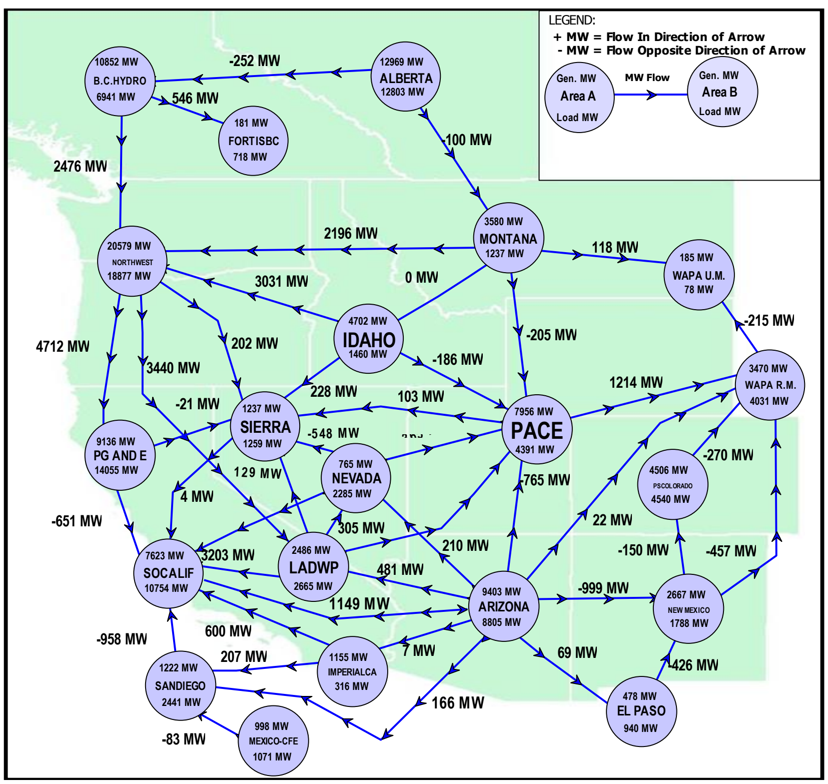


Figure 3-12: Tie-line Flows for Maximum Import Core Case – Sept. 8 17:00

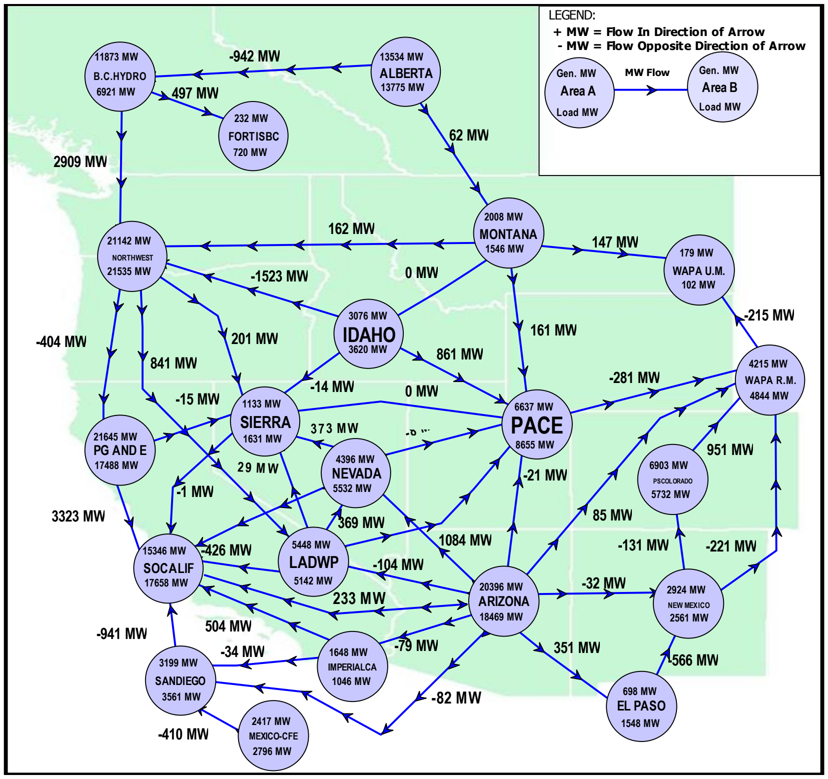
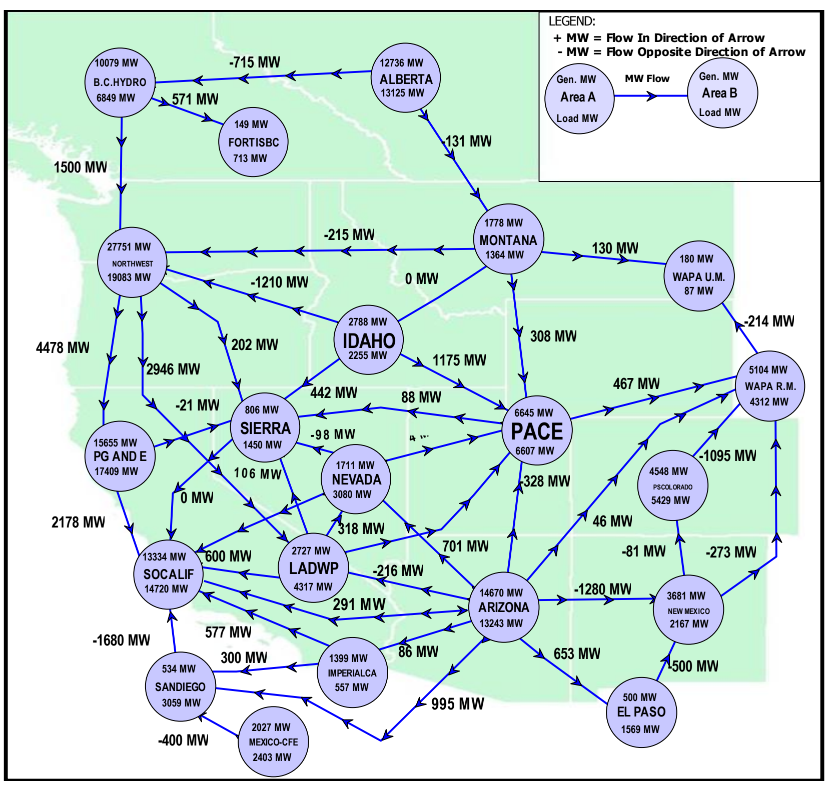


Figure 3-13: Tie-line Flows for COI/PDCI Core Case – June 6 12:00



Chapter 4 – NTTG Economic Studies

Obligation to Perform Economic Studies

FERC Order 890 mandates that transmission planning involve both reliability and economic considerations. Transmission providers fulfill the economic requirement by conducting economic planning studies, if requested by stakeholders. These studies evaluate transmission upgrades to reduce congestion or to integrate new resources and loads. In the process, the transmission provider must determine if the request is of local, subregional or regional scope. Those studies that are deemed regional in nature are forwarded to the regional transmission planning body. Economic study requests may be merged if the requests are similar in scope. NTTG performs up to two high-priority subregional studies, as determined by the Transmission Use Committee, each year of the two-year transmission planning process. Additional economic planning studies may be requested and funded by a stakeholder.

Economic Study Requests

NTTG received three economic study requests through NorthWestern Energy during the 2012-2013 planning process. Gaelectric requested a review of the transmission additions required to deliver up to 1,500 MW of renewable wind energy from Great Falls, Mont., to the California-Oregon border at the Malin, Ore., substation. They also requested the analysis of the amount of power that could be delivered without transmission additions. NorthWestern Energy requested studies of a new 500 kV line from Townsend, Mont., to Midpoint, Ida., (MSTI project) and a new 500 kV transmission-capacity upgrade from Colstrip through Townsend to Mid-Columbia in the Northwest. The requests were determined to be subregional in nature, and NTTG developed an Economic Study Plan.

Additionally, both submitters requested only power-flow reliability analysis be performed as opposed to security-constrained economic-dispatch analysis. The NTTG planning committee evaluated these requests and determined that all three requests could be combined as one cluster study. The combined study would determine if transmission additions were required to transport 1,500 MW of power from Great Falls to Malin, and to determine the how much power may be transported from Great Falls to Malin without transmission additions.

Study Procedure

NTTG analyzed four transmission configurations for the economic study. The analysis was an iterative process, with each configuration building on and incorporating prior additions. The additions were:

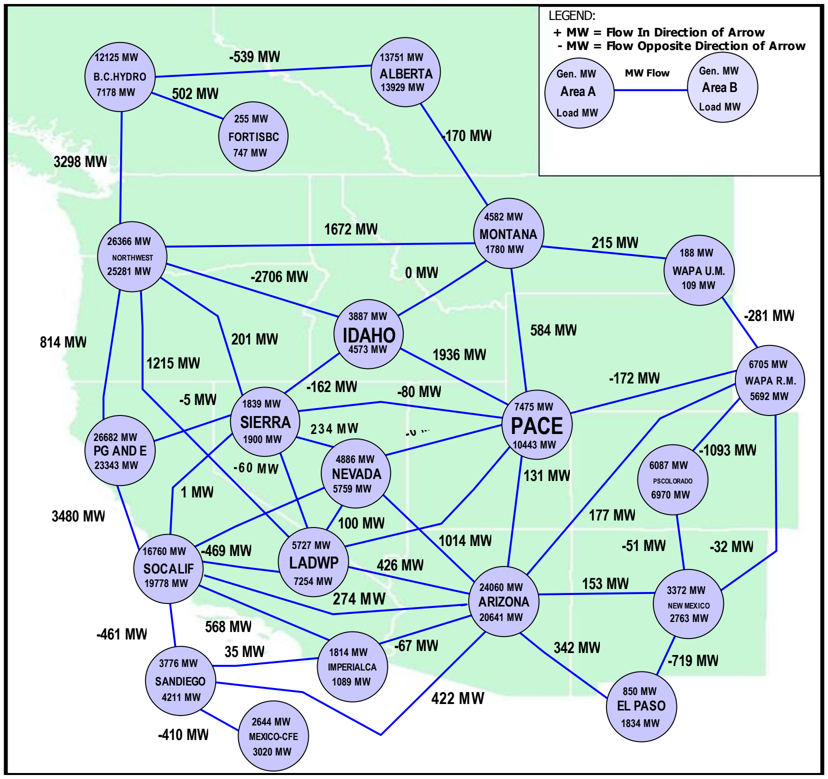
1. 1,500 MW of generation resource added to Great Falls and a 1,500 MW load in Malin
2. 500 kV line from Great Falls to Townsend to Midpoint with a new substation at Townsend
3. 500 kV line from Hemingway to Captain Jack
4. Second 500 kV line from Midpoint to Hemingway

As noted above, the combined study sought to identify what, if any, transmission additions were required for moving 1,500 MW of wind generation from Great Falls through Townsend to Malin. The first step was to study the NTTG Summer Peak-Load and Maximum Export cases without the requested transfer to determine if any transmission additions were required. This was done by performing a contingency analysis of each case. If any violations were identified in this analysis, they were investigated to resolve any incorrect information in the case or irrelevant busses, i.e., radial or sub-transmission busses. The next step was to model 1,500 MW of new generation in Great Falls along with a new 500 kV line from Great Falls to Townsend and a new substation at Townsend. A 1,500 MW load was also modeled at the Malin substation. The same contingencies were studied; any violations were identified and solutions recommended.

If the full 1,500 MW transfer produced unacceptable results, additional transmission facilities were added and evaluated in the following order: 1) a 500 kV line from Townsend to Midpoint, 2) a new 500 kV line from Hemingway to Captain Jack and 3) a second 500 kV line from Midpoint to Hemingway. See the Economic Study Report, Appendix D, which provides more detail about the modifications made to the core case. With each line addition, the cases were again tested to see if the reliability criteria were met for the contingency analysis. Any violations were identified and solutions recommended in order to obtain acceptable results.

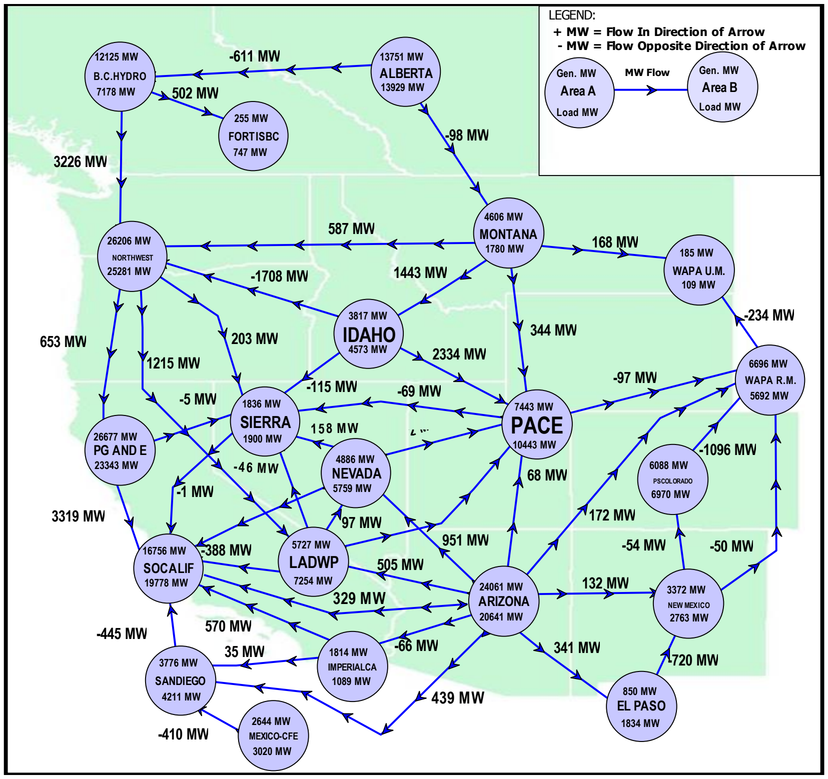
Figures 4-1 through 4-8 below display the tie-line flows between balancing areas for the Western Interconnection for each economic study case evaluated. Megawatt values for the total area generation, total area load and total area interchange are shown on each diagram.

Figure 4-1: Tie-line flows for Economic Study Summer Peak-Load Case 1



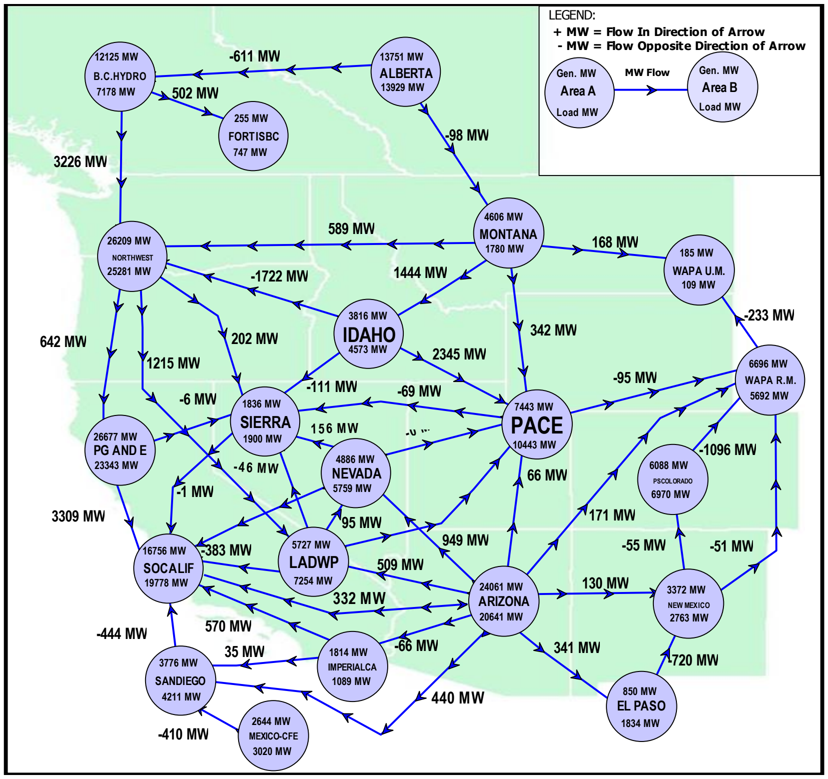
1,500 MW of generation added at Great Falls and 1,000 MW of load added at Malin

Figure 4-2: Tie-line flows for Economic Study Summer Peak Load Case 2



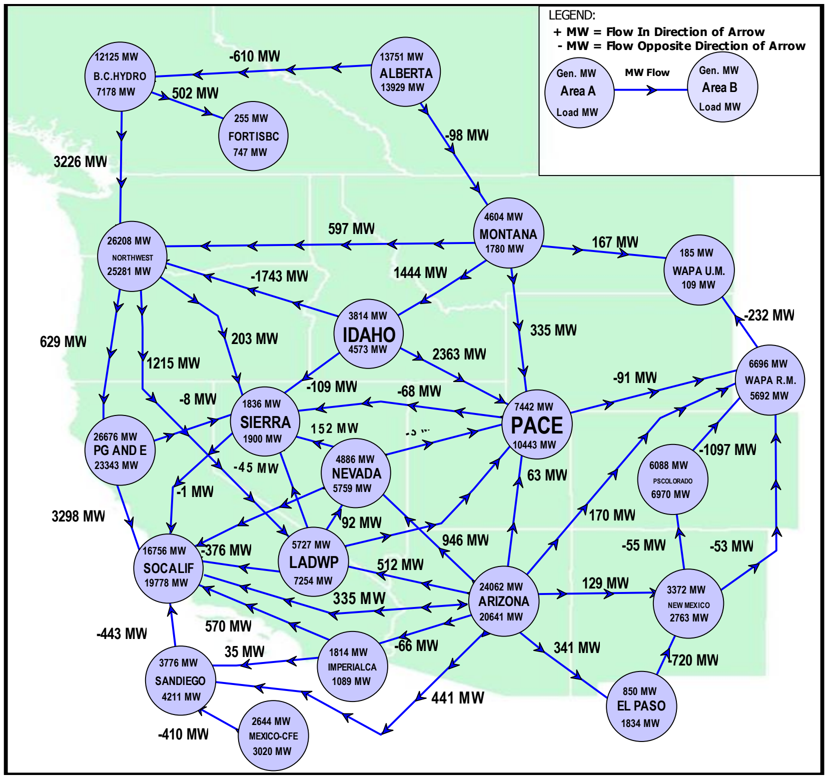
Generation added at Great Falls and load added at Malin with addition of 500 kV line from Townsend to Midpoint

Figure 4-3: Tie-line flows for Economic Study Summer Peak-Load Case 3



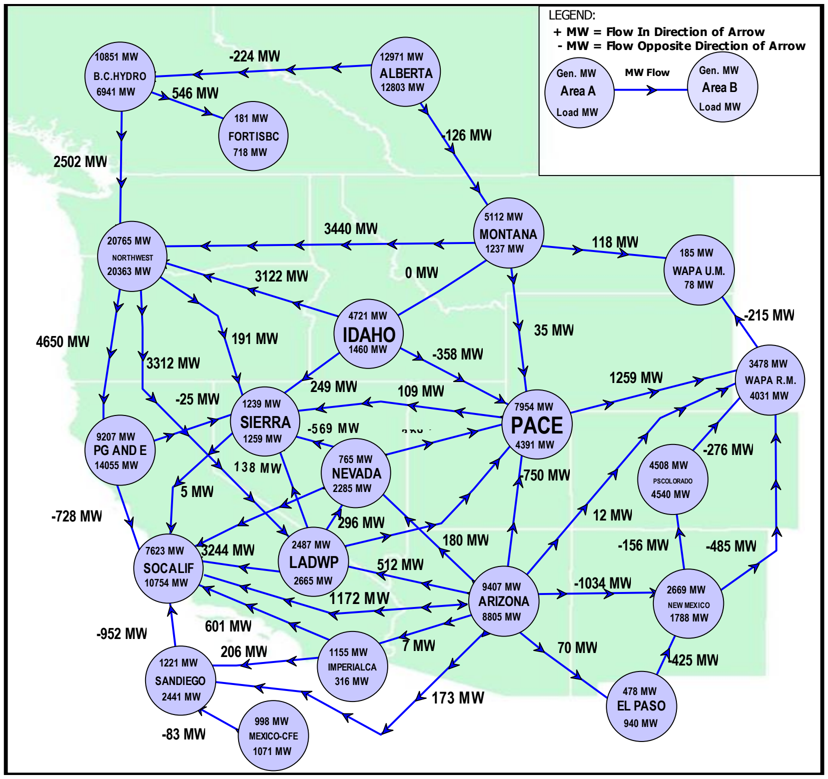
Generation added at Great Falls and load added at Malin with addition of 500 kV line from Townsend to Midpoint and a new 500 kV line from Hemingway to Captain Jack

Figure 4-4: Tie-line flows for Economic Study Summer Peak-Load Case 4



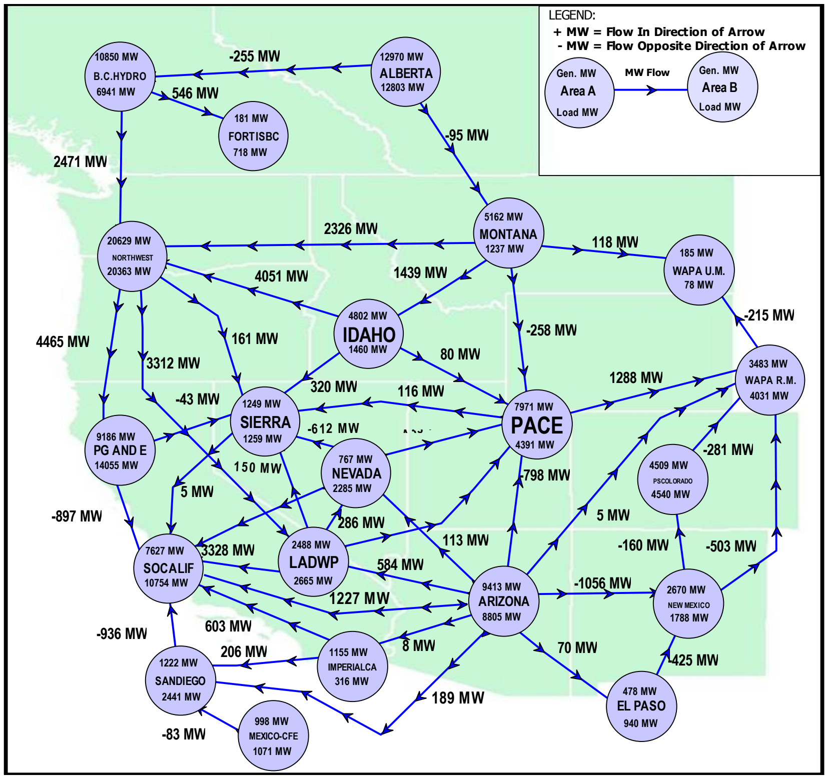
Generation added at Great Falls and load added at Malin with addition of 500 kV line from Townsend to Midpoint and a new 500 kV line from Hemingway to Captain Jack and a second 500 kV line from Midpoint to Hemingway

Figure 4-5: Tie-line flows for Economic Study Maximum Export Case 1



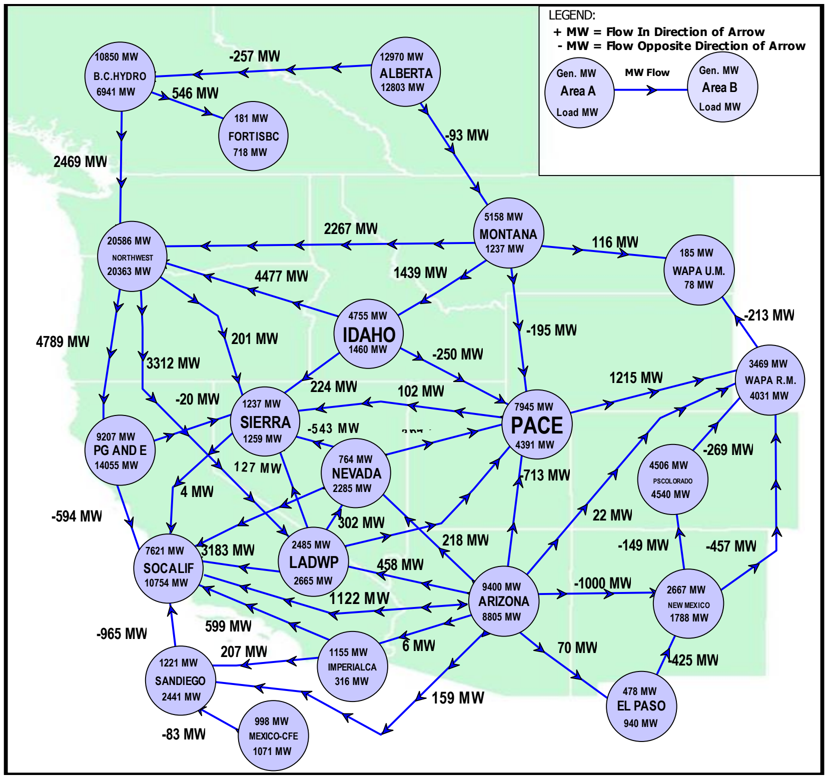
1,500 MW of generation added at Great Falls and 1,500 MW of load added at Malin

Figure 4-6: Tie-line flows for Economic Study Maximum Export Case 2



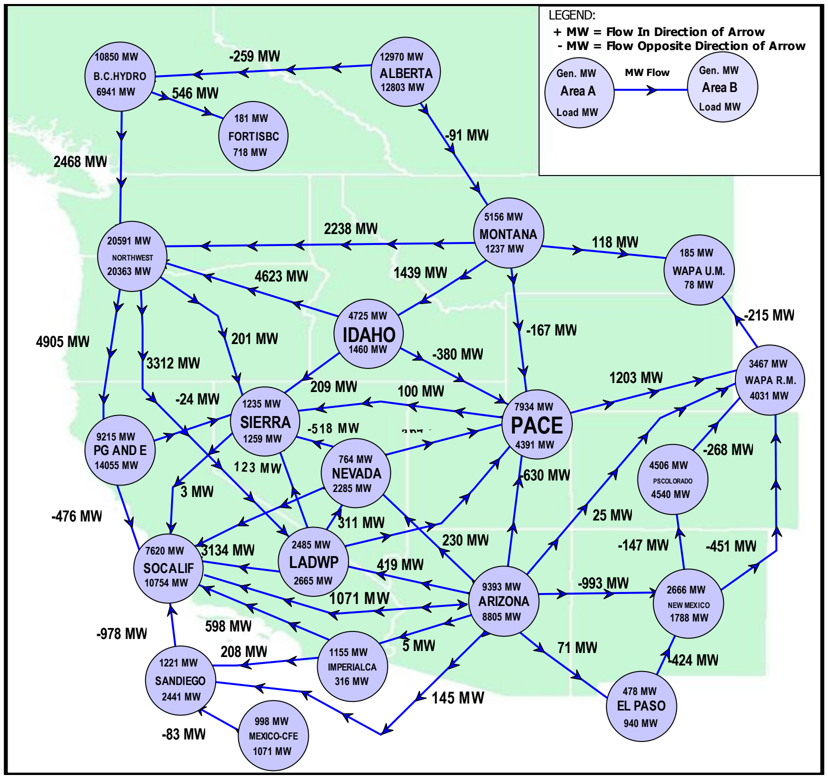
Generation added at Great Falls and load added at Malin with addition of 500 kV line from Townsend to Midpoint

Figure 4-7: Tie-line flows for Economic Study Maximum Export Case 3



Generation added at Great Falls and load added at Malin with addition of 500 kV line from Townsend to Midpoint and a new 500 kV line from Hemingway to Captain Jack

Figure 4-8: Tie-line flows for Economic Study Maximum Export Case 4



Generation added at Great Falls and load added at Malin with addition of 500 kV line from Townsend to Midpoint and a new 500 kV line from Hemingway to Captain Jack and a second 500 kV line from Midpoint to Hemingway

Study Results

In the Summer Peak-Load Case iterations, there were no N-0 thermal overloads or voltage-deviation issues. The only iteration with any N-1 contingency issues was Case 0, the case with an additional 1,500 MW of generation in Great Falls and an additional 1,500 MW load in Malin. See Appendix D for the complete contingency results of the Summer Peak-Load Case. The full 1,500 MW of requested transfer capability can be accommodated under heavy summer conditions with the addition of a new 500 kV line from Great Falls to Townsend to Midpoint.

In the Maximum Export Case iterations, only the core case without the 1,500 MW of additional transmission service and case 3, which includes all the proposed new transmission components, did not demonstrate N-0 voltage issues or thermal overloads. Cases 0, 1 and 2 all had both N-0 and N-1 voltage issues, thermal overloads or both. See Appendix D for the complete contingency results of the Maximum Export Case. The full 1,500 MW of requested transfer capability can be accommodated under maximum export conditions only with all the proposed additions to the transmission system. Up to 400 MW can be transferred with the single 500 kV line from Great Falls to Townsend to Midpoint.

Economic Study Conclusions

Summer Peak-Load Case: The results of the Summer Peak-Load Case show that the 1,500 MW transfer can be accommodated in the base case (N-0) without any transmission upgrades. The contingency analysis demonstrates that even with the CCTA additions, there are still a number of violations that need to be mitigated. Adding a 500 kV line from Townsend to Midpoint eliminates all of the significant violations in the Summer Peak-Load Case iterations. The study results do not show a substantial improvement by adding the Hemingway to Captain Jack or Midpoint to Hemingway 500 kV lines for the summer load study.

Maximum Export Case: The results of the Maximum Export Case show that in order to accommodate the 1,500 MW transfer from Great Falls to Malin in the base case, upgrades must be made to the Burns and Malin series capacitors. In addition to these upgrades, contingency analysis results show the need to also upgrade the Garrison series capacitors or add transmission improvements beyond the 30 CCTA projects that are already included. Results show that adding a 500 kV line from Townsend to Midpoint reduces some voltage issues and eliminates the Garrison series capacitor overload, but it overloads the Midpoint series capacitors in addition to the series capacitors at Burns and Malin. The study results do show a substantial improvement in adding the Hemingway to Captain Jack or Midpoint to Hemingway 500 kV lines, or both, for the Maximum Export Case study. However, even without these additional lines the results are acceptable with a new 500 kV line from Townsend to Midpoint and series capacitor upgrades at Burns, Malin and Midpoint.

The Maximum Export Case is the most limiting condition for establishing the maximum transfer utilizing a single 500 kV line from Great Falls to Townsend to Midpoint and no additional upgrades. The maximum transfer determined in the study, based on power-flow studies only, is 400 MW.

Several WECC-rated paths exceed the proposed future ratings in the export cases, namely Idaho-Northwest, Montana-Northwest, West of Hatwai and Hemingway-Summer Lake paths. Additional path-rating studies would be required to determine the scope of improvements required to operate these paths at the flows in the export base cases. Only power-flow studies—no stability studies—were conducted for this study request.

These study results are contingent on the loads, resources and transmission facilities used in the TEPPC 2022 production cost model. This includes 30 future transmission projects that constitute the CCTAs. Any changes to these assumptions, the generation dispatch or additional transmission would likely result in different transmission requirements.

Chapter 5 – The Null Case

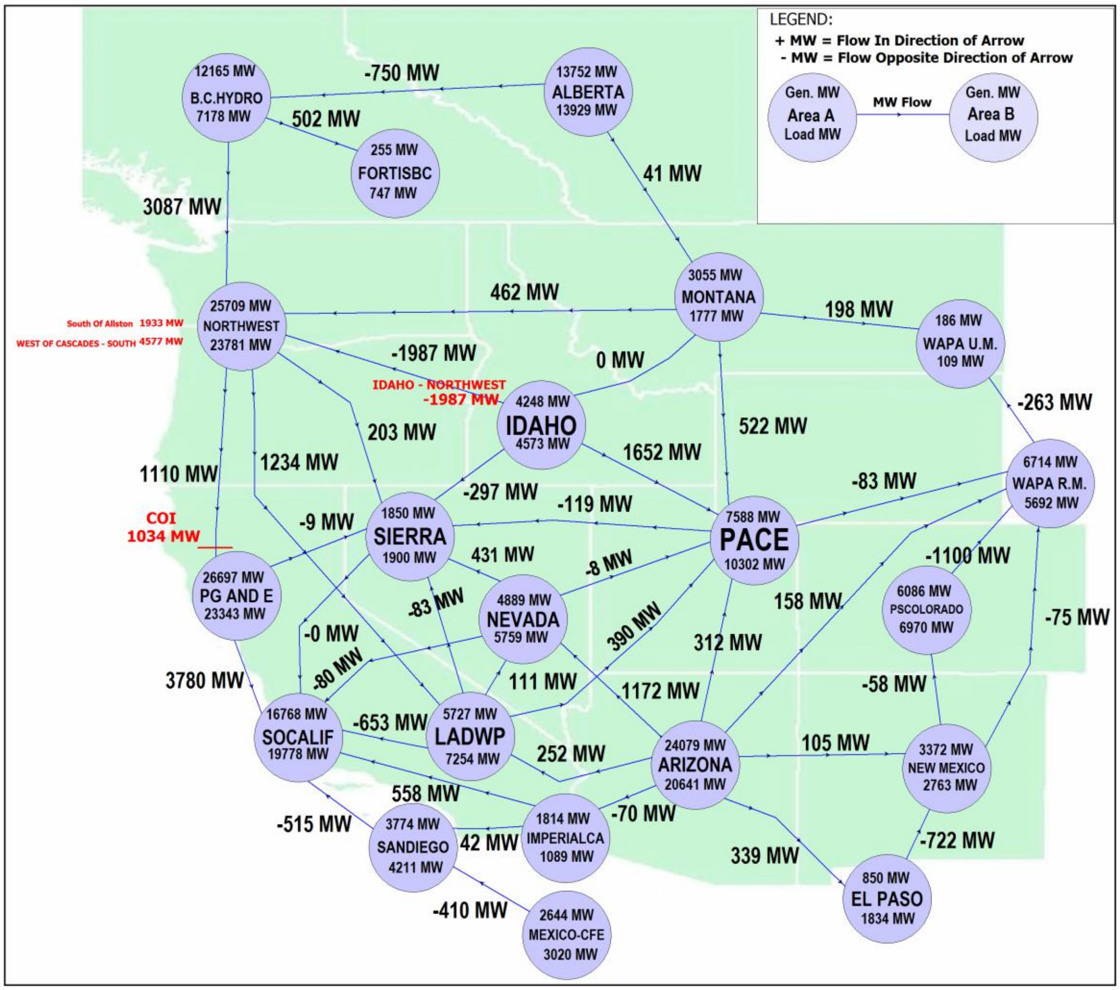
Introduction

The Null Case seeks to discover whether the near-term transmission system can meet the demands of the NTTG footprint year 2022 forecast load. In the 2010-2011 biennial planning cycle, NTTG adjusted a near-term WECC power-flow case to 2022 by increasing the NTTG loads to the submitted 10-year forecast. This was done without inclusion of the submitted 10-year network-resource additions. This produced a power-flow case with an unrealistic generation dispatch and resulted in many improbable transmission-facility violations. The NTTG planning committee decided not to repeat this process but instead to use the NTTG summer peak load case. Thus, the Null Case was derived from the July 21, 2022 @ 16:00 Hours Case. This case was modified to reflect the near-term transmission system by removing 23 of the 30 CCTA projects. The remaining seven of the 30 CCTA projects, listed in Table 5-1, are either currently in service or are expected to be in service within the planning cycle.

Table 5-1: Common Case Transmission Assumptions (CCTA) Projects Retained

Project	In Service	Under construction	Comments
04-Delany-Paloverde line		✓	WECC Portal, updated April 24, 2012, indicates line is under construction
16-Interior to Lower Mainland Project		✓	Project website indicates construction will be completed January 2015
17-Montana Alberta Tie Project (MATL)		✓	Construction to resume after right-of-way access permits are received
19-Midway to Waterton line	✓		Project completed and energized May 25, 2011
25-Sunrise Power Link	✓		Completed construction June 2012
29-West of McNary: McNary-John Day line	✓		Completed construction November 2011
30-West of McNary: Big Eddy-Knight line		✓	Began construction; schedule has been delayed. BPA estimates line will be energized winter 2014.

Figure 5-1: Null Case Area Tie-lines



Null Case Study Methodology

Other than the removal of all but seven CCTA projects, the transmission topology was not changed from the Summer Peak-Load Core Case. Power-flow analysis was performed on the Null Case to determine if any voltage or thermal overload violations existed during system normal (N-0 pre-disturbance analysis with all lines in service) and one transmission element out of service at a time (N-1 contingency analysis) as described in Chapter 2. Additionally, no transmission improvements were studied to resolve any deficiencies identified in the study process.

Power-Flow Analysis Results

The N-0 power-flow analysis on the Null Case identified five voltages below the 0.90 per unit threshold, 14 branch overloads and one path interface where the flow exceeded the path rating (Path 18-Montana-

Idaho). A high-level summary of overloads and voltage issues on major transmission elements under N-0 conditions is presented in Table 5-2. The detailed results regarding violations under N-0 conditions are shown in Appendix E.

Table 5-2: N-0 Performance Comparison between Summer Peak-Load Core Case and Null Case

Category	Summer Peak-Load Core Case *	Null Case
Branch Amp	5	14
Branch MVA	0	0
Bus Voltage High	0	0
Bus Voltage Low	0	8
* The branch overloads in the Summer Peak-Load Core Case were found to be acceptable.		

The N-1 contingency analysis resulted in many violations during outage conditions. Tables 5-2 and 5-3 compare the Null Case and NTTG Summer Peak-Load Core Case results. Two N-1 contingencies failed to solve to a stable operating point. The summary of these results is shown in Table 5-3. Detailed results for contingencies that reached maximum iterations and contingencies that failed to solve are located in Appendix E.

Table 5-3: N-1 Contingency Performance Comparison between Summer Peak-Load Core Case and Null Case

Category	Summer Peak-Load Core Case*	Null Case
Branch Amp	0	70
Branch MVA	5	18
Bus Voltage High	0	12
Bus Voltage High Deviation	0	30
Bus Voltage Low	0	23†
Bus Voltage Low Deviation	0	0- Unacceptable‡
* The branch overloads in the Summer Peak-Load Core Case were found to be acceptable		
† All Voltages are below 0.9 pu		
‡ Voltage Deviations >5% and falls below 0.9 pu		

The N-1 outage analysis showed thermal overload violations on several transmission elements. Five contingencies had overload violations greater than 125% under outage conditions, 15 exceeded 110% and the other overloads were under 110%. Detailed results of transmission elements that observed overloads greater than 125% are shown in Appendix E. Three different thermal overloads (>100%) were observed in the Northwest area, eight overloads (>100%) were observed in the PacifiCorp East area, six overloads (> 100%) were observed in the Idaho area and three overloads (>100%) were observed in the WAPA Rocky Mountain area. Voltage at some busses fell below 0.90 per unit under certain outage conditions. Detailed descriptions of the thermal overloads and voltage issues observed for different outage conditions are shown in Appendix E.

Null Case Conclusion

The Null Case study demonstrates that the transmission system will be subjected to overloads beyond NERC and WECC reliability criteria. The Null Case power-flow analysis discovered overloads on transmission elements under normal operating conditions and for N-1 contingencies. Voltage criteria violations were also observed on several 500 kV busses and at other voltage levels under certain N-1 outage conditions. Thus, the Null Case reveals that the existing NTTG transmission system is inadequate to fulfill the transmission requirements to reliably serve the 2022 forecast loads and resources. Additional transmission is required to reliably meet future needs.

Chapter 6 – The Core Cases

Introduction

As described in Chapter 3, the NTTG TWG created a set of five core cases to analyze future system reliability under five different stressed conditions within the NTTG footprint. The committee selected peak-load hours as well as high-import and high-export conditions that produced those stress points as described in Chapter 3.

Power-Flow Analysis

The power-flow software, PowerWorld Simulator, was used to perform power-flow analysis on the five core cases. See Section 2 for more detail about the analysis process. The violation tables for all five core cases can be found in Appendix F.

Summer Peak-Load Case – July 21 16:00 Hours

This case represents the maximum NTTG coincident summer peak-load condition of 23,846 MW. The net NTTG export is minimal (1,454 MW) in the case since most of the NTTG internal generation is utilized to serve the peak NTTG load. As stated previously, this case, along with all other core cases, contains all 30 of the CCTA projects.

The pre-disturbance (N-0) screening resulted in five overloaded elements. One local-area 46 kV line was within the NTTG footprint while the four other elements were outside the NTTG footprint. All elements were 161 kV or below and determined to be acceptable as a result of the generator dispatch or case stressing, or both, on local-area systems. Contingency analysis resulted in a total of five thermal overloads; however, the five overloads were on the same transformer for five different contingencies. The overloads occurred on a 161kV/100kV transformer in Montana that was loaded to 98% pre-contingency. The NTTG TWG determined that the overload condition was acceptable for NTTG purposes because the overload was a previously identified local planning issue.

Four voltage-deviation issues resulted from the contingency analysis. In all four instances, the post-disturbance voltage remained within the acceptable range. Therefore, each voltage deviation issue was determined to be acceptable.

Winter Peak-Load Case – Jan. 5 8:00 Hours

This case represents the NTTG winter peak-load condition of 20,280 MW. Similar to the summer peak case, most of the NTTG generation is used for serving NTTG loads, with only 731 MW of exports.

The pre-disturbance (N-0) screening resulted in no overloaded elements and no voltage issues. The N-1 contingency analysis resulted in zero thermal overloads and 14 voltage-deviation issues. Each voltage deviation produced a post-disturbance voltage within the acceptable range. Therefore, each voltage-deviation issue was determined to be acceptable.

Maximum Export Case – Nov. 6 10:00 Hours

This case represents a heavy NTTG export condition with NTTG exports totaling 10,077 MW. The heavy export condition corresponds with a low NTTG load (11,970 MW) and high internal generation.

The pre-disturbance (N-0) screening resulted in four elements with thermal overloads; however, all were deemed to be acceptable for study purposes. Three of the overloads were within the NTTG footprint, with each overload resulting from generation modeling in the PC1 base case. The overload outside of the NTTG footprint was a load-serving branch; it had no impact on the NTTG study. Two busses in the case exceeded 1.1 per unit voltage. The two busses were 500 kV busses in Arizona. Since the busses were outside of the NTTG footprint, they were each deemed to be acceptable for NTTG study purposes.

Contingency analysis resulted in four thermal overloads within the NTTG footprint. Upon further review, each overload was determined to be acceptable.

A total of 40 voltage deviation issues resulted from the contingency analysis. The 40 voltage-deviation issues all resulted in a post-disturbance voltage within an acceptable range.

Maximum Import Case – Sept. 8 17:00 Hours

This case represents the minimum coincident export condition from the NTTG footprint, also referred to as the Maximum Import Core Case. The net NTTG import was 81 MW. The net NTTG load is fairly high (20,086 MW), with reduced internal generation, thus producing an import condition.

The pre-disturbance (N-0) screening resulted in two slight overloads (both less than 0.5%), both outside of the NTTG footprint. Each overload was determined to be acceptable for NTTG study purposes. Nine busses had voltages below 0.9 per unit, but each of the low-voltage busses was within a 69 kV local-area network. Since the low voltages were isolated to a 69 kV local area network, the voltages were deemed acceptable for NTTG study purposes.

The N-1 contingency analysis resulted in zero thermal overloads and two voltage-deviation issues. The two reported voltage deviations resulted in a post-disturbance voltage within the acceptable range, and therefore, each issue was determined to be acceptable.

COI/PDCI Case – June 6 12:00 Hours

This case was studied to look at a relatively low NTTG footprint net-export coincident with fairly heavy flow conditions on the Pacific Intertie lines. Flows were 4,478 MW on COI and 2,946 MW on PDCI lines, while NTTG exports totaled 3,290 MW.

The pre-disturbance (N-0) screening resulted in no overloaded elements and no voltage issues.

The N-1 contingency analysis resulted in zero thermal overloads and 29 voltage-deviation issues. Each of the 29 reported voltage-deviation issues resulted in a post-disturbance voltage within the acceptable range, and therefore, each issue was determined to be acceptable.

Core Case Conclusion

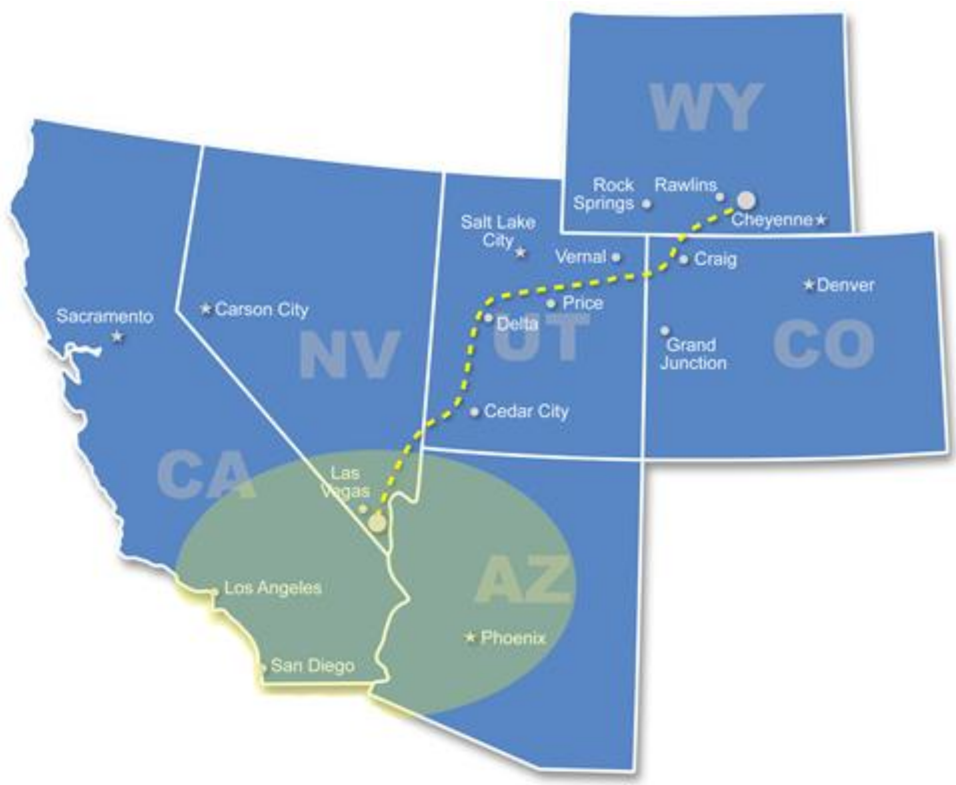
The results of the five core cases demonstrate that, with the CCTA projects added, there is adequate transmission to accommodate the projected 2022 loads and resources. No additional transmission facilities are needed in this time frame based on the analysis of the five stressed conditions represented in the core cases

Chapter 7 – The Scenario Case – TransWest Express

Introduction

In the first quarter of the biennial planning cycle, Power Company of Wyoming (PCW) submitted data for a new 3,000 MW wind resource in southwest Wyoming. TransWest Express (TWE) also submitted data for a proposed 600 kV extra-high-voltage direct-current electric-transmission system with 3,000 MW capacity. The planned 725-mile route begins in south-central Wyoming, extends through northwestern Colorado and central Utah and ends near Las Vegas as shown in Figure 7-1. The TWE project requested that the PCW generation and DC line be studied as a scenario case. The Planning Committee agreed to study the impact of these new facilities as a scenario case in the study process.

Figure 7-1: TransWest Express Transmission Project



The dotted line indicates the approximate route of the proposed transmission line project.

The power-flow data submitted to the TWG consisted of 3,120 MW of new generation at the sending end of the DC line in southwest Wyoming to provide for losses on the DC line, while still delivering 3,000 MW to Nevada. TWE also proposed limiting the DC line flow to 2,650 MW at the Nevada end during periods of high flow on the COI in order to resolve contingency violations during higher flows.

The Scenario Case

NTTG modified the Maximum Export Core Case by adding a new wind resource in Wyoming and delivering the power to Las Vegas via a new direct current (DC) bipole transmission line. The TransWest scenario was represented with both 3,000 and 2,650 MW flow levels on the DC line delivered to Las Vegas. Both scenarios were developed from the NTTG Maximum Export Core Case (Nov. 6 10:00).

The TWG incorporated the following TransWest Express recommendations regarding the scenario to be studied:

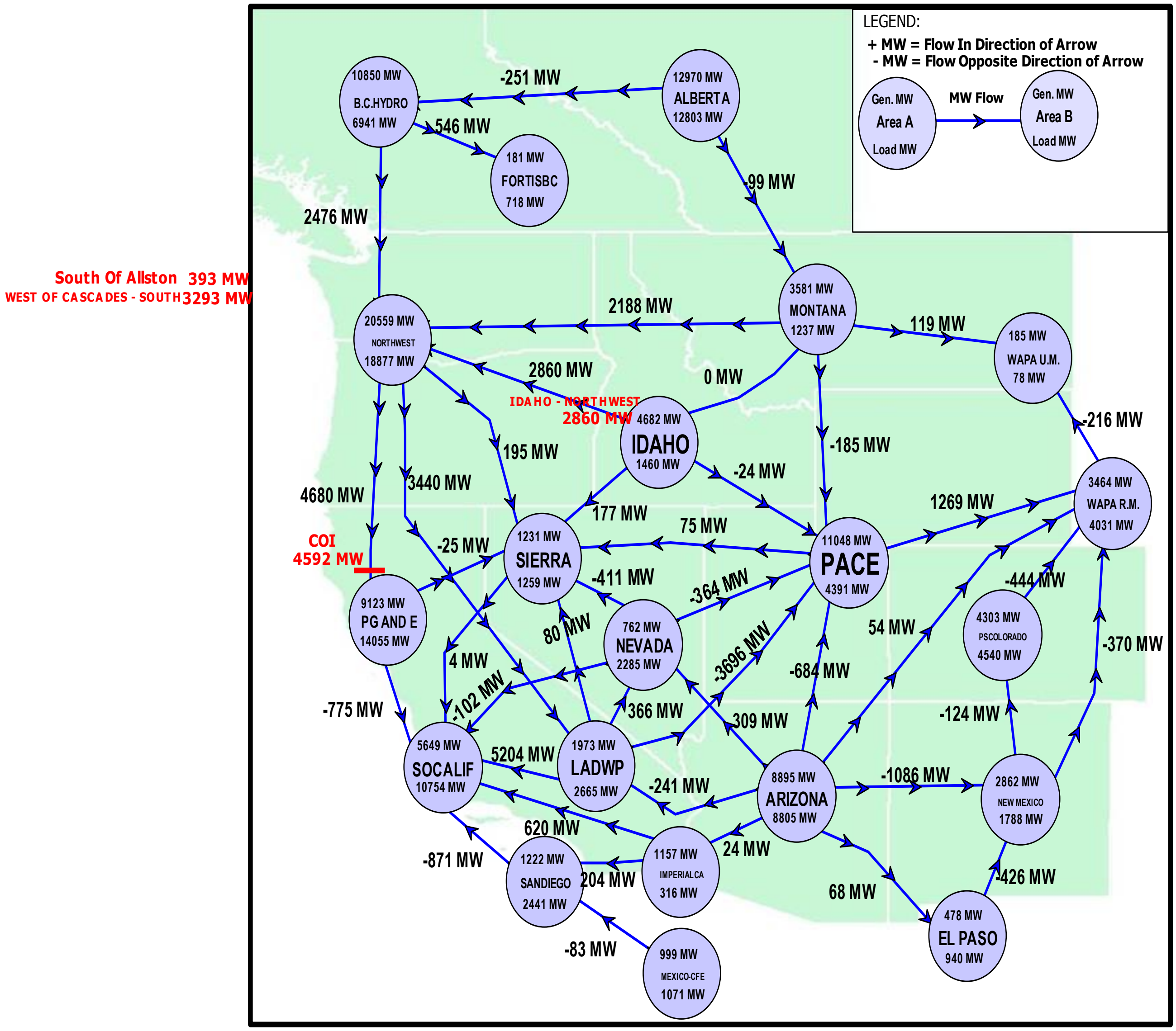
- Analyze the NTTG Maximum Export Core Case
- Schedule 3,000 MW at the Las Vegas end of the TWE DC line
- Reduce generation 2,000, 500 and 500 MW in Southern California Edison, Los Angeles Department of Water Power and Arizona state, respectively, to receive the scheduled power
- Trip 50% of PCW generation for the bipole transmission line contingency
- If the COI flow is near its 4,800 MW rating, reduce the scheduled flow in 100 MW increments while maintaining PCW generation, tripping at 50% of the flow until the case solves

3,000 MW Delivered to Nevada

The TransWest Express full-capacity scenario modeled 3,000 MW at the receiving end of the DC line, with 3,120 MW of new wind generation in southwest Wyoming. Path flows on adjacent transmission paths included 4,661 MW on COI, 465 MW on TOT 2B1, 219 MW on TOT 2B2 and 364 MW on TOT 2C. The scenario modifications required some re-dispatch of generators throughout the interconnection. These changes, as well as the resulting interface changes for this scenario, are listed in Appendix G.

Study results showed no violations for the TransWest Express DC monopole outage. However, the DC bipole outage did not solve without remedial actions. Tripping 1,560 MW (half of the sending-end flow on the DC line) of Wyoming wind generation for the DC bipole outage still resulted in 11 violations. These violations were for branch overloads on the Red Butte-Harry Allen 345 kV line (113% of limit) and the Pinto phase shifters (102% of limit). There were also low voltages (<0.9 p.u.) at several busses in the Pinto area (PACE-owned substations). The post-transient Malin voltage dipped to 95.6% in this case, which likely would cause the FACRI RAS scheme to initiate. With the switching of reactive devices associated with FACRI, the number of violations for the DC bipole outage reduced to only three — the overload of the two Red Butte-Harry Allen line sections (105% of limit) and one low-voltage bus in the Pinto area.

Figure 7-2: Maximum Export TransWest Express Full Capacity Scenario



2,650 MW Delivered to Las Vegas

The TransWest Express reduced scenario modeled the TransWest Express project with 2,650 MW of flow on the receiving end of the DC line and with high COI flow. The NTTG Maximum Export Core Case was modified to represent this DC line flow with 4,670 MW on COI, 466 MW on TOT 2B1, 220 MW on TOT 2B2 and 369 MW on TOT 2C. This was done by increasing generation in Nevada by 350 MW and reducing the new Wyoming wind generation to 2,740 MW. The results of the DC bipole outage, without generator tripping, showed that the case did not solve, producing 46 violations, including overloading on the Red Butte-Harry Allen line (134% of limit) and the Pinto phase shifters (107% of limit). By tripping 1,370 MW of wind generation (equal to one-half of the sending-end DC line flow) the number of violations was reduced to only two – the two sections of the Red Butte-Harry Allen line (106% of limit). The Malin post-transient voltage dipped to 507 kV in this case, which would likely initiate the FACRI scheme. The results for the same contingency with generator tripping and with FACRI employed showed no violations.

Figure 7-3: Maximum Export TransWest Express Reduced Scenario

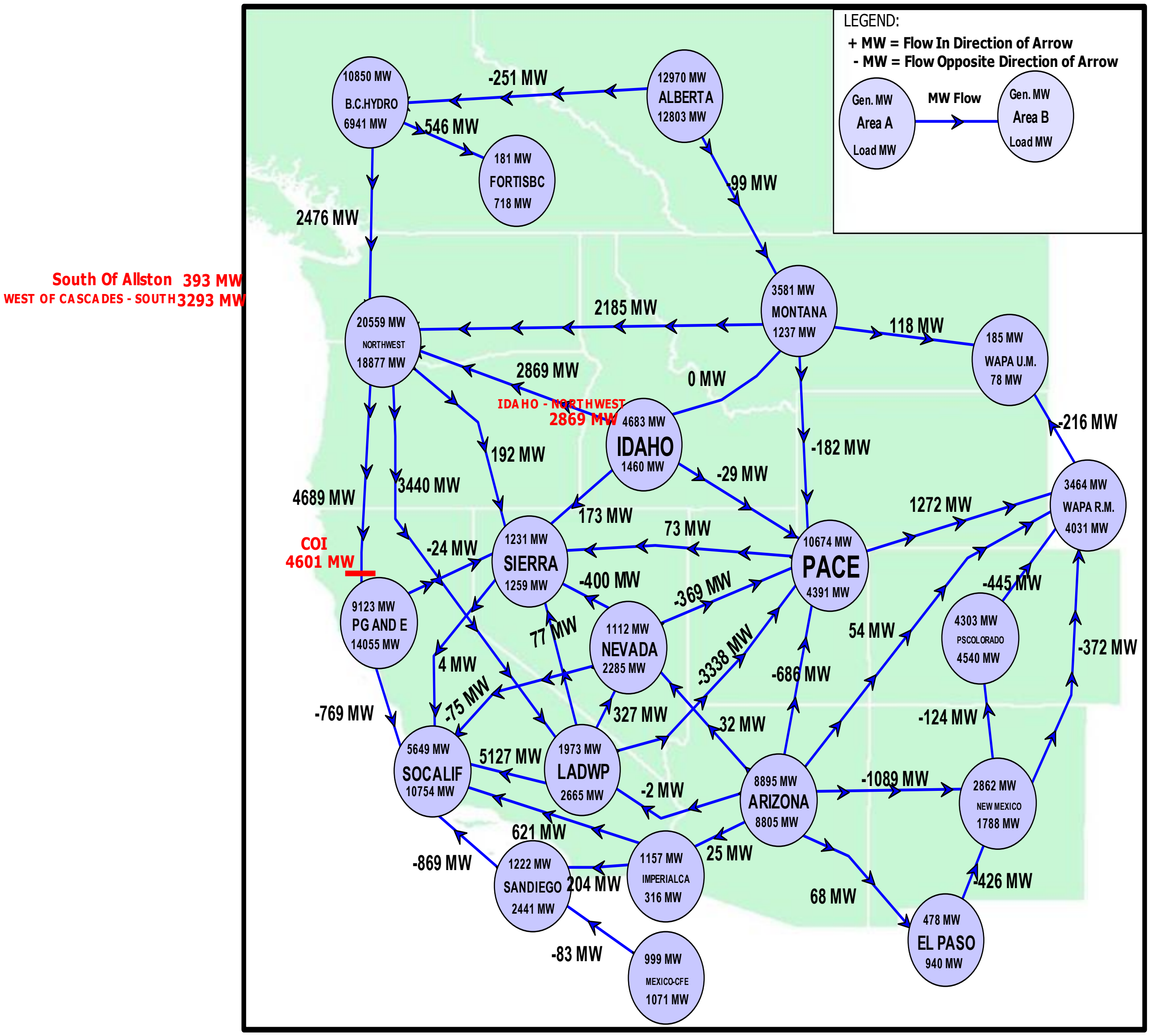


Table 7-1: Scenario Study Results

	3000 MW TWE DC line receiving end	2650 MW TWE DC line receiving end
Contingencies	Violations	Violations
TWE Bipole DC line outage	No Solution	47
TWE Bipole outage with 1560 MW WY gen-tripping	11	2
TWE Bipole outage with 1560 MW WY gen-tripping, FACRI	2	0
TWE Single pole DC line outage	0	0
TWE Single pole with 1560 MW WY gen-tripping	0	0
2PV unit outage with FACRI, RAS	0	0

Scenario Case Conclusion

Study results for the TransWest Express 3,000 MW Scenario Case show the need for remedial actions for loss of both poles of the new DC line. Even tripping one-half of the DC line flow (1,560 MW) of wind generation in Wyoming, as recommended by TransWest Express, was insufficient to achieve acceptable results within the NTTG footprint. Study results also show that if the TransWest Express DC line flow is reduced to 2,650 MW (receiving end), the loss of the DC bipole is less severe, with few or no violations, depending on whether FACRI action is employed.

Chapter 8 – Report Conclusions

The NTTG TWG performed reliability analysis on a Null Case (near-term transmission), five core cases (hours of NTTG transmission or load at maximum conditions) and a Scenario Case (TransWest Express DC line). NTTG expanded the use of exporting cases from security-constrained economic-dispatch modeling to power-flow cases in order to simulate five NTTG transmission-system loading conditions representing peak load, maximum NTTG export, maximum NTTG import and high COI path flow conditions. The Scenario Case analyzed 3,000 and 2,650 MW of Wyoming wind generation associated with a DC transmission line to southwest Nevada (Power Company of Wyoming and TransWest Express project).

In conclusion[5]:

1. The results of the Null Case demonstrate that the near-term transmission system is *not* adequate to meet the forecasted 2022 load and resource requirements.
2. The results of the five core cases demonstrate that the CCTA projects provide adequate transmission capacity to accommodate forecasted 2022 loads and resources.
3. The economic study demonstrates that 1,500 MW of power may be transferred from Great Falls to Malin, with the addition of a 500 kV line from Great Falls to Townsend to Midpoint and series capacitor upgrades at Burns, Malin and Midpoint. Additionally, only 400 MW may be transferred if only the 500 kV line from Great Falls to Townsend to Midpoint is added.
4. Study results for the Scenario Case show the need for remedial actions for loss of both poles of the new bipole DC line if transferring 3,000 MW. Even tripping one-half of the DC line flow (1,560 MW) of wind generation in Wyoming, as recommended by TransWest Express, was insufficient to achieve acceptable results within the NTTG footprint. Study results also show that if the TransWest Express DC line flow is reduced to 2,650 MW (receiving end), the loss of the DC bipole is less severe, with few or no violations, depending on the whether FACRI action is employed.[6]

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[5] The study results presented in this report are contingent on the loads, resources and transmission facilities modeled. Different assumptions in load, generation dispatch and transmission would likely result in different transmission requirements.

[6] This Scenario Case study does not provide a transmission path rating. The TransWest Express project must initiate the WECC path rating process to determine the actual capability of the TransWest Express DC transmission line. Any studies and ratings that rely on the use of the FACRI remedial action scheme must be coordinated with Bonneville Power Administration.