NTTG Biennial Study Plan
for the
2016-17 Regional Planning Cycle

This b~~B~~iennial Study Plan outlines the process to be followed by the NTTG Planning Committee in performing the 2016-17 biennial regional transmission planning process, as required under FERC Orders No. 890 and 1000, Attachment K – Regional Planning Process.

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I. Introduction

This Biennial Study Plan[1] (study plan) outlines the study process that the Northern Tier Transmission Group (NTTG) will follow to develop the ten-year Regional Transmission Plan for the planning cycle covering years 2016-2017. In addition to the information pertaining to the development of NTTG's 2016-17 Regional Transmission plan, this study plan also describes NTTG's process to determine if a properly submitted Interregional Transmission Project ("ITP") is a more cost effective or efficient solution to one or more of NTTG's regional transmission needs. This study plan will rely on the loads, resources, point-to-point transmission requests, desired flows, constraints and other technical data that were submitted in Quarter 1 and will be subsequently updated in Quarter 5 of the Regional Planning Cycle, and will be considered in the development of NTTG's 2016-17 Regional Transmission Plan. Additionally, the methodology, criteria, public policy requirements and considerations, assumptions, databases, identification of the analysis tools and project identification (including Initial Regional Plan and Alternative Project s[2]) will be established within the study plan and posted for comment by stakeholders and Planning Committee members. If there are any differences between what is stated in this study plan and the process stated in Attachment K of the NTTG FERC Order 1000, Attachment K will take precedent.

The NTTG Planning Committee chair has established the Technical Work Group (TWG) subcommittee to undertake the development of this study plan and perform the technical evaluations necessary to develop the Regional Transmission Plan and assess any ITPs submitted to NTTG. The TWG is established at the beginning of each biennial planning cycle and is comprised of individuals who are NTTG Planning Committee members or their designated technical representative, have signed NTTG's Confidentiality Agreement and have been authorized to have access to confidential data by any entity who may have submitted confidential data to NTTG. Members of the TWG work at the direction of the NTTG Planning Committee Vice-Chair, must have access to and expertise in power system power flow analysis or production cost modeling and are committed to accepting and completing technical planning assignments in a cooperative and timely manner.

[1] Capitalized terms in this document are from Attachment K definitions

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

II. Study Objective

The objective of the transmission planning study is to produce the NTTG Regional Transmission Plan, through the evaluation and selection of projects that meets the transmission needs within the NTTG footprint on a regional and interregional basis that are more efficient or cost effective than the Initial Regional Plan ("ITP").

III. General Schedule and Deliverables

The broad timing of the Regional Transmission Plan Development process and the work products to be delivered are presented in each of the NTTG Transmission Providers' Attachment K:

- **Quarter 1:** Collect load and resource forecasts, new regional and interregional transmission projects (sponsored, unsponsored and merchant), point-to-point transmission requests, and transmission needs driven by public policy requirements and considerations from stakeholders.
- **Quarter 2: By April 15th,** evaluate the completeness of data received from stakeholders and resolve any deficiencies. Develop the Biennial Study Plan for approval by the Steering Committee.
- **Quarters 3 and 4**: Analysis and Development of the Draft Regional Transmission Plan. The submitted system loads, resources, regional and interregional transmission project solutions will be modeled and technical screening studies will be performed to evaluate the Initial Regional Plan and a Change Case with Alternative Projects. By the end of Quarter 4 NTTG will post a Draft Regional Transmission Plan.
- **Quarter 5:** Stakeholders may review and comment on the Draft Regional Transmission Plan. Stakeholders may also submit new unsponsored projects during Quarter 5. New unsponsored projects will be considered, to the extent feasible, as determined by the Planning Committee without delaying the development of the Regional Transmission Plan. Stakeholders may also provide updates that may lead to a material change from data submitted in Quarter 1. The updated data will be evaluated by the TWG as part of the preparation of the Draft Final Regional Transmission Plan (DFRTP).
- **Quarter 6**: Cost allocations studies and analysis. The TWG will then prepare the DFRTP.
- **Quarter 7**: Stakeholders' are to review and comment on the DFRTP and the TWG will consider the Quarter 5 updates and unsponsored projects and stakeholder comments to produce an updated Draft Regional Transmission Plan.
- **Quarter 8**: The Planning Committee will submit the Regional Transmission Plan for NTTG Steering Committee approval and the Regional Transmission Plan will be posted.

IV. Study Assumptions and Representation

A. Major Study Assumptions and System Representation

1. Data Assumptions

The following loads, resources, transmission service obligations, transmission project and alternative project assumptions will be applicable for all NTTG transmission planning studies performed as part of this study plan:

a. Loads: 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 load serving entities' official load forecasts (such as those in integrated resource plans) and are similar to those provided to the Load and Resource Subcommittee of the WECC Planning Coordination Committee. Table 1 below shows a load comparison from data submitted during Quarter 1 of 2016 compared with loads that were forecasted in 2014-2015 study 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)	Difference (MW) 2024-2026
Idaho Power	3,730	4,193	4,346	153
NorthWestern	1,790	1,774	1,992	218
PacifiCorp	13,469**	14,002	13,414	-588
Portland General	3,958	3,933	3,885	-48
TOTAL*	22,947	23,902	23,637	-265

* Loads for Deseret G&T and UAMPS are included in PacifiCorp East
** Based on 2014 Actual Peak Demand (2015 Peak Demand will be provided when it becomes available)

Table 1: January 2016 Data Submittal – Load Comparison

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

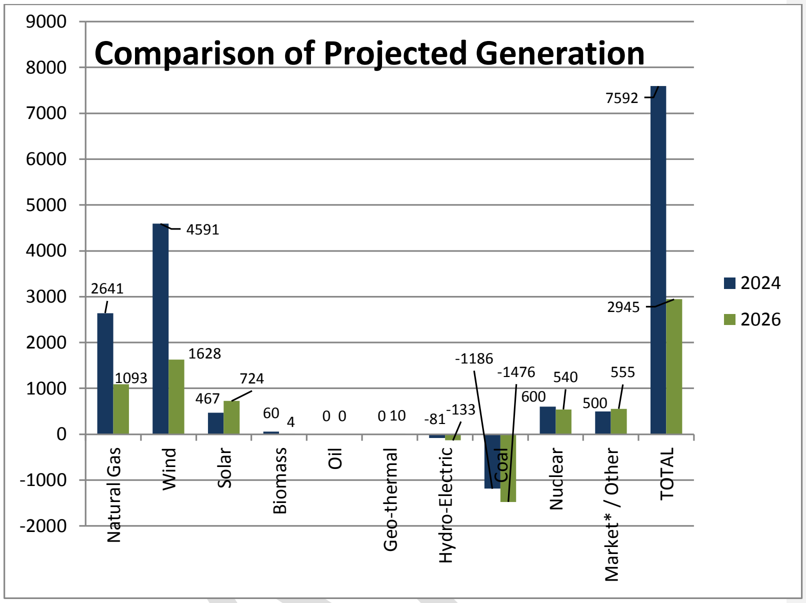

Figure 1: Comparison of Forecasted Resources

As shown in this figure, the total resource forecast of 3640 MW submitted this cycle is significantly reduced (-256 MW or -6.6%) from the 3896 MW forecast in 2014.

State	Resource Additions (MW)
Arizona[3]	-414
California	-59
Idaho	871
Montana	631
Oregon	11
Utah	782
Washington	3
Wyoming	564

Table 2: Location of 2026 Forecasted Resources

[3] Reflects PacifiCorp's retirement of Cholla 4, a coal resource outside the NTTG footprint.

> 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.

<u>Regional Transmission Projects</u>: 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 will be derived from projects included in the prior Regional Transmission Plan and projects included in the Full Funders local transmission plans. The TWG after consultation with the project sponsors, identified the regional transmission projects shown in the table below as the list of regional projects submitted in Quarter 1 data submittal that will be analyzed during this biennial Regional Planning Cycle.

JANUARY 2016 DATA SUBMITTAL – TRANSMISSION ADDITIONS BY 2026

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

Table 3 – New Transmission Projects

As shown in the above table, the unsponsored 2015 Alternative Project has been submitted by PacifiCorp as a sponsored project that is not requesting regional cost allocation.

[4] 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 (excluding the null case) and not tested for impact on the Regional Transmission Plan.

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The Sponsored Projects will be evaluated through the use of Change Cases as described below. Additionally, Merchant Transmission Developer and unsponsored projects will be evaluated in Change Cases to produce, if possible, a more efficient or cost effective Regional Transmission Plan.

c. Transmission Service Obligations: Listed below in Table 4 are the transmission obligations that were submitted in Quarter 1.

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
	887	2026	Miners / Point of Rocks	Network

Table 4 – Transmission Service Obligations

d. 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: 724 W-E: 706
14 - Idaho to Northwest	W-E: 1200 E-W: ~~2400~~2175	W-E: 0 E-W: ~~5141~~1489
16 – Idaho - Sierra	N-S: 500 S-N: 360	N-S: ~~168~~263 S-N: 0
17 – Borah West	E-W: 2557 W-E: 1600	E-W: 26~~0~~ W-E: ~~1445~~1350
19 – Bridger West	E-W: 2400 MW W-E: 600 MW	E-W: ~~60~~86* W-E: ~~200~~0*
20 – Path C	N-S: 1600 S-N: 1250	N-S: 0 S-N: 0
37 - TOT 4A	NE-SW: 960	NE-SW: 0 SW-NE: 761
38 - TOT 4B	SE-NW: 880	SE-NW: 33 NW-SE: 104
75 - Hemingway-Summer Lake	E-W: ~~1500~~710 W-E: 550	E-W: 710 W-E: 150~~0~~

*** IPCO Share**

Table 5 – Transmission Path Capacity and Available Transfer Capability

~~(Table to be updated by the Transmission Use Committee)~~

e. Interregional Transmission Projects: The following table provides a list of 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[5]	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

2. Analysis Tools

Three types of analysis tools will be utilized in the development of the power flow base cases. These are:

Power flow – The PowerWorld[6] power flow software will be used to evaluate transmission reliability under N-0 and N-1 conditions as well as certain credible N-2 contingencies. System performance analyses are conducted using power flow programs, given a snapshot of loads, resources and network topology provided by production cost studies, to determine whether the transmission grid can be operated to allow the electricity to flow reliably.

Dynamic Analysis – The dynamic analysis will be based on selected Power flow cases and the availability of the dynamic models for the newly submitted projects.

Production Cost – Production cost studies are used to simulate the economic dispatch of resources to meet load during a given period of time (e.g., a year) and performed using security-constrained hourly chronological generator commitment and dispatch programs that find feasible and least-cost resource operations, which deliver electricity from generators to loads distributed across the same underlying transmission grid modeled in the power flow programs. The GridView[7]production costing software will be

[5] The SWIP-North project submitted by Great Basin Transmission 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 direct CAISO connection to SWIP-North, effectively bringing CAISO to Robinson Summit. Therefore, SWIP-North was submitted as an interregional project to NTTG, WestConnect and CAISO.

[6] PowerWorld is an interactive power systems simulation package for the analysis of high voltage power systems operation and is a product of PowerWorld Corporation

[7] GridView is a production costing tool and product of ABB

used to evaluate the range of production scenarios that may occur in the Western Interconnection. Production cost studies results will be used to define power flow base case assumptions for several stressed hours during the year.

Study cases will be maintained in the PowerWorld power flow and GridView production costing database formats and made available to stakeholders interested in verifying, further analyzing, or extending the work done in this planning process, provided that appropriate steps are taken to maintain confidentiality.

3. Regional Plan Evaluation

This study process will evaluate the Initial Regional Plan, Regional and Interregional Transmission Project submittals and Alternative Projects through the creation of Change Cases.

The steps of the study process include the following:

- The cost and other physical information with respect to transmission projects forming the Initial Regional Plan and Alternative Projects (Sponsored, unsponsored submissions by stakeholders, or unsponsored identified in the prior Biennial Cycle) will be compiled for the tenth-year of the study period (study year) from data submissions, along with all other data to be used in the Interconnection-wide power flow and production cost modeling.
- A production cost model base case of the Initial Regional Plan, comprised of multiple hours within the study year, will be developed using the production cost program, GridView, to determine those hours in the study year when load and resource conditions are likely to stress the transmission system within the NTTG footprint.
- The production cost model base case consisting of those load, resource and interchange data (the combination of input and output data) for these selected hours will be transferred from GridView to a power flow model, PowerWorld, using the round trip process pioneered by NTTG.
- Using the power flow base case, the Initial Regional Plan will be evaluated using power flow analysis techniques to determine if the modeled transmission system topology meets the system reliability performance requirements and transmission needs including needs associated with Public Policy Requirements. If the power flow base case fails to meet these minimum performance or transmission need requirements, then one or more sponsored or unsponsored Alternative Project(s) that correct the deficiency(ies) or an unsponsored Alternative identified by the TWG will be included in the Initial Regional Plan base case. The study process as outlined below will be used to develop an Initial Regional Plan that meets the system performance requirements and transmission needs associated with Public Policy Requirements.
- Change Cases will be developed by the addition of an Alternative Project and/or ITPs to the Initial Regional Plan. Each Change Case may also exclude one or more uncommitted projects in the Initial Regional Plan provided the substitution of the uncommitted project(s)

with Alternative Project(s) in the change case have similar or better reliability impacts and is more efficient or cost effective.~~.~~

  - Analysis will be performed as needed to determine whether or not NTTG's transmission providers' future transmission system accommodates potential future transmission obligations as provided in the Q1 and/or Q5 data submittals. This analysis may encompass a power flow reliability analysis and/or a comparison between submitted transmission service obligations versus available transfer capability.
  - The ATC values listed in Table 5, plus any transmission capacity increase estimated from power flow analysis with and without the non-Committed transmission projects, will be compared to existing plus future transmission service obligations received during the Quarter 1 and/or Quarter 5 data submittal periods.
  - As part of the development of Change Cases, the TWG will also determine if there are additional Alternative Projects (which could include variations/modifications of projects submitted by a Sponsor or stakeholder) that should be evaluated through inclusion in a Change Case.
- Each Change Case will be evaluated to determine whether or not it meets the System Performance requirements and the transmission needs associated with Public Policy Requirements and other transmission obligations. If it fails to meet these minimum requirements, it will either be (i) set aside as unacceptable or (ii) modified by the TWG by the addition of another Alternative Project (which may include an unsponsored project identified by the TWG to form a new Change Case that will be subject to evaluation).
- The Initial Regional Plan and Change Cases power flow analysis will monitor the impacts of projects under consideration in the Initial Regional Transmission Plan on neighboring Planning Regions as well. If the Change Case or Initial Regional Plan may cause reliability standard violations on neighboring Planning Regions, the Planning Committee shall coordinate with the neighboring Planning Regions to reassess and redesign the facilities. If the violation of reliability standards can be mitigated through new or redesigned facilities or facility upgrades within the NTTG Footprint or through operational adjustments within the NTTG Footprint, the costs of such mitigation solutions shall be considered in addition to the cost of the project(s) under consideration when selecting a project for the Draft Regional Transmission Plan.
- The TWG will then review each Change Case to determine if a modification of any Change Case should be developed and evaluated that would be more efficient or cost effective in meeting regional transmission needs.
- A limited number of dynamic analysis studies will be performed on the Change Cases. ~~If a~~If a Change Case fails to meet dynamic stability requirements, it will either be (i) set aside as unacceptable or (ii) modified by the TWG by the addition of another Alternative Project (which may include an unsponsored project identified by the TWG to form a new Change Case that will be subject to evaluation) or other mitigation measure.

- Those Change Cases that are acceptable will be evaluated using three economic metrics for the study year: capital-related costs, energy losses, and reserves. The monetized incremental cost of each metric will be summed for each Change Case as compared with the Initial Regional Plan.
- If an examination of the incremental costs suggest that a different combination of Alternative Projects may result in Change Cases which are more efficient or cost effective than the Initial Regional Plan, then a new Change Case will be developed as a combined Alternative Project into one or more additional Change Cases.
    - When necessary, these new Change Cases will be re-evaluated to ensure each continues to meet the system performance requirements and transmission needs associated with Public Policy Requirements and other transmission obligations. For each new Change Case meeting these minimum requirements, the monetized incremental cost will be determined using the three metrics described above. Based on review by the TWG of the results for the new Change Cases, the process of developing and evaluating additional Change Cases from the Alternative Project initially selected may be repeated.
- The set of projects (either the Initial Regional Plan or a Change Case) with the lowest incremental cost, as adjusted by its effects on neighboring regions will then be incorporated into the Draft Regional Transmission Plan.
- The allocation scenarios developed by the Cost Allocation Committee (in consultation with the Planning Committee) for those parameters that will likely affect the amount of total benefits and their distribution among Beneficiaries will be evaluated using the Draft Regional Transmission Plan.
- All or portions of the above planning process may be used by the TWG to complete additional analysis to develop the Draft Final Transmission Plan.

4. 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[8] 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

[8] See Attachment K, Local Planning process

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 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 Attachment 1. The following RPS values will be used in its modeling:

	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

B. Transmission Planning Study Methodology

1. Request and Evaluate Data

Proper analysis of the NTTG transmission system requires data and models that describe the entirety of the Western Interconnection due to the significant transmission ties between regions and the substantial energy trading markets that span the interconnection. Consequently, NTTG bases its study efforts on the data collection and validation work of the Western Electricity Coordinating Council (WECC) and its committees.

The Transmission Expansion Planning Policy Committee (TEPPC[9]) database will be reviewed and modified as needed to assure conformance with the Initial Regional Plan. NTTG intends to use the 2026 TEPPC production cost base case with round trip capability as the foundation of its work. It is expected to be available by the end of Q2, should its availability be delayed, the TWG may have to develop an alternate base case for the foundation of its studies.

Reevaluation of selected projects in prior Regional Transmission Plan

NTTG expects the sponsor of a project selected in the prior Regional Transmission Plan (the "Original Project") to inform the Planning Committee of any project delay that would potentially

[9] TEPPC has four main functions: 1) oversee and maintain public databases for transmission planning; 2) develop, implement, and coordinate planning processes and policy; 3) conduct transmission planning studies; and 4) prepare Interconnection-wide transmission plans.

affect the in service date as soon as the delay is known and, at a minimum, when the sponsor re-submits its project development schedule during quarter 1. If the Planning Committee determines that the Original Project cannot be constructed by its original in-service date, the Planning Committee will reevaluate the Original Project in the context of the current Regional Planning Cycle using an updated in-service date.

“Committed” projects, in the context of re-evaluation, are Original Projects that have all permits and rights of way required for construction, as identified in the submitted development schedule, by the end of quarter 1 of the current Regional Planning Cycle. Committed projects are not subject to reevaluation, unless the Original Project fails to meet its development schedule milestones such that the needs of the region will not be met, in which case, the Original Project loses its designation as a Committed project.

If “not Committed,” the Original Project —whether selected for cost allocation or not — shall be reevaluated, and potentially replaced or deferred, in the current Regional Planning Cycle only in the event that:

a. The Project Sponsor fails to meet its project development schedule such that the needs of the region will not be met,
b. The Project Sponsor fails to meet its project development schedule due to delays of governmental permitting agencies such that the needs of the region will not be met, or
c. The needs of the region change such that a project with an alternative location and/or configuration meets the needs of the region more efficiently or cost effectively.

If condition (a), (b), or (c) is true, then the incumbent transmission provider may propose solutions that it would implement within its retail distribution service territory footprint (the “New Project”). Both the Original Project and the New Project will be reevaluated or evaluated, respectively, in Quarter 2 as any other project for consideration in the Regional Transmission Plan.

During such reevaluation the Planning Committee shall only consider remaining costs to complete the Original Project against the costs to complete the other projects being evaluated.

2. Production Cost Model Analysis Define System Conditions to Study

The TWG studies will use production cost model analysis to examine all hours of the year for situations where available resources and forecasted loads across the Western Interconnection cause highest stress such as peak load, high transfers with other regions, etc. on the transmission system in the NTTG footprint. The following future transmission are part of TEPPC's 2026 Common Case Transmission Assumptions.

Figure 1 - CCTA

The WECC TEPPC 2026 common case production cost model will be analyzed for selecting hours for power flow analysis. This model includes 22 new transmission projects called the Common Case Transmission Assumptions (see CCTA in Figure 1 above).

Using the TEPPC 2026 production cost model and the GridView production cost software, the TWG will identify the hourly data for several system conditions, such as:

a) peak coincident NTTG summer load condition;
b) peak coincident NTTG winter load condition;
c) conditions with high flows across Montana to the Northwest (Path 8), which would provide a bases for the proposed PPC study;
d) conditions with high import to Idaho and export flows from Idaho across B2H;

e) conditions with high flows across The Utah/Nevada to Southeast interfaces (Tot2), which may be useful in studying ITPs focused on fulfilling future RPS requirements; and/or

f) conditions where persistent congestion occurred that might warrant transmission system reinforcement.

The hours that approximate the above system conditions will be identified, if possible, from the Production Cost Model results for power flow evaluation. Additional hour(s) representing a system condition(s) of interest to study may be identified through the production cost model results review and added to or replace one of the list of conditions identified above.

3. Power Flow Databases

a) Base Cases

The base cases for the various desired system conditions to be simulated are described in Section IV.B.2 above. These power flow cases will be derived from the TEPPC 2026 production cost model. The TWG will import the data for each system condition (i.e., hour) into the PowerWorld power flow program and create base cases for each of the study conditions.

For any updated L&R data (or other data) received in Quarter 5, the Technical Work Group will make a determination if it is appropriate to update the power flow data with the updated loads, resources and transmission information when conducting the additional reliability studies. The NTTG TWG studies may extend beyond the traditional focus on snapshots of winter and summer peaks to examine the change cases for situations where available resources and forecasted loads across the Western Interconnection cause highest stress on the transmission system in the NTTG footprint.

b) Change Cases

The TWG may add any number or combination of Alternative Projects or ITPs and may remove any non-committed transmission facilities from the base cases, as appropriate, in order to create Change Cases for the respective base cases. These Change Cases will be used for comparison purposes in evaluating the more efficient or cost effective Regional Transmission Plan.

4. Steady-State (N-0), and Contingency (N-1, N-2) Analysis

Power flow steady-state (N-0) and contingency (N-1, credible N-2) analysis will be performed using the procedures outlined in the WECC System Review Work Group (SRWG) – Data Preparation Manual, including utilizing governor power flow techniques for contingencies resulting in the loss of generation. Selection of specific contingencies shall be provided by NTTG members. The Peak RC standard contingency lists will be used for multiple contingency scenarios. All Special Protection Schemes related to the N-1 and N-2 contingencies, if any, will be included in the analysis.

A limited number of dynamic analysis studies will be performed. The TWG will use professional judgement to define the set of outage conditions that may result in instability or reliability performance issues.

5. System Performance (Reliability) Criteria[10]

The power-flow simulation performance results will be measured against the North American Electric Reliability Corporation (NERC) and WECC system performance criteria. Specifically, the NERC Reliability Standards TPL-001-4 requires transmission facilities to operate within normal and emergency limits.

The WECC System Performance Regional Business Practice TPL-001-WECC-CRT-3 establishes the basis for voltage performance criteria. The TWG will monitor and report post contingency and steady state voltages outside the following boundary conditions:

Nominal Voltage/Equipment	Less than or equal (pu)	Greater than or equal (pu)
500 kV	1.1	0.95
345 kV	1.05	0.95
Series capacitor and series reactor line	1.15	0.9

Table 8 – System Performance Table

The TWG will include in the Draft Regional Transmission Plan violations and mitigation measures on Bulk Electric System (BES) transmission elements based on local system performance criteria and exceptions as documented in the WECC Guideline, "Disturbance-Performance Exceptions". However, local transmission provider (within the same transmission system where contingency applied), series-capacitor and non-bulk-electric-system bus violations will not be reported.

- ***Pre-contingency State*** – Power-flow simulation performance requires all transmission facilities to operate within their continuous ratings under steady state conditions. The requirements for the pre-contingency performance criteria are summarized in the NERC's Transmission Planning standard TPL-001-4.
- ***Single Contingencies*** – Power-flow simulation performance results require all transmission facilities to operate within emergency limits following single contingences. The requirements for the post-contingency performance criteria are summarized in the NERC's Transmission Planning standard TPL-001-4.
- ***Credible Multiple Contingencies*** – Power-flow simulation performance results require all transmission facilities to operate within emergency limits following credible multiple contingences. The requirements for the (credible multiple contingency) post-

[10] WECC has changed the terminology from Reliability Criteria to System Performance Criteria

contingency system performance criteria are summarized in the NERC's Transmission Planning Standard TPL-001-4.

- ***Dynamic Contingencies*** – The TWG will utilize engineering judgement to study a subset of the single contingencies, and credible multiple contingencies, as dynamic contingencies to evaluate the transient stability of the transmission system.

The viability of specific transmission projects will be evaluated using power flow software to demonstrate compliance with NERC and WECC system performance criteria as noted above, and other system specific system performance criteria noted below shall also apply:

1) NorthWestern Energy, Criteria - 2015_Business_Practice_ETP_Method_Criteria_and_Process_effective_12-7-15 (updated check)

2) PacifiCorp Engineering Handbook section 1B.4 - https://www.pacificpower.net/content/dam/pacific_power/doc/Contractors_Suppliers/Power_Quality_Standards/1B_4.pdf

Link to NERC TPL Standards:

http://www.nerc.com/pa/stand/Pages/ReliabilityStandardsUnitedStates.aspx?jurisdiction=United

Link to WECC Regional Business Practice:

https://www.wecc.biz/library/Documentation%20Categorization%20Files/Regional%20Business%20Practices/TPL-001-WECC-RBP-2%201.pdf

C. Methodology for Comparison of System Performance Reliability Results

The following methodology shall be applied for comparing the results of the Change Cases with the results from the cases of the Initial Regional Plan projects.

1. Alternative Projects

Each of the Change Cases will be evaluated for the study year using the same system performance criteria as is used for the cases with the Initial Regional Plan. The study results of these Change Cases will be compared against results from the studies using the Initial Regional Plan.

Case	B2H*	Gateway S*	Gateway W*	Antelope Projects	SWIP N	Trans Canyon	TWE
null							
pRTP	X	X	X				
IRP	X	X	X	X			
CC1	X						
CC2		X		X			
CC3		X	X	X			
CC4	X		X	X			
CC5							X
CC6					X	X	
CC7					X		
CC8					X		X
CC9						X	

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

Table 9 – Illustrative Change Case selection

Project Descripotions:

- B2H includes: Boardman to Hemingway, Hemingway to Bowmont and Bowmont to Hubbard
- Gateway South includes: Aeolus to Clover
- Gateway West includes: Windstar to Aeolus, Aeolus to Anticline, Anticline to Jim Bridger, Anticline to Populus, Populus to Borah, Populus to Cedar Hill, Cedar Hill to Hemingway, Cedar Hill to Midpoint and the Borah to Midpoint uprate
- Antelope Projects includes: Antelope to Goshen and Antelope to Borah
- SWIP N includes: Midpoint to Robinson Summit
- Trans Canyon includes: Clover to Robinson Summit
- TWE includes: a line between Sinclair, WY and Boulder City, NV

The Change Case table is for illustrative purposes, and will be updated once the production cost model results have been run and a better understanding of the flow patterns is determined. It is impractical to run all combination of projects and all flow patterns, so TWG must use its professional judgement. For example, for the seven groups of projects above, to study all combinations requires 128 different change cases. On top of the128 change cases, there are likely 5 or so flow conditions to test. Utilizing professional judgment, the table above reflects some of the project combinations that could be analyzed as part of the Change Cases. Which change case is run on which flow pattern will be resolved in Quarter 3 and Quarter 7. TWG will provide updates to the Planning Committee on the continuing development of this table as the study progresses.

To develop the null case, TWG will take the 2026 production cost model and remove all significant future transmission facilities (the CCTA list plus any other identified 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.

The following analysis criterion will be used to determine if a Change Case is a more efficient or cost effective solution for the NTTG footprint than the Initial Regional Plan:

a. System Performance Analysis

The Change Case must meet all system performance criteria defined above. The TWG will monitor system conditions in each of the created base cases to determine if they meet the system performance criteria. If not, modifications may be made to transmission facilities until the case meets the system performance criteria. A Change Case can be modified at the discretion of the TWG to meet such system performance criteria using unsponsored projects.

b. Capital Related Costs

The TWG will validate all project submitted costs with the TEPPC Transmission Capital Cost Calculator, an MS Excel spreadsheet. The TWG will enter the submitted project data into the Calculator, adjusting (after consultation with the Project Sponsor if necessary) the project cost data for consistency and a common year assumptions with the TEPPC data, and compare the submitted project capital costs to the Calculator output. If the submitted costs vary from the Calculator output by 20%, the TWG will contact the Project Sponsor and seek to resolve the cost difference. However, if the difference cannot be resolved, the TWG will determine the appropriate cost to apply in the study process.

A reduction in the annual capital related costs from the Initial Regional Plan to a Change Case captures the extent that uncommitted project(s) in the Initial Regional Plan can be displaced (either deferred or replaced) while still meeting all regional transmission needs and system performance requirements. The annual capital-related costs will be the sum of annual return (both debt and equity related), depreciation, taxes other than income, operation and maintenance expense, and income taxes. Power flow analysis will be used to ensure the Change Case meets transmission System Performance requirements.

c. Energy Losses

Power flow and Production Cost software will be used to compare losses before and after a project is added to the system. A reduction in losses after a project is added represents the benefit.

NTTG will compute annual energy loss using multiple power flow cases extracted from the production cost base case. The calculation will be dependent upon the case selection, since each power flow case can be used to represent some portion of the study year. The energy loss valuation will be based on average energy price for the study year. TWG will evaluate the use of the Production Cost software as an alternative to the use of multiple powerflow cases.

d. Reserves

The Reserves metric is treated as a capacity sharing opportunity between Balancing Areas, not a production cost problem. The analysis must evaluate a number of capacity sharing opportunities amongst various combinations of Balancing Areas. The reserve metric will be accessed on a Balancing Area basis and is based on the incremental load and generation submitted by the TPs. The future reserve requirements will be priced assuming a simple cycle Frame F unit. Energy cost for each calculated reserve event will be priced at the Balancing Area gas price used in the NTTG production cost base case. In order for a Reserve benefit to exist, there must be uncommitted transmission capacity available on the projects under evaluation. The calculation will be performed using a spreadsheet which will consider the savings between each Balancing Area providing its own incremental reserve requirement and a combination of balancing areas sharing a reserve resource facilitated by uncommitted transmission capacity.

2. Cost Allocation Analysis

The projects eligible for cost allocation that are incorporated with the Draft Regional Transmission Plan will be evaluated for cost allocation by the Cost Allocation Committee. Those entities affected by a change in Capital-Related Costs, Energy Losses and Reserves, as defined above, shall be identified for use in the cost allocation process. NTTG will allocate the net benefits to TP’s.

V. Robustness of Draft Regional Transmission Plan

The robustness analysis will provide information regarding the Draft Regional Transmission Plan’s ability to reliably serve the transmission needs of an uncertain future. The Draft Regional Transmission Plan is developed using base assumptions (e.g., transmission topology, load level and generation dispatch patterns) of the TEPPC 2026 base case. These base assumptions represent a pre-defined future that drives the 2026 transmission topology in the Draft Regional Transmission Plan. The robustness analysis will use power flow analysis and input from production cost analysis as needed to test whether or not the 2026 Draft Regional Transmission Plan transmission system performance will remain acceptable assuming deviations from the base case assumptions. The TWG will use its discretion to define the deviations from base case assumptions to test and may draw on assumptions used in change cases or allocation scenarios and will seek input from stakeholders through the Planning Committee.

VI. Allocation Scenarios

Introduction

The Cost Allocation Committee applies regional cost allocation for allocating the costs of regional and interregional transmission projects (in the case of interregional projects, NTTG's allocated portion of the interregional project's cost) which the Planning Committee selects into the Regional Transmission Plan for purposes of regional cost allocation. The purpose of this portion of the study plan is to describe the allocation scenarios that were developed by the Cost Allocation Committee, in consultation with the Planning Committee, with stakeholder input. This allocation scenario analysis will determine the benefits and Beneficiaries of the Regional Transmission Plan[11] to be compared to the benefits and Beneficiaries of the four allocation scenarios. Costs will be allocated if the benefits outweigh the costs of the project or scenario.

During NTTG's biennial planning cycle, NTTG's Regional Transmission Plan is developed in draft form at the end of the Quarter 4 technical analysis and updated, if appropriate, after the Quarter 5 data submittal period. Through the TWG technical analyses, the projects that have requested cost allocation and have been selected into the Regional Transmission Plan will receive cost allocation.

Pre-Qualification for Cost Allocation

Non-incumbent and Incumbent Transmission Developers intending to submit a project for cost allocation consideration must satisfy NTTG's project sponsor pre-qualification requirements by submitting the Project Sponsor Pre-Qualification Data form to info@nttg.biz by October 31, 2015. Project Sponsors must resubmit the project sponsor prequalification data in Quarter 8 of each succeeding cycle to demonstrate that they remain qualified to be considered a Sponsored Project in subsequent Regional Transmission Plans.

For the 2016-2017 cycle, the window for Project Sponsors to submit pre-qualification data closed at midnight on Saturday, October 31, 2015. NTTG received no requests from Project Sponsors seeking to be pre-qualified. As a result, unless the Planning Committee identifies and selects an unsponsored Alternative Project as a more efficient or cost effective solution during the development of in NTTG's Regional Transmission Plan, cost allocation will not be performed during this planning cycle.

Allocation Scenario Change Cases

The Regional Transmission Plan is the basis for creating the allocation scenario Change Cases. Therefore, a change in the benefits and allocation to Beneficiaries from the Initial Regional Plan to each allocation scenario Change Case is estimated as the difference between the Initial Regional Transmission Plan and the allocation scenario Change Case.

[11] Throughout the planning cycle the Regional Transmission Plan will be represented by the Draft Regional Transmission Plan or Draft Final Regional Transmission Plan.

Allocation Scenarios

The Cost Allocation Committee (in consultation with the Planning Committee) with stakeholder input, will create allocation scenarios for those parameters that likely affect the amount of total benefits of a project and their distribution among Beneficiaries. This process will provide the overall range of future cost allocation scenarios that will be used in determining a project's benefits and Beneficiaries. The variables in the allocation scenarios will include, but are not limited to, load levels by load-serving entity and geographic location, fuel prices, and fuel and resource availability. The purpose of the allocation scenarios is not to stress the system in cost allocation, but to define reasonable alternative scenarios for the Regional Transmission Plan that represent a legitimate alternative view of the future.

The following allocation scenarios were developed by the Cost Allocation Committee (in consultation with the Planning Committee) and with stakeholder input.

High and Low Load Allocation Assumptions:

Load forecasting is uncertain. The following allocation scenarios test the effects of load forecast uncertainty on the amount of total benefits and their distribution among Beneficiaries associated with the Regional Transmission Plan.

A. High Load - Assumes the 2026 load forecast in the Regional Transmission Plan is too low:

   Add 1,000 MW of NTTG load MW in the NTTG footprint for a high load scenario. Allocate the 1,000 MW to each Balancing Authority (BA) based on historical BA actual peak demand and projected 2026 Common Case BA peak demand.

B. Low Load- Assumes the 2026 load forecast in the Regional Transmission Plan is too high:

   Subtract 1,000 MW of NTTG load in the NTTG footprint for a low load scenario. Allocate the 1,000 MW to each BA based on historical BA actual peak demand and projected 2026 Common Case BA peak demand.

Resource Location and Type Allocation Scenario Assumptions:

Identifying the location and type of future resource is uncertain. The following allocation scenarios tests the future resource mix uncertainty for wind, solar and coal resources types and their location on the amount of total benefits and their distribution among Beneficiaries associated with the Regional Transmission Plan.

C. Wind Replaced with Solar - Assumes a shift in type and location of renewable resource away from wind to solar resources that is assumed in the Regional Transmission Plan:

   Remove 800 MW of wind capacity and replace with 800 MW of solar capacity. The geographic location and accompanying quantity of the 2026 wind capacity removed will likely be based on each TP's forecast share of 2026 Common Case wind resource's (e.g., IPC, NWMT, PACW, PACID and PACWY). The location and quantity of solar capacity added will likely be based on each TP's share of 2026 Common Case solar resource (e.g., IPC, PACUT).

D. Coal Replaced by Wind and Solar - Assumes a replacement of some of the existing coal resource with wind and solar resource in different locations than assumed in the Regional Transmission Plan:

Remove 1,000 MW of coal and presume units that are not retired in the 2026 Common Case can be reduced pro rata and replaced with equivalent amount of energy in equal shares of wind and solar in the appropriate geographic locations (e.g. wind in WY and MT and solar in ID and UT).

ALTERNATIVE TEXT: Remove coal resources as outlined in each NTTG member's Integrated Resource Plan (IRP) by unit and year projected in the IRP. For planning purposes, assume that the retired units are replaced with equivalent amount of energy in equal shares of wind and solar in the appropriate geographic locations (e.g., wind in WY and MT and solar in ID and UT).

See Attachment 4 for additional detail on the cost allocation scenarios. Note that Attachment 4 has not been updated at this time since the 2026 Common Case numerical data that will be used to develop the allocation scenarios is not final at this time. However, Attachment 4 provides an example of the methodology used to define the allocation scenarios.

Power Flow Analysis

The allocation scenarios will be analyzed using power flow analysis. The power flow analysis will be an N-0 and limited N-1 study to create a solved cases that may include thermal or voltage reliability issues. If mitigation is required to meet reliability criteria, these will be identified, including an estimate of the capital cost for the mitigation. If after study, a future uncommitted transmission project is not needed because of the allocation scenario assumptions, then for the purposes of this allocation scenario, the uncommitted transmission project and its costs may be deferred beyond the 10 year planning horizon with appropriate capital cost adjustments.

Benefits and Beneficiary Analysis

The three economic metrics that will be used by the TWG to define benefits and Beneficiaries for the allocation scenarios are capital costs, line losses and reserve margin. Each metric will be expressed as an annual change in costs (or revenue) and provided to the Cost Allocation Committee. A common year will be selected for net present value calculations for all cases to enable a comparative analysis between each allocation scenario Change Cases and the Initial Regional Plan, as adjusted for updated Quarter 5 load and resource data. The following describes each metric and the calculation of its benefit.

A) Capital Cost Benefit - The capital cost benefit will be computed from the annual capital-related costs[12] for each Transmission Provider. The difference between the Initial Regional Plan incremental capital cost and the Regional Transmission Plan (or allocation scenario) capital cost computes the benefit related Regional Transmission Plan (or an allocation scenario). This difference will provide the capital cost benefit. The beneficiaries will be defined from the TWG technical analysis and may be any entity, including, but not limited to, transmission providers (both incumbent and non-incumbent), Merchant Transmission Developers, load serving entities, transmission customers or generators that utilize the regional transmission system within the NTTG Footprint to transmit energy or provide other energy-related services.

B) Line Loss Benefit - The line loss benefit is computed as a change in energy generated to serve a given amount of load. The change in estimated energy loss between the Initial Regional Plan and the Regional Transmission Plan (or a cost allocation scenario) measures the line loss impact benefit of the Regional Transmission Plan or an allocation scenario. The line loss will be computed through power flow or production cost model analysis and monetized using an index price of power for each Transmission Provider. Again, the beneficiaries will be defined from the TWG technical analysis and may be any entity including, but not limited to, transmission providers (both incumbent and non-incumbent), Merchant Transmission Developers, load serving entities, transmission customers or generators that utilize the regional transmission system within the NTTG Footprint to transmit energy or provide other energy-related services.

C) Reserve Margin Benefit - This metric is based on savings that may result when two or more Balancing Authority Areas could economically share a reserve resource when unused transmission capacity remains in transmission project. The reserve margin metric will be computed through spreadsheet analysis and monetized using an index price of power for each Balancing Authority Area and measures the benefit of the Alternative Project in the DFRTP (or a cost allocation scenario). The beneficiaries are the Balancing Authority Areas.

For an example of the application of the cost allocation methodology defined in the Attachment K see Appendix J Cost Allocation Workbook posted with the 2014-2015 Draft Final Regional Transmission Plan. ~~SHOULD WE MAKE THIS REFERECE AND IF SO SHOULD WE ATTACHED IT OR HOT LINK THE DOCUMENT?~~

Cost Allocation Committee

The TWG will provide the benefit information calculated above to the Cost Allocation Committee to be used in the cost allocation process.

[12] Annual capital-related costs will be the sum of annual return (both debt and equity related), depreciation, taxes other than income, operation and maintenance expense, and income taxes.

VII. ~~The TWG will provide the benefit information calculated above to the Cost Allocation Committee to be used in the cost allocation process.~~Impacts on Neighboring Regions

The Initial Regional Plan and Change Case Plan(s) power flow studies will monitor the BES voltage and thermal loading in NTTG's neighboring planning regions: ~~ColumbiaGrid, WestConnect~~ColumbiaGrid, WestConnect, and CAISO. These power flow studies will identify any BES thermal and voltage violations using NERC criteria unless a neighboring planning region provides alternative criteria. Should a BES violation be observed in the neighboring region, either in the Initial Regional Plan or the Change Case Plan(s), the TWG will coordinate with the affected planning region to verify that the study results are valid and that this a new violation and is not a pre-existing problem that the affected planning region should mitigate. If there is a new violation caused by the Initial Regional Plan or Change Case plan, the TWG will endeavor to alleviate the violation using acceptable mitigation options within the NTTG footprint. If the violation in the neighboring planning region cannot be eliminated (i.e., the thermal and/or voltage are not within acceptable planning criteria) after all reasonable NTTG internal mitigation measures have been studied, then the TWG will again coordinate with the impacted planning region to determine if that region will ameliorate the violation through mitigation measures within the affected planning region at its expense. If the answer is no, the Initial Regional Plan or Change Case Plan will be eliminated from possible consideration as a plan that is more efficient or cost effective. Should the violations remain after all options for alleviation, both within the NTTG footprint and within the affected region, have been exhausted, then the Change Case or Initial Regional Plan will not be selected for the Draft Regional Plan.

Mitigation costs incurred as a result of changes made to facilities inside the NTTG footprint that eliminate the thermal or voltage violations observed in neighboring planning region(s) will be quantified and added to the cost of the plan under study when selecting a project for the Draft Regional Transmission Plan.

VIII. Interregional Coordination and evaluation of Interregional Transmission Projects

Evaluation of a properly submitted ITP will be in the context of ITP joint evaluation/interregional coordination and NTTG's regional planning process as an Alternative Project.

As part of the interregional coordination, NTTG and the other regional entities in the western interconnection will collaborate during their transmission planning processes to ensure regional transmission stability and efficiency. These coordination efforts inform each planning regions' transmission plans. An annual Interregional Coordination Meeting (ICM) was held on February 25th, 2016 to discuss and begin to coordinate this year's interregional studies by different planning regions. Prior to the annual ICM, NTTG met its obligations per Attachment K by posting on its website the following information:

(i) Updated Quarter 1 information, as of February 6, 2016 including load, resource, transmission submissions and new transmission service; and
(ii) prior cycle's regional transmission plan

At the Annual Interregional Coordination Meeting, stakeholders discussed conceptual solutions and potential proponents of ITPs were reminded to submit the projects to the applicable regions by March 31st.

For each ITP that is properly submitted to all Relevant Planning Regions (that may include NTTG) the region is to participate in a joint evaluation/coordination of the ITP study assumptions. The joint evaluation between regions with respect to any such ITP, NTTG (if it is a Relevant Planning Region) is to confer with the other Relevant Planning Region(s) regarding the following:

(i) ITP data and projected ITP costs; and
(ii) the study assumptions and methodologies it is to use in evaluating the ITP pursuant to its regional transmission planning process.

For each ITP that is properly submitted to all Relevant Planning Region (that may include NTTG):

a. is to seek to resolve any differences it has with the other Relevant Planning Regions relating to the ITP or to information specific to other Relevant Planning Regions insofar as such differences may affect NTTG's evaluation of the ITP;
b. is to provide stakeholders an opportunity to participate in NTTG's activities in accordance with its regional transmission planning process;
c. is to notify the other Relevant Planning Regions if NTTG determines that the ITP will not meet any of its regional transmission needs; thereafter NTTG has no obligation to participate in the joint evaluation of the ITP; and
d. is to determine under its regional transmission planning process if such ITP is a more cost effective or efficient solution to one or more of NTTG's regional transmission needs.

The Interregional Transmission Project coordination timeline is included as Attachment 2. Significant events in that timeline are the Interregional Coordination meeting held in February, the project submittal deadline to the relevant regions and the region's developing agreed upon common study assumptions, data, methodologies, cost assumptions and a schedule for determining the selection of an ITP into a regions' Transmission Plan.

A properly submitted ITP will be evaluated as an Alternative Project in NTTG's regional planning process. The set of uncommitted projects (regional and/or interregional) that result in the more efficient or cost effective regional transmission plan will be included in NTTG's Draft (or Draft Final or Final) Regional Transmission Plan. See section IV.A.3 for additional information regarding NTTG regional planning process. Stakeholders are welcome and encouraged to be involved and participate in NTTG's regional Planning Committee meetings and Quarterly Stakeholder meetings.

IX. Requests for Public Policy Considerations

Public Policy Considerations are those relevant factors that are not established by local, state, or federal laws or regulations.

Public Policy Considerations will be separate scenario analysis or sensitivity cases. The results of the analysis may inform the Regional Transmission Plan, but will not result in the inclusion of additional projects in the Regional Transmission Plan.

In Quarter 1 of the 2016-2017 Regional Planning Cycle, a request with three sensitivities for Public Policy Consideration was submitted:

- The RNW/Northwest Energy Coalition requested a study to consider the effects of retiring Colstrip units 1, 2, and 3 in 2026 and replace with:
    a. 1474 MW of Montana wind,
    b. Add a synchronous condenser to a) above,
    c. 1224 MW of Montana wind and 250 MW natural gas combustion turbine located near Billings.

A study plan to evaluate this request with agreed to changes has been included as Attachment 3.

X. Draft Regional Transmission Plan

The Planning Committee shall produce a Draft Regional Transmission Plan by the end of Quarter 4. The projects selected into the Draft Regional Transmission Plan are determined according to the study methodology in this document, and the projects selected into the Draft Regional Transmission Plan for cost allocation are determined according to the Cost Allocation process described above.

Attachment 1
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	Large Utilities - - 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;	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			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
			d) Geothermal e) Biomass (specified types) Hydrogen-RE Resource must be operational on or after 1995	Electricity and Coal Transition 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	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			

NTTG Member Utility	State	Applicable Entities	Applicable Energy	RPS % requirements	Energy Preference / Credits	In-state /delivery restrictions	Cost Cap
		(Rocky Mtn Power), UAMPS, UMPA, Deseret Power		to "adjusted retailed sales" (=sales less power from nuclear, effective" demand-side mgt, fossil fuel with CCS) Utilities must pursue renewables to the extent that it is "cost			
	Washing-ton	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	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;	

NTTG Member Utility	State	Applicable Entities	Applicable Energy	RPS % requirements	Energy Preference / Credits	In-state /delivery restrictions	Cost Cap
			in PNW, or hydro generation in irrigation pipes				
	Wyoming	No RPS Requirement					
PGE	**Oregon**	See Oregon above.					

Attachment 2

Interregional Transmission Project Coordination Timeline[13]:

The following table provides a proposed timeline for such joint evaluation of an Interregional Transmission Project.

Objective	Target Date	Target
1. Distribute and post Meeting Notification to Stakeholders	January 11, 2016	45 days prior to Annual Coordination Meeting
2. Post and share Annual Interregional Information	February 4, 2016	21 days prior to the Annual Coordination Meeting
3. Engage in discussions about how shared information (regional needs) will be presented	February 5 thru February 17, 2016	After posting of the Annual Interregional Information and prior to posting the Annual Coordination Meeting materials
4. Post meeting agenda and presentation materials	February 18	7 days prior to the Annual Coordination Meeting
5. 2016 Annual Coordination Meeting – West Connect Hosts in Phoenix	February 25, 2016	Sometime between February 1st and March 31st
6. ITP Submittal Deadline	March 31, 2016	The common ITP Submittal deadline for all Regions is no later than March 31 of every even numbered calendar year
7. Notify applicable Planning Regions of need to confer on any ITP proposals that may have been submitted	April 7, 2016	No less than 7 days following the ITP submittal deadline of March 31 of an even numbered calendar year
8. Resolve ITP data submittal deficiencies, if any	Per each region's process	Each region will follow its regional process and notify the other planning regions if deficiencies are not resolved
9. Develop and post an ITP Evaluation Process Plan, including agreed to common study assumptions, data, methodologies, cost assumptions and a	June 14, 2016	No later than 75 days following the ITP submittal deadline

[13] This document is for discussion purposes only and does not supplement or modify any procedure or process contained in any entity's filed OATT (including Attachment K to such tariff) or other filed rate schedule. To the extent that anything herein is inconsistent with any entity's OATT or filed rate schedule, such OATT or other filed rate schedule shall control.

	schedule for determining the selection of an ITP		
10.	Ongoing coordination of planning data and assumptions, including potential ITP benefits	Per ITP Evaluation Process Plan milestones	Per milestones, as may be developed and posted in the ITP Evaluation Process Plan, but not later than December 31 of each odd numbered calendar year
11.	2017 Annual Coordination Meeting – ColumbiaGrid Hosts	February 23, 2017	Sometime between February 1st and March 31st
12.	Final determination of ITP selection[14]	Prior to December 31, 2017	Per the ITP Evaluation Process Plan, but no later than December 31, 2017

[14] Depending on each region's process, the completion of ITP determination may go beyond this date due to various factors such as re-evaluation process.

Attachment 3

Public Policy Consideration Study Proposal for a Scenario Analysis:

Renewable Northwest and the NW Energy Coalition jointly submitted a Public Policy Consideration ("PPC) Study request to the Technical Work Group ("TWG") of Northern Tier Transmission Group ("NTTG"). This study is similar to a previous request, but has a larger scope and will take advantage of the TWG's ability to run dynamics in this study cycle.

Comments on Submission: Members of the TWG met with both Renewable Northwest ("RN") and the NW Energy Coalition "NWEC" and agreed upon clarifications to the requested study. These clarifications are described below:

1. In the original submittal, RN and NWEC stated, "(a) 1494 MW of new wind in Montana with a point of receipt at the Broadview 500 kV transmission bus, sinking to LSE owners Avista, PacifiCorp, PGE and PSE in accordance with their proportional ownership of Colstrip units 1, 2 and 3, and the remainder to sink at Northwest market hub." Subsequently, the agreed upon language is "the new generation will be moved out on Path 8".
2. In the original submittal, RN and NWEC stated, "(b) If the resource mix in (a) shows significant voltage violations, add a synchronous condenser of appropriate size at Colstrip, and rerun the analysis." The agreed upon language is, "The TWG will model in a synchronous condenser of appropriate size at Colstrip, and rerun the analysis only if the voltage violations found as a result of the replacement of wind for coal inhibit flows on Path 8."
3. RN and NWEC agreed with the TWG in that PCM will only be run on a case resulting in no voltage, thermal, or stability-related violations. It was also specified that the TWG would not re-run stability analysis after PCM.

Base case: The TWG will use the same base case with heavy westbound Path 8 flows for this scenario analysis as it will for the analysis done for the Regional Transmission Plan.

Study 1: TWG will run steady-state and dynamics analysis on the selected case.

Study 2: From the Study 1 case, TWG will retire Colstrip units 1, 2 and 3 (being sure to turn off generator and auxiliary load) and add in 1494 MW of wind (generic type 4 machines) at the Broadview 500 kV bus. All new wind at the Broadview bus will be exported on Path 8.

a. Dispatch the new wind at 35%, perform steady-state analysis
b. Dispatch the new wind at 100%, perform steady-state analysis
c. Dispatch the new wind at 0%, perform steady-state analysis

These cases will be referred to as 2a, 2b and 2c.

Study 3: If voltage violations are found in 2a, 2b, or 2c, that inhibit the ability of Path 8 to move power, then the TWG will add in a synchronous condenser of appropriate size. The TWG will re-run steady-state analysis on applicable case(s) to ensure the condenser doesn't cause any violations. There will be up to three cases that move on to Study 4, those being: 2a with or without condenser, 2b with or without condenser, and 2c with or without condenser. These cases will be referred to as 3a, 3b and 3c. If the introduction of the appropriately sized condenser does not alleviate the violations it is purported to fix, then that case will be removed from further study.

Study 4: The TWG will run dynamics on Study cases 3a, 3b and 3c, as appropriate. The dynamics will focus on Path 8 outages.

Study 5: Starting with cases 2a, 2b, and 2c: the TWG will reduce the introduced wind from 1494 MW to 1244 MW (total) and add in a 250 MW natural gas generation plant in Billings. These cases will be referred to as 5a, 5b and 5c. Run steady-state analysis on cases 5a, 5b and 5c.

Study 6: Run dynamics on cases 5a, 5b, and 5c. The dynamics will focus on Path 8 outages.

Study 7: A case that is selected by the TWG as being the "best" case from both reliability and Path 8 westbound flow perspectives will be run through Production Cost Modeling and a general comparison will be made of the resulting generation dispatch.

In general:

It is anticipated that Colstrip Unit 4 will be at or near full dispatch for all of the analyses; Colstrip Unit 4 will not be the swing bus.

If a Remedial Action Scheme ("RAS") is needed for the introduced wind at Broadview, the TWG will examine a limited number of solutions which will focus on either a 6-cycle or a 10-cycle trip of the wind farm. The TWG will not estimate the cost of any resulting RAS.

Revision History

Version	Date	Comment	Author
Version 1	3/xx/16	Drafted	R. Schellberg
Version 1.2	4/20/16	Reviewed and edited by TWG	Various
Version 1.7	4/27/16	Reviewed and edited by TWG	Various
Version 1.8	4/28/16	Near Final Draft	
Version 2	5/3/16	Draft to distribute to Planning Committee and Stakeholders	
Version 2.1	5/6/16	Minor edits for posting	
Version 2.2	6/1/16	Incorporated Stakeholder Comments	