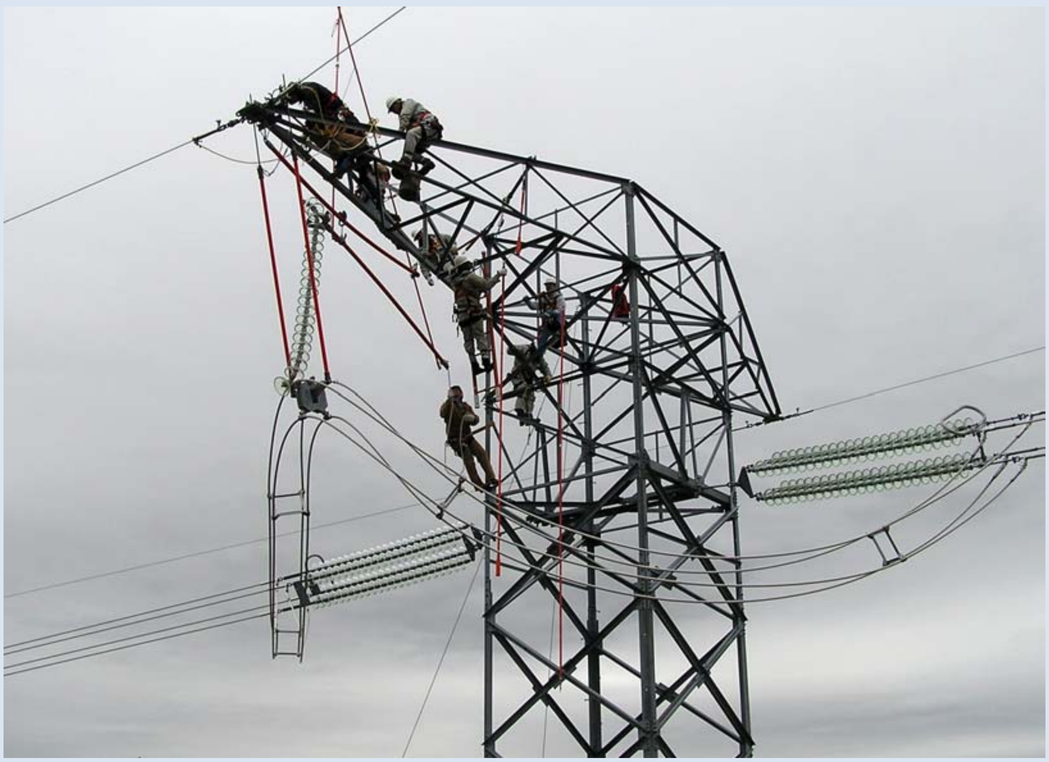
NORTHERN TIER TRANSMISSION GROUP

2010-2011 Biennial Plan

Cost Allocation Committee

Final Report



High-Voltage Transmission Construction in Montana

December 1, 2011

Approved by the NTTG Cost Allocation Committee on November 14, 2011
Approved by the NTTG Steering Committee on November 29, 2011

Preface

To ensure efficient, effective, coordinated use and expansion of the members' transmission systems in the Western Interconnection to best meet the needs of customers & stakeholders.

Figure 1: Map Illustrating Northern Tier Members' Principal Transmission Lines

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Summary

The Northern Tier Transmission Group created the Cost Allocation Committee ("Committee"), which primary purposes, in brief, are --

> "[t]o apply the Cost Allocation Principles consistently, openly and fairly while conducting analyses of cost allocation that accompany transmission project proposals developed in the NTTG planning processes and to make recommendations on cost allocations to the Steering Committee based on those analyses."

In the 2008-2009 Biennial Plan, the Committee compiled and considered information regarding sixteen transmission projects that were presented in the report of the Planning Committee. For the second planning cycle, 2010-2011, the focus of the Planning Committee was shifted from specific, proposed projects to a broader evaluation of transmission needs and options. This Committee, however, retained much the same process utilized in the prior planning cycle; that is, the Committee requested the dataset detailed in the Committee charter from each project sponsor for those projects for which data was submitted to the Planning Committee. Since most projects were included in the 2008-2009 report, the request made clear that the project sponsor could elect to provide only information that required updating.

The Committee charter also calls for the Committee to –

> "[r]epresent NTTG in regional and national transmission pricing, regulatory, and cost allocation forums."

In the 2010-2011 planning cycle, representation by the Committee was aimed in three areas: First, the Committee took an active role in preparing a NTTG position paper regarding the relationship between transmission planning and decisions to investment in new transmission projects. The paper (provided in Appendix D) summarizes the purposes of transmission planning, while pointing out the important information and evaluation "gaps" between the results of the transmission planning process and the decision to proceed with investment in a new transmission project.

Second, as a follow-on to its work on the NTTG position paper, Committee members also worked to have the distinctions between planning versus investment, as described in the NTTG position paper, incorporated in the 10-year west-wide Regional Transmission Expansion Plan report prepared by the Transmission Expansion Planning Policy Committee of the Western Electricity Coordinating Council.

Third, Committee members were also active in the preparation of comments submitted by NTTG in response to the Notice of Proposed Rulemaking (NOPR) on Transmission Planning and Cost Allocation issued by the Federal Energy Regulatory Commission on June 17, 2010. In addition to preparation of comments, Committee members have been involved in NTTG's review of the Order 1000 resulting from the NOPR, preparation of a request for clarification and rehearing regarding this order, and planning the steps necessary for the transmission providers of NTTG to develop compliance filings.

Data requests (and requests for updates) were sent to the sponsors of the following projects:

Table 1: Project Sponsors and Projects

Project Sponsor	Project(s)
Grasslands Renewable Energy LLC	• Multiple Montana projects in NTTG footprint
Idaho Power Company	• Gateway West (Populus-Hemingway)[1] • Boardman-Hemingway[1]
Northwestern Energy	• Mountain States Transmission Intertie (MSTI) • MSTI Collector System • Existing Path 18 Upgrade • Existing 500-kV Upgrade
PacifiCorp	• Gateway Central (Mona-Oquirrh, Sigurd-Red Butte)[2] • Gateway South (Aeolus-Mona) • Gateway West (Windstar-Populus, Populus-Hemingway)[1] • Hemingway-Captain Jack • Walla Walla-McNary

[1] These projects were as part of seven pilot projects for application of the Interagency Rapid Response Team for Transmission (RRTT). The purpose of the RRTT is to closely coordinate the review of transmission projects by nine Federal agencies. The seven projects were selected for the pilot based on their potential to "help increase electric reliability, integrate new renewable energy into the grid, and save consumers money."

[2] The Sigurd-Red Butte 345-kV segment is also identified on certain PacifiCorp documents as part of Gateway South. Consistent with PacifiCorp's data response to this Committee, this Report will identify this segment as part of Gateway Central. To be clear, PacifiCorp uses both the "Gateway South" and "Gateway Central" to describe the same 345-kV project.

Portland General	• Cascade Crossing (Coyote Springs-Hemingway, Boardman-Bethel)
TransCanada	• Chinook • Zephyr
TransWest Express LLC	• TransWest Express[1]

For those project sponsors responding to the data request, a liaison from the Committee reviewed the information supplied and, in some instances, helped clarify or supplement the information submitted by the project sponsor.

It did not appear that any material submitted by sponsors was developed specifically to respond to the Committee's data request. In particular, none of the sponsors provided "a risk and benefit analysis focusing on the distribution of costs, benefits, and risks among the parties proposed to share in the cost allocation of the project." Without such analysis of the distribution of risks and benefits, however, demonstrating consistency with the cost allocation principles is problematic for the Committee. Given this, and the fact that the only projects for which the sponsor provided a substantive data response were for those projects already considered by the Committee in the 2008-2009 planning cycle, the Committee did not made any additional recommendations regarding cost allocation for the transmission projects presented in this 2010-2011 Biennial Report.

This report summarizes the information provided by the sponsor for each project. This submitted information included (i) physical and financial parameters, (ii) reference(s) where appropriate to the "needs" assessment for the project, and (iii) status of project development. In the case of some projects, the Committee reviewed the information presented and developed in the project sponsor's most recent integrated resource plan (IRP), mainly as this information related to the overall (i.e., total system, rather than by individual or class of beneficiary) benefits of the transmission project relative to other transmission and resource options being considered by the sponsor. For those projects considered in an IRP, the results of the IRP were an significant first step towards an evaluation of beneficiaries that would ultimately be used in allocation of project costs.

Statements and positions taken by the Committee, in general, and presented in this report are those of the Committee as a whole and not any individual member and are non-binding on Committee members, the entities they represent, and the NTTG Steering Committee, pursuant to the Committee's Charter. Thus, the following disclaimer pertains to this entire Report:

This Cost Allocation Recommendation is created on behalf of the Northern Tier Transmission Group Cost Allocation Committee in conjunction with the Northern Tier Transmission Group's Biennial Draft Transmission Plan per the Cost Allocation charter. This is a recommendation only and not binding upon committee members or the Northern Tier Transmission Group Steering Committee.

If the state commission's designated representative (or alternate) is a member of the Committee, with respect to the Committee said individual will not be acting as a representative of a state commission. No action or position taken by the individual or the Committee will preclude a state commission from taking contrary actions or positions in proceedings before it or other regulatory bodies.

The Committee's statements, positions, and/or recommendations shall not be framed as binding on individual state members and shall state clearly that each state retains its decision-making prerogatives. No action or position taken by a state commission's representative or by NTTG shall preclude a state commission from taking conflicting action consistent with its jurisdiction or constitute prejudgment of any issue in a proceeding before it.

Committee Introduction

The Committee Charter establishes the Committee's purpose, principles, and responsibilities, as well as procedures and a process for the review of a project's benefits and cost allocation. Among the responsibilities of the Committee are to "[r]eview proposed cost allocations for projects proposed in the NTTG planning process" and to "[m]ake recommendations on cost allocations for incorporation into the . . . biennial plans submitted to the Steering Committee."

Membership of the Committee is composed of one person appointed by each state regulatory commission and state consumer agency within the NTTG footprint and by each publicly-owned or consumer-owned entity which is a NTTG member. Entities with a representative on the Committee are –

- Idaho Public Utilities Commission
- Oregon Public Utility Commission
- Montana Public Service Commission
- Montana Consumer Counsel
- Utah Public Service Commission
- Wyoming Public Service Commission
- Wyoming Office of Consumer Advocate
- Deseret Power Electric Cooperative
- Utah Associated Municipal Power Systems.

The Committee elects a chairperson from its members every two years. The Committee holds meetings as required to perform its responsibilities. For the 2010-2011 cycle, conference calls were generally held bi-weekly. In addition, the Committee is required to have a minimum of two open stakeholder meetings per year.

While the Committee is specifically tasked with making recommendations on cost allocations to be incorporated in the annual and biennial plans and other analyses as needed to carry out its functions, it looks to project developers and sponsors and interested stakeholders to provide detailed data, analyses, and studies sufficient for the Committee to make recommendations with respect to proposed benefit and cost allocations. The Committee also has the responsibility of notifying the appropriate project entities that it has not been provided sufficient information to undertake its review.

As provided for by its charter, the Committee votes on any actions, decisions, or recommendations. Votes with respect to cost allocation are recorded as part of the Committee meeting minutes and available for review through the NTTG website.

Committee Activities

1. Drafting of NTTG position paper on the link between planning and investment decisions.

In response to the positions advanced by some stakeholders in the Western Electricity Coordinating Council (WECC) planning process (funded by the U.S. Department of Energy (DOE) grant authorized by the American Recovery and Reinvestment Act (ARRA), as described further below), members of the Cost Allocation Committee drafted a position paper laying out the Committee's view of the role of transmission planning, and in particular the role of a transmission plan, in the determination of what projects are built and how investment decisions are made. The paper is attached to this report as Appendix D.

In sum, this paper stressed the distinction between transmission plans developed for a wide range of assumptions and forecasts with regard to load growth, resource development, and public policy versus decisions by project sponsors on pursuing the permitting and construction of specific transmission projects. This paper offered the following points:

- Planners study alternate scenarios of future states of the regional power system and examine how various transmission additions perform to meet system needs. If they find solutions that appear to be robust with regard to many alternate visions of the future needs of the regional grid, or if they find a superior solution to a particular view of the future that is deemed to be very likely, they may recommend that project as one that merits consideration by management for investment commitments and for construction. However, planners are not investment decision makers and transmission plans are not blueprints for construction.

- Planning involves projections of uncertain future conditions, such as load growth and the likely pattern of new generation, retirements of existing generation, exogenous decisions about new and existing transmission lines, and future public policy decisions. Not only is the future state of these variable unknown, but the probability distribution of the various outcomes is unknowable in advance.

- Investment decisions about new transmission projects are typically made by investor-owned companies or publicly-owned (i.e., municipal or cooperative) utility entities who may have differing views on the likelihood and associated risks of some or all of the variables looked at by planners, but who certainly have additional concerns not shared by planners. Investment commitments will typically be made for projects for which there are clear and likely benefits relative to other options (including the status quo) sufficient for the project sponsor, or for other parties, to be willing to commit contractually to use of the project sufficient to ensure costs will be recovered.

2. Participation in DOE/TEPPC/ARRA planning process and commenting on TEPPC 10-year west-wide Regional Transmission Expansion Plan.

The WECC was the recipient of a DOE grant funded through the ARRA to develop a western interconnection-wide study of congestion relief. This planning work is referred to as the Regional Transmission Expansion Plan (RTEP) and was performed through the Transmission Expansion Planning Policy Committee (TEPPC) of the WECC Board of Trustees.

A parallel grant went to the Western Governors Association (WGA) to develop a process for stakeholder input into the WECC process. The WGA funds supported two groups: a State and Provincial Steering Committee, composed of representatives of the Governor's Office and Public Service Commission in each western state and Canadian province; and a Scenario Planning Steering Group, composed of state representatives and other stakeholders, whose mission is to provide advice on scenario development, modeling tools and input assumptions for RTEP.

The modeling effort was largely driven by a focus on the development of large–scale, renewable resources in Montana and Wyoming aimed at displacing projected solar and wind development in California. The early drafts of the report on RTEP concluded that there was a high value to construction of the capacity that would facilitate the renewable development envisioned in the renewable scenarios, and it contained draft recommendations to utilities and regulators that substantial, inter-regional transmission be built.

The Committee believed that the discussion regarding the plan and planning process was, at best, unclear, and possibly misleading as to what actions should be expected to issue from the RTEP results. For example, various scenarios for renewable development were analyzed in the RTEP process with respect to transmission requirements and overall economics of large-scale, remote renewable projects, but no determination was made as to the relative likelihood of these scenarios actually being supported by utility and commercial interests or local and state land-use and economic policies.   CAC developed comments and responses to the RTEP report stressing this planning process was primarily about modeling projected economic outcomes of various resource development scenarios and not a process that would directly result in commercial decisions as to which transmission projects will or should be pursued. The RTEP process is ongoing but the Committee continues to be concerned that the results of the final RTEP report be viewed in their appropriate context..

3. FERC Notice of Proposed Rulemaking and Order 1000 on Transmission Planning and Cost Allocation

On June 17, 2010, the FERC issued a Notice of Proposed Rulemaking (NOPR) on Transmission Planning and Cost Allocation, indicating its belief that regional planning is required to ensure that regional solutions are not overlooked by transmission providers (TPs) that may be superior and lower cost solutions to their needs than the solutions based on planning by individual TPs. The NOPR also posited that the absence of clear understanding of how costs will be allocated to beneficiaries of new transmission projects may be a barrier to their construction. FERC announced its intention to issue rules governing regional transmission planning and cost allocation, and requested comments from interested parties.

Because these issues had been subjects of great interest to NTTG, the NTTG parties spent considerable time developing comments to FERC on its proposal. The CAC initiated the first draft of the comments to the FERC on the need for cost allocation, the possibility that it could be a vehicle for, rather than a solution to, free ridership, and the importance of understanding the inherent uncertainty in estimating benefits and the likelihood of significant error associated with a mandatory allocation of costs associated with an uncertain estimates of benefits. The comments also stressed the NTTG view of the role of planning in informing investment decisions discussed above. The NTTG comments were filed with FERC on September 29, 2010.

On July 21, 2011 FERC released Order 1000, with publication following on August 11 in the Federal Register. The rule becomes effective two months after publication, or October 11, and compliance filings by regional planning groups and jurisdictional transmission providers are due in 12 months from the effective date, or October 11, 2012, to describe how each party is meeting the regional planning and cost allocation portions of the order. A further compliance filing is due 18 months from the effective date, or April 11, 2013, on how the requirements for cooperative agreements between adjacent regions for planning and cost allocation will be met.

Currently the CAC, and other committees of NTTG, are digesting the implications and requirements of the Order. In brief, Order 1000 requires the following:

- Each TP participate in a regional planning effort (which membership in NTTG appears to satisfy) with ample opportunity for stakeholder participation

- The regional transmission planning process meet certain requirements, including a process to identify solutions to regional needs that may be better, or more cost effective, than those that would emerge from individual utility transmission planning.

- Regions must develop methods for selecting transmission projects in the plan for cost allocation, and for such projects provide a methodology that allocates costs among entities in a manner at least roughly commensurate with the estimated benefits associated with the project.
- Each region must collaborate with adjacent regions to develop planning processes that will allow the regions to evaluate projects that cross regional boundaries; to develop planning processes that meet the same standards as those guiding regional planning, including the selection of projects for cost allocation; and to develop a cost allocation methodology for selected projects.

Order 1000 leaves many questions unanswered, and FERC staff has generally indicated that the blanks will be filled in as compliance filings are made and evaluated by the Commission. Among the most important of these question is the authority and mechanism through which a project costs allocated by the cost allocation process can actually be assigned to and subsequently recovered from unwilling parties who dispute being beneficiaries and who have no contractual agreement with the project developers or owners.

The CAC anticipates considerable effort in the next 12 months preparing for the required compliance filings. In particular, it expects to work with the TPs and stakeholders in NTTG in devising criteria for selecting projects for cost allocation and developing a cost allocation methodology that will meet the requirements of Order 1000. In addition, the negotiations with adjacent planning regions promise to be challenging, given the differing approaches that have emerged in the past several years.

Data Request to Project Sponsors

The key to the Committee's work is receipt of complete and timely information from project sponsors and interested stakeholders regarding project purposes (e.g., maintaining reliability, relieving economic congestion, increasing inter-regional transfers, etc.), benefits, costs, optional configurations, and alternative facilities. The Committee Charter enumerates the basic information in the "application package" (Section V.1.) that should accompany a project proposal submitted for inclusion in the NTTG Planning Process. This information list includes –

- Cost/benefit analysis
- Proposed cost allocation
- Proposed cost recovery
- A risk and benefit analysis focusing on the distribution of costs, benefits and risks among the parties proposed to share in the cost allocation of the project
- How each NTTG cost allocation principle was applied in the analysis.

As it did in the 2008-2009 cycle, the Committee prepared a standardized data request in letter format formally requesting specific information related to the development of a draft cost allocation recommendation. (The letter is provided in Appendix A.) This letter was sent to each project sponsor in late March/early April 2011.[3] Sponsors were asked to supplement and/or update information provided for a project also included as part of the 2008-2009 cycle.

Project sponsors were asked to respond to the request within sixty (60) days. Responses were reviewed and, in some instances, follow-up requests were made.

The following summarizes the data requests and the responses from the sponsors.

[3] Due to an oversight, the data request to one project sponsor was delayed until May 20, 2011.

Table 2: Projects Receiving a Data Request

Project Sponsor	Project(s)	Response
Grasslands Renewable Energy LLC	Multiple Montana projects in NTTG footprint	Limited; most information is "not public" or "to be determined."
Idaho Power Company	Gateway West (Populus-Hemingway); Boardman-Hemingway	Provided most information directly or through reference to other documents (e.g., recent IRP); key risk and benefit analysis has not been performed.
Northwestern Energy	Mountain States Transmission Intertie (MSTI); MSTI Collector System; Extg. 500-kV Upgrade; Extg. Path 18 Upgrade;	Provided basic information on each project and references to and excerpts from other studies related to project use and overall economic benefits. (Some items in response were designated as confidential.)
PacifiCorp	Gateway South (Aeolus-Mona); Gateway Central (Mona-Oquirrh, Sigurd-Red Butte); Gateway West (WindStar-Populus, Populus-Hemingway); Hemingway-Captain Jack; Walla Walla-McNary	Provided basic information and updates on each project and references to WECC studies and most recent IRP which included a least-cost analysis of alternative transmission development scenarios, in conjunction with various resource options.
Portland General	Cascade Crossing (Coyote Springs-Hemingway, Boardman-Bethel)	Provided basic information as to project alternatives being considered, its planned open-season process, and permitting status.
TransCanada	Chinook, Zephyr	No response
TransWest Express LLC	TransWest Express	Responded that it was premature to provide information.

Discussion regarding the scope and specifics of the responses in aggregate (not by project sponsor) and a more detailed description of the individual is provided below.

Evaluation of Project Information

Responses, Generally Speaking

The Committee is not structured in terms of staffing or other resources to prepare basic analysis of a project's benefits and beneficiaries, nor a cost allocation based upon distribution proportionate to benefits. The Committee depends on information and analysis prepared or compiled by the project sponsor for these seminal analyses, which the Committee's data request and follow-up questions are intended to elicit.

Sponsors provided information already developed, compiled and submitted for other purposes, be that purpose for regulatory approvals (e.g., land-use permits, financing, etc.), industry rating/impact studies (which, with the advent of standards, may be another form of regulatory approval), or industry planning studies. This information can be categorized as follows:

> Physical parameters – line type, voltage, terminals, length,
>
> Financial parameters -- estimated cost, participants (or expected participation),
>
> Needs assessment – statements and/or references to studies regarding the project need (i.e., reliability, congestion relief, transmission service requests),
>
> Economics assessment – summaries and/or references to studies regarding economic analysis of the overall costs in relation to the need and/or project benefits, and
>
> Development status – related transmission service requests and executed service agreements, open season plans/responses, permitting and other regulatory approvals, WECC ratings process, construction plans and decision/development milestones.

It did not appear that any material submitted by sponsors was developed specifically to respond to the Committee's data request. In particular, none of the sponsors provided "a risk and benefit analysis focusing on the distribution of costs, benefits, and risks among the parties proposed to share in the cost allocation of the project." Without such analysis of the distribution of risks and benefits, however, demonstrating consistency with the cost allocation principles is problematic for the Committee.

Idaho Power Company

Gateway West

According to information in the 2011 Integrated Resource Plans (IRPs) of Idaho Power and PacifiCorp, Gateway would consist of two 230-kV lines from Windstar, Wyoming to Aeolus, Wyoming, a single 500-kV line from Aeolus to the Populus substation in Idaho (via an annex substation at Jim Bridger, Wyoming). Idaho Power and PacifiCorp would jointly participate in these segments. From Populus to Hemingway, Idaho, two 500-kV lines would be built in a generally east-west orientation, with one taking a more northerly route owned by Idaho Power and running through Borah and Midpoint (with PacifiCorp owning the line running on a more southerly route). A single 500-kV line would tie together the two 500-kV lines at Midpoint. The fully completed project from Populus to Hemingway is expected to provide 3,000 MW of transfer capacity (one-half of which would be owned by Idaho Power).

Review of Idaho Power's 2011 IRP indicates that the timing, level of commitment, and cost of its Gateway West participation is substantially changed from the information provided in the 2008-2009 study cycle. The 2011 IRP includes Gateway West as part of the 2021-2030 portfolio analyses, indicating that the project would not be available until sometime after 2020. The 2011 IRP also indicates that (i) only one portfolio included the originally-planned participation level and (ii) several other portfolios during this second 10-year period included less or no new transmission capacity from Gateway West (as reflected in the lower capital levels includes in these portfolios for new transmission). In the portfolio that apparently assumed the original 50% participation level, the estimated costs appear to be greater than the estimate of $600 million in (12/2008 $). More specifically, the Long-Term Action Plan of the 2011 IRP indicates that, although the preferred portfolio for the long-term action plan does not include Gateway West, Idaho Power "plans to continue permitting the Gateway West project because of uncertainty associated with the location of resources planned * * * the future * * *."

Idaho Power's response to the Committee's data request was limited and indicated the only change from the information submitted in the 2008-2009 cycle was the reference to 1000 MW of PTP queue requests as part of the project's contractual commitments. There was no discussion of changes in the timing of the project or likelihood of its participation vis-à-vis the analysis and action plan present in its 2011 IRP.

Boardman to Hemingway

The project consists of a new, single-circuit 500-kV transmission line running approximately 300 miles from a new substation near Boardman, Oregon to the Hemingway substation, southwest of Boise, Idaho. The transmission line would span approximately 300 miles at an estimated cost of $820 million (2008 dollars). The expected in-service year is 2016. The project is expected to have a west-to-east transfer capacity of 1,300 MW and east-to-west capacity of 800 MW. (The increase in import capability from the Pacific Northwest would, however, be 850 MW.)

Idaho Power states that the project would meet native/network customer obligations. As a result, Idaho Power anticipates that project investment will be rolled-in to existing capital investment used in existing FERC and state regulatory rate processes.

NorthWestern Energy

Mountain States Transmission Intertie (MSTI)

The project consists of a new, single-circuit 500-kV line from Townsend, Montana to Midpoint, Idaho, plus new and upgraded substations and microwave communications system. Total line miles are estimated at 420-445 miles at a cost of $1.0 billion. No estimated in-service date was provided. According to studies referenced by NorthWestern, the project could be used in conjunction other transmission system additions to economically transmit renewable generation in Montana to southern Nevada and California.

NorthWestern expects a north-to-south rating of 1,500 MW and south-to-north rating of 1,100 MW. All technical studies for the WECC Phase 2 path rating process have been completed.

NorthWestern propose to use an open-season process for transmission customers to commit to a level of transmission service on the MSTI project and to pay an associated transmission rate based on project costs (including rate of return). NorthWestern does not propose to allocate any project costs to calculation of its existing transmission rates.

NorthWestern provided excerpts and summaries of information developed as part of the 2010 Study Program of TEPPC with respect to the MSTI project. The economic study results indicated that the MSTI project, coupled with other transmission system additions, could provide a less expensive alternative for the development and delivery of renewable resources into southern Nevada and California. The information provided by NorthWestern directly, or by reference to the TEPPC studies, does not indicate what might be the full range of net benefits resulting from the MSTI project (e.g., reliability, deferral of other transmission projects, regulation and contingency reserve impacts, etc.), nor the distribution of benefits among transmission systems, transmission customers, and generation developers and operators. NorthWestern makes clear that the development concept underlying MSTI is for prospective entities to self-select themselves as likely beneficiaries of the project and seek participation accordingly.

NorthWestern also provided a copy of its Phase 2 rating progress report to WECC.

MSTI Collector System

This project represents an aggregation of relatively short transmission system additions necessary to connect the anticipated development of new wind projects with a new, 500-kV substation at Townsend, the proposed northern terminus of the MSTI project. NorthWestern expects that there would be five of these “generator lead” lines, all radial, connecting to Townsend. The size, configuration, length, and location of the Collector System lines would be based on those entities committing to transmission service through an open-season process.

Given there being only a broad, conceptual description of the project at this time, no cost/benefit analysis at an aggregate or disaggregated level has been prepared for the project. NorthWestern intends to allocate costs (i.e., recovery its costs) through its normal OATT "or" transmission rate methodology. That is, transmission customers on the Collector System would pay the greater of (i) NorthWestern's OATT rate or (ii) an incremental rate based on the costs and capacity of the Collector System.

Existing Path 18 Upgrade

The project is described in information submitted to the Planning Committee as involving series compensation on the AMPS line (from the AMPS substation in Idaho to the Mill Creek Substation in Montana) and the addition of a DVAR device at the AMPS substation. Project owners would also include Idaho Power and PacifiCorp, increasing path capacity by 64 MW. NorthWestern indicates that the purpose of the project is to satisfy transmission service requests.

NorthWestern has designated its response to the Committee's data request as confidential.

Existing 500-kV Upgrade

This project involves the "Colstrip Transmission System" located in NorthWestern's balancing area between Colstrip and Townsend, Montana. The project would increase transfer capacity by 500-700 MW through increase of series compensation from 35% by up to 70%. The increased capacity would be used to satisfy transmission service requests.

NorthWestern has designated its response to the Committee's data request as confidential.

PacifiCorp

Similar to Idaho Power, PacifiCorp included the evaluation of transmission alternatives as part of its 2011 IRP. (That is, transmission options were explicitly considered in evaluating the net costs and risks of various resource portfolios). The conclusion was that, as a whole, the Gateway strategy would be cost-effective – assuming additions of new wind generation consistent with PacifiCorp's current plans. The IRP did allow, though, that the range of results among the scenarios was relatively small and did not indicate a clear winner.

While the IRP evaluation provided an indication of benefit versus cost of the transmission build-out in total, it did not clearly disaggregate the results (i) among the various components of the Gateway strategy, (ii) among types of benefits, or (iii) among beneficiaries. This type of analysis could, perhaps, be expanded in the future to provide at least some significant portion of the information necessary to estimate benefits by type and among various beneficiaries.

Energy Gateway Central (Mona-Oquirrh; Sigurd-Red Butte)

Energy Gateway Central consists of two project segments being actively pursued. The first segment, Mona-Oquirrh, is approximately 100 miles and is comprised of a single, 500-kV sub-segment from Clover (adjacent to Mona) to Limber and a double-circuit, 345-kV sub-segment from Limber to Oquirrh. (PacifiCorp's 2011 IRP also indicates another sub-segment would be extended from Oquirrh to Terminal, also consisting of double-circuit 345-kV facilities.) The planned in-service date for the Mona to Oquirrh portion is 2013 and initially (i.e., prior to completion of future Gateway segments) expected to increase transfer capability by 700 MW bi-directionally.

The second segment, Sigurd-Red Butte, consists of a single, 345-kV line running approximately 160 miles from the Sigurd substation in central Utah to the Red Butte substation near the Utah-Nevada border, roughly paralleling an existing 345-kV line. The original plan for a sub-segment from Red Butte to Crystal, near Las Vegas, was been deferred indefinitely. PacifiCorp hopes to place the project in-service in 2014 with a north-to-south rating of 400 MW and south-to-north rating of 550 MW.

PacifiCorp did not provide updated information regarding the expected capital costs of these segments. An estimate of $569 million was provided for the Mona-Oquirrh in the 2008-2009 cycle. As with other portions of the Gateway Project, the Gateway Central is being constructed, according to PacifiCorp, in order to meet "current and project network load service" as well as maintain its compliance with reliability performance standards. PacifiCorp states that all costs and benefits have been assigned to network customers. If equity partners come forward, they would be expected to share in project costs based on their impact on costs and allocated project capacity.

Gateway South (Aeolus-Mona)

The Aeolus-Mona line is a single, 500-kV line from a new substation in central Wyoming to the Mona substation in central Utah. The scheduled completion is in the 2017-2019 timeframe and has an expected rating of 1,500 MW north-south.

The segment of Gateway South from Mona to Crystal, Nevada has been deferred indefinitely.

PacifiCorp did not provide updated information regarding the expected capital costs of Gateway South. As indicated above, the Gateway South is being constructed, according to PacifiCorp, in order to meet "current and project network load service" and meet reliability requirements. As with all Gateway segments, all costs and benefits have been assigned to network customers.

Gateway West (Windstar-Populus, Populus-Hemingway)

The Windstar-Populus consists of (i) two, single-circuit, 230-kV lines running about 80 miles from Windstar to Aeolus in central Wyoming, and (ii) a single, 500-kV line from Aeolus to Populus, Idaho running about 350 miles via a new annex substation near the existing Bridger substation in western Wyoming. PacifiCorp expects this eastern segment will be completed in the 2015-2017 timeframe.

The 2011 IRP concludes that this segment would provide transfer capability from an area of the West with rich, diverse resources, consistent with use of transmission to meet the future resource needs of its retail and wholesale power customers.

The western segment of this project consists of (i) a single, 500-kV line from Populus to a new substation south of Midpoint and (ii) a single, 500-kV line from Midpoint to the Hemingway substation south of Boise, Idaho. The segment is approximately 135 miles. PacifiCorp expects this western segment will be completed in the 2016-2018 timeframe.

The 2011 IRP states that the project will provide access to existing and new generating resources to accommodate the retail and wholesale loads included in its IRP evaluation.

PacifiCorp's 2011 IRP states that it expects to partner with Idaho Power on the project, although the timing for development is inconsistent with the conclusions reached in the 2011 IRP of Idaho Power.

Hemingway - Captain Jack

The project is described as a new, single-circuit 500-kV line that would run approximately 375 miles from the Hemingway substation in western Idaho to the Bonneville Power Administration's Captain Jack substation. The western terminus of the project, while planned for Captain Jack, could be moved within the same general area if equity partner and/or wholesale customer commitments are secured and efficiencies are identified. PacifiCorp provided no information as to project in-service date, specific need, and capacity. It estimated the project cost, without AFUDC, at $931 million (nominal dollars). No partners exist to date on this project. The 2011 IRP states that PacifiCorp is considering participation in the Boardman-Hemingway and Cascade Crossing projects as an alternative to this project. Moreover, the 2011 IRP did not include this project as part of any of the reported power supply scenarios.

Walla Walla - McNary

The project is described as a new, single-circuit 230-kV line that will run approximately 56 miles between Walla Walla, Washington and Umatilla, Oregon and will connect existing substations at Walla Walla, Walulla and McNary. PacifiCorp is proceeding with the Walulla - McNary portion of the project with, according to its 2011 IRP, an expected completion in the 2012-2013 timeframe. While PacifiCorp did not provide information as to project capacity, its 2011 IRP indicates that the line is needed to "address energy constraints on the system" and transmit "resources from remote locations to customer load centers." The 2011 IRP further indicates that it has signed to transmission service agreements on this segment totaling 120 MW. No cost information was provided for this segment.

PacifiCorp has placed the Walla Walla – Walulla segment on hold pending further review with no scheduled completion date

Portland General

Cascade Crossing

Depending on the level of commitment expressed through an open-season process, the project would consist of a single-circuit, 500 kV transmission line from PGE's Coyote Springs generator, located near Boardman, Oregon, to the Bethel substation. The line length would be approximately 210 miles and propose a path rating of 1,500 MW. This project is proposed to satisfy several generator interconnection requests, including a substantial number of renewable/wind projects (totaling approximately 2100 MW). If the level of commitment from the open-season process warrants, the bulk of the project could be re-designed as a double-circuit, 500-kV project.

The project is described as having five segments; (1) Coyote Springs to a new substation at Grassland; (2) Grassland to a new Cedar Spring substation near Arlington, Oregon; (3) Cedar Springs to a new substation near Mikkalo, Oregon; (4) Mikkalo to Bethel; and (5) from a tap on the Mikkalo-Bethel segment to the Santiam substation.

As indicated above, Portland General is discussing some form of possible joint participation in this project with PacifiCorp and Idaho Power.

Northern Tier Transmission Group

2010-2011 Cost Allocation

Draft Report: Appendices

High Voltage Transmission Towers in Utah

Appendix A: Data Request to Project Sponsors

NORTHERN TIER
TRANSMISSION GROUP

March 31, 2011

Via Electronic Mail

[Recipient]
Vice-President, Transmission Planning
[Project Sponsor]
[City, State, Zip Code]

RE: Project XXX

Dear [Recipient]:

As a project developer/sponsor having submitted a project proposal to the Northern Tier Transmission Group (NTTG) Planning Committee, you are also responsible for submitting a packet to the NTTG Cost Allocation Committee containing the following information:

a. Project description
b. Physical location
c. Cost/benefit analysis
d. Investors (description and interest)
e. Operator
f. Subscribers/Contracts
g. Pertinent transmission study results
h. A copy of any WECC economic and reliability determinations relative to the project
i. Proposed siting process
j. Proposed cost allocation
k. Proposed cost recovery
l. A risk and benefit analysis focusing on the distribution of costs, benefits and risks among the parties proposed to share in the cost allocation of the project.
m. Proposal on dealing with cost overruns
n. Degree of consensus among stakeholders on all of the above
o. How each NTTG cost allocation principle was applied in the analysis
p. A description of any regulatory rulings needed prior to examination of the project
q. Any NTTG Planning Committee analysis pertinent to the project and a description of how it fits into the NTTG Annual or Biennial Plan
r. Description of any proprietary or commercially sensitive information applicants believe should remain confidential during the review process

To the extent that you have already provided this information as part of this Committee's request in 2009, we ask that you carefully review your prior submittal and update that information, as necessary, as well as include information that may have been omitted in the original submission. To the extent that your application excludes, or is not fully responsive to one or more of the items a. – r. above, please indicate when you expect to supplement your application with the required information or provide an explanation as to why you will not be submitting that item of information.

Please also (i) clearly mark the information as responsive to the specific items a. – r. above and (ii) consider this to be an on-going request to update your application when and as there are any significant changes in the project information previously submitted. Please provide this information within 60 days.

It is the intent of the Committee to take the following actions within 45 days of receipt of your application:

a. Make a general determination of the completeness of the application and its readiness for consideration. If it is incomplete, the Committee will inform you as to those items which require additional information.
b. Decide what, if any, information is to be kept confidential during the review process (with an emphasis on the greatest possible degree of openness and transparency in order to encourage public discussion and input during the NTTG Planning Process).
c. Determine whether and to what extent the application has fairly observed the NTTG's cost allocation principles.
d. Provide all applications to the NTTG Steering Committee.

It is not within the scope or resources of the Committee to independently develop an allocation of benefits and costs associated with your proposed project. Accordingly, the Committee emphasizes the following should be considered in developing or be part of the information submitted in your application:

1. Identify, quantify and propose an allocation of benefits and cost for the project.
Your proposal should address the following at a minimum: the benefits which are the basis for any inter-jurisdictional or other methodology used to assign costs to retail customers or to assign costs among transmission user groups. To the extent the project is required exclusively to meet transmission service requests and/or transmission service obligations, so stating will suffice the underlying benefits of the project. If you have integrated resource plans or other forecasts indicating future changes in project uses and/or cost allocations, please provide the results to the Committee.

2. Proposed cost recovery
Please indicate the applicable rate processes – federal, state, contractual, or other – needed to recover costs. Please include or refer to applicable ratemaking decisions already rendered or anticipated to be rendered because of a pending application or future application to be filed. If new or innovative rate processes or designs are anticipated, e.g., regional, multi-jurisdictional,

incentive, project-specific, or negotiated rates, please describe. Please explain how these rate processes or designs will accommodate and reflect future changes in project use (e.g., formula rates).

3. A risk and benefit analysis focusing on the distribution of costs, benefits and risks among the parties proposed to share in the cost allocation of the project

Please provide any internal or third-party-prepared analysis for the project. This item should provide supporting documentation for the proposed cost allocation, including forecast future shifts in use. Some examples of benefits include improving reliability, serving existing retail load or anticipated retail load growth as indicated in your Integrated Resource Plan, fulfilling interconnection and transmission queue requests, accessing new or existing generation resources, and providing increased capacity for existing wholesale customers' load growth or other needs. Please demonstrate the distribution of costs to beneficiaries. For example, are costs proposed to be directly proportionally distributed to beneficiaries on a load or energy or some other basis? With regard to risk, please indicate the level of risk for the project to be assumed by each beneficiary group and any proposals to mitigate risk. For example, differences in return on equity or its treatment for different customer groups constitutes a risk mitigation tool. The risk analysis will preferably provide the probability distribution assumed for benefits accruing to each party or class of party and include an explanation of how benefits were estimated. If benefits are foreseen for parties outside of the NTTG footprint, describe how costs and risks will be assigned to those parties.

5. Additional project configuration options

If you are considering an alternative size or configuration for your project, this Committee needs to know what will drive this decision and what implications the decision will have for costs and cost allocations. Thus, if you are considering alternative size or other configurations, please indicate (i) the decision factors leading to the decision to implement the alternative, (ii) any studies or process employed to support that decision, (iii) the additional costs, benefits, and risks associated with the alternative, and (iv) the additional capacity and other operational benefits associated with the alternatives.

6. Degree of consensus among stakeholders

Your response should indicate areas of agreement and disagreement among the stakeholders and should include supporting documentation. For example, a regulatory order can point to consensus or lack of it among stakeholders, or local or NTTG stakeholder processes or any other solicitation of public input can demonstrate the level of participation and consensus on the cost allocation for your project(s).

The more thoroughly you can describe all of these items, the better the Cost Allocation Committee will be able to evaluate your project(s). The Committee requests that your responses be submitted via email by June 1, 2011 to Lyndee Restad at Lyndee.Restad@comprehensivepower.org. Please let me know if you cannot meet this deadline or have any questions.

Sincerely,

Curtis Winterfeld
Chair, NTTG Cost Allocation Committee

Appendix B: Project Templates

This appendix provides templates for each project that summarize its key physical characteristics, the need for and/or intended purpose(s), proposed cost allocation and recovery mechanism(s), and its adherence to NTTG's four Cost Allocation Principles

NOTE: The information provided in this appendix is dynamic and subject to change without additional notice. The information from the project sponsor regarding the project characteristics, status, and cost allocation/recovery is collected and provided here for convenience; specific data should be confirmed on the project sponsor's Web site or via processes posted on their respective OASIS systems.

Disclaimer:

These Cost Allocation Project Summaries are created on behalf of the Northern Tier Transmission Group Cost Allocation Committee in conjunction with the Northern Tier Transmission Group's Biennial Draft Transmission Plan per the Cost Allocation charter.

If the state commission's designated representative (or alternate) is a member of the Committee, with respect to the Committee said individual will not be acting as a representative of a state commission. No action or position taken by the individual or the Committee will preclude a state commission from taking contrary actions or positions in proceedings before it or other regulatory bodies.

No action or position taken by a state commission's representative or by NTTG shall preclude a state commission from taking conflicting action consistent with its jurisdiction or constitute prejudgment of any issue in a proceeding before it.

Gateway West (Idaho Power)

NTTG Cost Allocation Project Summary As of August 31, 2011	
Committee Liaison:	Lou Ann Westerfield, Idaho Public Utilities Commission
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	The Gateway West project would allow delivery of new resources from Wyoming and other areas to the east of Idaho. This project would also tend to relieve congestion on multiple transmission paths including Bridger West, Borah West, West of Midpoint, and mitigate existing reliability limits by potentially reducing some reliance on remedial action schemes. This total project (not just Idaho Power's share) would increase capability through Idaho by up to approximately 3,000 MW and by up to 3,000 MW through Wyoming (with other Energy Gateway projects in service).
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	Idaho's 2011 IRP indicates that this project is not part of its preferred portfolios, but, as a hedge, it would continue with permitting of the project.
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	Gateway West segments through Idaho are proposed as single circuit 500-kV AC, in addition to the broader description of the Energy Gateway projects. This allows construction phasing, in addition to meeting reliability separation for rating studies. Estimated total circuit length of Gateway West is approximately 1,000 miles (undergoing routing, siting, and permitting) from eastern Wyoming to southwestern Idaho.
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates only.	• No sooner than 2022 • None
• WECC Rating Process – Phase	Phase 2
• Status and estimated completion date of federal, state, and local permitting/siting processes	Received an approved EIS as of August 3, 2011
Project sponsor(s):	
• Organization name(s)	PacifiCorp and Idaho Power Company
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.idahopower.com/AboutUs/PlanningForFuture/ProjectNews/GatewayWest/default.cfm
• Date of last information update (Note source of update: NTTG PC, NTTG Cost Allocation Committee, FERC or state filing, WECC filing, etc.)	June 2011 Data response by Idaho Power to NTTG CAC; 2011 IRP

Other project participant(s):	PacifiCorp
Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Please note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	• $600 million (2008 $) • 12/1/2008 • Idaho Power project management (from 2008-2009 Biennial Plan, Cost Allocation Committee, Final Report, NTTG)
Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	No information
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	No information
• Decision factors for choosing alternative configuration options	No information
• Additional cost estimate for alternative configurations (marginal cost)	No information
• Potential increased capacity for alternative configurations	No information
Level of commitment:	
• Is there a committed Anchor Tenant?	No
• What is the percent of contractual commitment from PTP customers	None
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	This project need has previously been part of Idaho Power's 2009 and 2011 IRP analyses.
Cost allocation plan:	
• Sponsors proposed cost allocation plan	Given Idaho Power's existing FERC formulary rate design and state jurisdictional allocation processes, Idaho Power expects costs will be directly allocated to users of the project according to existing policies and jurisdictional rate design.
• How project plans to recover cost	Include Idaho Power's share of project costs in existing FERC and state rates.
• Contingency plan if initial cost recovery plan is not realized	Project is currently in the siting and permitting process. Construction will be initiated only as further analysis demonstrate the economic benefit and need for the project relative to other resource and transmission options.
• Has the Project received, or does it intend to apply for FERC incentives?	Idaho Power has not applied for FERC incentives at this time.

• Risk mitigation plan if market does not develop as expected	If needs or participants materially change, the project construction may be delayed to match timing or modified as required.
Cost allocation principles (How does the project meet, or not meet, the principle.)	
• Principle 1 As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	Idaho Power's native and network load requirement costs will be borne by the retail and wholesale customers according to existing OATT provisions and state jurisdictional processes. Additional users are directly accommodated through tariff pricing and recovery.
• Principle 2 Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and subregional planning resources should be utilized and the results demonstrated.	Transmission access to additional resources is evaluated as part of Idaho Power's IRP processes. Idaho Power's 2011 IRP indicates that this project is not part of a preferred resource portfolio. Accordingly, while Idaho Power will pursue permitting of the project, it has deferred any construction plans.

• Principle 3 Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • Principle 3a Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • Principle 3b Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	As proposed by including Idaho Power's share of the project costs in existing rates and revenue requirements at both the federal and state levels, the project is expected to achieve full recovery and regulatory treatment, but no more. 3a - As proposed, the project costs will be directly allocated to users under existing OATT tariff provisions and revenue requirements including credits and system usage passed through to state jurisdiction load ratio uses of the transmission system. 3b - This project is not based directly upon economic efficiencies to reduce market congestion, but primarily upon access to cost-effective resources for native load, especially renewable resources. To the extent required to meet new requests, transmission service requestors are allocated costs based upon their requests for service under existing FERC pricing methodologies including higher-of and rolled in calculations. Contractual obligations via the resultant service agreements provide for cost recovery of the prorated share of the project costs over the term of service agreement preventing cost shifting. Existing WECC rating processes prevent the service request or project from doing harm to network reliability or existing regional commercial capabilities.
• Principle 4 For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	This project is directly related to providing increased service to Idaho Power's native and network customer loads. Any third-party usage or requests result in additional OATT revenues directly offsetting revenue requirements and/or an increase in System Peak Demand resulting in a decrease of the transmission rate to all customers. Based upon the requirements and drivers of this project independent of additional uses, any Type 2 project costs and uses will serve to reduce costs to all users to the extent capacity is available beyond the needs of native and network customer loads.

Boardman-Hemingway 500 kV (Idaho Power)

NTTG Cost Allocation Project Summary As of August 31, 2011	
Committee Liaison:	Lou Ann Westerfield, Idaho Public Utilities Commission
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	Reliably meet network service obligations in a cost-effective manner.
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	Purpose and need remain the same. Additional equity partners' needs are expected to align with their participation level.
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	500 kV AC, estimated length approximately 300 miles (undergoing routing, siting, and permitting) from southwest Idaho to northeast Oregon.
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates ONLY.	• 2014 estimated construction start • May 2016 estimated in-service
• WECC Rating Process – Phase	Phase 2
• Status and estimated completion date of federal, state, and local permitting/siting processes	Idaho Power is actively engaged in the federal National Environmental Protection Act siting process for federal lands and the Oregon Energy Facility Siting Committee process for the Oregon portion of the route. BLM draft EIS expected March 2012.
Project sponsor(s):	
• Organization name(s)	Idaho Power Company
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.boardmantohemingway.com/
• Date of last information update (Note source of update: NTTG PC, NTTG Cost Allocation Committee, FERC or state filing, WECC filing, etc.)	5/31/2011 Data response by Idaho Power to NTTG CAC; 2011 IRP; WECC Transmission Project Portal

Other project participant(s):	Idaho Power is exploring participation with transmission providers and other developers pending proposed routing and timing. It is expected participants' ownership interest will align rights with needs. Idaho Power expects to retain import capacity for network/native load growth in addition to providing for any transmission service requests under their OATT.
Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Please note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	• $820 million • 1/20/2011 • Idaho Power Project Management – based upon preliminary scoping and estimated length of 300 miles. Currently undergoing public routing process.
Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	Conductor selection allows for latent capacity beyond the initial WECC rating study results for the single circuit configuration. With future projects on separate corridors in the region, the 1300 MW west-to-east and 800 MW east-to-west (1400 MW with the Gateway West project in service providing additional source capabilities removing constraints near Midpoint) expected ratings of the proposed configuration may be increased to nearer the 3000+ MW thermal capabilities of the line. Lower voltages or smaller conductors will not meet the currently defined needs of the project. Increasing voltage or addition of another circuit would not be able to achieve any additional capacity through the WECC rating process and reliability criteria as this element is the single critical outage. Additional constraints on the West of McNary (WOM) cut plane would likely require additional projects to deliver additional power into northeastern Oregon. Therefore efforts to up-size this project is unwarranted and not cost effective at this time.

• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	No other projects are being proposed through this corridor. However, projects in northeastern Oregon are coordinating study and siting efforts to allow development of a North East Oregon (NEO) substation to interconnect proposed projects. Technical studies are also being coordinated through the TCWG efforts. Portland General and Idaho Power are coordinating the Cascade Crossing and B2H in the Boardman area to minimize circuits and line construction, while integrating multiple project needs. The Hemingway-Captain Jack project (PacifiCorp) has not begun siting, but has a different termination in Oregon and would only consider common corridor with appropriate separation until the B2H project proceeds northwestwardly toward Boardman substation.
• Decision factors for choosing alternative configuration options	Transmission service requests under the OATT which could not be supplied by the proposed project, and are willing to pay the "higher of" FERC rate, or third party willing to fund and assume entire risk of alternative configuration.
• Additional cost estimate for alternative configurations (marginal cost)	Double-circuit configuration could cost approximately an additional $350 million, and until other major projects reinforce the region, would produce no additional capacity or benefits.
• Potential increased capacity for alternative configurations	Until/unless additional projects reinforce the region, there is no expected incremental capacity beyond the current project's expected WECC rating.
Level of commitment:	
• Is there a committed Anchor Tenant?	Idaho Power transmission to meet native/network customer obligations. Other potential partners are exploring future capacity requirements and options.
• What is the percent of contractual commitment from PTP customers	There are no PTP customers at this time.
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	This project has been included in Idaho Power's IRP analysis updates as provided to the Oregon PUC in 2009. Project was part of the preferred portfolio selected in Idaho Power's 2011 IRP.

Cost allocation plan:	
• Sponsors proposed cost allocation plan	Idaho Power anticipates including project costs in existing FERC and state regulatory rate processes as rolled-in capital investments. Potential equity partners' share of rights, capacity, and costs are under discussion and not public at this time. Given the existing FERC formulary rate design and state jurisdictional allocation processes, Idaho Power expects costs will be directly assigned to users of the project according to existing policies and jurisdictional rate design. As information regarding other participants' information becomes publicly available, updates will be provided.
• How project plans to recover cost	Include Idaho Power's share of project costs in existing FERC and state rates.
• Contingency plan if initial cost recovery plan is not realized	Project is currently in the siting and permitting process. Prior to commencing construction, capacity rights and equity participation will be established through construction agreements. If needs or participants materially change, the project construction may be delayed to match timing or cancelled if cost recovery risks are unacceptable.
• Has the Project received, or does it intend to apply for FERC incentives?	Not at this time.
• Risk mitigation plan if market does not develop as expected	If needs or participants materially change, the project construction may be delayed to match timing or cancelled.
Cost allocation principles (How does the project meet, or not meet, the principle.)	
• Principle 1 As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	Idaho Power's native and network load requirement costs will be borne by the retail and wholesale customers according to existing OATT provisions and state jurisdictional processes. Additional users are directly accommodated through tariff pricing and recovery.

• <u>Principle 2</u> Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and subregional planning resources should be utilized and the results demonstrated.	This project was identified in Idaho Power's IRP processes, with the most recent analysis provided under the February 2009 IRP Addendum and NTTG processes to satisfy needs consistent with portfolio and queue requests, in addition to FERC Order 890 Attachment K transmission planning requirements. Idaho Power's current 2009 IRP will be completed later in 2009. Preliminary economic dispatch simulations are being conducted by NTTG with inclusion of the NTTG proposed transmission projects. Results are still pending.

• <u>Principle 3</u> Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • <u>Principle 3a</u> Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • <u>Principle 3b</u> Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	As proposed by rolling in Idaho Power's share of the project costs to existing rates and revenue requirements at both the federal and state levels, the project is expected to achieve full recovery and regulatory treatment, but no more. As proposed, the project costs will be directly allocated to users under existing OATT tariff provisions and revenue requirements including credits and system usage passed through to state jurisdiction load ratio uses of the transmission system. This project is not based directly upon economic efficiencies to reduce market congestion, but primarily upon reliable network service obligations. Transmission service requestors are assigned costs based upon their requests for service under existing FERC pricing methodologies including higher-of and rolled in calculations. Contractual obligations via the resultant service agreements provide for cost recovery of the prorated share of the project costs over the term of service agreement preventing cost shifting. Existing WECC rating processes prevent the service request or project from doing harm to network reliability or existing regional commercial capabilities.
• <u>Principle 4</u> For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	This project is directly related to providing increased service to Idaho Power's native and network customer loads. Any third-party usage or requests result in additional OATT revenues directly offsetting revenue requirements and/or an increase in System Peak Demand resulting in a decrease of the transmission rate to all customers. Based upon the requirements and drivers of this project independent of additional uses, any Type 2 project costs and uses will serve to reduce costs to all users to the extent capacity is available beyond the needs of native and network customer loads.

Mountain States Transmission Intertie (Northwestern Energy)

NTTG Cost Allocation Project Summary As of August 31, 2011	
Committee Liaison:	Brian DeKiep, Montana Public Service Commission
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	Provide capacity to meet requests for transmission service from an open season solicitation from energy marketers, utilities and power generators. MSTI will relieve constraints in the area's high voltage transmission system. Project is not needed as a network resource.
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	Not Applicable
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	Approximately 430 mile, 500-kV AC line with 1,500 MW north-to–south and 1,100 MW south-to–north transfer capability. Northern terminal is on the existing 500-kV transmission line at Townsend Montana and will terminate in Midpoint substation in Idaho. Proposed Montana collector system to terminate and connect to MSTI at Townsend Montana substation.
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates ONLY.	Project has been delayed due to Major Facilities Siting Act (MFSA) and NEPA process in Montana. MFSA is stalled until resolution of the suit between Jefferson county and Montana DEQ. Original completion date 2013. Estimate final siting process complete 2012 and in-service 2016.
• WECC Rating Process – Phase	Phase 1 is complete. Phase 2 technical studies complete. Phase 2 rating expected to be final before year-end 2011.
• Status and estimated completion date of federal, state, and local permitting/siting processes	Montana Major Facility Siting Act (MFSA) application filed July 2008. Final DEQ/BLM EIS expected in 2012.
Project sponsor(s):	
• Organization name(s)	Northwestern Energy
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.msti500kv.com http://www.msti500kvos.com/ http://www.wecc.biz/Planning/TransmissionExpansion/Transmission/Pages/default.aspx
• Date of last information update (Note source of update: NTTG PC, NTTG CAC, FERC or state filing, WECC filing, etc.)	May 2011 Data response by NWE to NTTG CAC
Other project participant(s):	

Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Please note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	o $1.0 billion (excl. the "Collector System") o March 31, 2009 o Response to comments submitted to Northwestern on March 19, 2009 by CAC
Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	Feasibility studies for 230, 345 kV AC configuration and 500 kV DC configuration complete.
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	Not Applicable
• Decision factors for choosing alternative configuration options	Open season solicitation response.
• Additional cost estimate for alternative configurations (marginal cost)	Not Applicable
• Potential increased capacity for alternative configurations	Not Applicable
Level of commitment:	
• Is there a committed Anchor Tenant?	No
• What is the percent of contractual commitment from PTP customers	Information not available until Open Season.
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	No
Cost allocation plan:	
• Sponsors proposed cost allocation plan	Northwestern Energy's proposal for subscribers to pay negotiated rates for service filed January, 2009 was rejected by FERC. Northwestern Energy intends to move forward with MSTI applying cost of service principles and not as a merchant transmission line.
• How project plans to recover cost	Cost recovery will be from transmission service agreements with customers wishing to use the line. No cost recovery will be allocated to native load in Montana. Northwestern Energy intends to file for appropriate tariff waivers to isolate native load customers.
• Contingency plan if initial cost recovery plan is not realized	If open season does not materialize sufficient subscription the project will not move forward.
• Has the Project received, or does it intend to apply for FERC incentives?	No, not at this time.
• Risk mitigation plan if market does not develop as expected	Project size will be evaluated on open season subscription.
Cost allocation principles (How does the project meet, or not meet, the principle.)	

• <u>Principle 1</u> As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	Intent to isolate any adverse impacts to native load and insure new transmission uses/users support the cost of the line through transmission rates is consistent with this principle.
• <u>Principle 2</u> Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and sub-regional planning resources should be utilized and the results demonstrated.	
• <u>Principle 3</u> Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • <u>Principle 3a</u> Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • <u>Principle 3b</u> Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	Intended development is consistent with Principle 3a.

• <u>Principle 4</u> For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	MSTI is proposed as a type 2 project. All costs will be directly recovered from transmission subscribers to the line and not Northwestern Energy's native load customers. Type 2 transmission costs are typically FERC jurisdiction and not subject to state review. However, due to the FERC order on June 18, 2009 there remains uncertainty surrounding Principle 4. Northwestern intends to file for the appropriate tariff waivers to isolate native load. This line relies on the resource planning process acceptance by the load serving entities that purchase the power from sources in Montana. The project is not in conflict with the stated policy and planning requirements affecting transmission development. The project will not harm the existing transmission network in MT or elsewhere because all mitigation necessary to maintain reliability will be implemented. The WECC path rating process also requires that the upgrade will not harm other transmission systems.

MSTI Collector System (Northwestern Energy)

NTTG Cost Allocation Project Summary As of August 31, 2011	
Committee Liaison:	Brian DeKiep, Montana Public Service Commission
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	The Collector Project transmission lines are radial generator lead lines that will connect high wind areas to the existing 500-kV transmission system at a new substation at Townsend MT. The Townsend substation will be the northern terminal of the Mountain States Transmission Intertie Project (MSTI).
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	Not Applicable
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	Proposed Montana collector system to terminate and connect to MSTI at Townsend Montana substation. Size, configuration and input terminal will depend on expression of interest and binding customer commitments and potentially include five, radial 230-kV generator lead lines
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates ONLY.	The commercial operation date for collector is dependent on the development of the MSTI project and/or the existing 500-kV, path 8 upgrade.
• WECC Rating Process – Phase	Phase 0
• Status and estimated completion date of federal, state, and local permitting/siting processes	Siting will begin after open season determines locations of lines
Project sponsor(s):	
• Organization name(s)	NorthWestern Energy
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.mt-rcs.com/ http://www.mt-rcsos.com/index.aspx
• Date of last information update (Note source of update: NTTG PC, NTTG CAC, FERC or state filing, WECC filing, etc.)	June 5, 2011 Data response by NWE to NTTG CAC
Other project participant(s):	
Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Please note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	Cost dependent on line configuration and route.

Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	Study will be complete once the collector open season complete.
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	To the extent appropriate and possible NorthWestern will likely use existing right of ways to site new facilities.
• Decision factors for choosing alternative configuration options	Response to the Collector Open Season will determine potential alternative configurations.
• Additional cost estimate for alternative configurations (marginal cost)	Not Applicable
• Potential increased capacity for alternative configurations	Not Applicable
Level of commitment:	
• Is there a committed Anchor Tenant?	No
• What is the percent of contractual commitment from PTP customers	Information not available until Open Season.
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	No
Cost allocation plan:	
• Sponsors proposed cost allocation plan	Those who use the project will pay for the cost of the project through NorthWestern's tariff or an incremental tariff if the cost is greater.
• How project plans to recover cost	Full cost recovery will be from transmission service agreements with customers wishing to use the line. Actual upgrade costs will determine if rate is embedded or incremental to the existing tariff. No cost recovery will be allocated to native load in Montana.
• Contingency plan if initial cost recovery plan is not realized	If open season does not materialize sufficient subscription the project will not move forward.
• Has the Project received, or does it intend to apply for FERC incentives?	No
• Risk mitigation plan if market does not develop as expected	Project size will be evaluated on open season subscription. If there is not sufficient service agreement capacity the project may not be constructed.
Cost allocation principles (How does the project meet, or not meet, the principle.)	
• Principle 1 As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	

• <u>Principle 2</u> Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and sub-regional planning resources should be utilized and the results demonstrated.	
• <u>Principle 3</u> Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • <u>Principle 3a</u> Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • <u>Principle 3b</u> Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	

• <u>Principle 4</u> For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	The cost will recovered through long term service agreements from customers wishing to move power over the line. Those who use the collector project will pay for the costs of the project through NorthWestern's tariff or an incremental tariff if the cost is greater than the existing tariff. All costs will be directly recovered from transmission subscribers to the line and not NorthWestern Energy's native load customers. Type 2 transmission costs are typically FERC jurisdiction and not subject to state review. This line relies on the resource planning process acceptance by the load serving entities that purchase the power from sources in Montana. The projects are not in conflict with the stated policy and planning requirements affecting transmission development. The project will not harm the existing transmission network in MT or elsewhere because they are radial generator lead lines the tie directly to the Townsend substation.

Existing 500 kV (Path 8) System Upgrade (Northwestern Energy)

NTTG Cost Allocation Project Summary As of August 31, 2011	
Committee Liaison:	Brian DeKiep, Montana Public Service Commission
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	Increase transfer capacity of the Colstrip system by up to 600-800 MW. This project will increase the capacity from Broadview Montana (or Colstrip should transmission service be requested) to Mid-C in Washington. BPA ownership begins at Townsend Montana to Mid-C. Will deliver power from sources in Montana, likely renewable.
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	Line originally built to export base load thermal resources out of Montana from the Colstrip generation plants. The upgrade is primarily to export new variable generation resources.
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	The 500 kV Upgrade project consists of increasing the existing series compensation percent compensation (up to 70%) to achieve an increase of 600-800 MW of capacity.
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates ONLY.	• Anticipated in-service date of 2013/14
• WECC Rating Process – Phase	Not started, likely to start in 2011.
• Status and estimated completion date of federal, state, and local permitting/siting processes	Unknown, BPA may have to complete an EIS because of their ownership proximity to the new Townsend substation.
Project sponsor(s):	
• Organization name(s)	NorthWestern Energy and some or all of the other Colstrip Transmission owners east of Townsend and BPA west of Townsend.
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.wecc.biz/Planning/TransmissionExpansion/Transmission/Pages/default.aspx.
• Date of last information update (Note source of update: NTTG PC, NTTG CAC, FERC or state filing, WECC filing, etc.)	June 5, 2011 Data response by NWE to NTTG CAC
Other project participant(s):	
Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Please note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	• $210 million • July 2011 • WECC Project Portal

Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	Not Applicable
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	Not Applicable
• Decision factors for choosing alternative configuration options	Not Applicable
• Additional cost estimate for alternative configurations (marginal cost)	Not Applicable
• Potential increased capacity for alternative configurations	Not Applicable
Level of commitment:	
• Is there a committed Anchor Tenant?	No
• What is the percent of contractual commitment from PTP customers	None yet
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	No
Cost allocation plan:	
• Sponsors proposed cost allocation plan	Those who use the project will pay for the cost of the project through NorthWestern's tariff (and other owner's tariff) or an incremental tariff if the cost is greater.
• How project plans to recover cost	Cost recovery through long term service agreements from users of the line.
• Contingency plan if initial cost recovery plan is not realized	Upgrade may not be completed without long-term agreements. Those who use the project will pay for the cost of the project through NorthWestern's tariff (and other owner's tariff) or an incremental tariff if the cost is greater.
• Has the Project received, or does it intend to apply for FERC incentives?	No
• Risk mitigation plan if market does not develop as expected	Risk that the project will likely not be constructed because there is not sufficient service agreement capacity from customers wishing to move power over the line.

Cost allocation principles (How does the project meet, or not meet, the principle.)	
• <u>Principle 1</u> As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	
• <u>Principle 2</u> Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and sub-regional planning resources should be utilized and the results demonstrated.	

• <u>Principle 3</u> Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • <u>Principle 3a</u> Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • <u>Principle 3b</u> Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	
• <u>Principle 4</u> For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	All costs will be directly recovered from transmission service to the line and not NorthWestern Energy's native load customers through the FERC higher of (i.e., "OR") pricing. Type 2 transmission costs are typically FERC jurisdiction and not subject to state review. This line relies on the resource planning process acceptance by the load serving entities that purchase the power from sources in Montana. The project is not in conflict with the stated policy and planning requirements affecting transmission development. The upgrade project will not harm the existing transmission network in MT or elsewhere because all mitigation necessary to maintain reliability will be implemented. The WECC path rating process also requires that the upgrade will not harm other transmission systems.

Existing Path 18 Upgrade (Northwestern Energy)

NTTG Cost Allocation Project Summary As of August 31, 2011	
Committee Liaison:	Brian DeKiep, Montana Public Service Commission
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	The P18 upgrade is to upgrade the existing 230-kV line by adding series compensation to achieve 40-60 MW of additional capacity. NorthWestern has 538 MW of transmission service requests under study that the Path18 upgrade would partially fill.
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	Not Applicable
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	Adding series compensation to the existing 230-kV line between Mill Creek substation to the Peterson Flats substation in Montana to achieve 40-60 MW of additional capacity on Path 18.
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates ONLY.	Expected that the upgrade would be completed in 2012.
• WECC Rating Process – Phase	Not started
• Status and estimated completion date of federal, state, and local permitting/siting processes	No new siting required since project will use existing substations.
Project sponsor(s):	
• Organization name(s)	NorthWestern Energy and possibility the other AMPS line owners.
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	NWE's OATI OASIS website at URL: http://www.oatioasis.com/NWMT/index.html See the "Montana-Idaho Open Season" folder on the left. Not listed in the TEPPC Template Portal.
• Date of last information update (Note source of update: NTTG PC, NTTG CAC, FERC or state filing, WECC filing, etc.)	June 5, 2011 Data response by NWE to NTTG CAC
Other project participant(s):	
Project costs:	
• Estimated cost • Date of estimate • Source of estimate	

Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	Not Applicable
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	Not Applicable
• Decision factors for choosing alternative configuration options	Not Applicable
• Additional cost estimate for alternative configurations (marginal cost)	Not Applicable
• Potential increased capacity for alternative configurations	Not Applicable
Level of commitment:	
• Is there a committed Anchor Tenant?	No
• What is the percent of contractual commitment from PTP customers	No transmission agreements signed at this time, only requests for transmission service.
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	No
Cost allocation plan:	
• Sponsors proposed cost allocation plan	Those who use the project will pay for the cost of the project through NorthWestern's tariff or an incremental tariff if the cost is greater.
• How project plans to recover cost	Long Term service agreements with customers to line.
• Contingency plan if initial cost recovery plan is not realized	Upgrade will likely not be complete.
• Has the Project received, or does it intend to apply for FERC incentives?	No
• Risk mitigation plan if market does not develop as expected	Risk that project will not be constructed because there are not sufficient transmission service agreement.
Cost allocation principles (How does the project meet, or not meet, the principle.)	
• Principle 1 As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	

• <u>Principle 2</u> Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and sub-regional planning resources should be utilized and the results demonstrated.	
• <u>Principle 3</u> Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • <u>Principle 3a</u> Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • <u>Principle 3b</u> Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	

• Principle 4 For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	All costs will be directly recovered from transmission subscribers to the line and not NorthWestern Energy's native load customers through the FERC higher of (i.e., "OR") pricing. Type 2 transmission costs are typically FERC jurisdiction and not subject to state review. This line relies on the resource planning process acceptance by the load serving entities that purchase the power from sources in Montana. The upgrade project will not harm the existing transmission network in MT or ID because all mitigation necessary to maintain reliability will be implemented.

Gateway West, Windstar-Bridger-Populus (PacifiCorp)

NTTG Cost Allocation Project Summary As of June, 2011	
Committee Liaison:	Joni Zenger, Utah Division of Public Utilities
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	The Energy Gateway project is a system-wide transmission expansion program originally announced by PacifiCorp in May 2007. The project will enable economic dispatch of the network resources, link PacifiCorp's east and west balancing areas, enhance accessibility to location-constrained renewable energy sources, reduce congestion in the transmission-constrained Western Interconnection, improve the reliability of the system, and help PacifiCorp to continue to provide reliable, cost-effective electric service to its customers.
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	Gateway West, Segment 1A: Windstar – Bridger • 298 miles, single circuit, 230 kV and single circuit 500 kV Gateway West, Segment 1B: Bridger - Populus • 191 miles, single circuit, 500 kV Gateway West segment 1A (Windstar to Bridger) is proposed as 298 miles of single circuit 230-kV AC and single circuit 500-kV AC. Segment 1B is proposed as 191 miles of single circuit 500-kV AC. PacifiCorp's 2011 IRP indicates two, single-circuit 230 kV lines will run approximately 82 and 72 miles, respectively, between the recently constructed Windstar substation in eastern Wyoming and the Aeolus substation to be constructed near Medicine Bow, Wyoming. A single-circuit 500 kV line will run approximately 141 miles from the Aeolus substation to a new annex substation near the existing Bridger substation in western Wyoming. From Bridger, a single-circuit 500 kV line will run approximately 205 miles between the new annex substation at Bridger and the recently constructed Populus substation in southeast Idaho. The segments allow construction phasing, in addition to meeting reliability separation for rating studies.

	Estimated total circuit length of Segments 1A and 1B is approximately 500 miles from Windstar in eastern Wyoming (near Casper, Wyoming) to Aeolus (near Medicine Bow, Wyoming) to Jim Bridger (near Rock Springs, Wyoming) and to Populus in southeast Idaho (near Downey, Idaho)
• Estimated construction start date • Estimated in-service date **Note:** These dates are estimates only.	• 2014 • June 2017
• WECC Rating Process – Phase	Phase 3 completed.
• Status and estimated completion date of federal, state, and local permitting/siting processes	Permitting and obtaining rights of way – 2011 – 2015. The Bureau of Land Management (BLM) is currently developing an Environmental Impact Statement on Gateway West – a process that began in June 2008 with Public Scoping meetings. BLM has oversight of this process and hosted these meetings to collect official public comments. The BLM published the draft Environmental Impact Statement for the Gateway West project – including Windstar to Populus – on July 29, 2011, initiating a 90-day public comment period on the document. Next, BLM holds a new round of public open house meetings in various communities along the proposed and alternate routes.
Project sponsor(s):	
• Organization name(s)	PacifiCorp
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.pacificorp.com/tran/tp/eg/gw/sdwtp.html
• Date of last information update (Note source of update: NTTG PC, NTTG Cost Allocation Committee, FERC or state filing, WECC filing, etc.)	June 2011 Data response by PacifiCorp to NTTG CAC; PacifiCorp 2011 IRP; WECC Transmission Project Portal
Other project participant(s):	
Project costs:	
• Estimated cost • Date of estimate • Source of estimate **Note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	• $1.37 billion • February 2009 • PacifiCorp (from <u>2008-2009 Biennial Plan, Cost Allocation Committee, Final Report</u>, NTTG)

Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	None
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	Unknown
• Decision factors for choosing alternative configuration options	Unknown
• Additional cost estimate for alternative configurations (marginal cost)	Unknown
• Potential increased capacity for alternative configurations	Unknown
Level of commitment:	
• Is there a committed Anchor Tenant?	No
• What is the percent of contractual commitment from PTP customers	None
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	Yes
Cost allocation plan:	
• Sponsors proposed cost allocation plan	PacifiCorp's transmission assets and associated costs for network and retail load service are allocated to electric retail customers in states according to PacifiCorp's Revised Protocol (California, Idaho, Oregon, Utah, and Wyoming) or West Control Area (Washington) allocation methodologies. Any costs for upgrades necessary for queue service will be recovered from queue customers.
• How project plans to recover cost	The proposed projects are planned to meet PacifiCorp's network load per its Open Access Transmission Tariff (OATT), and will be recovered through state general rate cases and/or existing rate adjustment mechanisms related to transmission. Additionally, due to PacifiCorp's significant investment in its transmission system, the Company filed a rate case with FERC in May 2011 to increase its transmission and ancillary service rates contained in its OATT.

• Contingency plan if initial cost recovery plan is not realized	PacifiCorp believes the investment is prudent and necessary and will be allowed in rates.
• Has the Project received, or does it intend to apply for FERC incentives?	Yes
• Risk mitigation plan if market does not develop as expected	None. Capacity is required for load service.
Cost allocation principles (How does the project meet, or not meet, the principle.)	
• Principle 1 As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	For the base Energy Gateway, PacifiCorp has assigned all costs and benefits to network customers. If additional equity partners come forward, adding their needs to the project, they would be expected to share in the allocation of costs based on their impact on costs and allocation of the project.
• Principle 2 Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and sub-regional planning resources should be utilized and the results demonstrated.	The Energy Gateway projects are being incorporated into PacifiCorp's ongoing Integrated Resource Plan process.

• Principle 3 Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • Principle 3a Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • Principle 3b Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	PacifiCorp's share of the base Energy Gateway project is needed for network load service and will follow PacifiCorp's standard Transmission Rate treatment. In the event that accommodating the queue requests increases the size of the project, the pricing for queue customers will follow the FERC guidelines – the higher of average (rolled in) or incremental pricing would apply to avoid inequitable cost transfers across customer classes.
• Principle 4 For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	PacifiCorp is not currently proposing allocation to other transmission providers or equity partners not interested in ownership capacity in the project.

Gateway Central, Mona to Oquirrh, Oquirrh – Terminal (PacifiCorp)

NTTG Cost Allocation Project Summary As of June, 2011	
Committee Liaison:	Joni Zenger, Division of Public Utilities
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	The Energy Gateway project is a system-wide transmission expansion program originally announced by PacifiCorp in May 2007. The project will enable economic dispatch of the network resources, link PacifiCorp's east and west balancing areas, enhance accessibility to location-constrained renewable energy sources, reduce congestion in the transmission-constrained Western Interconnection, improve the reliability of the system, and help PacifiCorp to continue to provide reliable, cost-effective electric service to its customers.
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	Gateway Central – Segment C: Mona – Oquirrh, Oquirrh – Terminal • Mona – Limber, 65 miles single circuit 500/345 kV • Limber – Oquirrh, 35 miles double circuit 345 kV • Oquirrh – Terminal, 14 miles double circuit 345 kV The Clover Substation is located about three miles from the Mona Substation (by implication a transmission line connecting these substations). The Mona-to-Limber transmission line with 500 kV capacity is planned initially to operate at 345 kV. In about 2019, when Gateway South is completed, the line will be energized to 500 kV.
• Estimated construction start date • Estimated in-service date **Note:** These dates are estimates only.	• 2011 • June 2013 (Mona-Oquirrh); 2014 (Oquirrh-Terminal)
• WECC Rating Process – Phase	Phase 3

• Status and estimated completion date of federal, state, and local permitting/siting processes	*Mona-Oquirrh:* Permitting and obtaining rights of way – August 2009-2011 The Bureau of Land Management (BLM) has completed the Environmental Impact Statement (EIS) process for the Mona to Oquirrh project, and notification was published Feb. 10, 2011 in the Federal Register. On Feb. 4, 2011 the BLM signed the Record of Decision and the easement for the right of way across federal lands. Conditional use permits for the project have been obtained in all applicable cities and counties. The certificate of public convenience and necessity has also been issued by the Utah Public Service Commission. *Oquirrh-Terminal:* No information
Project sponsor(s):	
• Organization name(s)	PacifiCorp
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.pacificorp.com/tran/tp/eg/gc/scmto.html
• Date of last information update (Note source of update: NTTG PC, NTTG Cost Allocation Committee, FERC or state filing, WECC filing, etc.)	June 2011 Data response by PacifiCorp to NTTG CAC; PacifiCorp 2011 IRP; WECC Transmission Project Portal
Other project participant(s):	
Project costs:	
• Estimated cost • Date of estimate • Source of estimate	• $569 million (Mona-Oquirrh only) • February 2009 • PacifiCorp (from 2008-2009 Biennial Plan, Cost Allocation Committee, Final Report, NTTG)
Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	No information
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	No information

• Decision factors for choosing alternative configuration options	No information
• Additional cost estimate for alternative configurations (marginal cost)	No information
• Potential increased capacity for alternative configurations	No information
Level of commitment:	
• Is there a committed Anchor Tenant?	Not applicable; project is required for existing load commitments and reliability requirements.
• What is the percent of contractual commitment from PTP customers	Unknown
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	Yes
Cost allocation plan:	
• Sponsors proposed cost allocation plan	PacifiCorp's transmission assets and associated costs for network and retail load service are allocated to electric retail customers in states according to PacifiCorp's Revised Protocol (California, Idaho, Oregon, Utah, and Wyoming) or West Control Area (Washington) allocation methodologies. Any costs for upgrades necessary for queue service will be recovered from queue customers.
• How project plans to recover cost	The proposed projects are planned to meet PacifiCorp's network load per its Open Access Transmission Tariff (OATT), and will be recovered through state general rate cases and/or existing rate adjustment mechanisms related to transmission. Additionally, due to PacifiCorp's significant investment in its transmission system, the Company filed a rate case with FERC in May 2011 to increase its transmission and ancillary service rates contained in its OATT.
• Contingency plan if initial cost recovery plan is not realized	PacifiCorp believes the investment is prudent and necessary and will be allowed in rates.
• Has the Project received, or does it intend to apply for FERC incentives?	Yes
• Risk mitigation plan if market does not develop as expected	None. Capacity is required for load service.

Cost allocation principles (How does the project meet, or not meet, the principle.)	
• <u>Principle 1</u> As a matter of equity, cost allocations will reflect the classic principles that ‘cost causers should be cost bearers’ and that ‘beneficiaries should pay’ in amounts that are reflective of the benefits received.	For the base Energy Gateway, PacifiCorp has assigned all costs and benefits to network customers. If additional equity partners come forward, adding their needs to the project, they would be expected to share in the allocation of costs based on their impact on costs and allocation of the project.
• <u>Principle 2</u> Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and sub-regional planning resources should be utilized and the results demonstrated.	The Energy Gateway projects are being incorporated into PacifiCorp’s ongoing Integrated Resource Plan process.

• Principle 3 Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • Principle 3a Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • Principle 3b Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	PacifiCorp's share of the base Energy Gateway project is needed for network load service and will follow PacifiCorp's standard Transmission Rate treatment. In the event that accommodating the queue requests increases the size of the project, the pricing for queue customers will follow the FERC guidelines – the higher of average (rolled in) or incremental pricing would apply to avoid inequitable cost transfers across customer classes.
• Principle 4 For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	PacifiCorp is not currently proposing allocation to other transmission providers or equity partners not interested in ownership capacity in the project.

Gateway South, Aeolus - Mona (PacifiCorp)

NTTG Cost Allocation Project Summary As of June, 2011	
Committee Liaison:	Joni Zenger, Utah Division of Public Utilities
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	Gateway South includes a core set of facilities needed to meet the long-term energy needs of PacifiCorp customers.
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	400 mile, single-circuit 500-kV AC line from Aeolus WY (near Medicine Bow) to Clover UT (adjacent to Mona).
• Estimated construction start date • Estimated in-service date **Note:** These dates are estimates only.	• 2016 • 2018 (or 2019)
• WECC Rating Process – Phase	Phase 3
• Status and estimated completion date of federal, state, and local permitting/siting processes	The BLM is currently developing an EIS on the company's right of way application for this project, a process that began in December 2008. The BLM announced the start of Public Scoping for the project on April 1. Public Scoping continues through June 30, 2011. During this time the BLM will take comments from interested parties on the project. These comments will be evaluated as the BLM develops the draft EIS.
Project sponsor(s):	
• Organization name(s)	PacifiCorp
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.pacificorp.com/tran/tp/eg/gs.html
• Date of last information update (Note source of update: NTTG PC, NTTG Cost Allocation Committee, FERC or state filing, WECC filing, etc.)	June 2011 Data response by PacifiCorp to NTTG CAC; PacifiCorp 2011 IRP; WECC Transmission Project Portal
Other project participant(s):	

Project costs:	
• Estimated cost • Date of estimate • Source of estimate	• $782 million • February 2009 • PacifiCorp (from 2008-2009 Biennial Plan, Cost Allocation Committee, Final Report, NTTG)
Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	No information
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	No information
• Decision factors for choosing alternative configuration options	No information
• Additional cost estimate for alternative configurations (marginal cost)	No information
• Potential increased capacity for alternative configurations	No information
Level of commitment:	
• Is there a committed Anchor Tenant?	Not applicable; project is required for existing load commitments and reliability requirements.
• What is the percent of contractual commitment from PTP customers	Unknown
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	Yes
Cost allocation plan:	
• Sponsors proposed cost allocation plan	PacifiCorp's transmission assets and associated costs for network and retail load service are allocated to electric retail customers in states according to PacifiCorp's Revised Protocol (California, Idaho, Oregon, Utah, and Wyoming) or West Control Area (Washington) allocation methodologies. Any costs for upgrades necessary for queue service will be recovered from queue customers.
• How project plans to recover cost	The proposed projects are planned to meet PacifiCorp's network load per its Open Access Transmission Tariff (OATT), and will be recovered through state general rate cases and/or existing rate

	adjustment mechanisms related to transmission. Additionally, due to PacifiCorp's significant investment in its transmission system, the Company filed a rate case with FERC in May 2011 to increase its transmission and ancillary service rates contained in its OATT.
• Contingency plan if initial cost recovery plan is not realized	PacifiCorp believes the investment is prudent and necessary and will be allowed in rates.
• Has the Project received, or does it intend to apply for FERC incentives?	Yes
• Risk mitigation plan if market does not develop as expected	None. Capacity is required for load service.
Cost allocation principles (How does the project meet, or not meet, the principle.)	
• Principle 1 As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	For the base Energy Gateway, PacifiCorp has assigned all costs and benefits to network customers. If additional equity partners come forward, adding their needs to the project, they would be expected to share in the allocation of costs based on their impact on costs and allocation of the project.
• Principle 2 Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and sub-regional planning resources should be utilized and the results demonstrated.	The Energy Gateway projects are being incorporated into PacifiCorp's ongoing Integrated Resource Plan process.

• <u>Principle 3</u> Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • <u>Principle 3a</u> Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • <u>Principle 3b</u> Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	PacifiCorp's share of the base Energy Gateway project is needed for network load service and will follow PacifiCorp's standard Transmission Rate treatment. In the event that accommodating the queue requests increases the size of the project, the pricing for queue customers will follow the FERC guidelines – the higher of average (rolled in) or incremental pricing would apply to avoid inequitable cost transfers across customer classes.
• <u>Principle 4</u> For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	PacifiCorp is not currently proposing allocation to other transmission providers or equity partners not interested in ownership capacity in the project.

Gateway Central/South, Sigurd – Red Butte (PacifiCorp)

NTTG Cost Allocation Project Summary As of June, 2011	
Committee Liaison:	Joni Zenger, Division of Public Utilities
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	Gateway Central includes a core set of facilities needed to meet the long-term energy needs of PacifiCorp customers.
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	160 mile, single-circuit 345-kV line running between the Sigurd substation (central Utah) to an expanded Red Butte substation in southwest Utah.
• Estimated construction start date • Estimated in-service date **Note:** These dates are estimates only.	• 2012 • 2014
• WECC Rating Process – Phase	Phase 3
• Status and estimated completion date of federal, state, and local permitting/siting processes	The BLM is currently developing an EIS on the company's right of way application for this project, a process that began in December 2008. The BLM conducted Public Scoping for the project from January 5 through March 5, 2010. Various interested parties have provided input on the project for consideration as the BLM developed the draft EIS, which was published May 27, 2011. The BLM received public comments through July 18 and will develop the final EIS after considering the additional input. It is anticipated the final EIS will be published around May 2012.
Project sponsor(s):	
• Organization name(s)	PacifiCorp
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.pacificorp.com/tran/tp/eg/gs/sgstrb.html
• Date of last information update (Note source of update: NTTG PC, NTTG Cost Allocation Committee, FERC or state filing, WECC filing, etc.)	June 2011 Data response by PacifiCorp to NTTG CAC; PacifiCorp 2011 IRP; WECC Transmission Project Portal
Other project participant(s):	

Project costs:	
• Estimated cost • Date of estimate • Source of estimate	• Not provided • None • Not applicable
Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	No information
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	No information
• Decision factors for choosing alternative configuration options	No information
• Additional cost estimate for alternative configurations (marginal cost)	No information
• Potential increased capacity for alternative configurations	No information
Level of commitment:	
• Is there a committed Anchor Tenant?	Not applicable; project is required for existing load commitments and reliability requirements.
• What is the percent of contractual commitment from PTP customers	Unknown
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	Yes
Cost allocation plan:	
• Sponsors proposed cost allocation plan	PacifiCorp's transmission assets and associated costs for network and retail load service are allocated to electric retail customers in states according to PacifiCorp's Revised Protocol (California, Idaho, Oregon, Utah, and Wyoming) or West Control Area (Washington) allocation methodologies. Any costs for upgrades necessary for queue service will be recovered from queue customers.
• How project plans to recover cost	The proposed projects are planned to meet PacifiCorp's network load per its Open Access Transmission Tariff (OATT), and will be recovered through state general rate cases and/or existing rate adjustment mechanisms related to transmission.

	Additionally, due to PacifiCorp's significant investment in its transmission system, the Company filed a rate case with FERC in May 2011 to increase its transmission and ancillary service rates contained in its OATT.
• Contingency plan if initial cost recovery plan is not realized	PacifiCorp believes the investment is prudent and necessary and will be allowed in rates.
• Has the Project received, or does it intend to apply for FERC incentives?	Yes
• Risk mitigation plan if market does not develop as expected	None. Capacity is required for load service.
Cost allocation principles (How does the project meet, or not meet, the principle.)	
• Principle 1 As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	For the base Energy Gateway, PacifiCorp has assigned all costs and benefits to network customers. If additional equity partners come forward, adding their needs to the project, they would be expected to share in the allocation of costs based on their impact on costs and allocation of the project.
• Principle 2 Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and sub-regional planning resources should be utilized and the results demonstrated.	The Energy Gateway projects are being incorporated into PacifiCorp's ongoing Integrated Resource Plan process.
• Principle 3 Cost allocations will result in a reasonable opportunity for the transmission owner(s) to	PacifiCorp's share of the base Energy Gateway project is needed for network load service and will follow PacifiCorp's standard Transmission

achieve full recovery of the costs of the project, but no more. • <u>Principle 3a</u> Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • <u>Principle 3b</u> Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	Rate treatment. In the event that accommodating the queue requests increases the size of the project, the pricing for queue customers will follow the FERC guidelines – the higher of average (rolled in) or incremental pricing would apply to avoid inequitable cost transfers across customer classes.
• <u>Principle 4</u> For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	PacifiCorp is not currently proposing allocation to other transmission providers or equity partners not interested in ownership capacity in the project.

Cascade Crossing (Portland General)

NTTG Cost Allocation Project Summary as of September, 2011	
Project overview:	
• Purpose (e.g., renewable or non-renewable generation delivery, reliability, network load growth, transmission queue requests)	PGE is proposing Cascade Crossing to help meet Oregon's growing energy needs, enable development of more renewable power projects and enhance reliability of the region's electrical grid. Cascade Crossing would provide transmission access for renewable power, including wind projects that are planned in locations that are not currently served by transmission and provide transmission service associated with generator interconnection requests and the integration of resources for network load.
• Known changes of purpose over time (can be indicated in a study or forecast such as an IRP)	.
• Basic configuration of line (line distance, voltage level, AC or DC, list states that are traversed by project)	Single-circuit, 500-kV AC line, approximately 210 miles long, from Boardman to Bethel, Oregon. (If requests for service exceed capacity, 187 miles would be permitted and built as double-circuit.)
• Estimated construction start date • Estimated in-service date **Please note:** These dates are estimates ONLY.	• Spring 2014 • December 2016
• WECC Rating Process – Phase	Phase 2
• Status and estimated completion date of federal, state, and local permitting/siting processes	Environmental reviews and the permitting processes are expected to last up to three years, and will include several opportunities for public involvement. Permitting is estimated to be 40% complete.
Project sponsor(s):	
• Organization name(s)	Portland General Electric Company
• Project website (hyperlink) (Sponsor's and TEPPC Template Portal)	http://www.portlandgeneral.com/our_company/generation_transmission/cascade_crossing/default.aspx
• Date of last information update (Note source of update: NTTG PC, NTTG Cost Allocation Committee, FERC or state filing, WECC filing, etc.)	September 2011 Data response by Portland General to NTTG CAC; WECC Transmission Project Portal; PGE website
Other project participant(s):	Idaho Power and PacifiCorp are exploring participation with PGE.

Project costs:	
• Estimated cost – Single Circuit • Estimated cost – Double Circuit • Date of estimate • Source of estimate **Please note:** These are only estimates since the project may be early in the WECC rating and other permitting processes.	• $800 million • $1,000 million • September 2011 • Data response by NWE to NTTG CAC; WECC Transmission Project Portal
Additional project configuration options:	
• Study process for alternative configurations (e.g., added circuit, larger voltage)?	The Project will consider both single and double circuit options, however the determination of whether to construct double circuit towers, and to start out with a single or a double circuit on the towers will depend on the commitments for transmission service received through an open-season process and/or the addition of project partners.
• Efforts by the project sponsor(s) to study the economic and technical feasibility of combining the project with other proposed projects to minimize the use of corridor space and lessen environmental impact	Portland General is continuing to explore the possibility of coordinating with other transmission providers in the region to support the construction and configuration of Cascade Crossing.
• Decision factors for choosing alternative configuration options	• Level of commitments received through open-season process • Permitting process identifies critical issues • If an interested party is willing to fund and assume the risk of alternative configuration
• Additional cost estimate for alternative configurations (marginal cost)	Building the double circuit option for Cascade Crossing would add approximately $210 million in direct capital cost.
• Potential increased capacity for alternative configurations	Approximately 700 MW
Level of commitment:	
• Is there a committed Anchor Tenant?	There are three Network Integration Transmission Service reservations totaling 1091 MW and four Point-to-Point Transmission Service reservations totaling 850 MW.
• What is the percent of contractual commitment from PTP customers	None
• Is this project included in sponsor's IRP or wholesale transmission service obligations?	Yes

Cost allocation plan:	
• Sponsors proposed cost allocation plan	To existing retail and wholesale transmission users and those new users/uses who commit through an open-season process
• How project plans to recover cost	Rolled-in as part of normal transmission service rates
• Contingency plan if initial cost recovery plan is not realized	Unknown
• Has the Project received, or does it intend to apply for FERC incentives?	Unknown
• Risk mitigation plan if market does not develop as expected	
Cost allocation principles (How does the project meet, or not meet, the principle.)	
• <u>Principle 1</u> As a matter of equity, cost allocations will reflect the classic principles that 'cost causers should be cost bearers' and that 'beneficiaries should pay' in amounts that are reflective of the benefits received.	Open season process will receive commitments from new users or uses prior to construction; PGE is also exploring participation by PacifiCorp, BPA and Idaho Power, all of which could possibly benefit from completion of the project.
• <u>Principle 2</u> Projects brought forward for consideration will be shown not to be in conflict with state and federal IRP, Competitive Bidding, RPS (Renewable Portfolio Standard), siting, certification and other policy and planning requirements affecting transmission development, to the extent they are applicable to the project. Selecting an efficient portfolio of remote generation, in-state generation and demand-side solutions requires that the proposed allocation of transmission project costs be known with clarity. Therefore, the NTTG process will encourage efficient and stable resource planning processes by which the project developer identifies the extent of cost allocation consensus for a proposed transmission project as soon as practical in the project life cycle, allowing the states to evaluate the proposed project for compliance purposes and to understand costs relative to other resource options. Regional and subregional planning resources should be utilized and the results demonstrated.	Studied as part of PGE's IRP process.

• Principle 3 Cost allocations will result in a reasonable opportunity for the transmission owner(s) to achieve full recovery of the costs of the project, but no more. • Principle 3a Transmission project costs should be directly assigned to a single transmission customer or allocated to multiple transmission customers or areas (or the entire region) based upon the distribution of benefits. • Principle 3b Upgrades and other projects proposed on the basis of economic or other benefits for specific transmission customers will be accommodated if [i] the customers and/or transmission owner accept responsibility for the associated costs; [ii] the project does no harm to the network; and [iii] the project otherwise has no adverse impact on regional transmission service.	Transmission costs will be rolled-in to system transmission rates.
• Principle 4 For Type 2 project costs, the rest of the network and its customers will be held harmless and the transmission owner should look to its transmission customers for direct recovery of costs.	Not Applicable

Appendix C: NTTG Economic Studies for the 2010 – 2011 Biennial Study Cycle

Study Requests:

In the first quarter of every year, stakeholders are asked to submit requests for economic congestion studies. This year, no economic study requests have been submitted to NTTG; however, during the first half of the 2010-2011 biennial cycle, NorthWestern Energy in Montana submitted four economic study requests in March, 2010 to study the economic impacts of building the Mountain States Transmission Intertie (MSTI), along with two other separate, but related, transmission projects. NTTG's planning group decided that these requests could be grouped together for a study on the impacts of aggregating and exporting Montana resources to the Pacific Northwest, and to central and eastern Idaho. Economic studies were carried out during the second quarter of 2010.

The four scenarios were the following:
MSTI: Case BASE with the Mountain States

1. MSTI is a proposed 500-kV line, approximately 420 miles long, extending from Townsend, MT, to Midpoint, ID. It is series compensated and power flow is controlled using a phase-shifting transformer. An existing model used by NTTG utilities already exists from the previous Biennial Planning Cycle. MSTI is nearing completion of Phase 2 of the WECC Path Rating Process with a proposed rating of 1,500 MW north to south, and about 950 MW south to north. This rating could be used to support export of up to 1,500 MW of renewable resources from Montana.

BASE: Case PC1A with 1,500 MW wind generation added at Townsend Montana.

2. Collector Project: The purpose of the Collector Project is to provide a direct transmission line from the high wind areas in Montana to the northern terminal of MSTI. The Collector Project may consist of up to five separate 230-kV generator lead lines (i.e., radial lines), from the Cut Bank area, the Judith Gap area, the Belt area, the Broadview area, and the Ennis area. Each line will support about 300 MW.

AMPS: Case BASE with Path18 upgraded from 337 to 401 MW north to south

3. Path 18 Upgrade: NorthWestern conducted a MT-ID open season in 2004. As a result of this open season, NorthWestern and the other Path 18 owners are contemplating increasing the capacity of the existing 230-kV AMPS line through the installation of series capacitors and voltage support devices on various Path 18 busses. This upgrade is not in the WECC Path Rating Process yet. The line runs between the Mill Creek 230 kV switchyard and the Antelope 230-kV station. The upgrade will increase path capacity to 401 MW.

COLS: Case BASE with Path 8 upgraded from 2,200 to 2,800 MW east to west

4. 500-kV Upgrade: The owners of the Colstrip Transmission System and BPA are considering increasing the capability of the existing twin 500 kV transmission lines that may start as far east as Colstrip, Montana and end as far west as the Mid-Columbia area of Washington. Installation of series capacitors (up to 70% from current 35%) and appropriate voltage control and expanding the ampacity of existing busses on the 500-kV line may increase the transfer capability by as much as 500 to 700 MW. This upgrade is not in the WECC Path Rating Process yet.

Economic Study Process:

The NTTG Planning Committee decided to execute the economic studies using a two model approach, applying both Promod and GridView as both were available through the NTTG member companies. Given the timeline to run the studies was limited to just one month, the team decided to start by using an existing TEPPC database, the TEPPC 2019 PC1A case. Essentially, the Planning Committee team started with the TEPPC PC1A base case and ran the three expansion cases and some sensitivities analysis.

Economic Study Details:

PC1A was converted by ABB to Gridview format; minor edits were applied to align with the NTTG assumptions. Common to all cases, 1,500 MW of wind-powered generation was added at the Townsend Montana bus. As previously stated, the following three expansion cases were developed: 1) Increase capacity of the AMPS line (Path 18) from 337 to 401 MW, 2) Increase rating of Montana-Northwest path (Path 8) by 600 MW and add the 500-kV MSTI project.

Economic Study Outputs:

Outputs recorded were --

1. Variable production costs of thermal generation
2. Hourly output, in MWh, for relevant plants and generator classes
3. Hours of congestion on NTTG-relevant paths
   - Measured at 75%, 90% and 99% of path ratings
   - Paths including Path 8, Bridger West, Mona-Oquirhh, Idaho-Montana and others
   - External interfaces, including Montana-Northwest, Pacific Interties, Idaho-Northwest and others.

A sensitivity case was run to investigate methods to reduce any ‘excessive’ cycling of coal-fired generators caused by wind-powered generator output variability. Adding the 1,500 MW wind to an already saturated transmission system drove the Colstrip units to cycle for wind. Given that is not a realistic operation, sensitivities were run holding Colstrip hourly generation fixed, consistent with today’s operation, resulted in more meaningful results; increased exports were proportional to increased build of transmission capacity.

Results of the Economic Studies:

The 1,000 MW of MT wind already in the TEPPC 2019 base case are accommodated with modest coal plant cycling and little wind curtailment. The addition of another 1,500 MW of wind in Montana causes severe cycling of base load coal, in Gridview modeling. Without additional transmission, much of the additional wind energy cannot be used to serve load and is curtailed. Upgrading the capacity of Paths 8 and 18 provides some benefit, but a large fraction of the additional wind energy remains unused. Addition of the MSTI project provides the ability to move most of the added wind out of Montana.

Cost Allocation Recommendation:

TEPPC 2019 PC1A underlying case assumptions were kept constant as new renewable and NTTG projects were added. 2010 study results do not sufficiently impact current cost allocation evaluations to change current NTTG Cost Allocation Committee conclusions. The projects that relieve the congestion in these cases studied are "Type II, Principle 4" projects. The project costs are recovered by subscribers to the lines through long term service contracts. Native load is to be held harmless from the cost of the projects since they are not the beneficiaries of these projects.

Appendix D: "Transmission Planning in the West"

Summary

There has been much discussion and debate in recent years about whether society is investing enough resources in new transmission projects. Many suggestions have been made for transmission projects that are thought to provide great benefits, yet few of them have been built. The failure to build these lines has been cited as a failure of the system for decision making on transmission, rather than an indication they may not have been needed. The purpose of this paper is to explain how and why transmission lines are proposed, how they are evaluated, how decisions are made that get them built, and why some proposals may not get built.

Historically transmission lines were built by utilities[4] to connect generation to load, to ensure reliability, and to access lower cost power, often by interconnecting with neighboring systems. Federal Power Marketing Agencies (PMAs)[5] also built lines independently and\or cooperated on large projects to allow economy transactions such as the sale of surplus hydropower or remote thermal power. Recently, we have seen transmission lines proposed and being built by merchant transmission companies.

The discussion of why transmission lines are built must explain the reasons for building and the nature of the decision to build. Simply describing potential benefits of a project does not provide enough information to indicate whether it is worth building. The particular benefits projected for a proposed line may or may not be large enough or certain enough to justify the investment. In the case of utilities with the obligation to serve retail customers, transmission must compete with other resource choices – such as new or upgraded generation, distribution system upgrades, or demand-side programs (including demand-side management, conservation, and energy efficiency) – to provide least-cost solutions to providing for future electricity needs. Estimate of future benefits will be uncertain, for a number of reasons. Estimating benefits requires assumptions about the future and judgments about the value to be placed on benefits that are not directly quantified, such as increased reliability. Decisions to invest based upon uncertain benefits are inherently risky, and expected benefits must be great enough to warrant the risk of the investment. Further, assumptions about the future and estimates of the likelihood of those assumptions will vary from one person to another. Ultimately, the assumptions and judgments that count are those made by the parties whose resources will be at risk.

[4] Utilities include investor-owned utilities (IOUs); municipal utilities, such as Seattle City Light and LADWP; Public Utility Districts; and cooperative utilities such as rural electric cooperatives and generating and transmission cooperatives.

[5] Federal PMAs operating in the western United States are the Bonneville Power Administration and the Western Area Power Administration.

A key point stressed in this paper is that planners do not make investment decisions. Investment decisions are made by people who have responsibility for investment funds and for ensuring investments are made wisely on the best projects that are most likely to pay off, and a high burden of proof is required before a go-ahead is given. For benefits to translate into a decision to build transmission the investor must be assured of an opportunity to earn a commensurate return and customers must be willing and able to support the required revenue stream. If benefits are not sufficiently large or there is a significant chance of benefits not occurring, neither investors nor customers will be supportive of the new project.

Proposals that are deemed promising are studied by planners who ultimately make recommendations to decision makers. Planning and investment decisions are typically done by different people in different parts of an organization. Planning is a highly technical, forward-looking process, based upon existing loads and configurations of generation and transmission systems, forecasts of future conditions, and alternate future outcomes. Planning studies are generally designed to ensure that transmission reliability is maintained in the futures being studied. The results of the planning process are conditional recommendations by the planners, predicated on the forecasts and assumptions made in their studies. Planners look for robust solutions that work well under multiple sets of assumptions about the future.

The weighing of net benefit versus risk associated with an investment decision may be considerably more stringent for these management groups than for a recommendation in a transmission plan. Transmission planners make recommendations to their corporate or organizational management as to what new projects must be initiated in order to meet future contractual and regulatory commitments. Planners do not make investment decisions. Investment decisions are made by corporate management and financial executives of transmission providers and of load-serving entities and generation owners. Corporate management apply their own investment criteria to the projects recommended by planners, including the availability and competing uses for financing; management estimates of the likelihood of benefits and cost recovery; and management's evaluation of the risks inherent in the projects and whether the likely payoff is great enough to warrant those risks.

The nature of the investment decision is likely to vary depending on the nature of the party building the transmission line, whether a private utility, public agency, or merchant, and by the nature of the reasons for building. A utility's decision to build a line needed to meet reliability criteria, for example, may, depending on the likelihood and severity of the reliability problem, be a relatively straightforward decision by utility management to accept the judgment of transmission planners. In this case the "used and useful" test used by regulators is generally easily met and cost recovery for the project is likely not an issue. By contrast, a utility's decision to build a project designed to accommodate transmission service requests received from generation resource developers will likely be seen by utility management as too risky in the absence of adequate firm financial commitments and security from the requesting party, required by the utility's Federal Energy Regulatory Commission (FERC) approved tariff[6].

Utilities address the risk in building to serve transmission service requests through tariffs that require contractual commitments for new service requests, backed with credit support, and if the incremental project costs are greater than recovered by current tariff rates, through an incremental cost tariff. A merchant transmission developer might be willing to take greater risks if convinced that the demand for transmission services was likely to grow rapidly enough over time to warrant the near-term risk, but like a utility, a merchant developer will require long-term contractual commitments from the customers at rates sufficient to recover costs plus appropriate return on the investment before proceeding with the transmission project.

A second purpose of this paper is to provide context for the Regional Transmission Expansion Plan (RTEP) under development by the Western Electricity Coordinating Council's (WECC's) Transmission Expansion Planning Policy Committee (TEPPC) with funding provided by an American Recovery and Reinvestment Act grant received by WECC. The RTEP explores two categories of transmission projects identified in a report by the Subregional Planning Group (SPG) Coordination Group (SCG) as those being considered and/or planned for the Western Interconnection: Foundational Projects and Potential Projects. Foundational Projects are those for which investment decisions have been made, that have customer commitments, and that have a strong likelihood of being completed within the planning 10 year window and should therefore be included in all TEPPC planning. Potential Projects are those brought into the RTEP process which appear to be beneficial projects and are being analyzed in the TEPPC process but are not committed projects with committed customers meeting the SCG criteria to be on the Foundational Project List. Potential Projects may be included in the Plan to inform stakeholders of their potential performance and benefits in the planning horizon under the various future resource scenarios identified and studied in the TEPPC process. It is left to customers, project sponsors, and other investors to couple this performance data with other planning decision data and service commitments, and determine in their respective processes which transmission projects should proceed.

Some basic questions have been raised with regard to the TEPPC planning process: (1) Why are projects that indicate significant benefit in the TEPPC economic performance results not classified as Foundational Projects?; (2) Why are certain projects classified as Foundational Projects but others are not?; (3) What is needed to cause transmission to actually be built?; and (4) How does the TEPPC study process and report fit into the realm of "why transmission is built"? This paper will use examples from the Foundational and Potential Project lists, and will explain the ways the TEPPC analysis and report fits into the whole process. This paper will also describe the transmission projects that are not getting built despite their asserted benefits, because those benefits are not yet perceived as sufficiently great or sufficiently certain by those who would have to be willing to bear the risk of construction.

[6] This tariff requirement is applicable to utilities that are FERC regulated, though entities not regulated by FERC may have similar requirements.

Types of Transmission Proposals

Transmission lines may be proposed[7] for a number of different reasons.

Generation interconnection/integration: a line (or lines) might be proposed to connect and integrate a planned generating unit to the grid.

Meet/maintain reliability: a line might be proposed to solve an existing or projected reliability problem.

Economic: a line might be proposed (i) to allow greater access to generating units with lower operating costs which are not otherwise fully utilized due to transmission congestions or (ii) to allow development of new generation with overall costs (including capital) less expensive than the next best option for new generation.

There are also different methods by which a proposed project may be initiated.

Third party requests: a line might be proposed to provide for transmission service requests from third parties.

Public policy: federal PMAs and regulatory agencies such as the California PUC might propose transmission projects for public policy reasons, such as to access areas with significant renewable energy potential. Public policy motives could also create the need for the transmission project by placing requirements such as Renewable Portfolio Standards (RPS) on the generation choices of load-serving utilities.

Merchant transmission: merchant transmission developers may propose transmission lines to serve a variety of purposes because they think there will be a sufficient demand for the transmission services to make the project profitable.

Merchant generation: merchant generation developers may request utility planners to study their project, which may result in a transmission project that would allow them to access markets, either by connecting to the transmission grid at the nearest feasible point (if capacity is available on the grid) or by adding capacity all the way to their proposed market area. Renewable energy advocates may ask for study of transmission projects that would connect promising wind energy areas to prospective load areas. State economic development advocates may suggest projects to allow development of coal resources.

Each transmission proposal originates with the expectation, by the party proposing it, that it will provide benefits sufficient to warrant the related costs and risks.

[7] See attached summary of types of proposals by Jeff Miller, Reasons for Building Transmission

Generation integration transmission projects provide the benefit of allowing the least-cost or best integrated resource combination of generation, fuel and transmission.

Reliability transmission projects are expected to benefit customers with reliable transmission service and are proposed because mandatory reliability standards set by the North American Electric Reliability Corporation (NERC) and enforced through penalties must be met.

Economy projects are expected to provide benefits that will outweigh the costs and risks.

Projects initiated to satisfy public policy are expected to provide environmental and other societal benefits, plus the power benefits, that will outweigh the costs.

Merchant transmission and generation projects are initiated in the expectation that revenues will outweigh costs and the merchant developer will profit. Merchant generation developers expect that the transmission lines would allow them to profitably develop their projects, assuming they can find buyers at acceptable prices, without them having to bear the transmission development risks themselves.

It is often pointed out that transmission lines may provide additional benefits. In particular it is claimed they will provide direct and indirect economic development benefits in the form of jobs and income, and it is claimed that because they have long economic lives and because markets change in unpredictable ways they may provide future benefits that cannot be forecast at the time of a decision to build. However these benefits are not considered further in this paper because they are not key elements in planning and investment decisions on transmission projects. They do not contribute to the identification and selection of whether and which projects to build, nor to decisions by management on the likelihood of investments providing adequate returns.

Transmission Planning

Utility Local Transmission Planning

The following planning functions provide insight to the complex nature of utility transmission planning efforts. These functions coordinate with and are appropriately integrated into the utility's local area transmission plan.

Identification of Need for Transmission

Load Serving Entities (LSEs) are responsible[8] for serving their customers' loads and load growth in an economical and reliable fashion. They may also be required to meet legislatively set policy requirement such as Integrated Resource Planning (IRP), which requires consideration of demand side management on an equal footing with new generation. An IRP process may also require consideration of environmental impacts and/or potential changes in

[8] In some states large industrial customers can choose their source of power rather than acquiring their power through the LSE.

environmental regulation. An IRP may also incorporate legislative or regulatory requirements such as RPS or in-state generation requirements. The LSE studies how to serve its loads, which results in the selection of generation expansion plans that may carry requirements for new transmission or upgrades to existing transmission to integrate their preferred generation choices. IRP studies may also study the need for replacement of obsolete generation. The outcome of these studies is a decision by resource planners on specific generation projects that are studied in the context of the local area transmission planning, described below, to integrate the generation into the LSE's service area.

LSEs may also request transmission service to access existing, lower-cost power outside the utility area that is not currently accessible on a firm basis. They may see opportunities, outside their IRP studies, to reduce costs by scaling down the use of existing generation and building transmission to reach other sources of power that may be sufficiently cheaper to warrant the transmission costs incurred. Utility consideration of generation alternatives may be affected by, or driven by, current or expected state and federal policies, such as RPS or preferences for in-state generation, and the likelihood of future CO2 regulation.

The transmission planner receives load forecasts annually from all LSEs and non-LSE transmission customers. These forecasts are coupled with generation forecasts from these same entities and the transmission topology to assess the ability of the transmission planner's local transmission system to maintain safe, adequate and secure operation of the transmission network into the future. The ensuing transmission reliability analysis determines whether the transmission system is adequate to meet the projected needs of existing transmission customers.

Local Reliability Transmission Planning

Once the need for transmission is established the utility transmission planning analysis begins. This analysis is a technical study that examines the reliability of the transmission system under likely scenarios of generation development and dispatch for selected hours of the year, such as an hour that represent a high load and maximum generation condition. This analysis examines transmission system reliability with all transmission elements[9] in service and with the loss of one or more elements and is conducted for selected years up to 20 years in the future (e.g., current year, year 5, 10 and 20). The transmission system reliability performance must meet NERC and WECC reliability criteria. When transmission planners discover a future condition that fails to meet the planning criteria they look for alternatives for strengthening the transmission system and propose what they believe is the best long-term solution to the reliability problem.

[9] Elements include conductor, substation, transformers and other equipment.

Examples

The Gateway Phase 1 and Cascade Crossing projects on the Foundational Project List are examples of transmission projects needed to reliably meet customers' long term needs for delivery of network resources to network loads. Gateway Phase 1 projects are needed to reliably deliver new Wyoming and Utah generation to loads in both the PacifiCorp East and West Balancing Areas. The Cascade Crossing project is needed to reliably deliver new and existing resources in the least cost fashion to PGE customers. Both Gateway Phase 1 and Cascade Crossing are required to meet firm load service obligations with respect to reliability standards, as well as delivery of renewable resources and other long-term resource selection and development alternatives.

It should be noted that the Gateway Phase II projects, which are on the Potential Project List, are an economic way to meet regional RPS goals and third-party indications of potential service interest. In open-season solicitations of interest, however, no third-party customers have committed to commercial terms, so these projects remain on the Potential Project List. They are included in TEPPC's economic and congestion performance studies that indicate they may have potential benefit under future resource scenarios.

Economic Transmission Planning

Economic transmission planning is considered within the local area reliability planning, but because there are important regional transmission proposals driven primarily by economics, TEPPC has been designated by WECC to study and propose regional solutions.

The simplest example of economic transmission planning is a new project to relieve a congested transmission path. A transmission path can become congested at certain times for many reasons, such as increased usage of the line over time, or use of a line that was specifically designed to move power from a generation source to load but is now being used for new firm or non-firm requests. Congestion may simply mean that the transfer capacity is fully assigned and that no firm Available Transmission Capacity (ATC) is available to new users. Depending on how heavily ATC holders actually use the line, there may also be portions of the year during which the line is fully loaded and congestion may be high enough that no non-firm capacity is available. During these hours, economic dispatch of otherwise lower cost generation may be constrained and higher cost generation operated. If congestion occurs during a large enough proportion of the year, particularly when the spread between generation costs at opposite ends of the congested paths is high, planners may consider – or customers may propose – construction of transmission to increase access to lower cost generation. Planning studies for economic projects must involve more than just the selection of an optimal project and route. The question of projected benefits, particularly how great and how likely they are, will be of paramount importance, especially since the displacement of higher cost generation with lower cost power often involves short-term sales between unaffiliated parties.

LSEs may have similar considerations of economy and request additional transmission be built (through a new transmission service request or designation of a new network resource) if rising fuel costs render a utility's generating plant uneconomic compared to other power that may be available for purchase but is inaccessible on a firm basis because of insufficient ATC – even if the existing paths in question are never fully loaded and non-firm capacity is always available.

An economic congestion study provided by transmission providers at no charge is a way an interested party (e.g., stakeholder, non-utility generator, and non-utility transmission developers) can gain an understanding of existing transmission congestion. The number of economic studies performed each year by the transmission providers varies. Depending on the type of request, the economic studies may be conducted by the transmission provider, sub-regional planning entity or WECC TEPPC.

Examples

The 500 kV Mountain States Transmission Intertie (MSTI) project and the Montana-to–Northwest, 500 kV Upgrade project are examples of transmission projects designed to relieve the congestion out of Montana potentially created by renewable resource development in the state. The MSTI project is a proposed new high-voltage transmission line that will provide a transmission path to deliver up to 1,500 MW of renewable wind energy from Montana to Midpoint, Idaho, and to load centers in the western states. The 500 kV Upgrade project is a project to increase the transfer capability by up to 800 MW by both increasing series compensation ampacity (to 3000 amps) and percent compensation (to 70%). This project is expected to increase the capacity from Colstrip (or Broadview) to the Mid-C area in Oregon.

Transmission Service Request Planning

Transmission providers have the obligation to respond to requests from new and existing customers for point-to-point transmission service to move power into, out of, or across the transmission provider's system. The customer may be an LSE serving local load, or an LSE, Purchase or Sale Entity (PSE) or Generator Owner (GO) moving power over the transmission provider's system to serve load or make a power sale external to the transmission provider's system. A valid request for transmission service causes the transmission provider to conduct reliability studies similar to the local area reliability study to identify any unacceptable reliability impacts to the transmission system due to this request. Any unacceptable transmission reliability performance must be mitigated such that the NERC/WECC reliability criteria are met. It should be noted that an LSE follows the same process when it makes a new designation of a network resource to serve its load.

Example

Transmission providers routinely conduct transmission planning studies in response to a request for transmission service from an entity desiring to move power across the transmission provider's system. In addition to these requests, the transmission provider may initiate an open-season solicitation as a means to identify sufficient interest to construct a new transmission line for which at least a portion of the resulting capacity is not required to meet contractual obligations to existing transmission customers. There are numerous examples of the open-season solicitation process being used to identify customers to support the development of a transmission project. For example, the large amount of potential wind development in Montana and Wyoming, coupled with an RPS in several western states, has resulted in open-season solicitations by the sponsors of the Chinook and Mountain States Transmission Intertie projects out of Montana and the Zephyr and TransWest Express projects out of Wyoming. These projects will proceed if LSEs serving major load centers commit to resources in these high wind areas as their preferred renewable energy resource.

Merchant Transmission Planning

Merchant transmission planners may have a relatively simpler problem when compared to a utility planning for its load, since they do not have to worry about how to manage an existing integrated transmission network. Merchant transmission planners look for areas where they think there may be sufficient need for transmission service to support construction of a new transmission line.   The source of need may be from prospective resource developers, potential economy transactions, or power marketers seeking to bypass congestion, or LSEs seeking access to additional resources for serving load growth or satisfying policy requirements. Merchant transmission developers generally look for a firm, long-term contractual commitment from subscribers under a rate structure that will yield a high enough return on their investment to warrant the cost and risk they must undertake in constructing and operating the project. Because their projects will be underwritten by customers either signing up for specific long-term, point-to-point type service or for shares in the project, the project generally isn't funded by a transmission provider's tariff rates directly. Rather, the costs will be borne directly by the project's subscribers and, indirectly, by the LSE (or PSE) who purchases power from the subscribers of the merchant transmission.

Example

Montana Alberta Tie Ltd. and MATL LLP (MATL) are respectively Canadian and US based entities that are constructing the Montana Alberta Tie line, a 214-mile (345-kilometer), 230-kV transmission line that will interconnect electricity markets of Alberta and Montana. The MATL line will run from a substation outside of Lethbridge, Alberta to one near Great Falls, Montana. Northern Montana and southern Alberta are home to some of the best wind energy sources in North America. The MATL line will enable the development of new wind-energy projects by linking this renewable power to consumers across North America. Montana Alberta Tie Ltd. is a wholly-owned subsidiary of Tonbridge Power Inc.

Regional and Sub-Regional Transmission Planning

In addition to preparing its local area transmission plan (described above), a transmission provider participates in sub-regional and regional planning activities. The purpose of the sub-regional and regional coordination is to share system plans to ensure they are simultaneously feasible, use consistent assumptions and data where possible, and identify system enhancements that could relieve "significant and recurring" transmission congestion. Further, this coordination presents opportunities for finding synergies among system plans that can lead to 1) joint ownership projects in cases where common plans, needs, and goals coincide or 2) reduction of redundant projects where similar proposed projects meet similar needs and goals, or 3) both. Coordination of data and study results is an important aspect of the local, sub-regional and regional planning activities. FERC recognizes that the sub-regional and regional plans are not construction plans in the in the West, where there is no organized market.

Major transmission projects are studied by the sub-regional entities (such as Northern Tier Transmission Group, ColumbiaGrid and WestConnect) and through WECC's TEPPC process. These planning groups study transmission congestion and projects proposed by stakeholders, and they seek regional solutions to congestion problems and economic opportunities. In addition, ad hoc groups are often organized at the state, sub-regional and regional level to study proposed transmission projects that are thought to be beneficial. Sub-regional and regional planning entities also provide opportunities for stakeholders and interested parties to request an economic congestion study, performed at no cost by the sub-regional groups and WECC TEPPC.

TEPPC has long been studying the extent of congestion on major paths throughout the Western Interconnection. The RTEP studies are designed to identify and evaluate opportunities for economic projects that are associated with alleviating congested paths. These studies model generation throughout the West and look at the savings in capital and operating costs associated with incorporating large amounts of remote renewable generation instead of local renewable and fossil generation, and compare the costs and savings, including the costs of transmission. TEPPC's Potential Projects List includes the projects that emerge from the RTEP study.

WECC Rating Process

Transmission providers perform reliability analyses of the impacts and increased capability a new line brings to their system and neighboring systems. A major new transmission line that is proposed by a transmission provider or merchant transmission project developer must go through the WECC Three-Phase Rating Process. In the western interconnected system, individual transmission lines are grouped together in transfer paths with other lines with which they electrically interact. Upon loss of the new line, or an adjacent line in the same path, the resulting shift of power flow onto the remaining lines must remain within reliability performance limits. A path's transfer rating is the maximum amount it can carry with the strongest single element out of service, and the path rating given to a new transmission line is the amount its construction will add to the path rating. The Three-Phase Rating Process allows projects to enter the process in various stages of planning and both Potential and Foundational List Projects are currently in the process.

Investment Decisions and the Decision to Build

Generation developers look for markets and suggest potential transmission projects to carry their power, and planners evaluate projects and recommend the ones they think best fit those needs. However, the only time a project gets built is when an entity is willing and able to commit sufficient resources to building it. In order to pay for the project and recover the investment, the stream of benefits must be sufficiently large with a high probability of materializing for the project sponsor to be willing to take the risk of financing and building the transmission line. (For a transmission provider, the stream of benefits includes revenues from new sales; for an LSE committing to new transmission service, the stream of benefits includes lower capital and operating costs.)

Transmission projects are costly to build, and can be difficult to permit and to site. The costs and risks will be acceptable if decision makers are convinced the benefits are great enough and are deemed likely to materialize, and that there is a way to translate those benefits into a long term revenue stream that will pay for the project. There may be exceptions. For example, if regulators order a line to be built, transmission providers will build it and will recover their costs through rates whether or not they agree that the line is worth building. In this instance the regulator has accepted the cost and risk of the line on behalf of existing transmission customers and the public at large. Also, a project may be built if sufficient subsidies can be found to reduce the required investment and required revenue stream to pay the balance. Outside of these exceptions, most lines require approval and commitment by parties with responsibility for finance in order to be built.

Investment Decisions on IRP/Load Growth/Cost Reduction Projects

Transmission providers must respond to requests (such as transmission service requests stemming from IRP studies on the need for new generation and load growth) from their affiliate LSEs in the same manner and priority as they respond to requests from third parties. A transmission provider and its own LSE answer to the same management and, as will be discussed below, different criteria may be used for making these internal investment decisions.

Transmission planners make recommendations to management for transmission projects to be built. Management evaluates the recommendations in light of the required financial commitment, competing financing needs, and the urgency and likelihood of the projections and generation choices that are the basis for the recommendation. If financing is constrained or if there are other, more pressing immediate needs, the decision may be made to postpone construction of new generation, new transmission, or both, and to rely instead on market purchases in the interim.

Management will evaluate the need for cost-reduction projects in a similar manner: they will look at the likely cost savings in light of their magnitude and the likelihood of their occurrence, and they will look at the cost of the project, the difficulty of financing it, and the priority needs of competing projects. Their decision in either of these cases may end up different than the recommendations of either the transmission planners or the LSE IRP planners, because they apply different criteria and different considerations than those applied by the planners.

Finally, considerations of service for load growth generally show up first in greater stress on the transmission system under outage conditions, and are treated as part of the reliability studies and need for reliability projects described below.

Cost recovery is not generally an issue for projects designed to serve the native load of LSEs and the investment costs are rolled into transmission investment and recovered through rates charged to native load customers. In some cases where a utility is sensitive to the risk of disallowances and where the law provides for it, it may ask for preapproval by the regulatory commission before proceeding with construction.

Investment Decisions on Reliability Projects

There are many factors that may be considered when management is considering placing a reliability transmission project into the utility budget, including how far into the future the reliability problem first appears, what the consequence is of the outage (minor thermal equipment overload vs. severe low voltage) and siting/construction time. For example, a project designed to solve a potential voltage violation after a line outage that is forecast to occur 10 to 15 years in the future under high load growth and loading conditions that occur only for a few hours a year with a highly unlikely outage may reasonably be seen as a low priority. The same problem would likely gain higher funding priority as the forecast conditions draw nearer and high load growth makes the contingency more likely. By contrast, a project designed to solve a potential violation that would occur in the next 1 to 5 years, under load and operating conditions that are reasonably likely to be found on the system, will be seen as a high priority project and will probably receive immediate approval to proceed.

Cost recovery is generally not an issue for reliability projects and costs are rolled into transmission investment and deemed by regulators to be used and useful.

Utility Transmission Investment Decisions on Third Party Transmission Service Requests

When a third party submits a request for transmission service, there are a series of steps a transmission planner takes that require increasing levels of commitment by the requesting party. At each stage more detailed studies are done, that may require a new proposed transmission project. If the requesting party agrees with the proposal and the estimated cost of service a transmission service agreement will be signed that requires the new project to be constructed. The agreement will include financial commitment (i.e., transmission service agreement) and security provided by the requesting party. Under FERC's existing policies, the party requesting transmission service pays upfront for either upgraded or new transmission lines necessary to provide the requested service, and the upfront payments are refunded to the party over time[10] as the transmission service is used.

Federal Power Marketing Agencies Decisions

While most PMAs have reciprocal arrangements in their Open Access Transmission Tariff (OATT) in which they agree to provide service on the same basis as other transmission providers, Federal PMAs use a different set of criteria than utilities in deciding to build new transmission lines. They have constraints on how much financing they can use, that may or may not be binding.[11] They face an array of projects suggested by planners to serve various types of needs: reliability and load growth; integration of new generation; congestion management; ability to sell excess federal hydropower; transmission service requests by customers, other utilities and merchant generators; and policy. Planners will evaluate these requests and needs and recommend projects for management approval. Management decisions will involve balancing priorities, as discussed above for utility management decisions. The biggest difference between utility management and PMA management decisions is the ability of PMA management to translate policy into construction, without the mediation of a regulator or legislative body. If PMA management wants to encourage renewable resource development in a remote area they have the ability to build transmission in the absence of financial commitments from potential resource developers and users.

Merchant Transmission Project Decisions

While we have many proposals in the western United States for merchant transmission projects, we have very limited experience thus far with them being built. The Montana Alberta Tie Line (MATL) project is the only merchant line that has reached the stage of financial commitment and construction. However, MATL, a fully subscribed transmission line, had stimulus funding assistance in the form of a construction loan that will eventually turn into a 30-year fixed interest loan from the federal government through the Western Area Power Administration.

Merchant projects face some of the same factors that must be dealt with in investment decision on utility projects but in some ways a different set of criteria may be applied to them. Merchant developers seek a profit from building their projects and charging subscribers to use them. They have no load serving responsibilities and will only proceed with a project if they are convinced it will earn returns at least commensurate with the risks they perceive and with the risk adjusted returns they can earn in other endeavors. Further, they often take risks and they may be aggressive in some cases in seeking to reduce their own costs and risks by looking for subsidized financing or outright subsidies by government. Because they are risk takers, they may proceed with projects a utility could not be interested in. They also may have or seek tax

[10] The time period for refunding the upfront payments is specified in the Transmission Provider's tariff, but can be up to 20 years.

[11] In fact, both BPA and WAPA received approval from Congress in 2009 of additional borrowing authority for transmission projects.

advantages that utilities lack. Their investment decisions are thoroughly based upon their analyses of the marketability of their project and the likelihood of revenues being great enough to cover their costs and risks with a risk-commensurate return. This may mean reliance upon FERC-regulated sales of firm capacity to return their costs, and FERC-allowed incentive returns and sufficient non-firm sales and negotiated rate sales to ensure likely revenues to meet their hurdle rates.

Why Transmission Projects May Not Get Built

We can now begin to answer the question that is often raised: Given the need of the country for renewable energy, the need to reduce carbon emissions, the desire of developers to access markets, the multifold benefits that can be provided by transmission, why are we not building all the projects that have been proposed? Answers to this question have been suggested and fingers pointed. Regulation is to blame, or siting by states is incapable of considering national benefits. FERC should have federal eminent domain authority and the ability to override state siting decisions, or environmentalists are raising roadblocks and causing delays and unnecessary costs, or greedy landowners and NIMBY-driven naysayers are blocking construction and litigating.

The answer that this paper points to is different:

Projects are not getting built because, despite the projections or claims of significant benefits, those benefits are not perceived as sufficiently great or sufficiently certain by those who would otherwise be willing to bear the risk of investment and construction.

It is easy to propose that a line be built with someone else's money, and with someone else bearing the risk. It is harder to pin down the benefits, and their likelihood, sufficiently to convince the beneficiaries it is worth risking their own funds. Projects will not get build until an entity that sees benefits or a need from the project steps up and financially commits to the project. If they perceive their benefits to exceed the risks and cost of pursuing the project, project management or investors will commit funds and the project will move forward and likely get built.

Numerous projects have been proposed and studied over the past several decades which did not immediately result in construction. A variety of proposals to expand the Oregon-California interties were studied by ad hoc regional groups at various times under the "Third AC" banner. Studies have been conducted in recent years on additional major lines from Wyoming to California, from Montana to California, and from Alberta to California. These proposals remain on the drawing board, and they may yet be built if they can find commitments from investors who can be convinced of their merits, and particularly of their profitability.

TEPPC is currently devoting considerable effort to studying congestion in the Western Interconnection. TEPPC uses dispatch models to estimate re-dispatch savings over the entire year that are associated with projects that relieve congestion on major paths. The estimated savings are, of course, dependent upon the assumptions and scenarios built into the model runs. TEPPC's studies appear to show very large benefits associated with building three proposed transmission projects that would expand capacity between Montana and California by over 5,000 MW, and using that capacity to ship new wind generation from Montana and backing off generation in California.

Projected savings do not automatically translate into perception of benefits by all parties. TEPPC's modeled benefits rest upon assumptions about the costs of renewable power, the costs of the transmission projects, and the desirability of backing off existing and new generation in California. In practical terms, these conditions would have to be accepted by California LSEs in order for the projects to be built. If the benefitting parties accept TEPPC's benefit estimates and become convinced they will occur, the benefiting parties should be more than willing to invest in the transmission project.

Another example of a beneficial project that has had much analysis and interest, has been the subject of an open season solicitation, and is currently engaged in the siting and permitting process but is not yet on the Foundational Project List, is the Mountain States Transmission Interconnection project (MSTI). While conceptual planning and much design for this project have been completed, it is not on the Foundational Project List because as yet it does not have firm customers or shippers committed to its use and funding, which was one criteria to be placed on the list. Confusion and uncertainty in the southwest markets delayed completion of the open season process. In the context of this paper, this transmission project will be built when firm long term transmission service commitments are received by the transmission sponsor. This transmission commitment will happen when load serving entities identify sufficient benefit from Montana renewable resources to outweigh the delivered cost and perceived risk of securing long term resource commitment from renewable projects in Montana.

The Gateway Phase II projects are a further example of projects in the Potential Project List for which design and permitting efforts have begun, yet remain only Potential Projects. The Gateway Phase II projects are planned to be synergistic with the Phase I projects, sharing towers and rights of way to reduce costs. However, in the open season and OATT formal service commitment processes, customers have not yet committed to transmission service because of uncertainty, costs, risk and timing of markets and renewable resource additions.