NORTHERN TIER
TRANSMISSION GROUP

September 3, 2013

VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Report on the Status of Production Cost Modeling

PacifiCorp,	Docket No. ER13-64-___
Deseret Generation & Transmission Cooperative, Inc.	Docket No. ER13-65-___
NorthWestern Corporation	Docket No. ER13-67-___
Portland General Electric Company	Docket No. ER13-68-___
Idaho Power Company	Docket No. ER13-127-__

Dear Secretary Bose:

On October 10, 2012, pursuant to Section 206 of the Federal Power Act, Order No. 1000 of the Federal Energy Regulatory Commission (the "Commission"), and 18 C.F.R. Part 35 (2012), the five jurisdictional transmission providers comprising the full funding members of the Northern Tier Transmission Group - Deseret Generation & Transmission Co-operative, Inc., Idaho Power Company, NorthWestern Corporation, PacifiCorp, and Portland General Electric Company (collectively, the "Filing Parties") - each submitted a compliance filing addressing the regional transmission planning and cost allocation requirements of Order No. 1000 in the above-captioned proceedings.

In the transmittal letter accompanying their compliance filings, the Filing Parties committed to study further the use of Production Cost Modeling ("PCM") in order to capture benefits for potential use in cost allocation and to provide the Commission with a report on its findings by mid-2013.[1] The Commission, in its Order on Compliance Filing, acknowledged the Filing Parties' commitments.[2]

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[1] *Order No. 1000 Attachment K Joint Compliance Filing of the Jurisdictional Transmission Providers of the Northern Tier Transmission Group*, Docket No. ER13-64-000, *et al*., Transmittal Letter at 9 (October 10, 2012) ("Given the time required to compile the necessary information on generation and transmission entitlement and implement this information in input data and model modification to prepare an appropriate PCM methodology, NTTG compromised on a two-step approach for this compliance filing. Initially, NTTG developed a methodology that would limit cost allocation to instances of a project replacing or deferring another project. Subsequently recognizing that relying on a single benefit metric (cost-savings associated with a displaced project) was potentially overly prescriptive, NTTG established a metrics workgroup to explore additional methods of benefits measurement. . . . *Second, NTTG committed to further explore various metrics and tools, including a more robust PCM-based metric, for capturing benefits for potential use in cost allocation. The Applicants will provide this report to the*

Now, in compliance with the commitments, the Filing Parties hereby submit their report, *Evaluation of Production Cost Modeling for Transmission Cost Allocation* (August 30, 2013) ("Report"), on the use of PCM to capture benefits for use in cost allocation determinations. The Report indicates that,

> "The strong consensus of the cost allocation and PCM work groups was that the results of the study in the current modeling framework do not provide sufficient accuracy to be used at this time in the development of benefit metrics for the allocation of transmission project costs."[3]

As such, the Filing Parties do not intend to incorporate a benefit metric reflecting changes in net production costs into their respective Attachment Ks at this time.

With this filing, the Filing Parties believe they have fulfilled their reporting obligation to the Commission, and do not believe that any further action is required by the Commission.

Respectfully submitted this 30th day of August, 2013.

/s/ Malcolm McLellan
By ____________________________
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Attachment

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Commission by mid-2013. The Applicants will make any tariff changes regarding economic benefits for cost allocation prior to the start of the 2014 biennial planning cycle.") (Emphasis added).

[2] *Order on Compliance Filing*, 143 FERC ¶ 61,151 at P 215 (May 17, 2013).

[3] Report at p8.

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designed on the official service list compiled by the Secretary in Docket Nos. Docket Nos. ER13-64-000, ER13-65-000, ER13-67-000, ER13-68-000, and ER13-127-000.

Dated this 3rd day of September, 2013.

/s/ Malcolm McLellan
By ______________________________
Malcolm McLellan

EVALUATION OF PRODUCTION COST MODELING

8/30/2013

For Transmission Cost Allocation

NTTG investigated the suitability of production cost models using publicly-available data to estimate for market participants the operational benefits under various scenarios that could result from new transmission projects. The approach employed by

NTTG used a “backcast” technique that attempts to calibrate and compare model results with actual data. The study provided a step forward in terms of methodology and understanding of production cost modeling, but the result of the study in the current modeling framework do not provide sufficient accuracy to be used at this time in the development of benefit metrics for the allocation of transmission project costs.

Report prepared by NTTG with the assistance of Energy and Environmental Economics, Inc.

Evaluation of Production Cost Modeling

FOR TRANSMISSION COST ALLOCATION

EXECUTIVE SUMMARY

The jurisdictional transmission providers ("Filing Utilities") that are members of the Northern Tier Transmission Group ("NTTG") submitted their coordinated compliance filings with regard to compliance with Order 1000 regional transmission planning and cost allocation on October 10, 2012.[1] This filing included a transmittal letter ("Regional Transmittal Letter") and a clean and red-lined version of each entity's Attachment K to its OATT.

As described by the Regional Transmittal Letter, several benefit metrics were considered by the cost allocation working group of NTTG ("CAWG") that was given the responsibility for investigating and recommending the benefit metrics to be incorporated in the regional methodology for transmission project cost allocation. From the several benefit metrics that were considered, the CAWG recommended, and the Filing Utilities adopted, three metrics for incorporation in their cost allocation methodology: change in annual capital-related costs, change in losses, and change in reserves. The Commission found that these proposed benefits metrics were reasonable, subject to further description.

Several potential benefit metrics were excluded from the regional proposal submitted to the Commission. Because many of the excluded benefit metrics would utilize production cost modeling ("PCM") to estimate the benefit metric, the CAWG turned to a technical group within the Filing Utilities to provide additional information to the CAWG as to the

[1] The Filing Utilities are Deseret Generation & Transmission Co-operative, Inc., Idaho Power Company, NorthWestern Energy, PacifiCorp, and Portland General Electric Company.

inputs, methodology, resource-transmission topology, and output of PCM (collectively, the "PCM tool") in a regional and interregional context; however, so as not to delay the submission of the October 10, 2012 filing, the Filing Utilities committed to the Commission to explore ways that the PCM tool could be modified and/or augmented to produce estimates of certain benefit metrics that would be more reliable and robust and to provide this report to the Commission regarding these efforts by mid-2013.

NTTG engaged Energy and Environmental Economics ("E3") to perform this work, which was eventually divided into two phases. Phase one focused on selection of the PCM tool and initial database, selection of a study year (2010), demonstration of a spreadsheet post-processor to disaggregate and extend the results of the PCM for an individual market participant ("MP"), and to calibrate the model input data to best simulate the aggregate generation and transmission flow results for the Western Interconnection for the study year. Phase two built on the work in phase one to include sensitivity scenarios for key inputs (e.g., natural gas prices), a second transmission project for which dispatch and financial impacts were calculated, certain enhancements to the post-processor, and expansion of the post-processor for multiple MPs.

NTTG's PCM work group, in consultation with E3, selected the GridView software model of ABB for the PCM study. The PCM work group further determined that a "backcast" technique using actual dispatch and transmission flow data for 2010 would be best suited for evaluating the accuracy of the PCM tool and its feasibility for estimating benefit metrics.

In addition to describing the results and conclusions with respect to the phases one and two work prepared by E3, this report also provides an overview of PCMs, the use of PCMs in the Western Electricity Coordinating Council ("WECC") planning studies, and several details with regard to the use of the 2010 database of WECC's Transmission Expansion Planning Policy Committee's ("TEPPC") as the starting point for input to the PCM.

E3 made several enhancements to the TEPPC 2010 case, generally with the goal of more accurately representing generation operation (such as with respect to how reserves are carried on various units) and transmission flows. Chief among the PCM enhancements was the development of a tiered approach to the implementation of transactional costs for energy generated in one balancing authority area ("BAA") used to serve load in another BAA. Ultimately, the 2010 Base Case used in the study was the 25^{th} iteration developed by E3, resulting in approximately a 60% improvement in overall accuracy in dispatch results as compared with the initial base case iteration.

The post-processor provided by E3 was used (in phase two) to disaggregate the PCM results for the 2010 Base Case to fourteen MPs in the NTTG footprint and to develop a "net procurement cost" for each MP. The basic, logical steps of the post-processor are the following:

1) Determine the MP's load service obligations as the sum of hourly load plus contracted sales input to the post-processor
2) Determine the MP's owned and contracted generation as (i) the energy dispatched by the PCM times (ii) the MP's entitlement share for each generating unit
3) Calculate the MP's net hourly energy position as load obligations (from step 1) minus generation (from step 2)
4) Financially settle the net hourly energy position based on estimated wholesale market hub prices:
    - Purchase of net short
    - Sale of net surplus
5) Determine the production cost of owned and contracted generation as (i) the cost of dispatched energy for each generating unit from the PCM times (ii) the MP's entitlement share for each generating unit
6) Calculate MP's total portfolio cost in each how as the sum of --
    - Production cost of owned and contracted generation (from step 5), plus
    - net purchases and sales from the wholesale market (from step 4)
7) Sum hourly net procurement cost for all 8,760 hours for the year to obtain MP's annual net procurement cost

The 2010 Base Case was alternatively modified to include one of two proposed major transmission projects, the Mountain States Transmission Intertie or the Boardman to Hemingway project. For each "Change Case" (i.e., the Base Case adjusted to include of one of these two transmission projects) the post-processor estimated the net PCM benefits (or costs), as compared with the 2010 Base Case results, for each of the fourteen MPs in the NTTG footprint incorporated in this study. A similar calculation of net PCM benefits was also calculated for the six sensitivity scenarios developed for the study: low and high natural gas prices, high transmission hurdle rates, low hydroelectric generation, and remote and local generation increments.

The methodology, data and issues concerning both methodology and data are described in detail in the body of this report and will not be repeated here.

While the study provided a step forward in terms of methodology and understanding of production cost modeling, several concerns with use of the PCM tool were identified but remain unresolved:

- The dispatch by the PCM for individual generating units in the 2010 Base Case was substantially inaccurate, which could result in dramatic misestimates of net PCM benefits for certain MPs.
- The hourly market prices estimated by the PCM in the 2010 Base Case were substantially inaccurate as compared with actual prices. While an adjustment mechanism developed by E3 resulted in modeled prices reasonably estimating actual annual prices, this mechanism failed to remedy two issues: (1) the adjusted prices significantly varied from actual prices on a daily basis, though the errors in daily prices largely offset one another when aggregated over the entire year, and (2) no method was developed or outlined which could reasonably estimate the adjustment parameters for a forecast year at least 10 years in the future.
- While the backcast could compare actual and modeled energy dispatch by generating unit and transmission flows, data were not available to compare modeled versus actual “net procurement costs” which is the ultimate quantity used to determine the net PCM benefits of MPs. Accordingly, the study was unable to determine whether the PCM tool could reasonably simulate financial results – not physical dispatch and flow results – for areas relying on bi-lateral markets, as such is the case in the NTTG footprint.
- Incremental transmission payments associated with dispatch changes simulated by the addition of a new transmission project were not captured by the PCM tool,

which could result in a substantial overstatement of net PCM benefits to a MP (or understatement, if the MP is the beneficiary of the transmission payments through lower transmission rates).

- The PCM tool only evaluates changes in certain operating costs. Since major, new transmission projects are often associated with the development of new generation, failing to link the benefits identified by the PCM tool with the benefits of generation location that would be affected by and associated with transmission availability could result in cost allocation that is not roughly commensurate with benefits and ultimately result in sub-optimal decisions as to the type and location of new resource development.

The strong consensus of the cost allocation and PCM work groups was that the results of the study in the current modeling framework do not provide sufficient accuracy to be used at this time in the development of benefit metrics for the allocation of transmission project costs.

IMPETUS FOR THE STUDY

Through Order 1000 the Commission required that each jurisdictional transmission provider modify its open-access transmission tariff ("OATT") to include certain requirements with respect to the development of a regional transmission planning process and transmission plan, and for development of a cost allocation methodology for transmission projects, either individually or in the aggregate, accepted in the regional plan.

Further, in Order 1000 the Commission directed a principles-based approach for the allocation of costs of certain transmission projects included in a regional transmission plan and more specifically provided that the allocation process "may consider benefits including, but not limited to, the extent to which transmission facilities, individually or in the aggregate, provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, and/or meeting public policy requirements established by state or federal laws or regulations that may drive transmission needs."[2]

The Filing Utilities that are members of NTTG submitted their joint compliance with regard to compliance with Order 1000 regional transmission planning and cost allocation on October 10, 2012.[3] This filing included a Regional Transmittal Letter and a clean and red-lined version of each entity's Attachment K to its OATT.

As described by the Regional Transmittal Letter, several benefit metrics were considered by the CAWG of NTTG that was given the responsibility for investigating and recommending the benefit metrics to be incorporated in the regional methodology for transmission project cost allocation. From the several benefit metrics that were considered, the CAWG recommended, and the Filing Utilities adopted, three metrics for incorporation in their cost allocation methodology: change in annual capital-related costs, change in losses, and change in reserves. The Commission found that these proposed benefits metrics were reasonable, subject to further description of annual

[2] Order 1000, ¶ 586.

[3] The Filing Utilities are Deseret Generation & Transmission Co-operative, Inc., Idaho Power Company, NorthWestern Energy, PacifiCorp, and Portland General Electric Company.

capital-related costs and how such change in capital-related costs of a beneficiary will be used to allocate transmission project costs.[4]

Several potential benefit metrics were excluded from the regional proposal submitted to the Commission, however, because of concern as to whether these metrics could be reasonably and fairly be estimated for a new transmission project 3-10 years in the future. In particular, some members of the CAWG expressed their viewpoint that it is faulty logic to presume a bad estimate is necessarily better than no estimate.[5] Because many of the excluded benefit metrics would utilize PCM to estimate the benefit metric, the CAWG turned to a technical group within the Filing Utilities to provide additional information to the CAWG as to the PCM tool in a regional and interregional context. Based on this initial work, the majority of the CAWG concluded from these results that the PCM tool, in its current status, did not reliably reflect the operational and contractual realities of resources and transmission within the NTTG footprint without substantial modification. So as not to delay the submission of the October 10, 2012 filing, the Filing Utilities committed to the Commission to explore ways that the PCM tool could be modified and/or augmented to produce estimates that were likely more reliable and robust and provide a report to the Commission on these efforts by mid-2013.

Toward that end, the PCM workgroup was re-engaged by the CAWG to continue its investigation of the PCM tool for the purpose of estimating the impact of a transmission project on the net operating costs of market participants[6] within the NTTG footprint. In particular, there were several concerns with the PCM tool that needed to be addressed:

- Could the database input to the PCM be readily modified to reflect the fuel cost and other operating parameters of specific resources?
- Could the database input to the PCM be readily modified to reflect resource and transmission entitlements of market participants?

[4] Order on Compliance Filing," PacifiCorp *et al.,* 143 FERC ¶ 61,151 (May 17, 2013)("May 17 Order")
[5] That is, if a crude estimate indicating positive benefits proves faulty and results in an entity bearing a share of the project's capital cost when, in fact, the other impacts of the project prove negative to that entity, the misestimate and resulting allocation of capital costs only exacerbates the adverse impacts. Clearly, for that entity, no estimate would have been better – and more equitable – than a bad estimate.
[6] "Market participants" as used in this study include load-serving entities ("LSEs"), independent/merchant power producers ("IPPs"), transmission providers, and balancing authorities.

- Does the PCM tool reasonably estimate the operation of specific resources and transmission flows with and without changes to the transmission grid?
- Does the PCM tool reasonably estimate the operation of specific resources and transmission flows across different estimates of key inputs, such as natural gas prices and hydro-generation levels?
- Can the output of the PCM tool provide results at the market participant level of granularity?

STUDY OVERVIEW

In October 2012, the CAWG developed a preliminary work plan and schedule for the PCM investigation, anticipating that NTTG would engage an outside consulting firm with PCM expertise in the WECC "to address perceived deficiencies/inaccuracies of existing PCM databases and optimize a database for use by NTTG." This preliminary work plan further anticipated that this database work would focus on the WECC TEPPC 2022 database.

Phase One

In November 2012, NTTG engaged E3 to perform this work. E3 had substantial experience in working with the WECC TEPPC database and various PCMs used in the WECC region and had been involved in several recent west-wide studies utilizing PCM tools for similar purposes.[7] The E3 work was performed in two phases. Work in the first phase was expected to result in (i) development of input data and model adjustments to improve the accuracy of the PCM and (ii) development of a demonstration Net Benefits Model using the output of the PCM to estimate net benefits to individual MPs. The phase one work was completed February 2013.

The computational portions of the PCM tool, as envisioned in the E3 scope, comprised two components: (i) a commercial PCM (in this study, GridView™ by ABB) and (ii) a post-processor spreadsheet, developed by E3. The PCM developed the security-constrained least-cost dispatch of resources to load, subject to transmission path limits and estimated transmission costs, and the post-processor parsed the output of the PCM to individual MPs, calculated their net energy positions, and calculated their net resource operating costs. (The details of the modeling process are described below.)

The work performed in phase one departed, to some degree, from the original plan in a few respects. First, the NTTG work plan had expected that the database modifications and enhancements would focus on a future year (e.g., 2022). The decision was made early in phase one, however, that use of a historical time period would provide more

[7] For example, E3 was the principal consultant in the technical analysis of the potential benefits of the west-wide energy imbalance market commissioned by WECC.

meaningful results for many of the issues and concerns with PCM. In particular, concern was expressed that the study not be limited to demonstrating modeling capabilities and functionality, but should also seek to demonstrate that the model could reasonably estimate the bottom-line financial impacts on MPs associated with a new transmission project. As a result, this study was based on calendar year 2010 data, specifically the TEPPC 2010 case, allowing model results to be compared with actual data for market prices, generation dispatch, transmission path flows, etc. Basing the study on a backcast[8] allowed for evaluation of the model's ability to provide reasonably accurate estimates, not just copious calculations.

Second, while E3 made numerous modifications to the TEPPC 2010 database and modeling methods, information as to resource entitlements and, for the most part, transmission entitlements were not captured in the PCM, or the phase one version of the post-processor. Third, specific information on generator operating characteristics were generally not modified in the database.[9] These latter two departures were, in part, due to constraints of timing and budget.

E3 presented the results of the phase-one study to the PCM work group on February 15, 2013. The presentation included the benchmarking (i.e., actual versus modeled) of coal- and gas-unit generation state-by-state, hourly flows on major transmission paths, and generation of specific coal units (the "Base Case"). A change case was also presented which added the proposed mountain states transmission intertie ("MSTI") to the 2010 transmission topology ("W/MSTI Case"). E3 utilized the post-processor with the Base Case and W/MSTI Case results from GridView to illustrate the calculation of the net benefits of the addition of the MSTI project for a single market participant.

E3's work in phase one also included the development of an ad hoc regression analysis to relate the locational marginal prices ("LMPs") at key transactional hubs estimated by GridView with actual spot prices.[10] Since per-unit prices of energy at these hubs are used

[8] A "backcast" entails using a model with a database of known and/or historical information to see how well the model output matches actual data.

[9] The exception was in a scenario created using specific operating characteristics for certain of Deseret and PacifiCorp generating resources.

[10] The transactional hubs used in the study are (i) California-Oregon Border ("COB"), Mid-Columbia ("Mid-C"), and Mona, Utah ("Mona").

to calculate the value of short-term surplus or deficient energy positions calculated in the post-processor for each market participant, development of a translation function to apply to the LMPs from GridView was a significant methodological decision (i.e., "fix" to the PCM).

Phase Two

After review of the phase-one presentation by E3, the Cost Allocation and PCM work groups met jointly and decided that, while progress had been made, there was still insufficient information from the work in phase one for members to feel comfortable in making a decision whether or not to use a PCM tool for estimating one or more benefit metrics. NTTG went back to E3 and asked for the following additional work:

- Exercise the PCM tool with several sensitivities, including natural gas prices, hydro-generation levels, generation location, and transmission hurdle rates[11]
- Exercise the PCM tool with a second, alternative transmission project
- Apply the post-processor to multiple MPs
- Modify the post-processor to account for bilateral contracts between MPs

E3 completed phase two and presented the results to the Cost Allocation and PCM work groups in May 2013. The enhancements in phase two included modification of the post-processor to incorporate impacts of contract sales or purchases on the net energy position otherwise calculated for a MP. The contract characteristics used by the post-processor include maximum capacity, purchase (or sale) variable price, and any contingency relationship with a generation unit (that is, if the purchase or sale availability is tied to the availability of the generating unit).

[11] "Hurdle Rates" are price adders, in $/MWh, that production simulation models use to reflect transactional costs (e.g., transmission rates, losses, etc.) or to inhibit transactions between zones that would otherwise occur in excess of actual or expected results.

OVERVIEW OF THE PCM

The E3 analysis consisted of two primary components: (1) enhancements to a PCM to characterize dispatch across the Western Interconnection and within the NTTG footprint under a base case and a case with an additional transmission project in place, and (2) a post-processing tool to calculate the impact of a new transmission project to the net procurement cost of a MP within the NTTG footprint. This section focusses on the PCM modeling component while the next section describes the demonstration post-processing tool.

PCM Background

Production cost modeling uses generation, load and transmission data to simulate the dispatch of generators to serve load while respecting transmission limits and other operational constraints for a defined period. PCM tools have been widely used in analysis of a range of electric system planning and operational issues throughout North America. In the Western Interconnection, PCM tools are utilized by individual utilities and other MPs, as well as regional and interconnection-wide planning organizations including NTTG and WECC. The issues evaluated using PCM include short-term financial planning, economic evaluations of new resources and transmission lines, evaluating of transmission congestion issues, system planning for increased renewable resource penetrations, and operational issues such as implementation of an energy imbalance market ("EIM").

A number of software programs currently exist for implementing PCM, including ABB's GridView, GE MAPS™, Ventyx's PROMOD®, and Energy Exemplar's PLEXOS® model, among others. Each program has relative strengths. Currently utilized PCM software programs have differences in four major characteristics: geographic granularity, time granularity, dispatch algorithm, and reserves characterization.

For geographic granularity, PCM can be run as zonal or nodal models. Zonal models aggregate the generators and loads within a given BAA or other boundary into a single zone or "bubble", within which internal transmission constraints are assumed to be non-binding, so the generators in that zone can operate as a single resource stack, and aggregate zone-to-zone transmission capacities only affect the ability to transfer power between different zones. Nodal models characterize the individual transmission busses and line segments to model powerflows and potential internal constraints more explicitly, with some level of aggregation of the lower voltage distribution system.

For time granularity, PCM models can be run with daily, hourly, or sub-hourly simulation intervals, and the dispatch can be selected to optimize over varying durations of forward time windows. For the dispatch algorithm, most PCM programs typically run using a linear program ("LP") or mixed integer program ("MIP") to optimize unit commitment. LP models typically run faster while MIP models more accurately characterize the lumpiness of generation commitment decisions and resulting startup costs. For reserves, certain models explicitly optimize provision of energy for loads as well as ancillary services such as regulation down and spinning reserves. Other models augment load to reflect reserve requirements during the commitment decision (to ensure that aggregate committed generation in a given area have a sufficient headroom to meet both load and reserve needs), but do not explicitly identify and record which units are providing reserves. Certain programs have the option to be run in different modes to with respect to these characteristics.

GridView Detail

NTTG, with the support of E3, selected the GridView software program for the phase one and phase two studies. The selection of GridView was based in large part on (1) ABB's support team's ability to implement requested software enhancements to better characterize operations within NTTG, (2) GridView's nodal model granularity, which facilitated evaluating the impact of adding particular transmission facilities to the system, and (3) GridView's existing incorporation of Western Interconnection data scenarios developed based on WECC's TEPPC input.

Using Western Interconnection generation, load and transmission characteristics, GridView simulates a nodal, security-constrained least-cost generator dispatch to serve on an hourly time interval. This simulation is performed with two simulation sub-steps: unit commitment and economic dispatch. In the first step, unit commitment, the simulation identifies which units to commit to be online during each hourly interval to serve load and meet minimum BAA-level reserve requirements, accounting for startup variable operating and maintenance ("O&M") and fuel cost, generator ramping constraints, and minimum up and down times, and transmission constraints. In the second step, economic dispatch, GridView uses step-function operating cost curves for each generator unit committed from the first step to determining the optimized level to dispatch each unit (between a minimum committed production output level and a maximum unit production output level) to minimize the aggregate cost of serving load across the footprint with the portfolio of committed generators.[12]

PCM use by TEPPC

WECC's TEPPC coordinates interconnection-wide expansion plans, performs economic analyses of the Western Interconnection, and prepares interconnection-wide transmission studies on a recurring study-cycle.[13] Since its creation in 2006, TEPPC has utilized PCM tools to support these interconnection-wide studies, such as the recently completed 2022 TEPPC model. TEPPC compiles transmission, generation, and load forecast data provided to WECC by certain WECC participants (including BAAs and MPs), and incorporates this information into a common database to be used for PCM analysis by TEPPC as well as its members organizations. As part of TEPPC's regular study process, TEPPC creates a PCM "base case" (e.g., TEPPC 2022 study-year PC1 Common Case), as well as a range of scenarios that identify the impact that changes to transmission additions, generation additions or retirements, load levels, or fuel cost could create for expected WECC-wide generator dispatch, powerflows, and production cost. These results help to identify areas where planned generation additions or retirements may create transmission congestion or other issues in the Western system and are useful for showing the interaction of various planned changes across individual utilities' systems. Although recent studies performed by TEPPC have utilized the PROMOD PCM software program,

[12] For more information on GridView, see: http://www.abb.com/industries/db0003db004333/c12573e7003305cbc12570060069fe77.aspx.

[13] For more information on TEPPC see: http://www.wecc.biz/committees/BOD/TEPPC/Pages/TEPPC_Home.aspx.

ABB staff has regularly converted the TEPPC study-year scenario databases into the GridView input format.

In addition to planning cases, during 2012, TEPPC created a 2010 "backcast" dataset for PCM studies.[14] The TEPPC backcast was developed to help benchmark and compare PCM results against actual historical generation, to help validate and improve forward-focused TEPPC modeling approaches, produce more realistic simulations, and compare planning horizon dispatch results to historical simulation output. These benchmarking efforts help to identify limitations in the original data. TEPPC staff also devoted time to refine 2010 data, such as adjusting the simulation's planned generation outage schedules to match the dates of actual outage during 2010, and "tuning the model" output by adjusting per-unit transmission costs between BAAs to produce generation dispatch that more closely matched historical levels.

For this analysis, E3 made further refinements to the June 2012 release of the TEPPC 2010 Base Case model to further improve the accuracy of operational details described by NTTG members within the NTTG footprint and to calibrate the dispatch from the 2010 Base Case. Overall, E3 developed 25 iterations in implementing modifications to the TEPPC 2010 Base Case in the effort to improve accuracy compared to historical output.

Description of TEPPC Database for 2010 Simulation Cases

The TEPPC 2010 database characterizes the loads, generation, and resources for PCM modeling. The database includes over 16,000 nodes representing individual transmission buses, over 20,000 branches representing lines and transformers connecting different buses, and over 2,700 generation units.

[14] See: http://www.wecc.biz/Planning/TransmissionExpansion/RTEP/2010120601/Lists/Presentations/1/120601_2010Dataset_Meeting.pdf.

The database uses actual 2010 hourly BAA loads provided by the BAAs to WECC, and distributes these loads to buses based on the WECC 2010 HSB3 powerflow case.[15] The transmission topology of buses and branches is also based on the topology in WECC's 2010 HSB3 powerflow case. WECC compared this database to the WECC 2010 Path Rating Catalog to confirm correct historical limits on transfer capability over rated WECC transmission paths.

WECC staff identified resources from previous TEPPC database generator lists (based on comparison of the TEPPC 2022 planning case and other databases from prior study years) that were operational during the 2010 calendar year based on TEPPC data on unit addition and retirement dates. TEPPC also compiled hydro generation data from the 2010 to characterize the appropriate level of monthly hydro availability and energy, as well as historical hourly energy output for certain hydro plants and for units, such as wind, that are generally not dispatchable.[16]

For thermal generators in the TEPPC 2010 database, operating characteristics developed for the TEPPC 2022 and other planning cases were used, which includes generator minimum and maximum output levels, startup cost, variable O&M, and step-function curves to characterize marginal heat rates for different operating level segments of a given generator. TEPPC also identified 2010 monthly average natural gas and coal prices, aggregated within the footprint of each BAA, based on historical plant report data compiled by the U.S. Department of Energy's Energy Information Agency ("EIA") in EIA-923 forms. The Henry Hub spot price of natural gas averaged $4.50/MMBtu in 2010, although the prices for delivered gas in the Western Interconnection vary from the Henry Hub price by specific location.

Regarding reserves, the TEPPC 2010 database specified that the simulation commit sufficient generation capacity in each hour to serve load plus 4% (for reserves) within each

[15] The PCM work group noted the likely inconsistency created in this approach, in that it uses distribution factors for a summer load condition to apparently distribute actual load to buses in the other three seasons.

[16] A unit may be considered not dispatchable, for example, if (i) it has low, or even negative, variable production costs or (ii) its electrical production is tied to another process or requirement that necessitates a specific generation level, irrespective of electric load or its variable production cost relative to other units.

of eight WECC sub-regions (Northwest, Northern California, Southern California, British Columbia, Alberta, Basin, Rocky Mountain, and Southwest). This 4% addition for reserves approximates a regulation reserve requirement equal to 1% of load plus the spinning portion of contingency reserves equal to 3% of load.

TEPPC Granularity of BAA Boundaries & Resource Ownership

The TEPPC database and resulting PCM simulations group the transmission topology into 39 areas, which map closely to BAA boundaries, but with disaggregation of certain BAAs. For example, the Idaho Power and PacifiCorp East BAAs are each represented as three separate areas (i.e., six areas in total, rather than two). For simplicity, however, these areas as defined in the TEPPC database are referred to in this section and below as BAAs.

The TEPPC database assigns each bus in the transmission network to one and only one BAA. Generation units are then assigned to BAAs based on their electrical locations on the system. This mapping of units is approximate, in that it does not account for entitlements (either through ownership or by contract) by multiple MPs in major transmission facilities or generating units. The lack of information may be particularly significant when the primary load of, or the sink utilized by, a market participant is in multiple BAAs or in a BAA different from the generating unit ("remotely-owned generation").

Additionally, the TEPPC database uses a single shape for all loads within a given BAA. PCM analysis based on this common load shape will not account for the fact that one utility within a BAA may, for instance, have a "flatter" hourly load (i.e., less variation in hourly load) than another utility within the same BAA due to a larger share of industrial customers or due to different prevailing weather patterns due to a more coastal service territory.

No Representation of Transmission or Generation Contracts during Dispatch

The PCM model and TEPPC database is based on a physical representation of the transmission system. The model does not consider, and data are not incorporated to allocate, transmission capacity among multiple MPs based on ownership or contract rights. Similarly, the model developed by E3 does not consider power contracts between different entities that may take the form of options or fixed contract prices over a given time period. Instead, it simulates a centrally optimized dispatch of the system based on the estimated variable cost of each generating unit, subject to operational limits on the generators and transmission system.

E3 Enhancements to TEPPC 2010 Database

A PCM simulation of a historical time period may not reflect actual "business as usual" for a number of reasons. For example, the simulation does not incorporate long-term firm transmission rights or remotely owned generators, so modeling a centralized dispatch may behave differently than the results of independent decisions of a collection of MPs in a bilateral market structure with reservation-based transmission scheduling.

To create a 2010 Base Case for the NTTG Analysis, E3 made a number of changes to WECC's 2010 database for two reasons: (1) to enable the PCM to account for aspects of actual market operations that NTTG members identified as important to address in the analysis, and (2) to calibrate the model to more accurately reflect historical dispatch.

Model Enhancements

E3 made the following adjustments to the TEPPC 2010 case to reflect important details in fundamental aspects of utility operations for NTTG members operate:

- Implemented hurdle rates on a BAA-level boundary rather than at a TEPPC regional level.
- Created tiers in hurdle rates so that flows up to levels of certain remotely-owned generation could flow to the BAA in which the owners resided without imposing a hurdle rate
- Enforced reserve requirements at the BAA-level rather than TEPPC region level
- Implemented split-reserve sharing by generators that are co-owned by entities in different BAAs
- Limited reserves that could come from unloaded hydro generation to 12% of annual max capacity of the unit

Hurdle Rates: BAA-Level Implementation

Hurdle rates can be made to reflect real-life impediments to trade, including point-to-point transmission rates across BAA interfaces, average losses, inefficiencies due to illiquid markets, and the need to use owned or contracted resources to serve native load.

At a minimum, hurdle rates can be set to match local transmission rates between BAAs. As noted above, the TEPPC 2010 case began by implementing hurdle rates between the eight TEPPC regions; for the NTTG 2010 Base Case, however, E3 modified the database to apply hurdle rates between BAAs, as this is more likely the boundary at which transmission rates would be charged to MPs scheduling power from a source generating unit in one BAA to sink in another BAA.

Hurdle rates: Tiered Rates for Remote Resource Ownership

Due to contractual arrangements, there are a number of interregional transactions that occur in the real world that would not be subject to the incremental transmission costs (other than losses) due to dispatch of a remote generating unit. Many utilities that own or contract with generators in remote locations either own transmission or hold firm rights to deliver generation from the remote resources to load. In such cases, applying the hurdle rate to generation from the remotely-owned generators would impose a penalty on that unit that would not be considered in its real-world dispatch decision (and, accordingly, should not impact the dispatch simulated by the PCM).

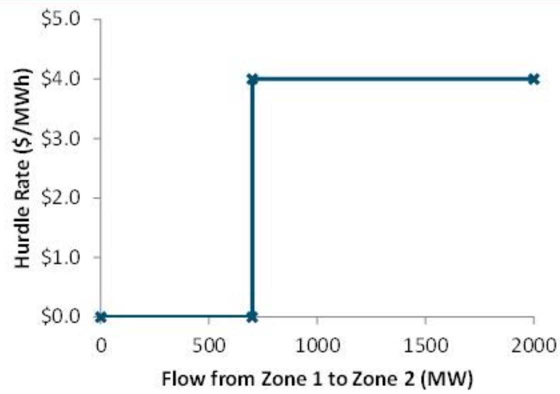
To account for the fact that dispatch decisions for certain remotely-owned resources should not be affected by a hurdle rate penalty, E3 and ABB implemented a "Tiered Hurdle Rate" methodology: For transmission flows up to the capacity owned by/contracted to the utility, no hurdle rate is imposed on flow between the BAA in which the generator is located in the model and the BAA that contains the owning/contracting utility's load. A full hurdle rate is imposed on all flow in excess of the capacity owned by/contracted to the utility.

The figure below provides an illustrative example of how Tiered Hurdle Rate function in the PCM case created for NTTG.

FIGURE 1: EXAMPLE OF TIERED HURDLE RATE METHODOLOGY

Illustrative Example:

- $4 hurdle rate from Zone 1 to Zone 2
- 2,000 MW transfer limit from Zone 1 to Zone 2
- 700 MW generator located in Zone 1 fully owned by utility located in Zone 2
- All flow up to 700 MW incurs no hurdle rate
- All flow above 700 MW incurs full hurdle rate



Tiered Hurdle Rates were implemented primarily on paths based on data provided by NTTG members on remotely owned resources with long-term transmission rights. In particular, tiered hurdle rates were used on paths between the NorthWestern Energy (also "NWE") BAA, in which the Colstrip coal plant is located in the model, and the BAAs of the utilities in the Northwest, such as Portland General and Puget Sound Energy, which own portions of the plant. Additionally, the model incorporated information provided by PacifiCorp that indicated PacifiCorp had long-term transmission rights to allow it to send power from the Jim Bridger coal plant in PacifiCorp East BAA to the PacifiCorp West BAA to serve loads in Oregon and Washington without needing to pay for additional transmission on an incremental basis. While an improvement, the Tiered Hurdle Rate methodology still does not account for many of the factors considered in the dispatch decision of remotely-owned generation.

Generation Reserve Enhancements: BAA level & remote ownership

The TEPPC model enforced reserve requirements for regulation and spinning reserves at the level of the eight TEPPC regions. NTTG members, however, indicated that even when participating in reserve pools (to share contingency reserves when needed), individual BAAs must have available reserves based on their individual responsibilities, and regulation in particular must be procured within the local BAA. Therefore, E3 updated the

TEPPC 2010 case to enforce reserve requirements on a BAA basis rather than a TEPPC region basis.

In some cases, NTTG members also indicated that they carry reserves on particular remote resources that they own or contract long-term but are located in a different BAA. For these resources, E3 used generator ownership data to attribute remotely owned generation toward reserve requirement of the owner's BAA. Additionally, certain generating units used for reserves have multiple owners. ABB created new coding in GridView to assign reserves for a portion of individual generation units to multiple utilities based on ownership shares.

Finally, recent TEPPC workgroup discussions indicated that unloaded hydro capacity is often not able to be counted 100% toward utilities' reserve needs, as monthly energy budgets, as well as other hydrologic constraints, would limit a hydro plant from ramping up to 100% in any given hour. Exact portions of the ability of hydro to contribute to reserves vary by plant. As a proxy for these limitations, however, E3 set a cap on hydro reserves equal to the lesser of (i) its unscheduled maximum annual capability or (ii) 12% of its maximum annual capability, based on information from the Northwest Power Pool. Thus, if a hydro unit has energy output in an hour of 50%, it is assumed to be able to ramp up to 62% output, and thus can contribute 12% reserves. If a plant, however, is already operating at 90%, then the plant's physical headroom in that hour, equal to 10% of capacity, would be the limiting factor on reserve provision.

MODEL CALIBRATION

In addition to the model enhancements described above, E3 also compared the resulting dispatch of the TEPPC 2010 case to historical production by generation technology on a state-by-state basis by comparing simulation results to the EIA production data reported on Form EIA-861. Based on these comparisons, E3 made a number of changes during an iterative process of modifying the database, running a simulation, and comparing results. This calibration of the Base Case was an important step. The attribution of benefits of a transmission project is based on a comparison of the Base Case to a Change Case (with a transmission line added) so it is important for initial conditions of the system in the simulation without the transmission line to be as accurate as is feasible to produce the most accurate reflection of how adding transmission would alter that dispatch. The four major changes for calibrating the model are listed below.

- Updated gas prices WECC-wide, and certain coal prices
- Fixed hourly shape for hourly flows between British Columbia ("BC") and the Northwest based on historically reported Path 3 flows
- Corrected the maximum rating of Intermountain Power Project ("IPP") DC line to 1920 MW to reflect the pre-2011 path rating
- Adjusted hurdle rates to equal 50% of OATT firm transmission rates plus cost of real power losses[17]

Fuel prices

Fuel prices for each generating unit are a major factor that affect the relative cost of dispatching different generators and are important to set as accurately as possible when creating a base case. Data on actual fuel prices for generating units were confidential and not available for this analysis. To the greatest extent possible, E3 attempted to improve the historical accuracy of fuel prices data used in the database using publicly-available information.

A natural gas-fired generator incurs two major costs when purchasing fuel, the sum of which is the "burnertip" gas price: (1) a commodity cost based on the cost of purchasing natural gas at point of purchase (usually a liquid trading hub); and (2) a transport cost to physically transport the gas from the point of purchase to the point of use.

For commodity pricing, E3 used transaction data from ICE OTC settlements at fifteen natural gas trading hubs around the WECC. For transport costs, E3 used the same incremental costs as TEPPC has used in its 2010 backcast for all areas outside of California. For California, E3 used tariff-based delivery charges from Pacific Gas &

[17] For power that passes through two BAAs, hurdle rates are pancaked. For example, energy exported from a generator located in PacifiCorp East ("PACE"), over transmission controlled by Los Angeles Department of Water and Power ("LADWP"), and on to loads in the Sierra Pacific Power BAA, the energy incurs two hurdle rates: (1) one for wheeling out of PACE (equal to 50% of the PACE OATT rate plus losses) , and (2) a second hurdle rate for wheeling through the LADWP transmission system to reach Sierra Pacific (with the hurdle rate equal to 50% of the LADWP OATT rate plus losses).

Electric ("PG&E") and Southern California Gas based on data provided by the utilities in California's 2010 Long-Term Procurement Planning proceeding.

In an effort to improve accuracy of historical simulation, E3 tested PCM runs using both daily and monthly average spot prices for natural gas. A review of aggregated results suggest that choice between daily and monthly fuel prices has a limited impact on results, so E3 used daily spot prices in NTTG production cost modeling case as the simulation is run on an hourly basis for each day of the year in 2010. The figure below shows an example of the comparison of daily natural gas prices versus monthly average natural gas prices for the PG&E Citygate location.

FIGURE 2: COMPARISON OF MONTHLY VS. DAILY GAS HUB PRICES FOR PG&E CITY GATE ($/MMBTU)

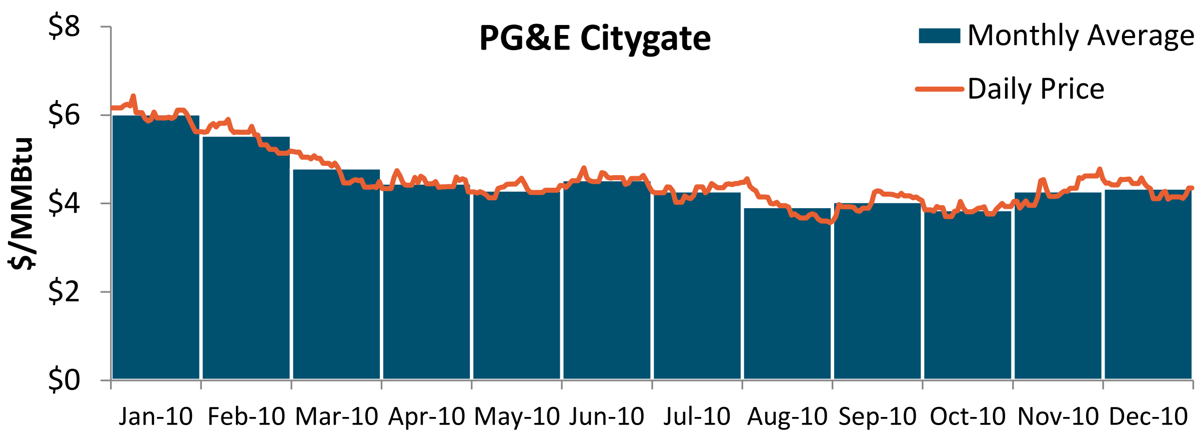
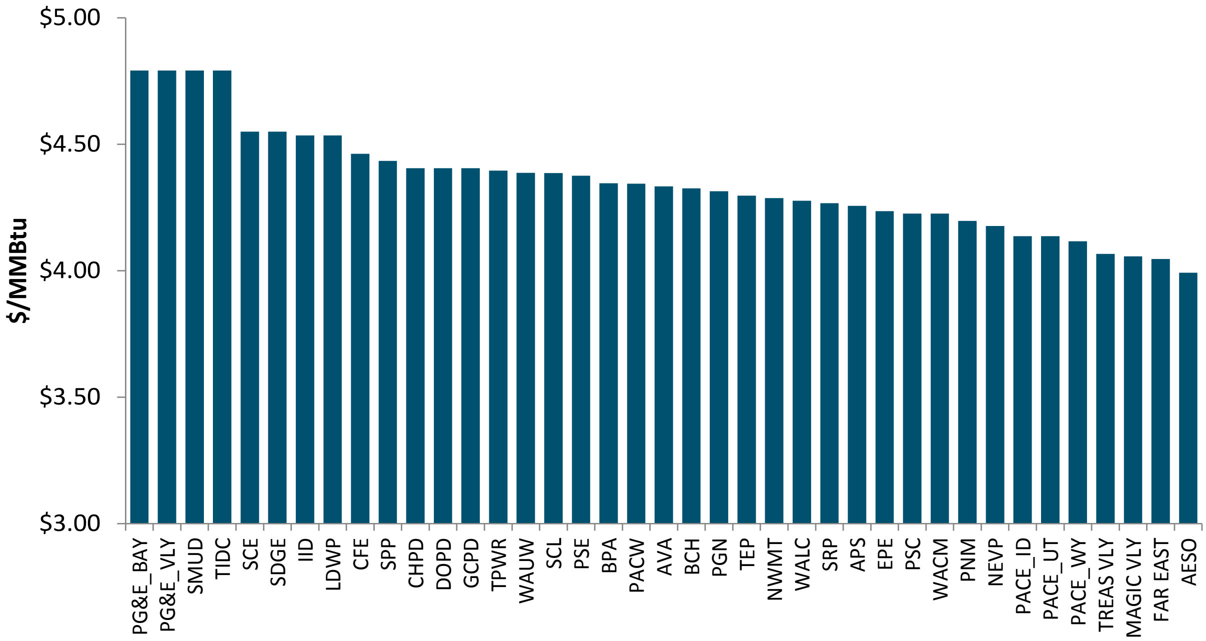


Figure 3 below shows the resulting annual average gas prices used for each of the BAAs simulated in the model, after adjusting for basis spreads and estimated delivery charges to generators locations.

FIGURE 3: ANNUAL AVERAGE GAS PRICES BY BAA USED IN THE 2010 BACKCAST ($/MMBTU)



In addition, coal dispatch for plants in the Public Service of Colorado ("PSCO") and the Wyoming portion of the PacifiCorp was low, and those zone's coal prices in the model were significantly higher than certain public indications of coal prices (such as for Rawhide Generation Station in Colorado) and relative to coal prices for generators in the WAPA Colorado-Missouri ("WACM") BAA. Based on these comparisons, E3 reduced the coal prices in PSCO and PACE-WY BAAs to match the WACM coal prices in the model. This resulted in coal generation simulated for these areas more accurately matching historical dispatch levels for 2010.

Fixed Hourly Flows for BC

Comparison of historical data to early simulation results indicated that imports into the Northwest from BC in the simulation was inaccurate, potentially due to the simulation's availability of hydro energy in BC. Data to improve accuracy of hydro in BC were not available. Since BC is outside of the NTTG footprint and, therefore, would likely not substantially affect the Change Case versus Base Case results, E3 chose to correct the problem by directly inputting into the simulation hourly flows on transmission between the Northwest and BC using publicly available data for 2010. As a result, the model does not explicitly model individual generators in BC or Alberta, but the 2010 Base Case reflects actual flows from BC into the US portion of the WECC. As indicated previously, hurdle rate penalties are a blunt modeling tool to introduce market friction into the model. It sometimes is associated with transmission wheeling costs and other effects. One fundamental element missing from these PCM tools when attempting to model operation is the lack of transmission rights representation, either for remote generation, contracted capacity or economic dispatch for Network Loads. These factors tend to reduce the appropriate hurdle rate adjustment to something less than the OATT firm rate, but the extent of their influence varies from transmission path to transmission path. Application of a single discount factor (e.g., 50%) assumes, however, that their proportion influence is uniform across all transmission paths.

Corrected rating of IPP DC line

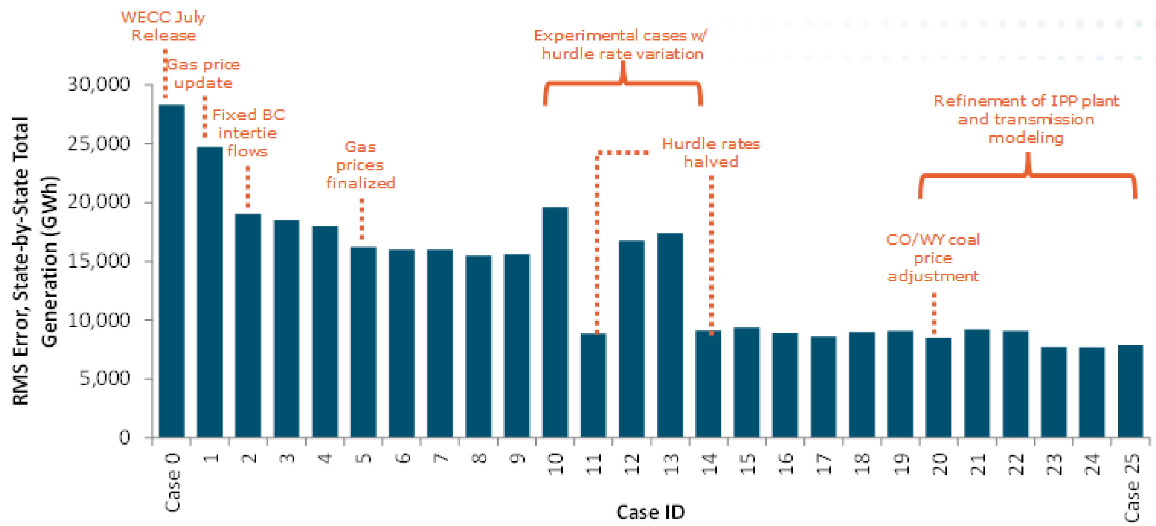
Simulation results indicated higher transmission flows than actual 2010 levels on the IPP DC line from Utah to Southern California. After researching older path rating data from WECC, E3 identified that the IPP DC line maximum rating in the TEPPC model was set based on upgrades implemented after 2011. E3 corrected this path rating to 1920 MW, which was the maximum level during 2010 prior to the upgrade. This update improved the historical accuracy of generator dispatch and powerflows for subsequent simulation cases.

Calibrated hurdle rates based on regional flows

The final mechanism that E3 used to improve the accuracy of the WECC 2010 case was an adjustment of hurdle rates. E3 started by that hurdle rates equal to the OATT rate for firm capacity plus the imputed cost of real power losses based on the average energy price of the nearest trading hub. This “100%” hurdle rate level, however, generally resulted in lower simulated flows across major paths than historical 2010 data suggest had occurred. After all other major sources for simulation improvement had been explored, E3 reduced the hurdle rates to 50% of the OATT firm rate plus losses and found a considerable improvement in simulation accuracy.

In all, E3’s calibration process comprised 25 Gridview cases, reflecting the piecewise implementation of many of the changes above. The figure below shows the evolution of the NTTG 2010 base case with notes for individual model enhancements and calibration inmprovemetns, as well as data refinements and updates that resulted in persistent improvements in aggregate modeling accuracy over the course of the benchmarking process. The figure shows the sequential effect of these changes on the root mean squared error ("RMSE") of state-by-state generation totals for the states in the Western Interconnection. Through the 25 interations to improve the Base Case, this RMSE value was reduced by over 60%, but subsequent iterations began to have a diminishing effect on improving model accuracy.

FIGURE 4: BACKCAST CASE ITERATION RUNS AND PROGRESSIVE IMPROVEMENTS IN ROOT MEAN SQUARED (RMS) ERROR OF STATE-BY-STATE TOTAL GENERATION LEVELS



RMS Error is calculated as the square root of the sum of the squares of the deviations of simulated total generation in each state from actual total in that state

Summary of PCM Base Case Creation

E3 sought to implement highest-value changes to PCM case to help simulation match historical data as well as possible. Overall, these did improve the dispatch historical accuracy in the aggregate for the WECC. Certain issues, however, were not feasible to address fully in this process due to project budget and timing limitations. A section in this report describes issues that may be useful to consider in future PCM efforts by NTTG.

PCM Change Case: MSTI & B2H

To demonstrate the process for using PCM data to characterize the economic impact of a representative transmission line, E3 obtained transmission capacity and location characteristics for two potential projects previously considered: the Mountain States Transmission Intertie line ("MSTI") and the Boardman to Hemingway line ("B2H"). MSTI was represented as a 500-kV transmission line between the Townsend and Midpoint substations (with interim nodes at Dubois substation). Based on the recommended configuration from NTTG members, the MSTI path was limited to a maximum 1500 MW north-to-south transfer capability and 1100 MW south-to-north transfer capability. The B2H line adds a 500-kV transmission line between the Boardman Substation in Oregon, and the Hemingway substation near Melba, Idaho. Analysis of these Change Cases were not intended to evaluate the net benefits or effectiveness of these potential transmission projects; rather this analysis used those facilities exclusively as examples to demonstrate how a PCM model could be used to identify the economic impact of a transmission line on different MPs. The facilities were selected based on their locations spanning multiple states within the NTTG footprint.

PCM Alternative Scenarios

As part of the project's Phase 2 work, NTTG members requested that E3 demonstrate the PCM tool and show the resulting output under 6 sensitivity scenarios. For each scenario, E3 modeled 3 cases for the 2010 study year: (1) "Base Case" (2) "MSTI Case", and (3) "B2H Case". The table below lists the PCM model runs to create these scenarios.

TABLE 1: SENSITIVITY SCENARIOS AND PCM CASE RUNS

Sensitivity Scenarios	Base Case	MSTI Case	B2H Case
2010 Conditions	√	√	√
High gas price sensitivity	√	√	√
Low gas price sensitivity	√	√	√
Local generation sensitivity	√	√	√
Remote generation sensitivity	√	√	√
Low hydro sensitivity	√	√	√

The high gas price sensitivity adjusted all gas prices upward to a $10/MMBtu average annual index price for Henry Hub from the $4.50/MMBtu Henry Hub price level in the scenario modeling 2010 conditions. The low gas price reduces gas prices to $2/MMBtu. Locational natural gas prices are scaled proportionally to the change in Henry Hub prices. The two most important potential impacts of varying natural gas prices in the model are (1) shifts between gas vs. coal dispatch, resulting in changes in transmission power flow patterns due to the locations of areas with high coal and gas plant capacities, and (2) increases or reductions in the economic impact of a given reduction in transmission congestion, as more efficient dispatch of a region's gas generation portfolio will be more or less valuable per MMBtu depending on gas prices.

The local generation sensitivity adds a 600 MW combined cycle combustion gas turbine ("CCGT") plant near the western terminus of the potential transmission line. For the MSTI demonstration cases, under the local generation sensitivity, a CCGT was added at Midpoint under both the Base Case (without the MSTI line) and the Change case (with the MSTI line). For the B2H demonstration cases, under the local generation sensitivity a CCGT was added at Boardman substation. The remote generation sensitivity adds a similar unit near the eastern point of the line (at Townsend for the MSTI case and at Midpoint for the B2H Case). This pair of sensitivity cases is included to illustrate how the resulting dispatch and costs to MPs would change with a single hypothetical change in generation addition, but is not indicative of the location for actual projected proposals for generation.

The low hydro sensitivity case uses an alternative hydro dataset developed by WECC based on historical hydro conditions from 2001, which was a lower water year with below average spring precipitation in the West. This scenario results in less monthly energy and more constrained operating ranges for some hydropower plants in the PCM simulation.

Confidential Data Issues

Implementation of this methodology required obtaining significant data from NTTG members. These data requirements include generator cost information (including fuel cost and plant efficiencies) for accurately simulating the dispatch, as well as contract data to characterize the hourly net position of a given MP.

Certain confidential cost information, including fuel cost for generators, was unavailable for the simulation of this 2010 Base Case.[18] In these cases, estimated cost information based on the TEPPC characterization of generator heat rates and BAA-average fuel prices was utilized. To the extent that actual cost information for generators within a given BAA, however, differ from the generic values used and could change the ordering of cost between different units, these differences could cause the PCM results to show higher or lower amounts of generation on certain units than historically occurred or than would be expected over a forecast period. While the regional or state-level average generation may be accurate, shifts among individual generating units will affect the MP benefits calculated for the ownership of those units, especially in cases where only a few generators make a large portion of a certain MP's overall resource portfolio.

[18] Even if data from NTTG members had been available, their use – in conjunction with generic data for units outside the NTTG footprint – would likely have still resulted in distortion and inaccuracy of the PCM results.

DESCRIPTION OF THE SPREADSHEET POST-PROCESSOR

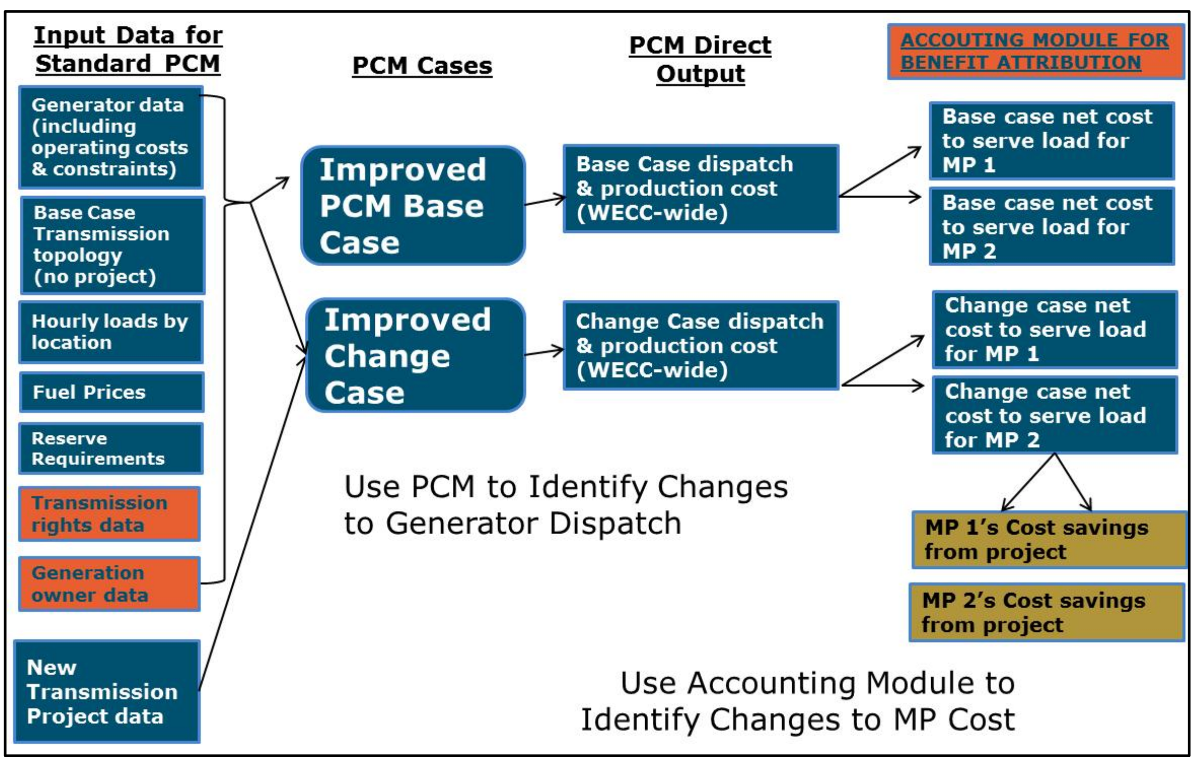
The other element of E3's analysis was the creation of a spreadsheet post-processing tool to estimate the impact that the PCM results would have on net procurement costs at the NTTG MP level.

Overview and motivation for Post-processor

WECC-wide raw output for "societal savings" cannot directly identify the project benefits for individual TSPs, independent power producers, or LSEs. Additional accounting outside of PCM simulation is required to estimate the net cost to serve load and contractual obligations. This accounting must reflect net positions after considering long-term generation entitlements and short-term market purchases.

The figure below shows the relationship of the PCM Base Case and Change Case to the spreadsheet post-processor model used to estimate economic impact for individual MPs.

FIGURE 5: OVERVIEW OF PCM AND NET BENEFITS MODEL



The resulting dispatch and unit specific production cost from the PCM Base Case is used to estimate each MP's procurement cost or "net procurement cost", which is the total variable cost of serving load and contracted power sales, net of any additional revenue (or expense) from market sales (or purchases). A similar calculation is performed on the output of the PCM Change Case with the new transmission project included in the simulation. At a high level, the calculation for each TSP or MP can be represented by the following formula:

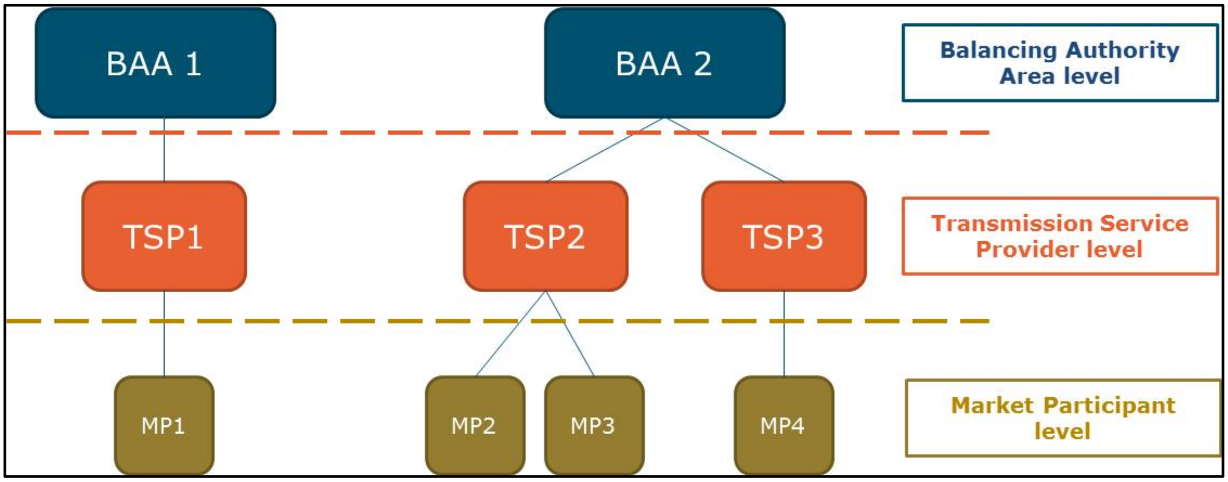
MP Variable Benefits ($) = Portfolio Cost without Line ($) – Portfolio Cost with Line ($)

The difference in the portfolio cost for each MP under the two cases represents the economic impact of variable revenues and expenses, or "MP Variable Benefit," of the transmission project on that MP.

Level of Aggregation for Loads and Resources

This calculation of MP Benefits can be performed at the MP level, where each independent power producer and load serving entity represents a single MP, and then the resulting MP benefits summed for all MPs served by a single TSP, as shown in the figure below for MP2 and MP3 which are served by TSP2. Alternatively, all the loads and owned and contracted resources for MPs served by a given TSP can be aggregated together to create a TSP-wide portfolio cost under each scenario, and then TSP benefits can be computed directly. These two calculation options may produce equivalent results in certain circumstances but will differ if a negative benefit (or net increase in cost) for a MP is set to zero for cost allocation purposes prior to aggregating the positive benefits of other MPs (if any) served by the same TSP.

FIGURE 6: 3 POTENTIAL LEVELS OF AGGREGATION FOR EVALUATING NET BENEFITS



The selection of the total number of MPs within NTTG evaluated for this demonstration analysis was guided based on the ability to obtain MP-specific information, as well as NTTG workgroup member discussion regarding the MPs most important to disaggregate for the demonstration. The table below lists the MPs identified within each NTTG TSP.

For MPs that did not provide data, information for this demonstration was aggregated into an "Other loads" and "Other generators" category for each BAA. The loads and resources for these categories were calculated as the net remaining unidentified loads and generators within each BAA. For example, PacifiCorp total load and generation was reported in the 2010 TEPPC data, and PacifiCorp load share and generation ownership shares that were attributable to the PacifiCorp load serving entity ("LSE") were provided by PacifiCorp staff. To calculate the "Other Loads (PACE)", the directly-reported PacifiCorp LSE hourly load data and the directly-reported Deseret Power's hourly load data were subtracted from TEPPC's 2010 hourly total loads for the PacifiCorp East (PACE) BAA. This "Other Loads (PACE)" includes Utah Associated Municipal Power Systems, Utah Municipal Power Agency, and other entities serving loads that are not retail customers of PacifiCorp or Deseret. Similarly, "Other Generators (PACE)" includes all generators located within the PACE BAA excluding generators that were already assigned to a particular MP (e.g., PacifiCorp LSE) based on NTTG member data on owned and contracted resources. Future analysis could attempt to obtain additional data to implement the post-processor to evaluate a larger number of more disaggregated MPs (but may face data confidentiality challenges if seeking to report disaggregated data for some entities).

TABLE 2: NTTG TRANSMISSION SERVICE PROVIDERS AND MARKET PARTICIPANTS REPRESENTED IN POST PROCESSOR

Transmission Service Provider (TSP)	Market Participants (MPs) evaluated in demonstration tool
Deseret	Deseret LSE
PacifiCorp	PacifiCorp LSE (PACE)
	Other Loads (PACE)
	Other Generators (PACE)
	PacifiCorp LSE (PACW)
	Other Loads (PACW)
	Other Generators (PACW)
Idaho Power Co	Idaho Power LSE
	BPA LSE (IPC)
NorthWestern Energy	NorthWestern Energy LSE
	Other Loads (NWE)
	Other Generators (NWE)
Portland General Electric	Portland General LSE
	Other Generators (PGN)

Method of Calculating Net Procurement cost for each MP or TSP

The net procurement cost for each MP for a case is equal to the variable production cost of owned or contracted generation plus the net cost of long-term contracts (which may be purchases or sales) plus (or minus) the cost of market purchases (or sales) as required to balance energy from the PCM dispatch with load and net long-term contracts.

Net procurement cost is evaluated in the post-processor on an hourly basis using the results of each PCM case, based on the following steps:

8) Determine the MP's load service obligations as the sum of hourly load plus contracted sales input to the post-processor
9) Determine the MP's owned and contracted generation as (i) the energy dispatched by the PCM times (ii) the MP's entitlement share for each generating unit

10) Calculate the MP's net hourly energy position as load obligations (from step 1) minus generation (from step 2)
11) Financially settle the net hourly energy position based on estimated wholesale market hub prices:
    - o Purchase of net short
    - o Sale of net surplus
12) Determine the production cost of owned and contracted generation as (i) the cost of dispatched energy for each generating unit from the PCM times (ii) the MP's entitlement share for each generating unit
13) Calculate MP's total portfolio cost in each how as the sum of --
    - o Production cost of owned and contracted generation (from step 5), plus
    - o net purchases and sales from the wholesale market (from step 4)
14) Sum hourly net procurement cost for all 8,760 hours for the year to obtain MP's annual net procurement cost in the Base Case and Change Case
15) Calculate the MP's Benefit as the change in net procurement cost under the Change Case as compared to the Base Case

Step 1: Determine MP's load service obligations

A MP's load service obligation is determined as the sum of the MP's load plus any contracted sales to other entities. For the 2010 historical year, some NTTG members were able to provide MP hourly load data. Other members reported their loads as a fixed percentage share of the total load in their respective BAAs, from which hourly MP loads could be calculated. Load data are assumed to be unchanged between the Base Case and the Change Case when a transmission project is added. To evaluate procurement for a future year, NTTG members and other MPs would need to provide a forecast of hourly loads, or could report their projected share of their BAA's total load, based on the BAA load forecast used in the TEPPC database.

An MP's contracted sales can be fixed block quantities, contracts with specific hourly energy shapes, or options contracts which counterparties will be expected to exercise under specific conditions, such as when spot market prices for energy from alternative sources exceed the strike price of the options contract. Only one NTTG member reported options contract prices for these demonstration cases. Treatment of options contracts for determining total MP load service obligations in the post-process calculations is discussed at the end of this section.

Certain MPs could potentially have zero load services obligations. For example, an independent power producer with generation ownership but no long-term contracts to sell its output would have no load service obligations, in which case its hourly net position would be exactly equal to its generation output in any hour.

Step 2: Determine MP's owned and contracted generation

The PCM simulation produces hourly energy output of each unit in the WECC for each case. NTTG members provided a list of units in which they have full or partial ownership or long-term contracts for a share of plant output. For each unit owned or contracted by a particular MP, the post-process tool multiplies the energy output (in MWh) from the PCM for each hour by the MP's entitlement share to calculate the MP's owned and contracted energy for each hour. The resulting hourly energy output is then summed for all of the MP's owned and contracted resources for each hour based on this equation:

$$\textit{MP's Owned \& Contracted Energy (MWh)} = \sum \textit{PCM Total Plant Hourly Output}_i \textit{ (MWh)} \times \textit{Ownership Share}_i \textit{ (\%)}$$

where i = each generating unit in which the MP has an entitlement share

The figure below illustrates this calculation for a single day based on NorthWestern Energy's 30% ownership share in the Colstrip 4 unit.

FIGURE 7: ILLUSTRATION OF CALCULATING MP HOURLY OUTPUT FOR NORTHWESTERN EXAMPLE

Colstrip 4 total hourly plant output (representative day shown)

Northwestern's assumed ownership share of Colstrip 4

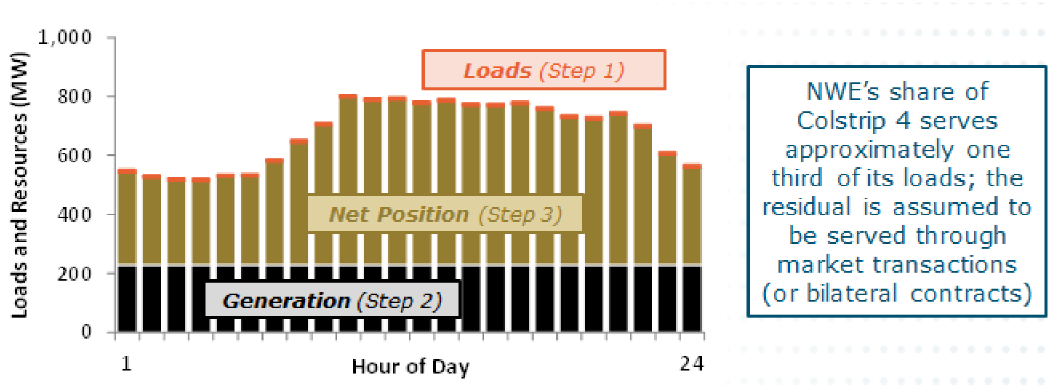
Northwestern share of Colstrip 4 hourly plant output (same representative day)

In addition to contracts linked to specific generation resources, the post-processor tool also allowed NTTG members to report generic contracts that provide the MPs with a specified quantity of energy in a given month or hour. These hourly contracted amounts are also added to the owned and contracted generation total. For options contracts, in which an NTTG MP receives the output of a generator under certain conditions, the post-processor seeks to use those conditions to calculate the hourly quantity contracted generation level. The treatment of options contracts is discussed in more detail later in this section.

Step 3: Calculate MP's hourly "net position" as load obligations minus generation

In each hour, the post-processor tool subtracts the MP's owned & contracted generation output (identified in Step 2) from the hourly load level (identified in Step 1) to obtain the MP's hourly "net position". The figure below illustrates this hourly net position (in this instance, a "short" position) for NorthWestern as the gold bars in the figure, which represent the difference between NorthWestern's hourly load level, shown as orange dashes, and the hourly owned and contracted generation output, shown as the height of the black bars.

FIGURE 8: ILLUSTRATION OF HOURLY NET POSITION FOR NORTHWESTERN (NWE)



Step 4: Settle net position based on estimated wholesale market hub prices

The post-processor tool assumes that each MP will balance its net position with short-term wholesale market purchases or sales. Thus, if the MP's load obligation in a certain hour exceeds its owned and contracted generation, the MP has a "short" net position and is assumed to buy energy from the wholesale market for that hour to serve the remainder of its load. If, instead, the MP's generation is greater than its load obligation in a given hour, the MP has a "long" net position, and the post-processor tool assumes that the MP will sell its excess energy in the wholesale market for that hour.

As a default, MPs are assumed to be able to settle wholesale transactions at a "local market" price. The calculation of this price is described in a later section. If the MP has transmission rights that allow it to access to a regional market hub of COB, Mid-C, or Mona, MPs also have the option to trade at that hub price for hourly quantities up to capacity of their transmission rights (if data regarding those rights are entered into the post-processor). For this demonstration, NTTG members provided sample data on their transmission rights on paths that connect their service territories to market hubs. MPs are assumed to settle net positions at the locations that yield the greatest economic benefit. Subject to transmission rights limitations, the MP will choose to transact at the location with the lowest market price if buying to fill a net short position, and to transact at the location with the highest price if selling a net long position.

Step 5: Determine the production cost of owned and contracted generation

The production cost of the MP's owned and contracted generation is calculated by multiplying the hourly production cost from the PCM simulation result in each hour by the

MP's ownership share of the plant. This calculation assumes that, like energy output, variable generation costs for each generator are shared among owners in proportion to their entitlement share. If the MP has any long-term contracts for market purchases (or sales), these costs are added (or sales) are added or deducted from the portfolio cost based on the contract price (which data are entered into the post-processor). While precise contract prices may be confidential, if the price is fixed and if the contract is must-take or must-sell, it will not change under the Base Case or Change Case and thus will not affect the resulting MP Benefits calculated in Step 7 below.

Step 5: Calculate MP's total portfolio cost

The total portfolio cost in each hour is the sum of two components: (a) the production cost of the MP's owned and contracted generation for that hour, plus (b) the market cost (or net revenue) to settle the hourly net position. The market cost or revenue can be taken directly from the Step 4 result.

Step 6: Sum hourly net procurement cost for all 8,760 hours of the year to obtain the annual net procurement cost for each case

This step simply adds up the net procurement cost for every hour for the simulation year to produce the annual net procurement cost for a specific case. A similar process is then applied with simulation results from a different case or for a Base Case and Change Case for an alternative scenario.

Step 7: Calculate the MP's Benefit as the change in net procurement cost under the Change Case compared to the Base Case

Calculating the difference between each MP's Benefit in these two cases provides an estimate of the impact on variable revenues (costs) that a transmission project would have for each MP. The figure below illustrates this perspective, by showing the cost of generation and market purchases for NorthWestern with and without the MSTI transmission line in place. For this demonstration, the MSTI line slightly increased the amount of generation dispatch by NorthWestern's share of the Colstrip plant, and reduced the size and cost of the net short position that NorthWestern fulfills with market purchases. In addition, the wholesale market prices that NorthWestern's purchases are linked to have increased slightly in this example, which increases the cost of all market prices, and creates a small net increase in NorthWestern's procurement cost under the Change Case.

TABLE 3: DEMONSTRATION EXAMPLE OF NET PROCUREMENT COST CALCULATION FOR NORTHWESTERN

Impacts on Colstrip's operations are limited

		Procurement (GWh)			Cost ($000)		
		Base Case	Change Case	Difference	Base Case	Change Case	Difference
Generation	Biomass	-	-	-	$ -	$ -	$ -
	Coal	1,823	1,837	14	26,853	27,044	190
	Gas	-	-	-	-	-	-
	Geothermal	-	-	-	-	-	-
	Hydro	-	-	-	-	-	-
	Nuclear	-	-	-	-	-	-
	Other	-	-	-	-	-	-
	Solar	-	-	-	-	-	-
	Wind	-	-	-	-	-	-
Market Purchases	MidC - LTF	16	24	8	214	301	87
	Mona - LTF	12	22	9	438	793	354
	Montana	4,391	4,359	(31)	127,358	130,423	3,065
	Total	**6,242**	**6,242**	-	**$ 154,864**	**$ 158,561**	**$ 3,697**

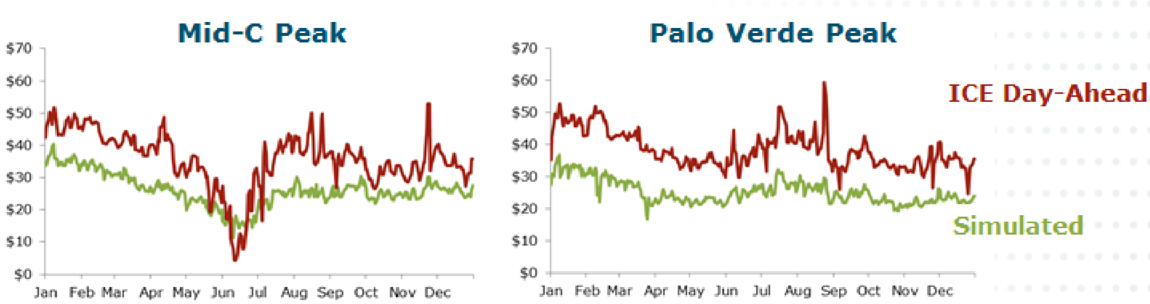
Most of NWE's net short position is settled locally in Montana; portfolio cost increase is driven by a rise in the market price of energy

(Note: This table was from the phase 1 post-processor demonstration; specific net benefits calculations were updated for phase 2 analysis)

Calculating Wholesale Market Prices

As noted for Step 4 above, the post processor uses an estimate of wholesale market prices to settle an MP's net long or net short position in any hour. The PCM results from Gridview produce hourly LMPs for each bus, but these results for the 2010 simulation case were found to typically be lower than historical market prices. The LMPs from the PCM model are based on marginal cost curves that consider step-function heat rate curves and variable O&M costs reported by TEPPC but do not include actual fuel price data or the effect of bidding behavior by generators to make up fixed costs. Additionally, there are likely other issues in actual practice that are not included in the PCM results, which cause the PCM to produce a flatter LMP series than is shown in historical data. Historical prices cannot be applied directly, however, because it is important to use a consistent methodology for estimating price series for the Base Case and Change Case to incorporate how an additional transmission project would impact those prices. Additionally, future analysis of a transmission line would need to consider benefits for a forecasted time period, when historical market prices are unavailable. The figure below highlights the difference between the unadjusted LMP values from the Gridview 2010 Base Case simulation against historical 2010 on-peak market prices from the InterContinental Exchange ("ICE") for the Mid-C and Palo Verde Trading hubs.

FIGURE 9: 2010 HISTORICAL PRICES VS. SIMULATED LMPS DIRECTLY FROM PCM ($/MWH)



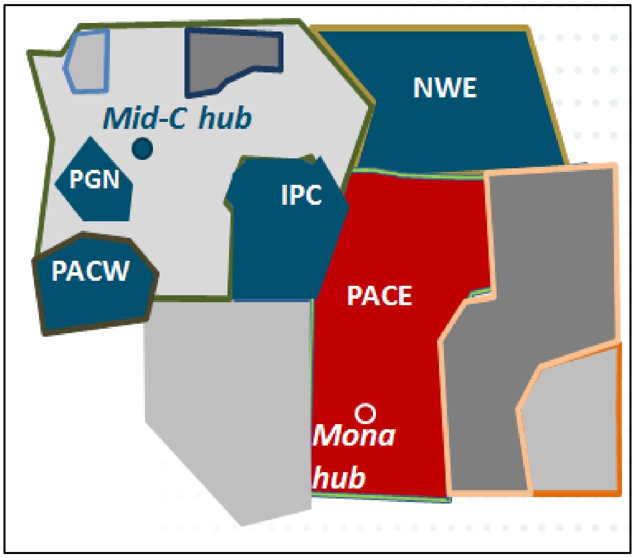
Additionally, for local transactions, or transactions for MPs when access to a market hub is not feasible or is not the most economically attractive option, the model also calculates a separate daily on-peak and off-peak "local market price" for each NTTG BAA. This serves as a proxy price for direct transaction between, for instance, a load customer in Montana and an independent generator in Montana when such options could avoid the need to wheel power from Mid-C.

Relationship of local wholesale prices and market trading hubs

To estimate the local wholesale market price, the model first associated each NTTG BAA to the nearest market hub of Mid-C or Mona. The chart below shows the association of BAAs to market hubs. The blue shaded BAs (Portland General, NorthWestern, Idaho

Power, and PacifiCorp West) are associated with the Mid-C hub, and PacifiCorp West is associated with the Mona trading hub.

FIGURE 10: ASSIGNMENT OF NTTG BAAS TO MID-C (BLUE) AND MONA (RED) TRADING HUBS



For each daily on-peak and off-peak period, the model calculated the locational "basis spread", or difference between the simulation's LMP value at the market hub bus compared to the load-weighted average LMP for the relevant BA. The local market price was then calculated as follows:

local market price = Regression-based hub price
+ Basis spread from simulation (LMP in local area minus LMP for hub)

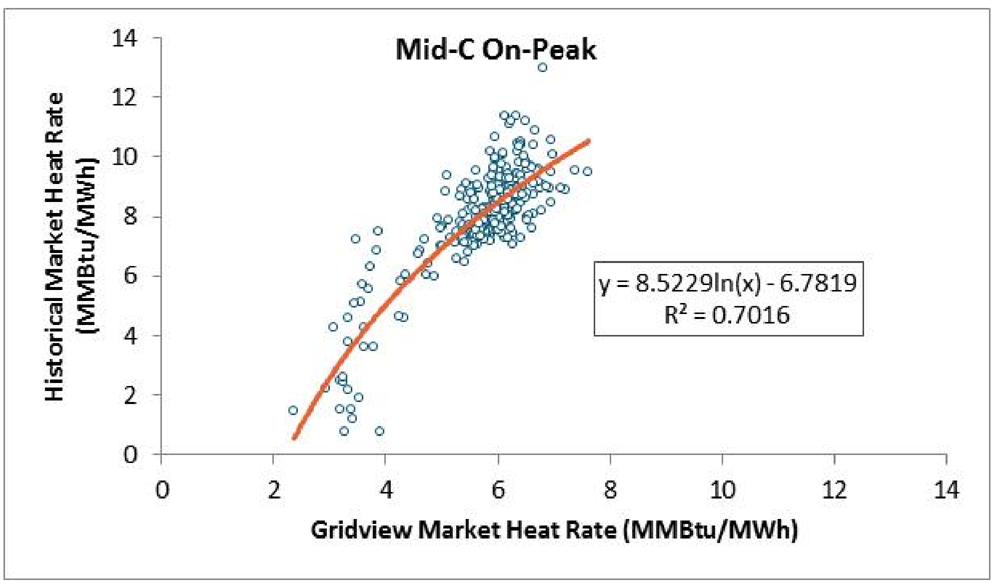
Regression analysis to estimate wholesale market prices

To adjust for the difference between average simulation LMPs and historical market prices, the post processor tool uses a separate process to estimate more historically accurate market prices when calculating net portfolio cost. For each power market (Mid-C, COB and Mona), E3 collected 2010 historical on-peak and off-peak daily firm power prices and natural gas prices from ICE. E3 then converted the hourly LMPs from GridView at the location of each of these three wholesale market hub to daily on-peak and off-peak prices to match the same time periods at the ICE data. The daily actual and simulated prices were then converted to daily market heat rates ("MHR") by first subtracting a generic variable O&M value and then dividing the result by the daily historical natural gas price (also from ICE). E3 then estimated a relationship between simulated and actual historical MHR with the following functional form:

*actual MHR = a * ln(simulated MHR) + b.*

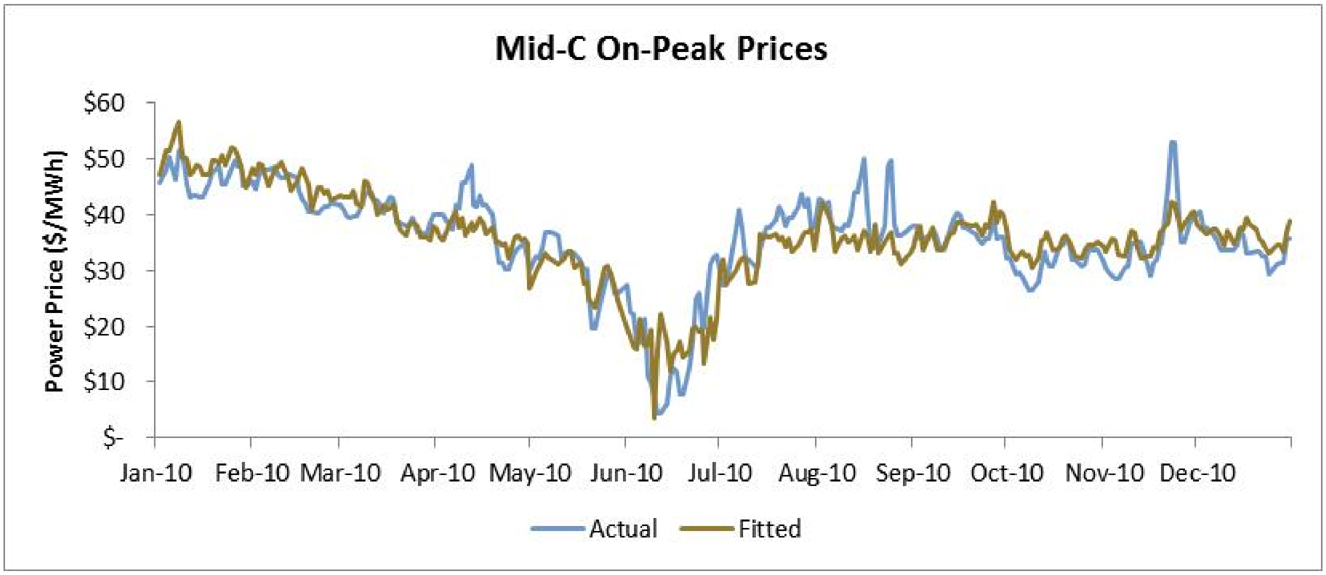
The figure below shows a scatter plot of simulated MHRs (x-axis) against actual MHRs (y-axis) for Mid-C on-peak in 2010. The regression equation and R-squared are also in the figure.

FIGURE 11: PLOT OF IMPLIED HEAT RATE FROM SIMULATION LMPS VS. IMPLIED HEAT RATE OF MID-C 2010 HISTORICAL PRICES



Finally, the analysis used these regression coefficients to estimate power prices. This regression results in a scaling factor that allows the model to calibrate a relationship between actual MHR and those produced by the simulation. The figure below shows an example of the results of the regression ("Fitted") against historical prices ("Actual") for Mid-C on-peak values. As discussed later in this report, an important remaining question is whether this relationship between simulated and actual MHRs would remain relatively consistent for different scenarios and different years, or with the addition of a new transmission project.

FIGURE 12: 2010 BACKCAST ADJUSTED PRICES VS. ACTUAL MID-C TRADING HUB PRICES ($/MWH)



Evaluating Options Contracts for Calculating Net Market Positions of MPs and Counter-parties

Options contracts, both for MP's purchases from generators and sales to third parties, present a specific challenge for calculating a net market position. The post processor tool attempted to work around this challenge by allowing a MP's contracted load obligations quantities and generator entitlements, to be set for each hour using conditional statements. For example, if a MP has sold an options contract to provide 100 MW in hours when a certain generator is online and Mid-C market prices are above $50/MWh, the post-processor added logic to evaluate the hourly results of the PCM (e.g., the Mid-C price and whether the generator was online in that hour), and set the contracted load obligation to 100 MW in hours when these conditions were met and to 0 MW in hours when one or both of these conditions was not met. This same logic was also applied to assign the output of a generator among its owners in a prioritized manner for example assigning hourly output to 200 MW to the first owner, and any additional generation above that dispatch level to the other owners. It is important to recognize that while this post-processor customization for characterizing options contracts can improve the accuracy in representing a MP's net position, the actual dispatch level of the plant will remain unchanged, as the same PCM simulation remains unmodified. Potential implications of this issue are discussed in the next section.

PRESENTATION OF THE RESULTS

Backcast Calibration for Base Case

The 25 step calibration of the WECC 2010 TEPPC case (Case 0) resulted in the final 2010 Base Case (Case 25). The benchmarking process, as described above, involved numerous case changes to Case 0 and tweaks to the PCM functionality. These combined changes resulted in a 2010 production simulation case that better tracked actual 2010 operations on a WECC-wide basis and, generally, a state-by-state basis. The calibration efforts resulted in the following:

- Improvement in simulated gas generation: Case 0 simulated 5% lower gas production compared to actual 2010 production; Case 25 corrected for the underproduction and increased gas generation to be within 0.1% of actual 2010 production on a WECC-wide basis.
- Improvement in simulated coal generation: Case 0 simulated 8.5% more coal production than actual 2010 operations; Case 25 reduced this over-generation by 6%, simulating coal production at just 2.5% higher than in 2010 operations on a WECC-wide basis.
- Improvement in flows on major paths WECC-wide: Case 0 was consistently high on flows on most major paths in the WECC; Case 25 tuned these flows to be lower and closer to actual 2010 flows.
- While the WECC-wide results were substantially better, Case 25 improved the results for most, but not all, statewide results.

Tables and charts that summarize the benchmarking efforts for the 2010 backcast case are included below:

TABLE 4: COMPARISON OF SIMULATED AND ACTUAL GAS DISPATCH BY STATE (GWH)

Annual Gas Generation by State (GWh)					
	Historical 2010 Generation (EIA Form 920)	Simulated Generation		Difference	
		Case 0	Case 25	Case 0	Case 25
Arizona	29,853	19,527	29,917	(10,326)	64
California	100,915	127,058	104,706	26,143	3,791
Colorado	10,288	9,487	10,748	(802)	459
Idaho	1,651	403	796	(1,248)	(855)
Montana	17	-	67	(17)	50
Nevada	23,650	8,353	22,230	(15,297)	(1,420)
New Mexico	4,099	2,614	4,017	(1,485)	(82)
Oregon	15,761	13,140	12,114	(2,620)	(3,646)
South Dakota	5	3	109	(2)	104
Texas	2,160	341	1,821	(1,819)	(339)
Utah	6,330	4,686	8,477	(1,645)	2,147
Washington	10,180	8,188	9,961	(1,992)	(219)
Wyoming	9	2	113	(6)	104
Total	**204,918**	**193,801**	**205,076**	**(11,117)**	**158**

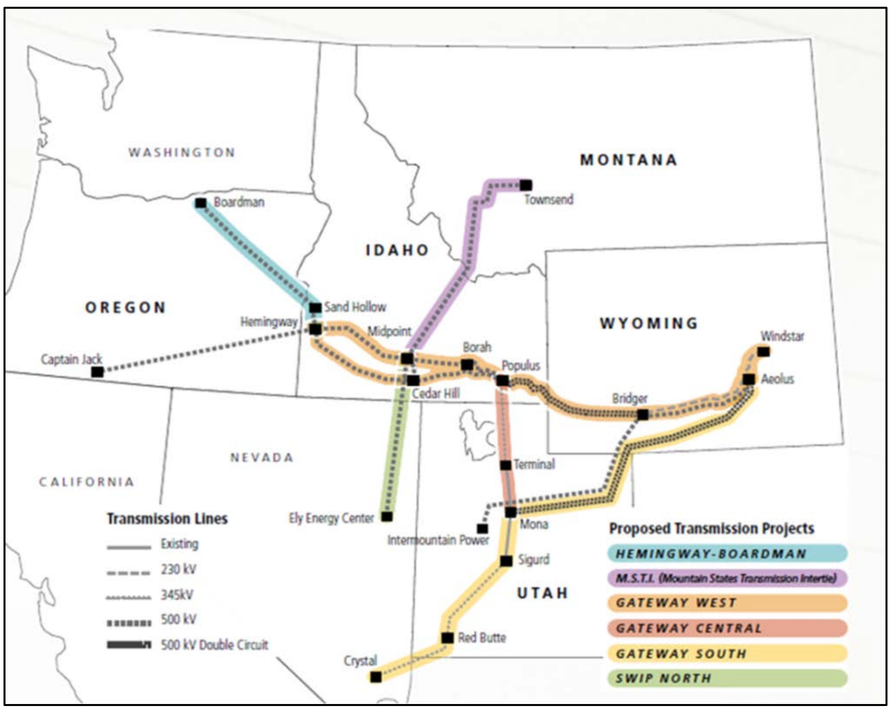
TABLE 5: COMPARISON OF SIMULATED AND ACTUAL COAL DISPATCH BY STATE (GWH)

Annual Coal Generation by State (GWh)					
	Historical 2010 Generation (EIA Form 920)	Simulated Generation		Difference	
		Case 0	Case 25	Case 0	Case 25
Arizona	43,117	46,142	45,319	3,025	2,202
California	2,063	1,950	1,935	(113)	(128)
Colorado	35,026	40,226	39,626	5,200	4,600
Idaho	0	-	-	(0)	(0)
Montana	18,305	19,343	18,769	1,038	464
Nevada	7,018	9,273	7,719	2,254	701
New Mexico	25,710	28,535	23,384	2,824	(2,326)
Oregon	4,130	3,631	3,678	(499)	(452)
South Dakota	133	134	242	0	109
Texas	-	-	-	-	-
Utah	34,267	37,607	34,834	3,340	567
Washington	9,013	10,181	10,008	1,168	995
Wyoming	38,594	38,854	37,443	260	(1,151)
Total	**217,377**	**235,875**	**222,959**	**18,498**	**5,581**

Transmission Projects Evaluated and 2010 Net Benefit Results

To test the use of production simulation for cost allocation purposes, two transmission projects were evaluated in the modeling: 1) the MSTI project which would connect southern Idaho to Montana; and 2) the B2H project which would connect western Idaho to northern Oregon. Both projects can be found in the map below of proposed major transmission projects in the NTTG footprint.

FIGURE 13: LOCATIONS OF PROPOSED TRANSMISSION PROJECTS



Source: http://boardmantohemingway.com/documents/Boardman2Hemingway.pdf

Each project was inserted into the 2010 backcast case separately to test how each line changed the dispatch of generators in the WECC. The results from PCM were post-processed in the Net Benefits Model (described in the previous section) which calculated the share of benefits allocated to each MP The following section describes the results of each of the PCM cases.

2010 MSTI Case Results

The MSTI project would connect Montana with southern Idaho. The insertion of MSTI into the 2010 backcast case showed increased flows from Montana to Idaho (N-S direction) ranging from 0-1000 MW, with average across the year at 400 MW, and highest flows during the summer (on and off-peak). The increased flow is explained by increased coal production in Montana (upstream of the MSTI project), which displaces gas and coal production in Idaho and Utah (downstream of the MSTI project).

The 2010 MSTI PCM results show that “Other Generators” in the NorthWestern transmission service area, such as independent power producers like Colstrip, are the main beneficiaries of the MSTI project. This is because the MSTI project allows these “Other Generators” to sell power to a new market and increase their revenue through more sales at higher average prices. Load serving entities within the NorthWestern transmission service area, such as NorthWestern and BPA, incur a net cost when the MSTI line is in place because their market purchases are more expensive relative to the Base Case because prices in the local area increase due to its close relationship with Mid-C prices. Mid-C prices increase in response to dampened flows along major paths from east to west with MSTI in place. The distribution of benefits among market participants and transmission service providers is shown in the graphs below:

FIGURE 14: MSTI LINE – NET PCM BENEFITS BY MARKET PARTICIPANT ($000)

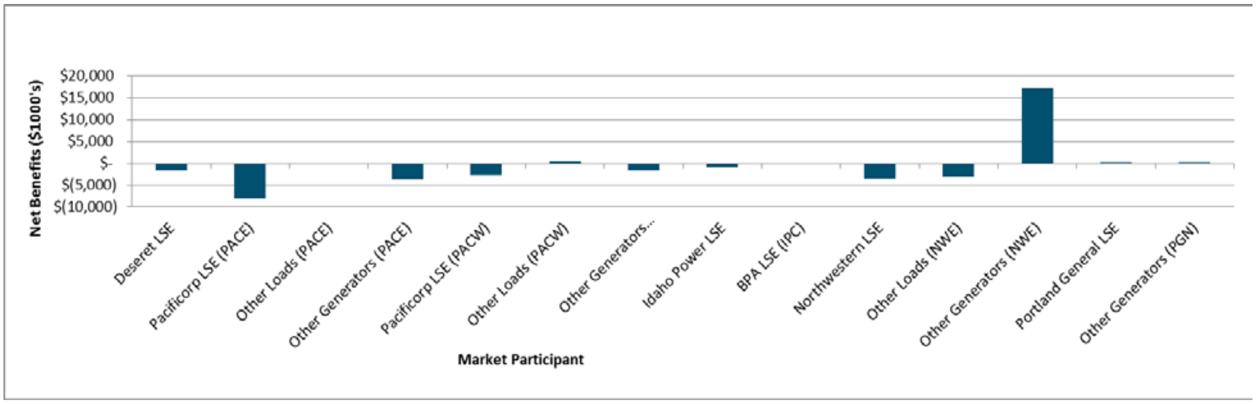
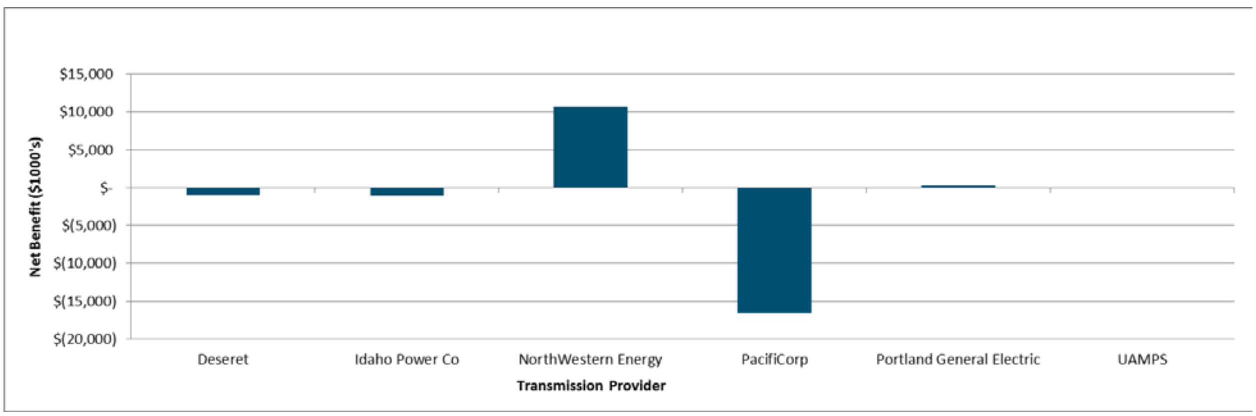


FIGURE 15: FIGURE 1: MSTI LINE – NET PCM BENEFITS BY TRANSMISSION PROVIDER ($000)



2010 B2H Results

The B2H project would connect northern Oregon to southwestern Idaho. The addition of the B2H project in the PCM reduces power flow within the Northwest. The Northwest also reduces its exports to California. The combined reduction in flow is diverted to serve loads at the downstream end of the project B2H project in Idaho and Utah. Due to its reduction in imports from the Northwest, California increases its local gas generation to offset its reduction in imports from the Northwest.

The 2010 B2H PCM results show benefits that are spread amongst a larger share of market participants than in the 2010 MSTI case. PacifiCorp LSE (east & west combined) is the largest beneficiary of the project.

FIGURE 16: B2H LINE – NET PCM BENEFITS BY MARKET PARTICIPANT ($000)

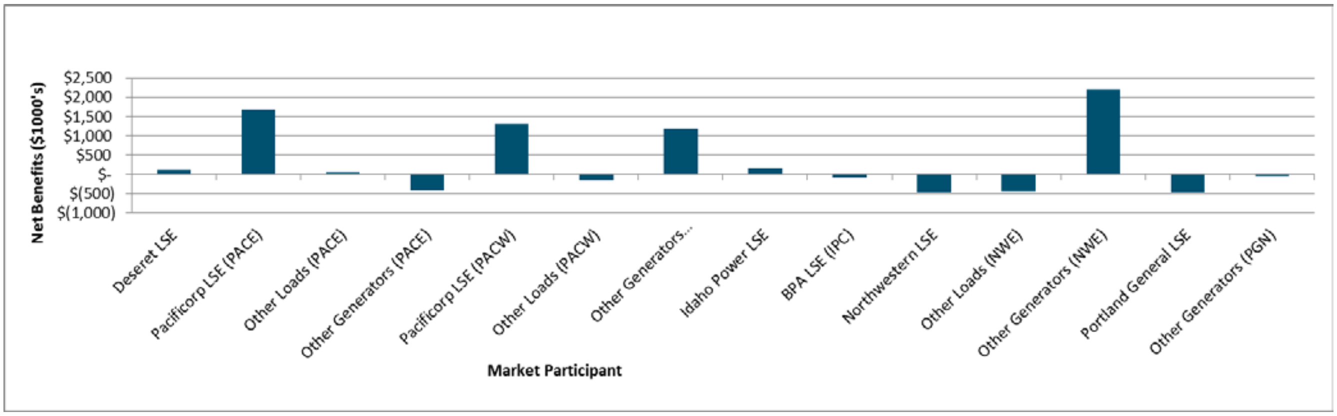
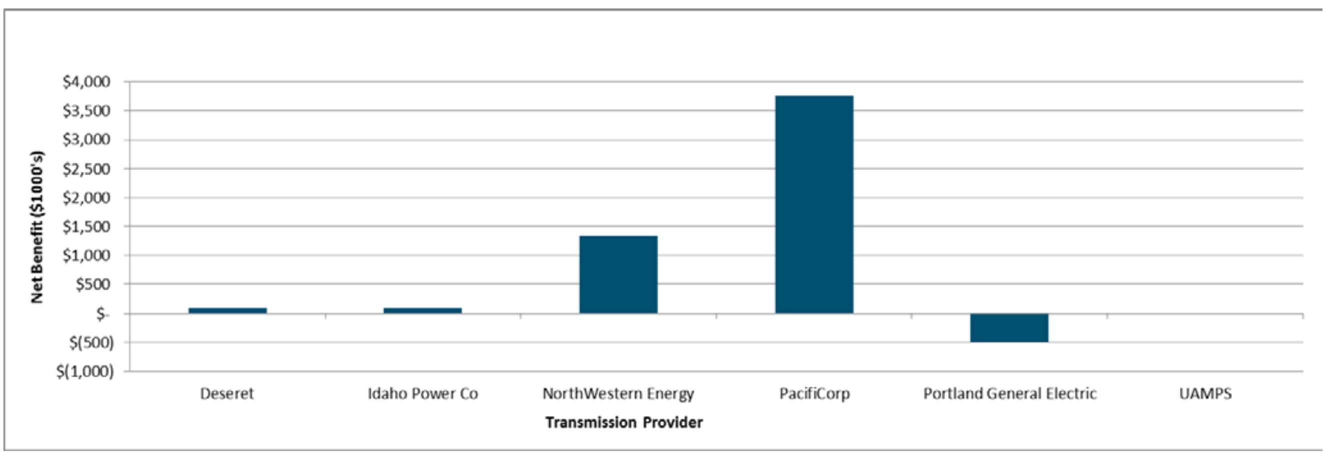


FIGURE 17: B2H LINE – NET PCM BENEFITS BY TRANSMISSION PROVIDER ($000)



Sensitivity Case Results

Once the 2010 Base Case was benchmarked and the MSTI and B2H lines were evaluated, a number of sensitivity cases were run. The objective of running sensitivities was to test the robustness of the PCM framework for cost allocation when variables, such as gas prices, generation location and hydro conditions, are changed in the model. The following section gives a brief description of the sensitivities studied. All the sensitivities began with the 2010 Base Case as a starting point and changed only the variables mentioned below

Natural Gas Price Sensitivity

The natural gas prices in the 2010 Base Case reflected an average Henry Hub price at $4.50/MMBtu. This sensitivity tested the extremes of natural gas prices to see how the net benefits may change among MPs in the NTTG footprint. Low and high natural gas price sensitivities were run. The low natural gas price sensitivity used an average Henry Hub price of $2/MMBtu and the high natural gas price sensitivity used an average Henry Hub price of $10/MMBtu.

Generation Location

To better understand how assumptions regarding the location of new generation may affect the net benefits of a new transmission project, a new 600 MW CCGT was placed at the local (west) and remote (east) end of each transmission project. The 2010 Base Case was modified to include this new generator at the local and remote location so that it could be compared to the transmission cases. Also, the generator location sensitivities used the low natural gas forecast created in the natural gas price sensitivity to ensure the new CCGT would be operating.

Low Hydro Conditions

Due to the fact that the WECC has a fair amount of hydro resources in its system whose level of operation can substantially change thermal dispatch, a low hydro sensitivity was run to see how that might change the net benefits associated with a transmission project. The low hydro profiles were extracted from the TEPPC 2022 Low Hydro case (based on the 2001 water year) and matched to their respective generators in the 2010 Base Case.

High Hurdle Rate Case

Tuning hurdle rates to optimize dispatch and flows across major paths was a large part of the benchmarking effort. To understand the effect of hurdle rates on the distribution of benefits, hurdle rates were doubled throughout the model (with few exceptions).

Sensitivity Results

Nineteen cases were run through PCM and evaluated through the Net Benefits model. The results of the sensitivity runs had relatively small economic benefits compared to the likely cost of the transmission projects. A table of the benefits aggregated to the Transmission Provider level is included below:

The high gas case sensitivity showed the largest overall net benefits to MPs of any of the cases run. The tables below show the breakdown of benefits (costs + benefits included) by TSP for each of the sensitivity runs.

TABLE 6: SENSITIVITY CASE RESULTS – IMPACT OF MSTI LINE BY TSP

Transmission Service Provider	Deseret	IPC	NWE	PacifiCorp	PGE	UAMPS
2010 Case	**($940)**	**($1,075)**	**$10,659**	**($16,534)**	**$232**	**$**
Share	***0%***	***0%***	***98%***	***0%***	***2%***	***0%***
High Gas	**($556)**	**($1,181)**	**$24,534**	**($14,811)**	**($650)**	**$**
Share	***0%***	***0%***	***100%***	***0%***	***0%***	***0%***
Low Gas	**$75**	**($15)**	**$2,102**	**($1,657)**	**($335)**	**$**
Benefits Share	***3%***	***0%***	***97%***	***0%***	***0%***	***0%***
Low Hydro	**($47)**	**($219)**	**$7,359**	**($5,144)**	**($298)**	**$**
Benefits Share	***0%***	***0%***	***100%***	***0%***	***0%***	***0%***
Local Gen: Midpoint	**($44)**	**($375)**	**$902**	**$1,453**	**($325)**	**$**
Share	***0%***	***0%***	***38%***	***62%***	***0%***	***0%***
Remote Gen: Townsend	**$277**	**($220)**	**$1,935**	**($1,796)**	**($371)**	**$**
Share	***13%***	***0%***	***87%***	***0%***	***0%***	***0%***
Hurdle Rate Sensitivity	**($702)**	**($2,469)**	**$55,479**	**($45,546)**	**$4,310**	**$**
Share	***0%***	***0%***	***93%***	***0%***	***7%***	***0%***

TABLE 7: SENSITIVITY CASE RESULTS – IMPACT OF B2H LINE BY TSP

Transmission Service Provider	Deseret	IPC	NWE	PacifiCorp	PGE	UAMPS
2010 Case	$81	$93	$1,333	$3,755	($491)	$
Share	*2%*	*2%*	*25%*	*71%*	*0%*	*0%*
High Gas	($160)	$1,677	$2,294	$3,066	$842	$
Share	*0%*	*21%*	*29%*	*39%*	*11%*	*0%*
Low Gas	$179	$20	$293	($3,078)	($136)	$
Share	*36%*	*4%*	*60%*	*0%*	*0%*	*0%*
Low Hydro	$329	$337	$796	$5,526	($174)	$
Share	5%	5%	11%	79%	0%	0%
Local Gen: John Day	($91)	($429)	$126	($5,498)	$499	$
Share	0%	0%	20%	0%	80%	0%
Remote Gen: Midpoint	($80)	($659)	$34	($1,401)	($28)	$
Share	*0%*	*0%*	*100%*	*0%*	*0%*	*0%*
Hurdle Rate Sensitivity	($64)	$28	$254	($769)	($1,800)	$
Share	*0%*	*10%*	*90%*	*0%*	*0%*	*0%*

The sensitivity results highlight two issues: (1) Sensitivities may produce consistent relative benefits for certain transmission projects (like MSTI), but may not for others (like B2H); and (2) The impact of sensitivities may not always be symmetric (low gas prices vs. high gas prices).

In general, the benefit distribution for the MSTI project remained fairly consistent across the scenarios evaluated. The MSTI sensitivities didn't typically change the order of primary beneficiaries, but rather the relative concentrations of benefits among those parties. The NorthWestern transmission provider entity was the primary beneficiary of MSTI in all but one of the sensitivity cases. The B2H project, however, had a wider distribution of benefits that varied between sensitivity cases. The NorthWestern transmission provider entity always accrued benefits from the B2H project ranging from 11%-100%. The remaining benefits were distributed to other transmission entities without a noticeable pattern.

The impact of sensitivities also appeared to be asymmetric. The low gas prices sensitivities showed a higher differential impact on benefit distribution than the high gas price sensitivities. This is because low gas prices begin to induce gas-to-coal switching, which is a significant change in system dispatch.

The results shown in this section are intended to be used for illustrative purposes only, and not indicative of the net benefits that would likely be associated with the two transmission projects for MPs within the NTTG footprint.

REMAINING MODELING CONCERNS

After review of the E3's PCM presentation materials and the post-processor spreadsheet, the Cost Allocation and PCM work groups discussed several issues that remain unresolved and continue to pose challenges for applying this methodology for determining benefit metrics to be used in transmission cost allocation. These issues and their potential causes are described below, beginning with the issues identified by the E3 work.

Dispatch of Individual Generating Units

As described above, E3 spent considerable effort – a total of 25 modeling iterations – to adjust the data inputs to the PCM to improve the results of the 2010 Base Case.

While the final Base Case appeared to improve the overall generation dispatch at an aggregate state-by-state level, the estimated dispatch of individual generating units by the PCM still showed substantial variation from actual results. The average error, weighted by unit output, for 35 coal units highlighted in the E3 study was slightly more than 12%. For 16 of these units with the greatest error, however, the weighted average was 30%. The table below summarizes the error of the annual PCM dispatch versus actual results for 2010.

TABLE 8: 2010 ENERGY BY COAL-FIRED GENERATING UNIT

Unit	Actual	Modeled	Error	Unit	Actual	Modeled	Error
1	16219	16569	2.2%	19	4130	3678	-10.9%
2	3606	2729	-24.3%	20	609	650	6.7%
3	1296	699	-46.1%	21	3672	4482	22.1%
4	8786	9269	5.5%	22	6039	8577	42.0%
5	6107	6639	8.7%	23	3378	3537	4.7%
6	5339	4433	-17.0%	24	2270	1101	-51.5%
7	4707	5570	18.3%	25	1091	1952	78.9%
8	14829	14416	-2.8%	26	2864	3489	21.8%
9	2565	2618	2.1%	27	1415	884	-37.5%
10	9752	9858	1.1%	28	8192	7863	-4.0%
11	3514	3898	10.9%	29	1625	2134	31.3%
12	9013	10008	11.0%	30	704	656	-6.8%
13	13080	13980	6.9%	31	481	897	86.5%
14	2753	3346	21.5%	32	1672	1779	6.4%
15	794	849	6.9%	33	640	532	-16.9%
16	961	1055	9.8%	34	729	678	-7.0%
17	1017	1189	16.9%	35	598	475	-20.6%
18	376	330	-12.2%				

The accuracy of the PCM dispatch depends heavily on the quality of generator cost information, including fuel cost and plant heat rates. Generator incremental operating cost (determined by the incremental heat rate curve and variable fuel cost) is generally considered by unit owners/operators to be confidential and, as such, was not available for the 2010 Base Case. Instead, generic characterization of generator heat rates from TEPPC and average fuel prices by state were utilized. To the extent that actual cost information for generators differ from the generic values used and could change the ordering of cost between different units, these differences could cause the PCM results to show higher or lower amounts of generation on certain units than historically occurred or than would be expected over a forecast period, even if state-wide aggregate dispatch levels are reasonably accurate.

Since several LSEs in the NTTG footprint own or contract with only a few generating units, the accuracy of dispatch results at a unit-specific level is an important factor is estimating the potential impact of a new transmission project on an individual LSE. For example, if the output of the primary generating unit of an LSE is underestimated in the PCM by 30% in a base case, the PCM could substantially over-estimate the increased dispatch of the generating unit due to addition of a new transmission project and, as a result, overstate the benefits of the new project to the LSE. Of course, the reverse could also be true, resulting in a substantially understated assessment of the benefits of the new project to the LSE.

Differences between PCM LMPs versus Short-term Bilateral Market Prices

As described above, the post-processor uses an “adjusted price” based on the hourly LMPs estimated by the PCM simulation to value a MP’s hourly net energy position with and without the presence of a new transmission project. The post-processor estimates the additional net revenue (or expense) associated with a new transmission project for each MP as the difference between the two results. This change in the net revenue (expense) position for each MP stems from a combination of (i) hourly changes in dispatch in the units in which the MP had l entitlements (i.e., increasing or decreasing its short-term net position) and (ii) hourly changes in the prices at which the MP “cleared” (i.e., bought or sold) its short-term net position.[19] Thus, under this methodology, the accuracy of prices used by the post-processor to value a MP’s net position, and how those prices change with a new transmission project, is highly influential in evaluating the net PCM benefits of a transmission project for each MP.

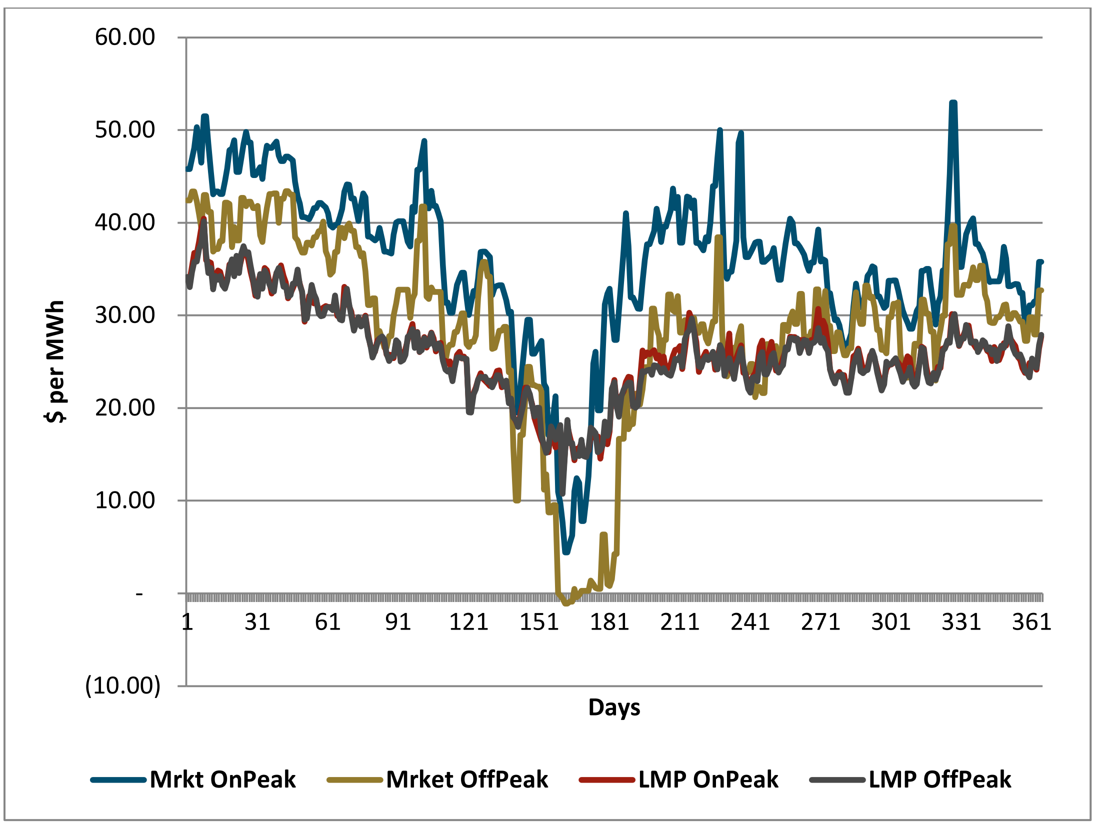
Given the importance of these prices to the estimation of MP benefits, the CAWG was concerned that the PCM backcast simulation cannot currently produce LMP values that closely match historical market prices. The unadjusted LMP values differ substantially from the actual, daily market prices in the backcast period. And, as described below, even the adjusted values have substantial differences. Additionally, it is unverified whether the relationship between the PCM results and actual market prices would remain relatively stable for different years or under different scenarios. Accordingly, it is reasonable to question whether the heuristic function created for the backcast to adjust the LMP values can produce reliable results in a forecast more than ten years in the future.

[19] In actual operations, the net position of a market participant may differ from the quantities assumed to “cleared” at a wholesale market price under these assumptions. These situations are described later in this section.

The unadjusted LMPs directly produced from the PCM were significantly different than historical bilateral market prices at the wholesale trading hubs located near the NTTG footprint. The errors can be characterized in two regards: First, in almost all hours, the hourly LMPs were substantially lower than actual market prices, especially during on-peak hours. Second, the variation between hourly on-peak and off-peak LMPs was almost non-existent, in contrast to the significant and persistent difference actually experienced in on-peak versus off-peak actual market prices.

The graph below highlights the significant differences between the Base Case LMPs estimated by the PCM relative to actual 2010 market prices, visually demonstrating the two problems described above. The average error of the LMPs relative to short-term market prices was 27%, with the average error higher in the on-peak hours and somewhat lower in the off-peak hours.

FIGURE 18: MID-C AVERAGE DAILY PRICES VS. LMP ESTIMATE FROM THE PCM



The table below quantifies the average on-peak to off-peak differential in actual market prices in 2010 at the Mid-Columbia and COB hubs, as compared with the differential in the average on-peak and off-peak LMPs directly produced by the 2010 PCM Base Case. While the PCM simulation produced an average differential of less than 4%, the actual hourly differential between on-peak and off-peak prices was about 25%.

TABLE 9: AVERAGE ON-PEAK TO OFF-PEAK PRICE DIFFERENTIALS

	Δ ($/MWh)	Δ %
COB		
Actual	9.24	25.4%
LMP	1.06	3.7%
MidC		
Actual	7.60	24.7%
LMP	0.51	2.0%

A number of factors may contribute to the inability of the LMPs from the Base Case of the PCM to accurately represent short-term, bilateral market prices for 2010. Limitations in input data, such as the use of generic data for unit heat rates and variable operating costs, likely were a substantial factor in the failure of the LMPs to reasonably simulate short-term prices. This LMP comparison highlights that the accuracy of PCM simulation cases depend significantly on the quality of the input data used for the simulation.

Other factors that may have also contributed to the difference between hourly LMPs and actual hourly prices include (i) the dispatch algorithms for the large amount of hydropower in the Western Interconnection, especially the Pacific Northwest, and (ii) price formation in the Western Interconnection's bi-lateral markets versus centrally-organized market which current PCM tools are designed to simulate.

As described above, to address this disparity in market prices compared to the LMPs estimated by the PCM, E3 developed functions using ordinary, least-squares regression to relate the implied heat rates of the simulation's LMPs with the heat rates implied by actual 2010 hub prices. While the resulting functions appear to provide an accurate method of converting the PCM's LMPs into adjusted values that closely match actual market prices when comparing average annual values, this adjustment method has two problematic issues.

First, while the regression-adjusted prices do closely match actual prices when averaged over the entire year, the results are less accurate when compared on each individual daily on-peak and off-peak trading period. As summarized in the table below, the average absolute value of the daily error, even after applying the regression-based adjustment, is still 8-9 percent for daily on-peak periods, and larger for off-peak periods. It is unclear whether these residual errors in price for specific days (despite the annual average prices being comparable) could adversely impact the accuracy of the net PCM benefits estimated for individual MPs.

TABLE 10: AVERAGE HOURLY ERROR OF REGRESSION-ADJUSTED PRICES*

	COB	MidC
On-Peak	8.2%	9.5%
Off-Peak	23.1%	10.1%

* *Outlier errors during spring run-off hours were excluded from the average values above. The average error would be significantly larger if these outliers were not excluded.*

If the exclusive objective of the analysis had been to estimate net procurement cost for MPs under a single backcast base case, then actual historical hourly market prices could have been used to avoid this residual error and avoid the need for the intermediate step of the regression. The functional estimation of the relationship between simulated LMPs and actual short-term prices was specified, however, to enable the analysis to also calculate a comparable series of projected market price under an alternative scenario with a proposed transmission facility added, or for a future simulation year (with, for example, lower or higher natural gas prices). Actual market prices are not available for such alternative scenarios, so these adjusted prices attempted to capture the LMP response to a change in a transmission scenario (or other inputs) and use the adjustment function with the new LMP values to infer how actual market prices would change under the alternative scenario.

The challenge with this adjusted price methodology, however, is that the analysis and available results have not been able to verify whether the functions estimated for the 2010 backcast define a relationship between LMPs simulated by the PCM and future short-term market prices that will persist in the future under a variety of different physical and economic conditions.

The estimation of the functions to relate the LMPs to actual prices was not based on a fundamental economic or physical hypothesis regarding the relationship between the underlying factors that may have caused the simulated LMPs to differ from daily market prices, but rather is a based on a simple, direct comparison of the resulting prices in the 2010 backcast. Thus, there is no fundamental reason that this relationship would not change, perhaps substantially, under different conditions. If the model used 2011 or 2009 data to develop the backcast, resulting in a different set of base case LMPs to be adjusted to a different set of actual prices, the regression functions estimated to correct the LMPs could likely have been quite different. Moreover, unless this relationship between simulated LMPs and actual market prices could be demonstrated to persist over a variety of historical conditions, the technique of adjusting LMPs simulated for a future year would fail, since for a forecast year there are no actual prices available to use to re-specify and re-estimate the regression function.

In sum, the approach of adjusting LMPs by using a functional relationship formed from a single base case and single year of actual price data is not an appropriate method for estimating future short-term market prices. If the PCM tool is used for estimating future changes in operating costs of MPs, the CAWG believes that PCM data input, topology and algorithms must be modified so as to allow the PCM itself to directly produce reasonable estimates of short-term prices in bi-lateral markets.

Lack of Actual Net Procurement Cost Data to Evaluate Backcast Results from Post-Processor

In modeling, the benefit of performing a backcast is comparing the modeled output with actual results, to assess whether the model produces relatively accurate and unbiased estimates. As indicated above, the output of the PCM Base Case with regard to energy dispatch from generating units and flow on transmission lines was compared with actual dispatch and transmission flows from 2010.[20]

The ultimate purpose of the PCM tool, however, is to estimate the change in net revenue (cost) associated with a new transmission project, and ability of the PCM tool to make credible estimates depends ultimately on whether the estimate of net revenue in the Base Case reasonably tracks actual net revenues among MPs. The effectiveness of the PCM tool to produce accurate net revenue estimates has not been tested or evaluated due to lack of readily available public data on actual procurement costs.

The PCM generation dispatch and transmission flow are intermediate estimates. While these components values have been compared against historical data, it is difficult to infer how errors in these components interact with each other to affect the overall results. For example, if the generation dispatch is off by 20%, transmission flow by 5%, short-term market prices by 30%, transmission expense by 10%, it is unclear whether is the overall estimate of net benefits for an individual MP is likely to be off by approximately the sum of the individual errors or whether there is some systemic offsetting of errors among the component estimates that would make the final estimate much more accurate.

More comparisons of the final post-processor results to actual net revenue data would be useful for evaluating the model's effectiveness. Additionally, comparisons as to how net revenue changes when new transmission projects are put in place would also be useful. Limitations in actual historical data for this validation process, however, make it difficult to quantify the error in the final results for the PCM tool.

Consistency of Model Output and Post-processor

The post-processor developed by E3 is a practical adaptation to a complex problem. The bulk power system in the Western Interconnection is largely a bi-lateral market affected by the economical use by each MP of its combination of short-term and long-term resource entitlements coupled with its short-term and long-term transmission

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[20] The generation dispatch in Table 8 shows that the PCM did not produce accurate results during for the 2010 backcast.

entitlements to meet its varied load obligations. While in theory the input and topology of a PCM could be modified to reflect the detail of each MP's load/resource portfolio, that approach would be impractical to implement. First, there is no readily available source for these data. Key pieces of data are not publicly available and, for the data that are available, a single database has never been compiled. Second, it is uncertain whether any currently available PCM software tool is be capable of simulating each MP in sufficiently accurate detail.

The E3 post-processor allows the results of the existing PCM software tool to be disaggregated by individual MP, as well as by TSP and BAA through aggregation of individual MPs. The application of this method for MP benefit calculations also can introduce inconsistencies between the PCM simulation output and the post processor.

For example, the post-processor assumes that any market participant having an entitlement in jointly-owned generating unit will dispatch their entitlements in the same manner: in proportion to the market participant's entitlement in the unit. That is, if a MP has a 15% entitlement in Unit X, the post-processor in calculating the net hourly energy position of that MP assumes that it took exactly 15% of the energy dispatched by the PCM in each hour for Unit X.

In practice, however, an assumption of pro rata dispatch among unit participants is substantially different from reality, especially for units that are closer to the margin in terms of whether or not their operating economics are "in the money."[21] Because joint participants in a unit typically do not have the right to utilize capacity unused by another participant in a unit, when one participant is not using its pro rata share of the unit capacity, that capacity must go unused.

In the post-processor, E3 developed a customization that can be used to prioritize certain owners and redistribute the hourly energy dispatched from a unit to one or more individual MPs with entitlements in the unit. No modifications to the post-processor, however, can change the total amount of energy dispatched from the unit, which would

[21] While a "work around" was developed in the post-processor that can be used to prioritize certain owners and redistribute the hourly energy dispatched from a unit to one or more individual market participants with entitlements in the unit, no post-processor work-around will change the total amount of energy dispatched from the unit, which would require re-running the PCM simulation.

require re-running the PCM simulation. Further, in implicitly assuming that the total energy dispatched by the PCM remains unchanged regardless of how this energy is allocated among owners, the post-processor makes no adjustment to unit's total energy output from the PCM which would affect the resulting LMPs. If a market participant's share of a unit's output is reduced in the post-processor, and the unit's other owners would not have need to dispatch their portion of the unit, the post-processor still relies on the original LMPs to calculate the net change in each MP's financial position.

The post-processor also allows, but doesn't require, transmission entitlements to be specified between a MP and a pricing hub. These entitlements effectively provide access to that pricing point at a potentially more advantageous price (either higher or lower, depending on whether the market participant is net long or short in that hour) than the local pricing point otherwise associated with the MP. In other words, the post-processor is able to recognize that for MPs having long-term transmission entitlements, access to a remote market may have no variable cost, other than losses.

While this representation may be more realistic in how long-term transmission entitlements, in fact, affect MPs, it can also potentially create inconsistency with the results produced by the PCM, which does not recognize many of these long-term transmission entitlements. As described above, the Base Case and Change Cases assumed that, in moving resources to load from one BAA to another, hurdle rates were set at 50% of the sum of the transmission rates and losses. While the PCM cases used tiered hurdle rates to characterize some of the more significant transmission entitlements (including rights between the Colstrip plant and it owners in the Pacific Northwest), these tiered hurdle rates were not applied for all transmission entitlements captured in the post-processor. In part, this was because some of the entitlements were identified after the base case had been finalized for this work, and because of the complexity of representing some transmission entitlements in a nodal PCM simulation.

Ability of PCM to Reflect Transactions in Bilateral Market

The hourly LMP calculated by the PCM is based on a mathematical calculation which represents the cost of serving an incremental (or decremental) unit of load at the pricing location. While many PCMs may have the ability of simulating bidding strategies by MPs, lacking any specific information about such strategies being employed, most PCM software algorithms typically assume that market participants "bid" energy from all available resources into the market at the variable costs of the various resources representing the surplus, with the assurance that they will be paid at the price of the highest bid accepted to clear the market. Various constraints, often transmission related, result in the hourly LMPs at different locations diverging from one another, sometimes by large amounts.

In organized markets, all resources are efficiently dispatched based on their variable costs and all MPs with surplus are assured that all short-term surpluses at a given location will be paid the same price, equal to the bid price associated with the most expensive generator serving load at that location. This organized-market paradigm underlies the calculation of net revenues/costs utilized by the PCM tool.

Bilateral markets, however, do not follow rules of an organized market. While brokers, electronic bulletin boards, and other devices are used for price discovery in bilateral markets, ultimately short-term transactions are completed between a single buyer and single seller at a negotiated price unique to that transaction, typically in a day-ahead market in which energy is transacted in uniform on-peak and off-peak blocks of 25 MWh per hour increments. On the seller side, not all energy from resources – not even all available surplus – is necessarily offered in the short-term market and the energy offered in the market is not offered at pure variable cost; on the buyer side, not all generation is subject to displacement from purchases.

Other than the calibration of the PCM to approximate annual dispatch level of generators, the evaluation of the PCM work for this analysis did not attempt to adjust the organized-market paradigm in the PCM tool reflect the actual workings of a bilateral market, nor did the evaluation attempt to estimate the financial impact among MPs of (i) resource dispatch being based on bilateral transactions or (ii) no "single price" settlement among buyers and sellers. At this point, there is no estimate of the potential impact of assuming an organized market for resource dispatch and financial settlements in calculating the results for either the Base Case or various Change Cases, or how the assumption of an organized market would affect the Base Case-to-Change Case differential among MPs.

Important Cost Issues Not Captured by the PCM Tool

Transmission Payments

The PCM tool calculates three cost (and revenue) categories: generation, contract, and market. "Generation" is the operational cost of resources dispatched by the PCM, which results can be disaggregated through the post-processor among MPs. "Contract" is the variable revenue or expense of long-term transactions between MPs not otherwise captured in apportioning "generation" costs among MPs based on an entitlement share. "Market" is the variable revenue or expense calculated in the post-processor to clear a MP's net hourly energy position (either long or short).

Although transmission hurdle rates are incorporated in the PCM itself to moderate dispatch of generation to serve remote load, the PCM tool does not account for either the revenue or expense associated with changes in transmission use. For example, assume in the Base Case a Generator in BAA#1 serves all load in BAA #1 and also generates surplus energy in 600 hours to serve load in BAA#2. That is, the PCM simulates that (i) there is transmission capacity available between the two BAAs during those hours and (ii) the variable per-unit cost of the Generator plus the transmission hurdle rate is less expensive than any other option available in BAA#2 in those 600 hours. During the 600 hours, the net gain to the Generator was $6/MWh (equal to the average LMP during those 600 hours less variable per-unit cost of operation). Suppose in the Change Case, that, with the addition of a transmission project in BAA#1, the Generator is able to generate surplus in an additional 1000 hours, and also sell somewhat more in the original 600 hours, but net only $5/MWh. If, in the Base Case, the surplus supplied by the Generator amounted to 60,000 MWh (i.e., an average of 100 MWh/hr) and if, in the Change Case, the surplus supplied amounted to 200,000 MWh (i.e., an average of 125 MWh/hr), the PCM tool would indicate a net benefit of $640,000 to the Generator. But that's a gross benefit, not accounting for transmission expense. If the transmission expense (excluding loss effects) averages $2.50/MWh, the net benefit to the Generator would be reduced to no more than $290,000, or less than half the gross benefit. Further, if the transmission expense was paid to the TSP(s) in BAA#2, assuming no other incremental transmission costs were incurred to effect the additional transfers, the TSP and its transmission customers would receive a net benefit of $350,000 (more than 50% of the gross benefit) in the form of either higher returns to stockholders or lower firm transmission rates (through revenue credits from additional short-term transmission sales) to other transmission customers.

The PCM tool as currently structured fails to account for the transfer of benefits among entities – especially MPs represented by different TSPs – due to increases or decreases in transmission use and the substantial impact of these changes in transmission payments in the form of return to stockholders or transmission rates. In either case, these transmission payments may represent substantial net benefits (or costs) to entities not part of or directly involved in the construction or use of the new transmission project and which are not otherwise considered by the PCM tool.

Resource Location Affecting Transmission Projects

The scenarios evaluated by E3 also demonstrate that assumptions regarding the location of new resources may have a large impact on the PCM tool's estimate of a MP's net benefits. Location of the new resources affects not only changes in the relative prices among pricing hubs calculated by the PCM, but will also likely change the estimates input to the PCM regarding the chronological profile and amount of energy available from the new resources. For example, a wind project in central Wyoming will have quite different operational impacts as compared with a similar project located the Columbia River gorge, or in western Utah.

While these different operational characteristics are input to the PCM tool, differences in resource per-unit fixed capital cost are not considered by the PCM tool or post-processor. For example, to the extent the per-unit fixed cost of a resource may be 10% in one location relative to another location, that benefit to the generation owner (as independent power producer or LSE) is not captured by the PCM tool, even though the location with lower per-unit fixed cost may require substantially more transmission investment. If a transmission project increases the estimated market prices in the vicinity of the new generation (by decreasing transmission congestion to areas having higher market prices) the new generation owner will be ascribed net benefits from the project. But, in using only the PCM, so too will owners of any existing generation during hours when these owners have a net long energy position. If net benefits of reduced congestion were roughly apportioned 50/50 between the owner of the new resource and the owner of pre-existing resources, the cost of the new transmission project, for example $200 million, would be divided evenly between the two groups. But, the locational decision of the resource developer (to locate in Wyoming, for example, rather than western Utah) may have saved it $60 million (of which it keeps 100%) in capital cost (the investment in wind turbines needed to produce the same amount of energy at a less "windy" location) while increasing the cost of transmission upgrades by $60 million (which added transmission capital cost it would share 50/50 with other beneficiaries based on changes in variable revenues/costs).

This situation emphasizes the fact that PCM tool reflects only changes in variable costs; capital cost changes would need to be evaluated through a separate type of analysis. If a transmission cost allocation process used variable cost savings (identified in PCM results) alone to allocate costs (without also analyzing changes in capital costs), that process could fail to meet the requirement of allocating costs roughly commensurate with benefits, since the benefits to the developer of the new generation exclude the benefit of lower fixed resource costs facilitated by the additional transmission investment by the TSP.

CONCLUSIONS

Model Structure

The PCM tool is based on a simplified representation of the contractual and operational topology of the western interconnection and its dispatch is based on an organized market framework. While the addition of the post-processor developed by E3 augments and corrects some of the representations used in the PCM itself (such as remote generation ownership), the resulting PCM tool still incorporates data and methodological shortcuts in estimating the dispatch of resources and/or the calculation of a MP's net energy cost, which include the following:

- Each resource is assumed to be dispatched at a single price, irrespective of multiple owners or contractual commitments associated with the resource.
- Not all long-term transmission entitlements are expressly recognized. Instead, hurdle rates are applied that assume a portion of transfers on the transmission path pay a transmission rate which is arbitrarily discounted from the filed rates of the appropriate transmission provider(s) by 50% to approximately calibrate regional transmission flows in the simulation to historical levels.
- Hourly differences between long-term resource entitlements and load of each MP are assumed to be satisfied through short-term purchase or sale at a single price, calculated based on the highest priced resource used to serve load. This price is likely not reflective of the level and pricing of transactions in the bilateral markets which prevail in the footprint of NTTG.
- The calculation of net benefits (costs) of a MP do not account for changes in transmission revenues received or transmission costs paid between the Base Case and Change Case.
- Only changes in variable costs are considered for MPs. Changes in fixed costs are outside of the scope of PCM analysis.

Although the structure of the PCM tool has been modified to estimate net PCM benefits for individual MPs, before the PCM tool could be relied on to provide reliable estimate net revenues (costs) at the MP-level, modification of the model structure to overcome or mitigate the effect of these issues would need to be made.

Input Data

The PCM tool, as evaluated in the study, relied primarily on generic data for per-unit fuel price, unit operational characteristics and, with but a few exceptions, long-term transmission entitlements. These generic data were often substantially different from actual data. These data errors likely had substantial impacts on the estimated dispatch of individual generating units and the resulting estimates of net revenue (cost) for individual MPs. Without a PCM database incorporating actual data for comparison, the degree to which the use of generic data affects the estimate of net PCM benefits cannot be determined using a backcast period. Based on review of the estimated versus actual results with respect to dispatch of generating units and hourly power prices in the 2010 backcast, the use of generic data may substantially reduce the accuracy of PCM tool to estimate net benefits for individual MPs.

Unless and until a backcast for one or more years can be performed that demonstrates the use of generic data does not substantially affect the accuracy of net revenues (costs) estimated by the PCM tool, it would be inappropriate and unreasonable to use the PCM tool with generic data for estimating net benefits for MPs during a forecast study period.

Results of the Backcast

Although the direction of the change between and among Change Case scenarios seemed logical, the absolute value of the estimated dispatch of generating units in the Base Case was substantially different from actual results in the backcast period. This calls into question any use of the PCM tool to determine benefit metrics for cost allocation, since absolute, not just relative, dispatch of generating units must be reasonable in order for a benefit metric derived from changes in net energy revenues (costs) to be combined on a consistent basis with other benefit metrics.

Of further concern was the failure of the PCM tool to reasonably estimate daily power prices, as compared to historical prices. A keystone of the PCM tool's ability to reasonably estimate the net revenue (cost) for individual market participants is the reasonableness of the estimated hourly power prices. The "raw" hourly power prices estimated by the PCM itself did not meet this standard, being both substantially understated in absolute terms and not reflective of on-peak and off-peak differences in relative terms. The mechanism in this study used to adjust the hourly prices estimated by the PCM itself has not been validated to produce reliable results for forecast periods or alternative scenarios when actual prices are unavailable and cannot be incorporated into the adjustment process.[22] Since actual prices cannot be available for a forecast period, and the relationship has only been tested for a single year, this adjustment mechanism cannot be relied upon to produce accurate forecasts of hourly power prices. Further, since any benefit metric developed with the PCM tool would be combined with other benefit metrics, the net benefits from the PCM tool must be reasonable in absolute dollars, not just the relative dollars among market participants evaluated with the PCM tool.[23]

While key intermediate quantities estimated by the PCM tool were shown to be substantially different compared to historical values for the 2010 backcast period, the study was not intended and, therefore, did not obtain historical data to evaluate the capability of the PCM tool to reasonably estimate the net revenue (cost) by MP, which is the end result of the analysis. So, while the study demonstrated the current capabilities of the PCM tool, as well as its limitations, the study did not evaluate whether the PCM tool is able to accurately estimate net energy revenues (costs) for individual MPs during a backcast, or forecast, period.

Use of the PCM Tool

The phase one and phase two study work by E3 relied on an existing interconnection-wide database as input to the PCM. E3 made and tested various modifications to the PCM

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[22] The adjustment process also continues to show differences from base case historical prices when compared an individual day-by-day basis.

[23] For example, if a new project results in $10 million of benefit to a transmission provider who is able to defer its own transmission project, the net benefits estimated for market participants with the PCM tool must be reasonably accurate in absolute terms, since these net PCM benefits will be combined with benefits estimated based on other metrics. It does the transmission provider no good if the PCM tool estimates net benefits that are understated, for example, by 50% even if the net benefits estimated by the PCM tool for various MPs were reasonably accurate among those MPs in relative terms.

database and model parameters to better estimate generation and transmission flow patterns for the 2010 backcast period. In addition, E3 provided a post-processor that, within the data and topology limitations incorporated in the PCM and general lack of access to long-term entitlements with respect to generation and transmission, disaggregated the results of the PCM among MPs within the NTTG footprint.

The price and individual generator outputs from PCM tool results continue to show key differences from historical data for the 2010 backcast period. The underlying cause of the inaccuracy appears to be a combination of data limitations and model topology. Even if these deficiencies were corrected, additional evaluation would need to be undertaken to determine if the results produced by the PCM tool reasonably reflect actual MP procurement costs, given that the PCM tool relies on an idealized, organized-market approach that is not generally reflective of the bilateral markets of the Northern Tier footprint.

The study provided a step forward in terms of methodology and understanding of production cost modeling, but the result of the study in the current modeling framework do not provide sufficient accuracy to be used at this time in the development of benefit metrics for the allocation of transmission project costs.