

# BPA 2010 Network Open Season

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## *Congestion and Production Cost Analysis*



May 2011

## Foreword

This report was prepared by Comprehensive Power Solutions, LLC, under contract to the Bonneville Power Administration. The work is based on an extensive effort by the Transmission Expansion Planning Policy Committee (TEPPC) of the Western Electricity Coordinating Council (WECC) to collect and develop data that allow simulation of hourly operation of the Western Interconnection's transmission grid and generating resources. Engineers and analysts at the Bonneville Power Administration have also provided essential information and direction to this project.

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## Executive Summary

This study employed an hourly power system simulator to help identify and estimate the production cost benefits and congestion impacts of adding generation associated with Transmission Service Requests (TSR's) in Bonneville Power Administration's 2010 Network Open Season (NOS). Although the simulation incorporated details for the entire Western Interconnection, the primary focus of the analysis was on the Northwest System.

While this analysis is based on a generator commitment and dispatch program that incorporates a detailed transmission model, it is only one of the tools needed to assess future transmission needs. In particular, this program does not perform the intra-hour dynamic analysis necessary to ensure the security and reliability of the transmission network.

The power system simulator does not directly evaluate the implications of Transmission Service Requests resulting from the Network Open Season. This study places generators sized and located consistent with the TSR's and assesses their integration with and impact on the power and transmission system. Most of the generators added in this study are assumed to be wind-powered generation projects. More detail on the power system simulator is included in the body of this document.

The amount of generation added to the system in this study, representative of the TSR's of the 2010 NOS, totaled 3,204 MW in nine generators. This included 814 MW in three generators added in British Columbia to represent supply behind service requests that were tied to generation. This compares to 947 MW added for the 2009 NOS study and 2,887 for the 2008 NOS analysis.

The NOS Cluster Studies identified transmission improvements that will facilitate delivery of services requested in the 2010 Network Open Season. These include an upgrade of transmission capability from Montana to the Northwest and from British Columbia into Western Washington, and a needed transformer and interconnection in Central Oregon.

This study found notable impacts on congestion and production costs from the modeled 2010 NOS generation and transmission. In particular, congestion on the West of Garrison and West of Slatt transmission flow gates, and on the California-Oregon Intertie was higher.

Production cost savings were estimated to be about 1.5% of the cost of dispatching the Western Interconnection. It was also noted that about two thirds of the production costs savings attributable to the NOS generation additions occurred in regions outside the Northwest. The simulation program used here, however, does a single-operator dispatch and the actual distribution of savings to power system participants would be different. For example, lower production costs in regions outside the Northwest due to transmission-enabled deliveries from less-expensive Northwest resources would leave part of the savings with the supplying system.

The analysis done here indicates that addition of resources associated with the 2010 NOS to the Northwest high voltage grid (with resource and transmission additions identified in the 2008 and 2009 NOSs), augmented with the transmission improvements proposed as a result of the 2010 Network Open Season studies, does not produce costly congestion. The results show a production cost savings of \$139 million in the Northwest when the 2010 NOS requests are added, and a further production cost savings of about \$33 million when the 2010 transmission improvements are added.

## Scope

This study addressed the following questions:

- Is there a reduction in future variable production costs (fuel and variable O&M) resulting from system operational changes with the addition of the 2010 NOS generation?
- What is the effect on BPA's internal flowgate loadings with the 2010 NOS generation additions (frequency of certain path loading levels)?
- Are the transmission improvements identified in 2008 NOS adequate to accommodate the additional requests associated with new resources under the 2010 NOS, as identified by the cluster study?
- Are there congestion and production cost reductions as a result of adding the 2010 NOS transmission improvements?

## Assumptions

In developing and executing this analysis, many assumptions were made, including the following:

- Precedent Transmission Service Agreements (PTSAs) were separated into those associated with new generation and those deemed to be used for existing generation or other uses.
- The simulator modeled the Western Interconnection as a 'single-owner' system, seeking an overall optimal operation (minimizing cost).
- Variable costs for wind-powered electricity are assumed to be negligible, the Production Tax Credit is not taken into account (although the model will use all wind generation if it is operationally possible), and the model dispatches thermal generation based on incremental cost and not an offered price (that might incorporate fixed cost recovery).
- Path loadings were considered high if there were hours at or above 75% of the path's limit
  - The analysis assumes all lines and voltage support are in service at all times
  - Under outage conditions, which change flows and reduce flowgate limits, variable production costs are expected to increase significantly and the flexibility of hydro-generation redispatch is expected to diminish.
-

Table 1 lists the representative generators associated with the 2010 NOS Cluster Studies and indicates their location (bus number and name) for purposes of this study. Integrating transmission needed to deliver the wind from its actual locations to these buses is not part of this study.

- The study assumes a 2002 hydro condition for the Northwest (near median), expected loads for the 2019 timeframe, and typical wind based on National Renewable Energy Laboratory data.

**Table 1: Generation Associated with 2010 Network Open Season Transmission Service Requests**

| Generator Name    | Bus Number | Bus Name | Capacity (MW) | Energy (MWh) | Wind Shape  |
|-------------------|------------|----------|---------------|--------------|-------------|
| NOS-10 Big Horn 4 | 40511      | HARVALUM | 100.0         | 22.9         | wnd_OR2     |
| NOS-10 Harlowton  | 40459      | GARRISON | 530.0         | 189.1        | wnd_MT2     |
| NOS-10 Ione Wind  | 40723      | MCNARY   | 800.0         | 183.5        | wnd_OR2     |
| NOS-10 Judith Gap | 40459      | GARRISON | 460.0         | 165.5        | wnd_MT2     |
| NOS-10 Montague   | 40989      | SLATT    | 200.0         | 53.1         | wnd_OR1     |
| NOS-10 Stanfield  | 40723      | MCNARY   | 300.0         | 68.8         | wnd_OR2     |
| NI Wind           | 50562      | GLN500   | 144.0         | 40.5         | Glenannan   |
| PR Wind           | 50559      | PCN500   | 403.0         | 118.7        | Peace River |
| VI Wind           | 50364      | GLD230   | 267.0         | 72.0         | Vanc Island |

### Cases Studied

This study looked at three cases:

- The Base Case is derived from a base case (TEPPC 2019 PC1A) developed by the Transmission Expansion Planning Policy Committee (TEPPC) with the support of the staff of the Western Electricity Coordinating Council (WECC).
- The Generation Case added the wind generators associated with the 2010 NOS.
- The Transmission Case added the wind generation and the 2010 NOS transmission improvements.

### Results Reported

Table 2 shows summary data for the cases studied. This table is described and commented upon in greater detail in the body of the report.

Results include:

- The number of hours (during the 2019 study year) that monitored transmission flowgates and paths were operated beyond 75% of their ratings,
- Variable production costs (fuel and variable operations and maintenance costs) for thermal generation in the Western Interconnection and major sub-regions.

Table 2: Path and Flowgate Congestion, and Variable Costs

|  | Study Case                                   |                   |                          | Change from Base Case |                          | Delta                    |
|--|--|-------------------|--------------------------|-----------------------|--------------------------|--------------------------|
|  | Base Case                                    | with 2010 NOS Gen | with 2010 NOS Gen, Trans | with 2010 NOS Gen     | with 2010 NOS Gen, Trans | Effect of 2010 NOS Trans |
| <b>Internal Congestion Hours</b>         | <i>(Hours above 75% of interface rating)</i> |                   |                          |                       |                          |                          |
| Raver - Paul                             | 14   | 63                | 5                        | 49                    | (9)                      | (58)                     |
| Paul - Allston                           | 278  | 279               | 292                      | 1                     | 14                       | 13                       |
| South of Allston                         | 41   | 45                | 42                       | 4                     | 1                        | (3)                      |
| North of Hanford                         | 273  | 245               | 168                      | (28)                  | (105)                    | (77)                     |
| North of John Day                        | 195  | 252               | 265                      | 57                    | 70                       | 13                       |
| West of Cascades - North                 | 184  | 175               | 198                      | (9)                   | 14                       | 23                       |
| West of Cascades - South                 | 14   | 18                | 16                       | 4                     | 2                        | (2)                      |
| West of McNary                           | 0  | 0                 | 1                        | 0                     | 1                        | 1                        |
| West of Slatt                            | 35   | 168               | 180                      | 133                   | 145                      | 12                       |
| West of John Day                         | 43   | 123               | 108                      | 80                    | 65                       | (15)                     |
| <b>External Congestion Hours</b>         |  |                   |                          |                       |                          |                          |
| NW to Canada East BC                     | 2,712  | 2,557             | 2,643                    | (155)                 | (69)                     | 86                       |
| NW to Canada West BC                     | 1,592  | 1,156             | 574                      | (436)                 | (1,018)                  | (582)                    |
| Montana - Northwest                      | 3,603  | 1,256             | 3,507                    | (2,347)               | (96)                     | 2,251                    |
| West of Garrison                         | 4,347  | 5,427             | 3,588                    | 1,080                 | (759)                    | (1,839)                  |
| Bridger West                             | 7,780  | 7,770             | 7,737                    | (10)                  | (43)                     | (33)                     |
| Idaho - Northwest                        | 4  | 4                 | 9                        | 0                     | 5                        | 5                        |
| Midpoint - Summer Lake                   | 34   | 25                | 18                       | (9)                   | (16)                     | (7)                      |
| California-Oregon Intertie               | 2,375  | 3,185             | 3,123                    | 810                   | 748                      | (62)                     |
| Pacific DC Intertie (PDCI)               | 195  | 376               | 421                      | 181                   | 226                      | 45                       |
| <b>Annual Variable Cost (\$Millions)</b> | <i>(Thermal Generation Only)</i>             |                   |                          |                       |                          |                          |
| Total WECC                               | \$24,854                                     | \$24,448          | \$24,419                 | (\$406)               | (\$435)                  | (\$29)                   |
| AZ-NM-NV                                 | \$6,749                                      | \$6,671           | \$6,685                  | (\$78)                | (\$64)                   | \$14                     |
| Basin                                    | \$1,627                                      | \$1,593           | \$1,607                  | (\$33)                | (\$20)                   | \$14                     |
| California                               | \$7,927                                      | \$7,803           | \$7,771                  | (\$123)               | (\$156)                  | (\$33)                   |
| Canada                                   | \$4,067                                      | \$4,059           | \$4,055                  | (\$8)                 | (\$12)                   | (\$5)                    |
| NWPP                                     | \$2,838                                      | \$2,699           | \$2,666                  | (\$139)               | (\$172)                  | (\$33)                   |
| RMPP                                     | \$1,647                                      | \$1,623           | \$1,636                  | (\$24)                | (\$11)                   | \$13                     |

*Includes only fuel and variable operations and maintenance costs*

## Observations

- The generation additions are accommodated<sup>1</sup> with the transmission improvements identified in the 2008 NOS analyses (though with increased transmission congestion and increased and perhaps unacceptable cycling of base-load generators). The transmission grid allows delivery of the added resources and redispatch of existing resources to produce substantial production cost savings.

<sup>1</sup> Accommodated in terms of the paths and flowgates monitored in this study.

- About 34% of production cost savings attributable to the new generation occur in the Northwest.
- The generation improvements associated with the 2010 NOS provide substantial additional production cost savings.
- The generation projects added for this study were in the same geographical area as the bulk of those associated with the 2008 NOS and 2009 NOS, resulting in a lack of wind-regime diversity.
  - The new wind generators have peak and minimum output at the same time as many previous resource additions.
  - The increased amplitude of wind variation causes cycling of thermal resources well down into the generation cost curve, with coal and even the nuclear generator moving to accommodate the wind.
  - At peak wind output, most of the Northwest fossil generation is already displaced by previously-built wind generators, leaving new wind to displace out-of-region generators.
  - At times of low wind in the Oregon-Washington wind zones, the new projects offer no diversity and exacerbate operational problems.
- Congestion on BPA's network flowgates (see **Error! Reference source not found.**) increases with the new generation, requiring some redispatch of other resources.
  - The new resources are accommodated by the transmission reinforcements associated with the 2008 and 2010 Network Open Seasons.
  - Adding 980 MW of wind generation at Garrison, Montana induced a significant increase in congestion hours on the West of Garrison interface, which was eliminated with addition of the Colstrip Upgrade Project West.
  - The West of Slatt and West of John Day flowgates show significant increases in congestion, as coincident peak wind pushes to get to the California interties, as reflected in higher loading of the California-Oregon Intertie and the Pacific DC Intertie.
- If the simulation model considered generator and transmission forced outages would result in greater price volatility and periods of increased congestion.
- If the simulation considered generator and transmission forced outages, greater price volatility and periods of increased congestion would be expected.

## Conclusions

- The energy produced by the new wind generators will displace highest-cost generation, much of which is located outside the Northwest. This makes it difficult to measure net economic impacts in the Northwest, particularly when renewable energy credits are considered.
- The new wind generation is co-located with substantial existing and 2008 and 2009 NOS wind generation, resulting in amplification of existing integration and operational issues.
- The transmission grid, with the reinforcements introduced with the 2008 and 2010 NOS analyses, is adequate (as measured by this study's criteria) to integrate the new generation, though congestion does remain on several paths and flow gates, as shown in Table 2,

- As noted in the Observations, the economic dispatch model strives to accommodate all wind generator output, given its low variable cost, to the extent that more expensive generators may be cycled while still meeting load. This cycling may not be practicable in actual operations, given priorities on transmission use and dedication of generator output to particular loads. Some economic or policy inducements may be required to implement such cycling; those are not modeled here.

## Economic Analysis of the BPA 2010 Network Open Season

This Regional Economic Benefit Analysis study was undertaken to support the Bonneville Power Administration's 2010 Network Open Season (NOS). Information available to the public regarding BPA's 2010 open season may be found on the BPA Transmission Web site, at:

[http://transmission.bpa.gov/customer\\_forums/open\\_season\\_2010/](http://transmission.bpa.gov/customer_forums/open_season_2010/).

The intent of this study is to inform the analysis by simulating the operation, ten years from now, of the electric power system of the Western Interconnection (the Continental US from Montana, Wyoming, Colorado and New Mexico westward, plus British Columbia, Alberta and parts of Northwestern Mexico). Output from the simulation will help to estimate some of the costs to operate the region's generating plants to serve forecasted loads, and to determine the extent to which the power transmission network may become congested under alternative scenarios.

### Objectives and Focus

This report analyzes the impacts of transmission service requests by connecting appropriately sized and located new generation to BPA's transmission system and performing an hourly commitment and dispatch simulation over the year 2019, and assesses the implications of certain alternative assumptions (details of these cases will be described below). Two metrics taken from model outputs are particularly useful – the amount of transmission congestion and the change in variable production costs.

1. The first metric is the degree of congestion on defined transmission paths, as measured by the number of hours during the sample year that flows on the paths exceed certain percentages of their transfer limits. It provides an indication of potential reliability problems should a line outage or other unexpected system disturbance occur, or an indication of excessive costs due to redispatch of generation as inexpensive power cannot reach loads and more-costly generators must provide the energy.
2. The second metric examines the cost implications of congestion, by recording the amount of unserved load, if any, and accumulating the total fuel and variable operations and maintenance cost (variable (O&M) of thermal (coal and natural-gas-fueled) generation compared to a base case.

In looking at these metrics, it is important to note that the cases are examined here in the context of a differential analysis: The majority of data inputs (assumptions) are held constant across the simulations, reducing the impact of uncertainty or errors in their estimation.

### Indications of Congestion – Where and How Much

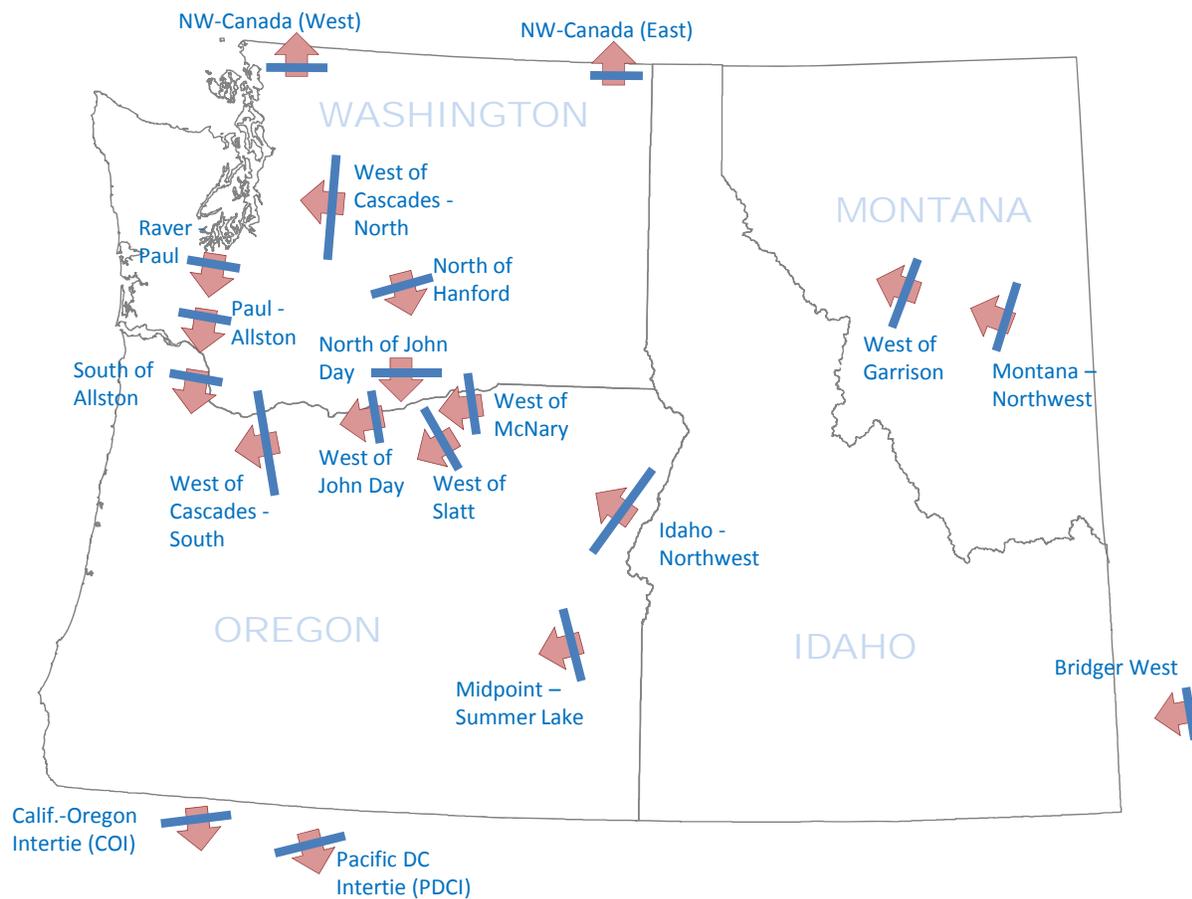
Two sets of transmission interfaces (also referred to as paths or flowgates) were examined for congestion in this study. The term paths will be used to refer to those interfaces lying between Balancing Authorities or otherwise defined as paths by the Western Electricity Coordinating Council (WECC), while the interfaces measuring flows within BPA's system will be termed

flowgates. One set of ten interfaces consists of paths and flowgates internal to the Northwest and are important to an analysis of congestion on BPA’s system.

The second set of nine interfaces consists of paths lying between the Pacific Northwest and adjacent sub-regions of the Western Interconnection, including Canada, California, Montana and Idaho.

The transmission lines comprising these interfaces and the flow limits on the interfaces are shown in tables in the Transmission segment of the Assumptions section of this report.

**Figure 1: Transmission Interfaces (Paths & Flowgates) Reported in this Study**



The maximum permissible flows across these interfaces are established through processes defined by the WECC (for paths) or by BPA (for flowgates) and are listed in Table 9. When flows on an interface approach or reach the limit, the line is considered congested. The specific threshold level is set at different percentages of interface ratings; the Transmission Expansion Planning Policy Committee (TEPPC) of the WECC reports the frequency of congestion at 75%, 90% and 99% of the interface rating. The frequency is reported as the number of hours during the year that the flow equals or exceeds the thresholds (so hours above 75% include hours above 90% and 99%).

While the simulation program recognizes the quadratic increase in losses as a line is loaded, no cost penalty occurs until the line reaches its limit, at which point a penalty of \$1,000/MWh is imposed by the program's optimizer, which tends to force the flow back below the limit except in order to avoid higher penalties, such as that associated with loss of load.

Experience suggests that frequently loading an interface above 75% of its rating exposes the network to risk, as failure of a transmission line on this or another part of the network may immediately send the interface to and beyond its limit, with adverse economic or load-service consequences. For that reason, we focus on the 75% threshold for existence and measurement of congestion.

### Impacts of Alternative Scenarios on Operating Costs

As noted above, a congested interface will force the power system to seek a more expensive dispatch to serve loads. Changes in resource assumptions and resource operating characteristics will also change system operation. This change in generation pattern may be measured as the sum of variable fuel and O&M costs.<sup>2</sup>

### Study Scope – Limited to the Northwest Region

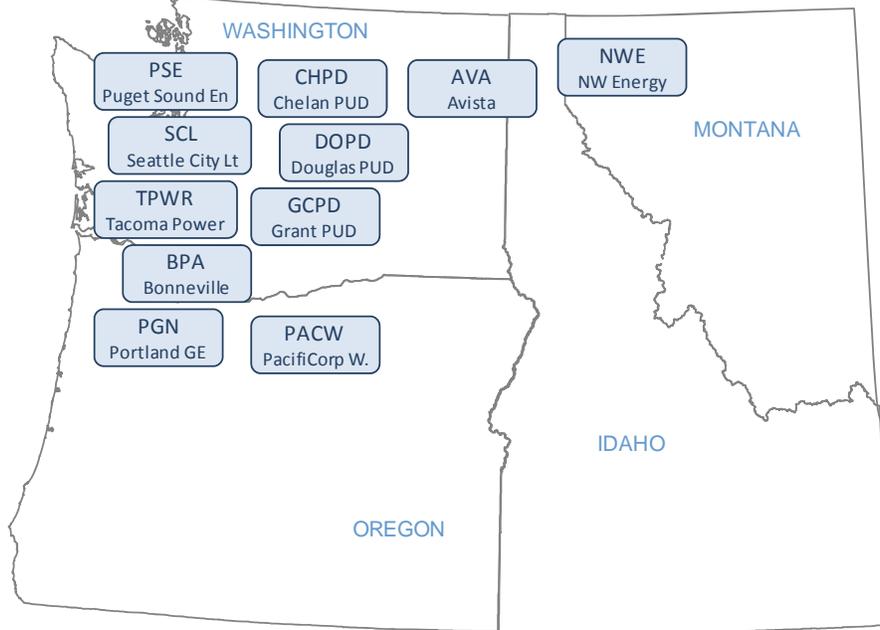
Production cost modeling in this study focused on the BPA transmission footprint, represented by the aggregation of load areas defined by TEPPC that encompass Oregon, Washington, and parts of Idaho and Montana. Specifically, this encompasses the eleven areas shown in Figure 2.

Model data for regions outside the Northwest have not been modified for this study. The data in this model were used for TEPPC's study of 2019 cases run in 2009 and 2010 and have been subjected to scrutiny and development by the WECC staff and participants in the many TEPPC work groups.

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<sup>2</sup> Note that care must be taken when comparing such costs among cases with different amounts of available generation. Financial parameters like fixed costs, financing and taxes are not incorporated into the simulation and subsequent analysis; nor are some variable costs (and benefits) like the Production Tax Credit for renewable project output.

Figure 2: Load Areas Comprising the Northwest Region Modeled in GridView



## Cases and Scenarios

### The Base Case

The starting point for this study, as mentioned above, was the 2019 PC<sub>1</sub> case developed by TEPPC.<sup>3</sup> That case was adjusted to account for additional detail in the Northwest sub-region, such as the generation additions associated with BPA’s 2008 and 2009 Network Open Seasons, and some additional transmission changes, like the addition of the Mercer Ranch 500 kV bus to aid the integration of the generation associated with the 2008 NOS.

### The NOS Generation Case

The second case in this study adds the new generating resources associated with the 2010 Network Open Season and BPA’s attendant cluster study.

<sup>3</sup> Relevant TEPPC studies are reported in the TEPPC 2009 Annual Report, located in the WECC Web site at <http://www.wecc.biz/committees/BOD/TEPPC/Shared%20Documents/Forms/AllItems.aspx?RootFolder=%2fcommittees%2fBOD%2fTEPPC%2fShared%20Documents%2fTEPPC%20Annual%20Reports%2f2009&FolderCTID=&View=%2f7b3FECCB9E%2d172C%2d41C1%2d9880%2dA1CF02C537B7%2d>

Table 1 lists the wind generators that are assumed to represent the energy supply associated with the 2010 NOS transmission service requests. Initial runs of this case did not demonstrate that additional transmission (at the level of detail and under the simulation methodology of the model used) was needed for resource integration or delivery to loads.

### The NOS Transmission Case

The third case developed for this study is the same as the second, with the inclusion of transmission additions intended to help service the 2010 NOS generation. The three modifications included:

1. The Colstrip Upgrade Project – West, consisting of additions and modifications of series capacitors and shunt capacitors, modification of shunt reactor switching schemes, and reconductoring the Dworshak-Taft circuit 1 500-kV line, resulting in an increase of the West of Garrison rating from 2,200 to 2,800 MW from east to west;
2. Adding a 500-230 kV transformer on the 500-kV line between the Grizzly and Captain Jack substations in Oregon, located near and connecting to the 230-kV Ponderosa bus;
3. Adding a second 230-115 kV transformer at the Portal Way substation in Washington and making other adjustments to increase the Northwest to Canada West path rating in the north to south direction from 1,571 to 2,335 MW.

### Results and Observations

Figure 3 shows the variable fuel and O&M costs for thermal units operating in the Western Interconnection in 2010. About 11% of these costs are incurred in the Northwest region, where the majority of generation comes from hydro and wind, which show no variable costs in this study.

Figure 3: 2019 Variable Production Costs, in \$Millions

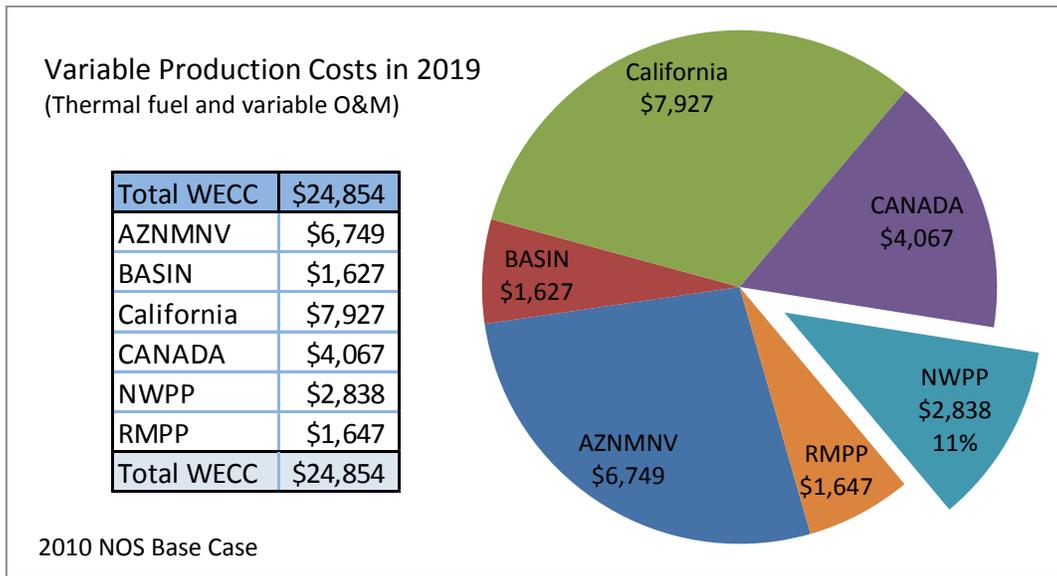


Figure 4 and Figure 5 show the fraction of the energy needed to serve 2019 loads that came from various types of generation, for the entire interconnection and the Northwest, respectively.

Figure 4: Sources of Energy Used to Serve WECC Loads in 2019

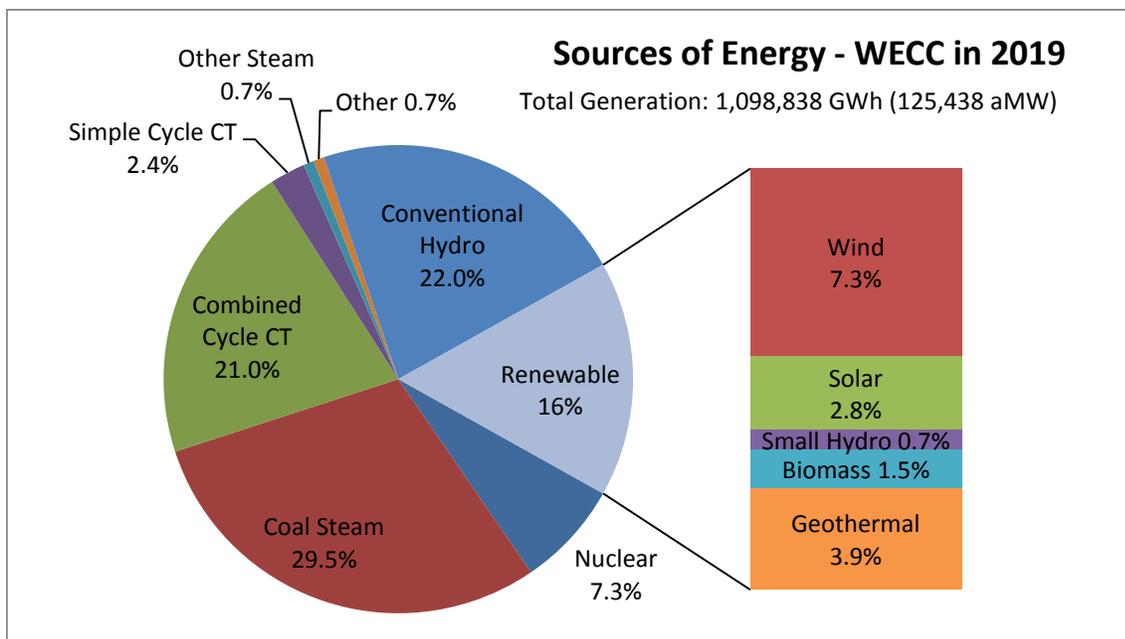
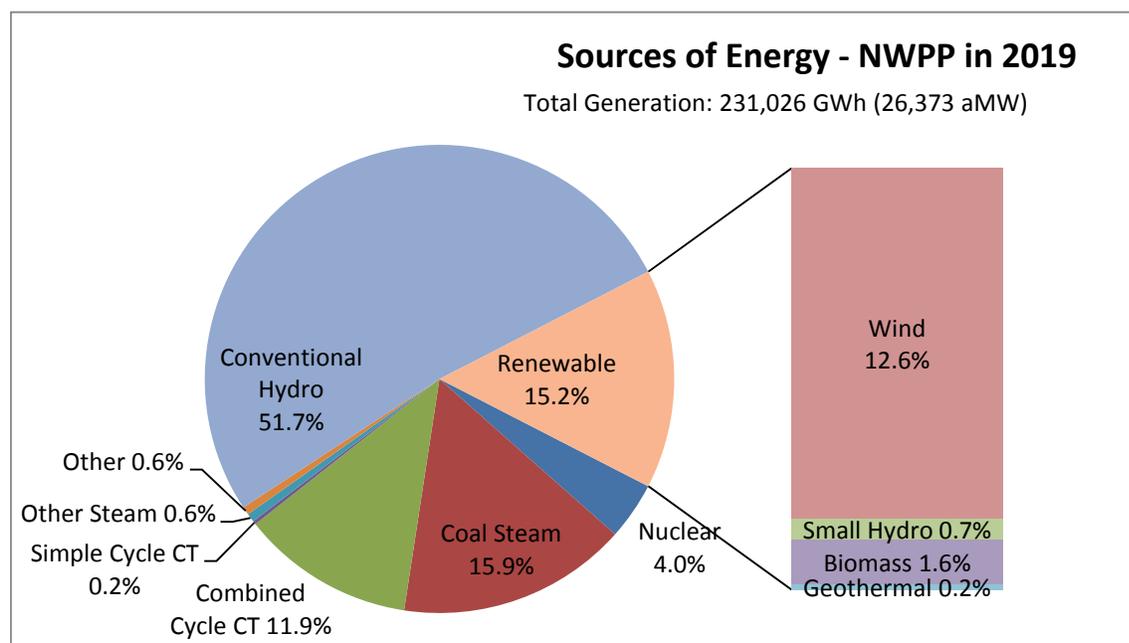


Figure 5: Sources of Energy Used to Serve Northwest Loads in 2010



Overall, the West is estimated to get about 16% of its energy from renewable resources, while the Northwest gets over 15% from renewables – more than one eighth from wind alone. This compares, for the Northwest, to 5.3% of energy from renewables in the earlier 2010-focused study done for the 2008 NOS and 13% of energy in the 2009 NOS study.

Table 3: Annual Variable Cost Savings with 2010 NOS's TSR-Associated Resources

Total Annual Generation Cost (\$Millions)

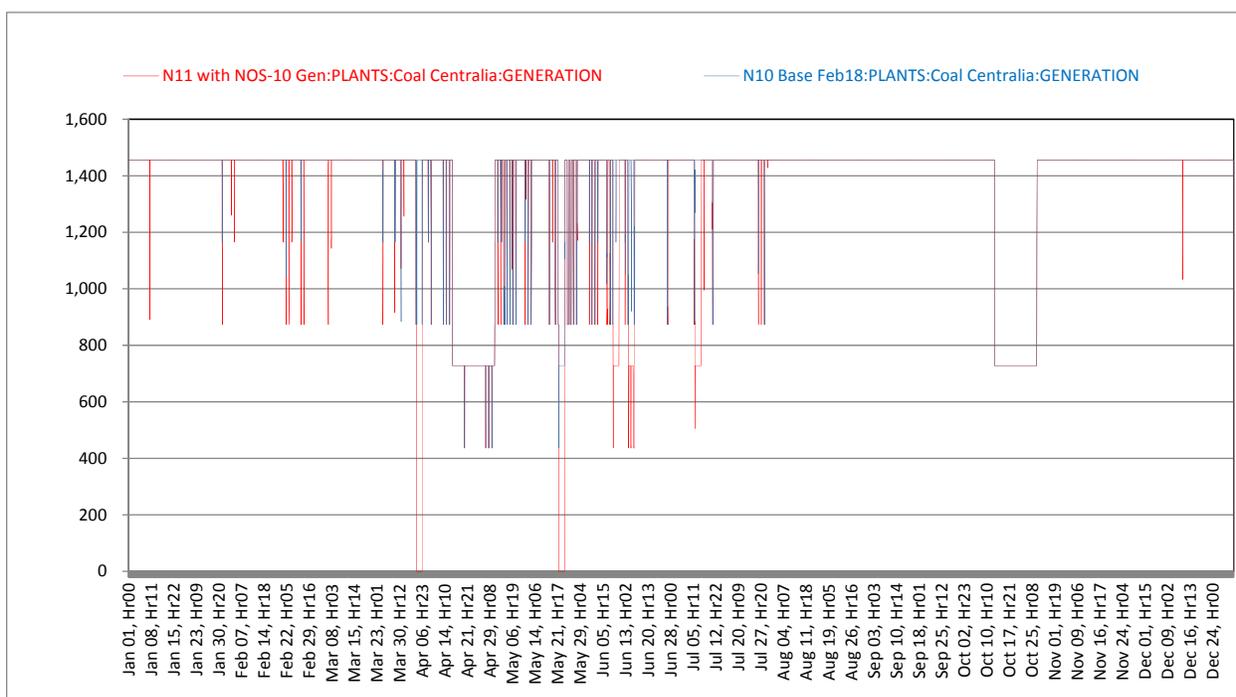
|                           | Change from Base Case |                   |                          |                   |                          | Delta  |
|---------------------------|-----------------------|-------------------|--------------------------|-------------------|--------------------------|--------|
|                           | Base Case             | with 2010 NOS Gen | with 2010 NOS Gen, Trans | with 2010 NOS Gen | with 2010 NOS Gen, Trans |        |
| (Thermal Generation Only) |                       |                   |                          |                   |                          |        |
| Total WECC                | \$24,854              | \$24,448          | \$24,419                 | (\$406)           | (\$435)                  | (\$29) |
| AZ-NM-NV Basin            | \$6,749               | \$6,671           | \$6,685                  | (\$78)            | (\$64)                   | \$14   |
| California                | \$1,627               | \$1,593           | \$1,607                  | (\$33)            | (\$20)                   | \$14   |
| Canada                    | \$7,927               | \$7,803           | \$7,771                  | (\$123)           | (\$156)                  | (\$33) |
| NWPP                      | \$4,067               | \$4,059           | \$4,055                  | (\$8)             | (\$12)                   | (\$5)  |
| RMPP                      | \$2,838               | \$2,699           | \$2,666                  | (\$139)           | (\$172)                  | (\$33) |
|                           | \$1,647               | \$1,623           | \$1,636                  | (\$24)            | (\$11)                   | \$13   |

Includes only fuel and variable operations and maintenance costs

As can be seen in Table 3, about 34% of production cost savings resulting from addition of the 2010 NOS resources occur in the Northwest, with the remaining savings appearing in all other regions to varying degrees. The thermal production cost savings (estimated by this model at \$406 million in 2010) come at the expense, not just of reduced output from thermal generators, but of increased cycling of generators designed for base-load operation.

The generation additions associated with the 2010 NOS TSRs are accommodated with the transmission improvements identified in the 2008 NOS analyses (though with increased transmission congestion) and with substantial production cost savings. However, as can be seen in Figure 6, normally low-cost and constantly-loaded coal-fired generators show increased cycling to accommodate the variable output of additional wind-powered generation. This cycling reflects the single-system dispatch of the computer model and actual operation may require economic or policy inducements for generators to incur such cycling.

**Figure 6: Base Load Coal Cycling to Accommodate Substantial Wind Generation**



The generation projects added in this study are in the same geographical area as the bulk of those associated with the 2008 and 2009 NOS TSRs, resulting in a lack of wind-pattern diversity. Consequently, the new wind generators have peak and minimum output at the same time as many previous resource additions. At peak wind output, most of the Northwest fossil generation has already been displaced by the ‘older’ wind generators, leaving the new wind to displace out-of-region generators, while at times of low wind in the Oregon-Washington wind zones, the new projects offer no diversity and only exacerbate operational problems.

Congestion on BPA’s network flowgates increased with the new generation, requiring some redispatch of other resources. As can be seen in Table 4, the Base Case hours above 75% of rating

were, for example, 80 fewer on the West of John Day flowgate than when the new generating projects were added.

But the new resources are accommodated (again, as measured by metrics in this study) by the transmission reinforcements associated with the 2008 and 2010 Network Open Seasons. Congestion hours on internal interfaces are relatively small, with all of them at less than 2% of annual hours. The West of Slatt and West of John Day flow gates shows increases in congestion, as coincident peak wind pushes to get to the California interties.

There were no unserved loads and only trivial amounts of ‘spilled’ or unusable generation in these simulations. However, if the additional cycling of base-load generation is not permissible, the energy associated with the cycling could be interpreted as feathered (lost) wind generation.

**Table 4: Congestion Hours above 75% of Limits on Northwest Interfaces**

| Annual Hours At or Above 75%<br>of Path or Flowgate Rating | Congestion Hours |                      |                                | Difference           |                                |
|--|------------------|----------------------|--------------------------------|----------------------|--------------------------------|
|  | Base Case        | with 2010<br>NOS Gen | with 2010<br>NOS Gen,<br>Trans | with 2010<br>NOS Gen | with 2010<br>NOS Gen,<br>Trans |
| <b>Internal</b>  |                  |                      |                                |                      |                                |
| Raver - Paul   | 14               | 63                   | 5                              | 49                   | (9)                            |
| Paul - Allston   | 278              | 279                  | 292                            | 1                    | 14                             |
| South of Allston   | 41               | 45                   | 42                             | 4                    | 1                              |
| North of Hanford   | 273              | 245                  | 168                            | (28)                 | (105)                          |
| North of John Day  | 195              | 252                  | 265                            | 57                   | 70                             |
| West of Cascades - North                                   | 184              | 175                  | 198                            | (9)                  | 14                             |
| West of Cascades - South                                   | 14               | 18                   | 16                             | 4                    | 2                              |
| West of McNary   | 0                | 0                    | 1                              | 0                    | 1                              |
| West of Slatt  | 35               | 168                  | 180                            | 133                  | 145                            |
| West of John Day   | 43               | 123                  | 108                            | 80                   | 65                             |
| <b>External</b>  |                  |                      |                                |                      |                                |
| NW to Canada East BC                                       | 2,712            | 2,557                | 2,643                          | (155)                | (69)                           |
| NW to Canada West BC                                       | 1,592            | 1,156                | 574                            | (436)                | (1,018)                        |
| Montana - Northwest  | 3,603            | 1,256                | 3,507                          | (2,347)              | (96)                           |
| West of Garrison   | 4,347            | 5,427                | 3,588                          | 1,080                | (759)                          |
| Bridger West   | 7,780            | 7,770                | 7,737                          | (10)                 | (43)                           |
| Idaho - Northwest  | 4                | 4                    | 9                              | 0                    | 5                              |
| Midpoint - Summer Lake                                     | 34               | 25                   | 18                             | (9)                  | (16)                           |
| California-Oregon Intertie (COI)                           | 2,375            | 3,185                | 3,123                          | 810                  | 748                            |
| Pacific DC Intertie (PDCI)                                 | 195              | 376                  | 421                            | 181                  | 226                            |

The Colstrip Upgrade Project (West) reduces overall variable operations and maintenance and thermal fuel costs in the Western Interconnection by about \$27 million in 2019 assuming addition

of the NOS-associated wind in Montana. Congestion on the West of Garrison flowgate (at 75% of path rating) is reduced by 1,857 hours.

The Northern Intertie improvements associated with the 2010 NOS reduce WECC-wide production costs by about \$4 million in 2010, based on the assumed generation additions in BC Hydro’s system. The Northern Intertie fixes reduce Northern Intertie (West) congestion by 559 hours, Raver – Paul by 48 hours, and increases congestion on the Northern Intertie (East) by 129 hours and on the Montana – Northwest path by 57 hours, at 75% of path ratings.

**Table 5: Congestion Hours above 90% of Limits on Northwest Interfaces**

| Annual Hours At or Above 90% of Path or Flowgate Rating | Congestion Hours |                   |                          | Difference        |                          |
|---|------------------|-------------------|--------------------------|-------------------|--------------------------|
|   | Base Case        | with 2010 NOS Gen | with 2010 NOS Gen, Trans | with 2010 NOS Gen | with 2010 NOS Gen, Trans |
| <b>Internal</b>   |                  |                   |                          |                   |                          |
| Raver - Paul  | 0                | 2                 | 0                        | 2                 | 0                        |
| Paul - Allston  | 42               | 52                | 49                       | 10                | 7                        |
| South of Allston  | 0                | 0                 | 0                        | 0                 | 0                        |
| North of Hanford  | 48               | 56                | 16                       | 8                 | (32)                     |
| North of John Day                                       | 0                | 8                 | 3                        | 8                 | 3                        |
| West of Cascades - North                                | 0                | 0                 | 0                        | 0                 | 0                        |
| West of Cascades - South                                | 0                | 0                 | 0                        | 0                 | 0                        |
| West of McNary  | 0                | 0                 | 0                        | 0                 | 0                        |
| West of Slatt   | 0                | 0                 | 0                        | 0                 | 0                        |
| West of John Day  | 0                | 3                 | 1                        | 3                 | 1                        |
| <b>External</b>   |                  |                   |                          |                   |                          |
| NW to Canada East BC                                    | 1,476            | 1,328             | 1,329                    | (148)             | (147)                    |
| NW to Canada West BC                                    | 672              | 596               | 94                       | (76)              | (578)                    |
| Montana - Northwest                                     | 990              | 36                | 701                      | (954)             | (289)                    |
| West of Garrison  | 1,343            | 3,610             | 1,600                    | 2,267             | 257                      |
| Bridger West  | 4,818            | 4,731             | 4,587                    | (87)              | (231)                    |
| Idaho - Northwest                                       | 1                | 2                 | 2                        | 1                 | 1                        |
| Midpoint - Summer Lake                                  | 0                | 0                 | 0                        | 0                 | 0                        |
| California-Oregon Intertie (COI)                        | 1,052            | 1,669             | 1,656                    | 617               | 604                      |
| Pacific DC Intertie (PDCI)                              | 86               | 219               | 218                      | 133               | 132                      |

**Table 6: Congestion Hours above 99% of Limits on Northwest Interfaces**

| Annual Hours At or Above 99%<br>of Path or Flowgate Rating | Congestion Hours |                      |                                | Difference           |                                |
|--|------------------|----------------------|--------------------------------|----------------------|--------------------------------|
|  | Base Case        | with 2010<br>NOS Gen | with 2010<br>NOS Gen,<br>Trans | with 2010<br>NOS Gen | with 2010<br>NOS Gen,<br>Trans |
| <b>Internal</b>  |                  |                      |                                |                      |                                |
| Raver - Paul   | 0                | 0                    | 0                              | 0                    | 0                              |
| Paul - Allston   | 0                | 0                    | 0                              | 0                    | 0                              |
| South of Allston   | 0                | 0                    | 0                              | 0                    | 0                              |
| North of Hanford   | 7                | 3                    | 0                              | (4)                  | (7)                            |
| North of John Day  | 0                | 0                    | 0                              | 0                    | 0                              |
| West of Cascades - North                                   | 0                | 0                    | 0                              | 0                    | 0                              |
| West of Cascades - South                                   | 0                | 0                    | 0                              | 0                    | 0                              |
| West of McNary   | 0                | 0                    | 0                              | 0                    | 0                              |
| West of Slatt  | 0                | 0                    | 0                              | 0                    | 0                              |
| West of John Day   | 0                | 0                    | 0                              | 0                    | 0                              |
| <b>External</b>  |                  |                      |                                |                      |                                |
| NW to Canada East BC                                       | 846              | 760                  | 734                            | (86)                 | (112)                          |
| NW to Canada West BC                                       | 321              | 378                  | 10                             | 57                   | (311)                          |
| Montana - Northwest  | 107              | 0                    | 90                             | (107)                | (17)                           |
| West of Garrison   | 359              | 2,586                | 739                            | 2,227                | 380                            |
| Bridger West   | 832              | 577                  | 615                            | (255)                | (217)                          |
| Idaho - Northwest  | 0                | 1                    | 1                              | 1                    | 1                              |
| Midpoint - Summer Lake                                     | 0                | 0                    | 0                              | 0                    | 0                              |
| California-Oregon Intertie (COI)                           | 515              | 914                  | 928                            | 399                  | 413                            |
| Pacific DC Intertie (PDCI)                                 | 57               | 143                  | 149                            | 86                   | 92                             |

## Modeling Assumptions

### Simulation

#### Program

This analysis is performed using the ABB GridView hourly generation commitment and dispatch simulation model – a detailed load, generator, transmission and market simulator. This program is considered a valid alternative to the Ventyx PROMOD simulation model used by TEPPC and others; it employs similar methods, scope and data elements.

#### Data Sources

Data used in this project are largely those collected and developed by the Technical Advisory Subcommittee (TAS) of the Transmission Expansion Planning Policy Committee (TEPPC) of the Western Electricity Coordinating Council (WECC). Additional model data and assumptions are provided by BPA staff. Without specific attribution, many descriptions and details are taken from the TEPPC 2008 Annual Report, Appendix B and its attachments, presentations and other documents of TEPPC TAS and its several work groups, and from the actual GridView datasets used in the modeling.

#### Time Horizon

Simulations were performed for calendar year 2019, consistent with the 2009 NOS studies. This examines a period ten years in the future (allowing for an extensive and time-consuming development process), appropriate to the time-scale of generation and transmission development timelines.

### General Data Assumptions

#### Loads

Hourly loads used by the simulation model are created from forecasts of monthly peak-hour and total energy loads, applied to hourly load shapes. Load shapes and forecasts are provided at a 'load-area' geographical scale (roughly corresponding to balancing authority areas). The forecasts are so-called 'system input' loads, with metered customer loads increased by estimates of transmission and distribution system losses. Energy forecasts are either mean or median forecasts, otherwise termed expected loads, while peak-hour loads are generally set at the 95% confidence level of assumed distributions.

#### Resources

Generator data come from a wide range of sources, depending on resource type and the availability of non-confidential plant-specific information. The 2019 TEPPC model of the Western Interconnection has over 2,000 generators, which includes all current in-service generators as well as incremental resources needed to serve loads in 2019.

The TEPPC 2019 PC<sub>1</sub> case models two sets of incremental resources to fill the generation gap – a set of known and generic renewable resources and a set of known and generic conventional resources. The gap is the difference between existing generating capacity and the capacity needed to meet forecasted peak load in 2019 plus a planning reserve margin. In preparing data for these studies, the generic renewable resources in the Northwest were replaced by more specific resources at appropriate buses. Also, resources selected for analysis by the NOS Cluster Study were added. The set of conventional resource additions includes all committed generation (i.e. Class 1 & 2 resources reported to WECC LRS), LRS Class 3 gas-fired resources, and expensive default generators needed to fill the remaining gap.

Fifteen generators associated with 2008 NOS TSRs and nine associated with the 2009 NOS were added to the TEPPC 2019 PC<sub>1</sub> case. Projects were generally given locational names and connected at appropriate buses, though generally at higher-voltage buses to avoid unnecessary modeling of sub-transmission.

Some generators are modeled based on given (primarily historical) hourly data. These include some hydroelectric projects, small generators that are operated without regard to price or demand, and low or zero cost generators, which are assumed to operate whenever they are able.

Dispatchable generators are generally classified as thermal or hydroelectric, which have different modeling representations.

Hydroelectric generators may be simulated using monthly peak and energy values, which are assigned to hours in different ways. One method is base-loading and peak-shaving, where a specified amount of energy is assigned to all hours and the balance of energy is used to serve load when it is highest. A second method, termed proportional load following, is used to shape hydrogeneration into hours in a pattern similar to the load it serves, but with an amplitude that is user input and derived from historical patterns. A third method, called variously dynamic hydro or hydro-thermal co-optimization, uses a more detailed model of hydroelectric project characteristics, such as streamflows and reservoirs. This method is still under testing for GridView and is not used in this project.

Thermal generators use a substantial list of data inputs in the GridView simulation model. These include data for maintenance, forced outages (where Monte Carlo simulation is used), heat rates, emission rates, fuel costs, minimum up and down times, ramp rates, startup and operations and maintenance costs, among others. Due to the need to make model results and assumptions public, most of this data must be taken from public domain information sources and so is often generic and may differ substantially from actual operating parameters of individual generators.

#### Transmission

The PROMOD and GridView simulation models both use detailed transmission models imported from power flow calculation models, such as GE PSLF, PTI PSS/E and PowerWorld. The 2019

TEPPC base case is derived from the WECC 2012 heavy summer base case, and has about 16,000 buses, of which nearly 6,000 are less than 69 kilovolts.

The simulation models perform direct current (DC) optimized power flows for each hour of the study horizon, simultaneously optimizing generator dispatch and flow calculations. In addition to buses, the transmission model includes branches connecting the buses, but does not explicitly model transformers or dynamic elements.

## Loads in More Detail

### Monthly Peak and Energy

Forecasted loads used in the TEPPC 2019 studies come from several sources. The forecasts collected by the WECC Loads and Resources Subcommittee for its forecast are modified by subsequent data submission, such as the California Independent System Operator's forecast and the load forecasted by the Northwest Power and Conservation Council (NPCC).

### Hourly Shapes

Hourly load patterns come, for the most part, from 2002 hourly loads reported to the Federal Energy Regulatory Commission (FERC) on its Form 714. This is done to provide correlated shapes for loads and for hourly hydrogeneration modeled with fixed hourly historical values.

For the WAUW balancing authority area (WAPA Upper Great Plains Region West), the 2005 hourly load shape was used. For four load areas in Nevada and Canada, hourly shapes from the Seams Steering Group – Western Interconnection (SSWGI) were used in deriving the 2017 hourly loads. PacifiCorp provided hourly loads to be used for the modeled load areas in the TEPPC study that fall within its eastern balancing authority area, while the California ISO provided shapes for six load-areas within California. For fourteen load areas associated with the NPCC (in Montana, Idaho, Washington and Oregon), 2002 hourly load shapes were adjusted so that their sum matched the hourly NPCC forecast.

### Losses

The detailed transmission modeling in the GridView program calculates losses between generators and distribution load buses. However, the forecasted loads provided to the model are in the form of 'system input' loads, which generally begin with forecasts by load-serving entities based on metered customer loads and are then increased for the electricity lost in the distribution and transmission system.

GridView provides a built-in mechanism to estimate and remove losses using a quadratic loss matrix calculated at the beginning of program execution. This algorithm produced a loss estimate for BPA's load area (7%) that was out of line with experience. Review of WECC power flow base cases indicated that losses of about 3.4% were generally seen for transmission-level losses, which was approximately equal to the average generation forced outage rate for thermal generation. Given the inability to model forced outages (variation in results due to random outages was

greater than the size of changes being studied), loads were not reduced by transmission losses as an approximate energy offset.

#### Bus Level Loads

The hourly loads are allocated, within the program, to buses in the modeled transmission network using the distribution factors in the TEPPC case's underlying WECC power flow case. In California, the load mapping was adjusted to incorporate information regarding specific pumping loads and their characteristics. Load is allocated to over 6,900 buses across the WECC.

#### Efficiencies and Demand Side Management

Some of the load forecasts used in the modeling incorporate programs to reduce or control energy demand; these are modeled in some programs as separate energy 'resources,' to include them as planning alternatives. These alternatives are not studied here and are included in the area loads.

### Resources in More Detail

#### Thermal Generators

### Fuel Costs

Natural gas prices in the TEPPC 2010 studies and in the BPA economic studies are based on a forecasted annual price at the benchmark Henry Hub in Louisiana, and then adjusted according to a Northwest Planning and Conservation Council methodology that uses basis differences and transportation costs to provide forecasted prices at western regional hubs. Historical seasonal shapes are used to produce monthly gas price forecasts, which are further adjusted for transportation from regional hubs to the load areas of the production cost models. Natural gas costs range from \$7.41 per million Btu near hubs to \$9.00 in more remote areas.

### Emissions

#### *Emissions Modeling*

GridView provides considerable flexibility in modeling emissions. Data in the TEPPC cases and in studies performed here are available for carbon dioxide, sulfur dioxide, and nitrogen oxides. The rates are specified in pounds of emissions per million Btu of fuel consumed, for each type of fuel used at each generator. For this study, no costs were applied to the emissions.

### Operating Characteristics

#### *Maintenance*

Planned maintenance for thermal generators may be specified with specific start and end dates, or by specifying a maintenance window (start and end dates) and a maintenance duration (in days). In the latter case, GridView will adjust the maintenance dates for all such generators to produce

an optimal schedule. For the 2019 PC<sub>1</sub> case, GridView was given explicit maintenance dates from the TEPPC base case.

### ***Forced Outages***

Forced outages are provided for in the GridView model, but their implementation via Monte Carlo outage simulation is too time consuming to use – too many iterations are required to get sufficient convergence to allow the differences among cases to be resolved.

### ***Heat rates***

This study uses heat rate and other operational characteristics (ramp rates, start-up costs, and minimum up and down times) culled from public sources, with some data provided by plant operators and generic heat rates developed from similar-unit data.

Heat rate data for aggregate combined cycle plants was provided by NewEnergy Associates based on the 2006 Gas Turbine World Handbook. These heat rates are difficult to ascertain from public sources, as not all of the combined cycle components are required to have their operating characteristics reported.

Heat rates for thermal units other than combined cycle plants are a mix of data taken from the SSGWI dataset and heat rates provided by NewEnergy Associates.

### ***Minimum run-time***

For TEPPC cases (and consequently in the current project) some tuning adjustments were made by increasing minimum run-times of large coal plants and adjusting combined-cycle operational parameters. These adjustments produced an operation more in line with historical records.

### **Hydroelectric Generators**

The analysis is based on a single streamflow condition, largely the 2002 actual streamflow year, which approximates a median (50-50) hydro year, except for California hydro, where 2003 is used (2002 was a low water year there).

Data from 2002 were also used because, as a more recent year, the operation is more reflective of current operating constraints imposed by evolving ‘biological opinions’ that require special efforts be made to favor survival of threatened and endangered salmon stocks.

### **Wind Generators**

Wind generators comprised about 70% of the incremental resources for the PC<sub>1</sub> case. Reserves required to integrate 3000 MW of Northwest wind generation are assumed to be held by proportional load-following hydro generation. Wind generation in excess of this amount is integrated by re-dispatch of thermal generators or, where constraints prevent delivery, by ‘spilling’ the energy. Wind shapes used for this study were developed by the National Renewable Energy Laboratory. Five shapes were developed by WECC staff and others for geographical areas in Oregon and four for areas in Washington, with additional curves in other Western states.

Six generic ‘RPS’ generators, amounting to 2,930 MW of capacity, were removed from the TEPPC 2019 PC1 starting case. These had been added by TEPPC in order to create the 2019 case with target renewable levels. From the 2008 NOS, 20 more-specific generators were added to create the base case for this study. They were mostly wind generators. As mentioned above, the generating resources associated with the 2008 and 2009 Network Open Seasons were also added.

#### Solar, Geothermal and Biomass Generators

Generation from solar-powered facilities is modeled, like wind, with given hourly energy values. Geothermal and biomass generators are treated as thermal generators with associated fuel costs and heat rates, and generally allowed to be dispatched between 50% and 100% of their capacity.

### Transmission

#### Network Model

The TEPPC 2019 cases are based on WECC’s approved 2012 heavy summer power flow case (12HS2A1). A review by a WECC Transmission Focus Group determined the transmission additions to be made to the 2012 base case that were needed to reliably serve loads and so were likely to be built, irrespective of future resource trajectories.

Among the transmission added by TEPPC were most of the proposed West of McNary and I-5 Corridor reinforcements, including new 500 kV substations at Castle Rock, Knight, and Central Ferry.

The Mercer Ranch substation, bisecting and joining the McNary-John Day and Ashe-Marion lines, does not appear in the TEPPC 2019 PC1 case and was added for this study. While the GridView translation of the TEPPC 2019 PC1 case correctly showed the addition of the Castle Rock substation between Napavine and Allston and the addition of a line from Castle Rock to Troutdale, it did not take the existing Napavine-Allston branch out of the model.

#### Interfaces and Flowgates

The 2019 base case defines interfaces (also referred to as paths or flowgates) in the Western Interconnection. Interfaces are the sum of flows on one or more branches that describe power flow between areas of the power flow network. The WECC Transmission Focus Group began with the path definitions and path ratings in the WECC Path Rating Catalog, then made modifications to capture operating limits for a number of key paths, and made selected de-rates to recognize historical operating transfer capability constraints.

In addition to limiting transfers, interfaces may also be used to model wheeling charges. To help the optimizer in the simulation models solve, the interface limits come with a penalty cost for violation – the model can temporarily exceed the limit while it looks for a minimal cost solution, but the high penalty tends to force the solution back below the limit. However, one may define an interface with a very low limit (1 MW) and a modest penalty cost (say, \$5/MWh) and the model may well find a minimal-cost solution that exceeds the low limit and accepts the penalty (‘wheeling’) cost. No wheeling charges were imposed on interfaces in this study.

There are nineteen interfaces reported in this study, ten internal to the Northwest and nine connecting to or in other regions.

| Interface Name           | From Bus |          |      | Direction | To Bus |          |      | Circuit |
|--------------------------|----------|----------|------|-----------|--------|----------|------|---------|
|                          | Number   | Name     | kV   |           | Number | Name     | kV   |         |
| <b>Raver - Paul</b>      | 40821    | PAUL     | 500. | ←         | 40869  | RAVER    | 500. | 1       |
| <b>Paul - Allston</b>    | 40045    | ALLSTON  | 500. | ←         | 40821  | PAUL     | 500. | 2       |
|                          | 40774    | NAPAVINE | 500. | →         | 40046  | CASTLERK | 500. | 1       |
| <b>South of Allston</b>  | 40041    | ALLSTON  | 115. | →         | 43776  | RAINIER# | 115. | 1       |
|                          | 40045    | ALLSTON  | 500. | →         | 40601  | KEELER   | 500. | 1       |
|                          | 40046    | CASTLERK | 500. | →         | 41095  | TROUTDAL | 500. | 1       |
|                          | 40899    | ROSS     | 230. | ←         | 41161  | WOODLAND | 230. | 1       |
|                          | 43229    | HARBORTN | 230. | ←         | 43601  | TROJAN 2 | 230. | 1       |
|                          | 43541    | ST MARYS | 230. | ←         | 43599  | TROJAN 1 | 230. | 1       |
|                          | 45011    | ASTOR TP | 115. | →         | 45275  | SEASIDE  | 115. | 1       |
|                          | 47095    | VIEW TAP | 115. | ←         | 45201  | MERWIN   | 115. | 1       |
| <b>North of Hanford</b>  | 40287    | COULEE   | 500. | →         | 40499  | HANFORD  | 500. | 1       |
|                          | 40499    | HANFORD  | 500. | ←         | 41113  | VANTAGE  | 500. | 1       |
|                          | 40957    | SCHULTZ  | 500. | →         | 41138  | WAUTOMA  | 500. | 1       |
| <b>North of John Day</b> | 40061    | ASHE     | 500. | →         | 40062  | ASHE R1  | 500. | 2       |
|                          | 40061    | ASHE     | 500. | →         | 40989  | SLATT    | 500. | 1       |
|                          | 40723    | M McNARY | 500. | ←         | 40917  | SACJWA T | 500. | 1       |
|                          | 40821    | PAUL     | 500. | ←         | 40869  | RAVER    | 500. | 1       |
|                          | 41401    | ROCK CK  | 500. | ←         | 41138  | WAUTOMA  | 500. | 1       |
|                          | 41450    | KNIGHT   | 500. | ←         | 41138  | WAUTOMA  | 500. | 1       |

Table 7: Definition of Internal Interfaces (Paths &amp; Flowgates)

| Interface Name           | From Bus |          |      | Direction | To Bus |          |      | Circuit |
|--------------------------|----------|----------|------|-----------|--------|----------|------|---------|
|                          | Number   | Name     | kV   |           | Number | Name     | kV   |         |
| West of Cascades - North | 40223    | CHIEF J3 | 345. | →         | 40993  | SNOHOMS3 | 345. | 3       |
|                          | 40225    | CHIEF J4 | 345. | →         | 40994  | SNOHOMS4 | 345. | 4       |
|                          | 40233    | CHIEF JO | 500. | →         | 40749  | MONROE   | 500. | 1       |
|                          | 40261    | COLUMBIA | 230. | →         | 40303  | COVINGTN | 230. | 1       |
|                          | 40285    | COULEE   | 300. | →         | 40795  | OLYMPIA  | 300. | 1       |
|                          | 40381    | ECHOLAKE | 500. | ←         | 40957  | SCHULTZ  | 500. | 1       |
|                          | 40691    | MAPLE VL | 345. | ←         | 40891  | ROCKY RH | 345. | 1       |
|                          | 40869    | RAVER    | 500. | ←         | 40957  | SCHULTZ  | 500. | 1       |
|                          | 40869    | RAVER    | 500. | ←         | 40957  | SCHULTZ  | 500. | 3       |
|                          | 40869    | RAVER    | 500. | ←         | 40957  | SCHULTZ  | 500. | 4       |
|                          | 42312    | CASCADEP | 230. | ←         | 46831  | ROCKYRH1 | 230. | 1       |
|                          | 42361    | WIND RDG | 230. | ←         | 46169  | WANAPUM  | 230. | 1       |
| West of Cascades - South | 40039    | ALFALFA  | 230. | →         | 40141  | N BONNVL | 230. | 1       |
|                          | 40061    | ASHE     | 500. | →         | 40062  | ASHE R1  | 500. | 2       |
|                          | 40111    | BIG EDDY | 500. | →         | 40809  | OSTRNDER | 500. | 1       |
|                          | 40155    | BUCKLEY  | 500. | →         | 40699  | MARION   | 500. | 1       |
|                          | 40585    | JOHN DAY | 500. | →         | 40699  | MARION   | 500. | 1       |
|                          | 40721    | MCNARY   | 345. | →         | 40901  | ROSS     | 345. | 1       |
|                          | 40809    | OSTRNDER | 500. | ←         | 41450  | KNIGHT   | 500. | 1       |
|                          | 41341    | BIGEDDY1 | 230. | →         | 40813  | PARKDALE | 230. | 1       |
|                          | 41342    | BIGEDDY2 | 230. | →         | 40213  | CHEMAWA  | 230. | 1       |
|                          | 41343    | BIGEDDY3 | 230. | →         | 43313  | MCLOUGLN | 230. | 1       |
| West of McNary           | 47814    | JONESCYN | 230. | →         | 41079  | TMBLCR T | 230. | 1       |
|                          | 40721    | MCNARY   | 345. | →         | 40901  | ROSS     | 345. | 1       |
|                          | 40723    | MCNARY   | 500. | →         | 49962  | MERC RAN | 500. | 1       |
|                          | 40939    | SANTIAM  | 230. | ←         | 41079  | TMBLCR T | 230. | 1       |
|                          | 41343    | BIGEDDY3 | 230. | ←         | 40511  | HARVALUM | 230. | 1       |
| West of Slatt            | 43123    | COYOTE   | 500. | →         | 40989  | SLATT    | 500. | 1       |
|                          | 40155    | BUCKLEY  | 500. | ←         | 40989  | SLATT    | 500. | 1       |
|                          | 40585    | JOHN DAY | 500. | ←         | 40989  | SLATT    | 500. | 1       |
| West of John Day         | 49962    | MERC RAN | 500. | →         | 40585  | JOHN DAY | 500. | 1       |
|                          | 40111    | BIG EDDY | 500. | ←         | 40585  | JOHN DAY | 500. | 1       |
|                          | 40111    | BIG EDDY | 500. | ←         | 40585  | JOHN DAY | 500. | 2       |
| West of John Day         | 40111    | BIG EDDY | 500. | →         | 41450  | KNIGHT   | 500. | 1       |

Table 8: Definition of External Interfaces (Paths)

| Interface Name                     | From Bus |          |      | Direction | To Bus |          |      | Circuit |
|------------------------------------|----------|----------|------|-----------|--------|----------|------|---------|
|                                    | Number   | Name     | kV   |           | Number | Name     | kV   |         |
| NW to Canada East BC               | 50822    | NLYPHS   | 230. | ←         | 40145  | BOUNDARY | 230. | 1       |
|                                    | 52219    | WAN230   | 230. | ←         | 40145  | BOUNDARY | 230. | 1       |
| NW to Canada West BC               | 50194    | ING500   | 500. | ←         | 40323  | CUSTER W | 500. | 1       |
|                                    | 50194    | ING500   | 500. | ←         | 40323  | CUSTER W | 500. | 2       |
| Montana - Northwest                | 40391    | ELMO     | 115. | ←         | 62066  | KERR     | 115. | 1       |
|                                    | 40451    | GAR1EAST | 500. | →         | 40459  | GARRISON | 500. | 1       |
|                                    | 40453    | GAR2EAST | 500. | →         | 40459  | GARRISON | 500. | 1       |
|                                    | 40457    | GARRISON | 230. | ←         | 62072  | OVANDO   | 230. | 1       |
|                                    | 40551    | HOT SPR  | 230. | ←         | 62344  | PLACIDLK | 230. | 1       |
|                                    | 40867    | RATTLE S | 230. | ←         | 62009  | RATTLE S | 161. | 1       |
|                                    | 48053    | BURKAVAA | 115. | →         | 48051  | BURKE    | 115. | 1       |
|                                    | 48055    | BURKAVAB | 115. | →         | 48051  | BURKE    | 115. | 1       |
|                                    | 62004    | MILL CRK | 230. | →         | 40457  | GARRISON | 230. | 1       |
|                                    | 62339    | ANA BPA  | 230. | →         | 40457  | GARRISON | 230. | 1       |
| West of Garrison                   | 40391    | ELMO     | 115. | ←         | 62066  | KERR     | 115. | 1       |
|                                    | 40457    | GARRISON | 230. | →         | 40867  | RATTLE S | 230. | 1       |
|                                    | 40459    | GARRISON | 500. | →         | 41057  | TAFT     | 500. | 2       |
|                                    | 40459    | GARRISON | 500. | →         | 41057  | TAFT     | 500. | 1       |
|                                    | 48053    | BURKAVAA | 115. | →         | 48051  | BURKE    | 115. | 1       |
|                                    | 62072    | OVANDO   | 230. | →         | 62344  | PLACIDLK | 230. | 1       |
| Bridger West                       | 60085    | BRIDGER  | 345. | →         | 60092  | BRIDGE&B | 345. | 1       |
|                                    | 60085    | BRIDGER  | 345. | →         | 67791  | POPCAP&1 | 345. | 1       |
|                                    | 60085    | BRIDGER  | 345. | →         | 67792  | POPCAP&2 | 345. | 1       |
|                                    | 67801    | JB PST   | 345. | ←         | 60085  | BRIDGER  | 345. | 1       |
| Idaho - Northwest                  | 48197    | LOLO     | 230. | ←         | 60278  | IMNAHA   | 230. | 1       |
|                                    | 60150    | HELLSCYN | 230. | →         | 45103  | HURICANE | 230. | 1       |
|                                    | 60155    | HEMINWAY | 500. | →         | 45029  | BURNS    | 500. | 1       |
|                                    | 60192    | LADD     | 230. | →         | 40621  | LAGRANDE | 230. | 1       |
|                                    | 60310    | QUARTZTP | 230. | →         | 40621  | LAGRANDE | 230. | 1       |
|                                    | 61826    | HINES    | 115. | →         | 40507  | HARNEY   | 115. | 1       |
| Midpoint - Summer Lake             | 60155    | HEMINWAY | 500. | →         | 45029  | BURNS    | 500. | 1       |
| California - Oregon Intertie (COI) | 40687    | MALIN    | 500. | →         | 30005  | ROUND MT | 500. | 2       |
|                                    | 40687    | MALIN    | 500. | →         | 30005  | ROUND MT | 500. | 1       |
|                                    | 45035    | CAPTJACK | 500. | →         | 30020  | OLINDA   | 500. | 1       |
| Pacific DC Intertie (PDCI)         | 40111    | BIG EDDY | 500. | →         | 41311  | CELILO1  | 500. | 1       |
|                                    | 40111    | BIG EDDY | 500. | →         | 41312  | CELILO2  | 500. | 2       |
|                                    | 41341    | BIGEDDY1 | 230. | →         | 41313  | CELILO3  | 230. | 3       |
|                                    | 41343    | BIGEDDY3 | 230. | →         | 41314  | CELILO4  | 230. | 4       |

## Ratings

**Interfaces and Flowgates**

The simulation programs, PROMOD and GridView, allow monthly limits in ‘forward’ and ‘reverse’ directions to be specified (branches are defined by the two buses they connect, as ordered pairs, with positive flow associated with flow from the first bus to the second).

**Table 9: Interface Limits used in this Study**

| Interface Limits (Megawatts)     | Without NOS 2010 Trans |          | With 2010 NOS Trans |          |
|----------------------------------|------------------------|----------|---------------------|----------|
|                                  | + Limit                | - Limit  | + Limit             | - Limit  |
| <b>Internal</b>                  |                        |          |                     |          |
| Raver - Paul                     | 1,450                  | (1,450)  | 1,700               | (1,700)  |
| Paul - Allston                   | 2,900                  | (3,000)  | 2,900               | (3,000)  |
| South of Allston                 | 4,100                  | (2,000)  | 4,100               | (2,000)  |
| North of Hanford                 | 4,100                  | (3,300)  | 4,100               | (3,300)  |
| North of John Day                | 8,400                  | (8,400)  | 8,400               | (8,400)  |
| West of Cascades - North         | 10,200                 | (99,999) | 10,200              | (99,999) |
| West of Cascades - South         | 7,700                  | (9,999)  | 7,700               | (9,999)  |
| West of McNary                   | 4,500                  | (9,999)  | 4,500               | (9,999)  |
| West of Slatt                    | 5,500                  | (9,999)  | 5,500               | (9,999)  |
| West of John Day                 | 3,450                  | (9,999)  | 3,450               | (9,999)  |
| <b>External</b>                  |                        |          |                     |          |
| NW to Canada East BC             | 300                    | (300)    | 300                 | (300)    |
| NW to Canada West BC             | 1,500                  | (1,571)  | 1,500               | (2,335)  |
| Montana - Northwest              | 2,200                  | (1,350)  | 2,200               | (1,350)  |
| West of Garrison                 | 2,200                  | (99,999) | 2,800               | (99,999) |
| Bridger West                     | 2,200                  | (9,999)  | 2,200               | (9,999)  |
| Idaho - Northwest                | 2,400                  | (1,200)  | 2,400               | (1,200)  |
| Midpoint - Summer Lake           | 1,500                  | (550)    | 1,500               | (550)    |
| California-Oregon Intertie (COI) | 4,800                  | (3,675)  | 4,800               | (3,675)  |
| Pacific DC Intertie (PDCI)       | 3,100                  | (2,780)  | 3,100               | (2,780)  |

**Branches**

Branches (transmission line segments between buses) have ratings and may or may not be monitored (enforced). In the 2019 TEPPC base case, 910 branches are monitored, out of 19,637 in service. In general, enforcement of branch limits produces a computational burden, and many of the branches in the model are insignificant (low voltage) or unlikely to be loaded beyond their limits by any expected system operation.

Branches in GridView have three rating levels, termed RateA, RateB, and RateC. The TEPPC cases and earlier BPA studies use RateA for normal commitment and dispatch and RateB for emergency ratings for both commitment and dispatch. Emergency ratings are only used when the model performs Monte Carlo simulation or contingency analysis of transmission, and so do not come into play for this study.

## The Simulation Model

### The Model Used: ABB GridView

GridView is a detailed and capable simulation model based on linear and dynamic programming, and includes thermal unit commitment and dispatch, hydrogeneration and pumped storage scheduling, wind modeling and so on. The model performs an optimal power flow using security constrained generating unit commitment and dispatch, including co-optimization of energy and ancillary service needs, which provides detailed and flexible modeling of transmission and generation.

GridView performs an hourly chronological simulation for periods from one day to multiple years. It is capable of Monte Carlo simulation to support risk and reliability analyses. It has provision for modeling bid strategies and emissions policies.

The model uses Microsoft Access databases organized at the global (GridView), project and case levels. The case databases for the Western Interconnection are between 30 and 60 megabytes in size, while model output, stored in proprietary binary files, consumes about 2 gigabytes per case. GridView's graphical user interface provides a number of mechanisms for examining and modifying input data and selecting, viewing and exporting outputs.

ABB has developed tools to convert the PDF (Public Database Format) databases exported from PROMOD by the WECC TEPPC into GridView format. The general characteristics of the Ventyx PROMOD model and the GridView model are sufficiently comparable to make the conversion fairly robust and efficient.

### Modeling Hydrogeneration in GridView

The complexity in operating large hydroelectric systems, where output is a function of stream flows, reservoir content, rates of discharge through powerhouses and spillways, and myriad constraints related to flood control, fisheries, recreation, irrigation, releases into downstream projects and so on, makes simulation of these projects problematical.

The initial response to these difficulties by the model developers was to require the user to input hourly generation values for these projects. However, this approach removes any ability of the hydroelectric system to change operation to match loads and the output of other resources. In the WECC, which derives a large fraction of its energy from hydro, this is a serious shortcoming.

GridView and other models have made an effort to better accommodate hydroelectric generation by using a base load, peak-shaving methodology. Some portion of available megawatt-hours is placed in each hour of a period (perhaps a month) at equal levels to provide a constant output. The remaining generation is then assigned to hours where the load is largest, in amounts equal to the maximum capability of the plant less the base-load level.

The next level of hydroelectric generation modeling is to do what is termed proportional load-following (PLF). This is a more sophisticated shaping method than base load, peak-shaving hydro, where the amount of generation in each hour is set in proportion to the per unit load. For instance, where a generator is deemed able to precisely mimic the load shape (its ‘k-factor’ is 1.0), the ratio of hydrogeneration in two hours is the same as the ratio of load in the same two hours. See the section “Proportional Load Following Hydrogeneration Dispatch” below.

The most recent, and most complex, level of hydro modeling in GridView is termed ‘dynamic hydro’ and attempts to account for a number of the operational complexities of these projects. Such a model has been developed in GridView and will accommodate reservoir accounting, routing of discharges, accretions and depletions respecting lag times between upstream release and downstream arrival. This modeling capability has not had data developed and results vetted and so was not available for this study.

### The Load-Hydro-Wind Issue

Like most power system simulation models, GridView does not have a sophisticated system for developing forecasted hourly energy demands. It relies on user-generated hourly loads for what it calls Load Areas that are approximately mapped, in the WECC, to Balancing Authorities.

Similarly, resources with more-or-less random output, like wind, solar power and smaller hydroelectric projects, are also provided as hourly data streams by the user. As noted above, much of the WECC’s regional hydrogeneration may be modeled as fixed hourly inputs as well.

In an effort to provide a more realistic simulation, hourly loads and fixed generation are usually abstracted from historical data. A ‘typical’ historical year might be chosen, or hourly data from a sample of historical years might be averaged.

These hourly shapes or patterns are then scaled to match forecasted monthly or annual values; most often, peak and energy values are forecasted for each month and the hourly shapes are then scaled in such a way that the largest hourly value equals the forecasted peak and the sum of the hourly values equals the energy forecast.

In studies with substantial hydro-generation, a first cut at providing the model with consistent load and hydrogeneration data uses shapes from the same historical year. If other operational constraints on the hydroelectric system remain fairly constant, and if the availability and characteristics of other generating resources do not change substantially, this technique will provide a credible hydrogeneration profile to serve the load.

The introduction of a large amount of wind-powered generating capacity, which is poorly correlated with load, complicates the effort to shape hydrogeneration. The lack of control over when wind energy is available requires that flexible, dispatchable resources change their operation to accommodate the wind output, or the wind output must be rejected (or ‘spilled’). Since wind-powered generation has essentially zero incremental cost and modest environmental

impact, there is strong incentive to accept it to the extent that output from other resources may be modified.

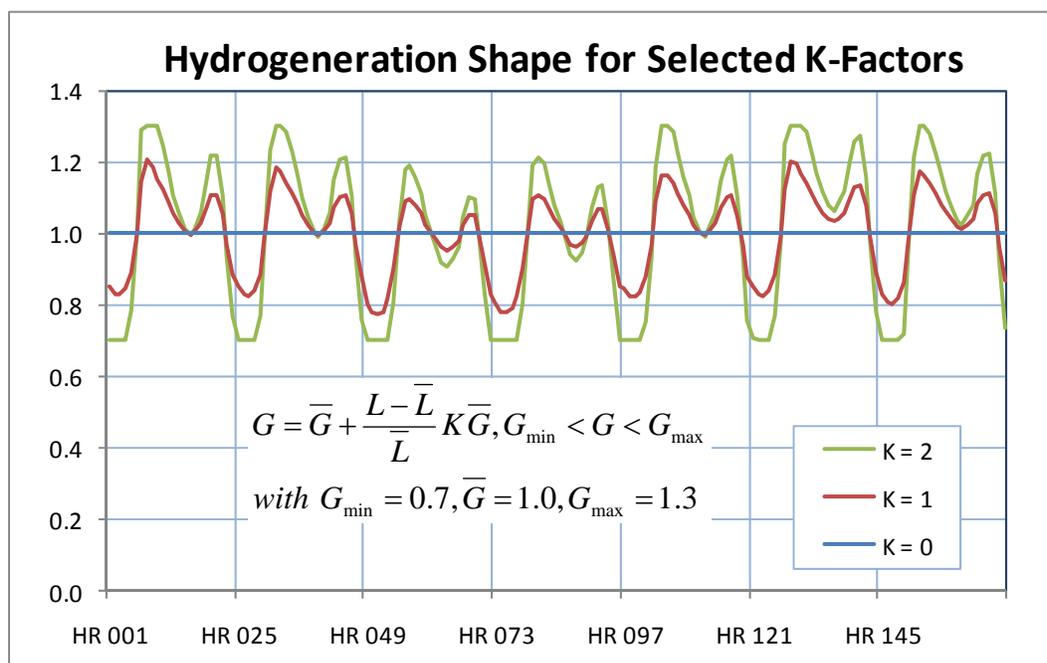
GridView provides a mechanism by which the modeler may specify the amount of wind-powered generation that is to be accommodated by hydrogeneration. This mechanism is based on the proportional load-following hydroelectric dispatch model and its integration with GridView's commitment and dispatch algorithm.

### Proportional Load Following Hydrogeneration Dispatch

Hydroelectric projects with access to sufficient storage, either locally or at upstream projects, may be flexibly dispatched to produce electricity that follows a varying pattern, most often the demand for electricity by customers. Analysis of historical correlations between hydroelectric project generation and load show that it is reasonable to designate various projects as having the ability to follow loads; the degree of this ability is referred to as the 'k-factor'.

Figure 7 shows how the ability to shape hydrogeneration is affected by the k-factor; when it is zero, the project produces a flat output equal to its period average energy; when it's one, the project can closely replicate the shape of load over all hours; and when it's two, the project can actually generate with twice the amplitude of the load. The algorithm for proportional load following allows for limits to be set on maximum and minimum hourly generation from the project, as illustrated in the diagram for the k=2 curve. (The vertical scale measures the 'per unit' output of the project's average energy and per unit of the average energy load, to provide a dimensionless basis for comparison.)

Figure 7: Examples of proportional load following for different k-factors

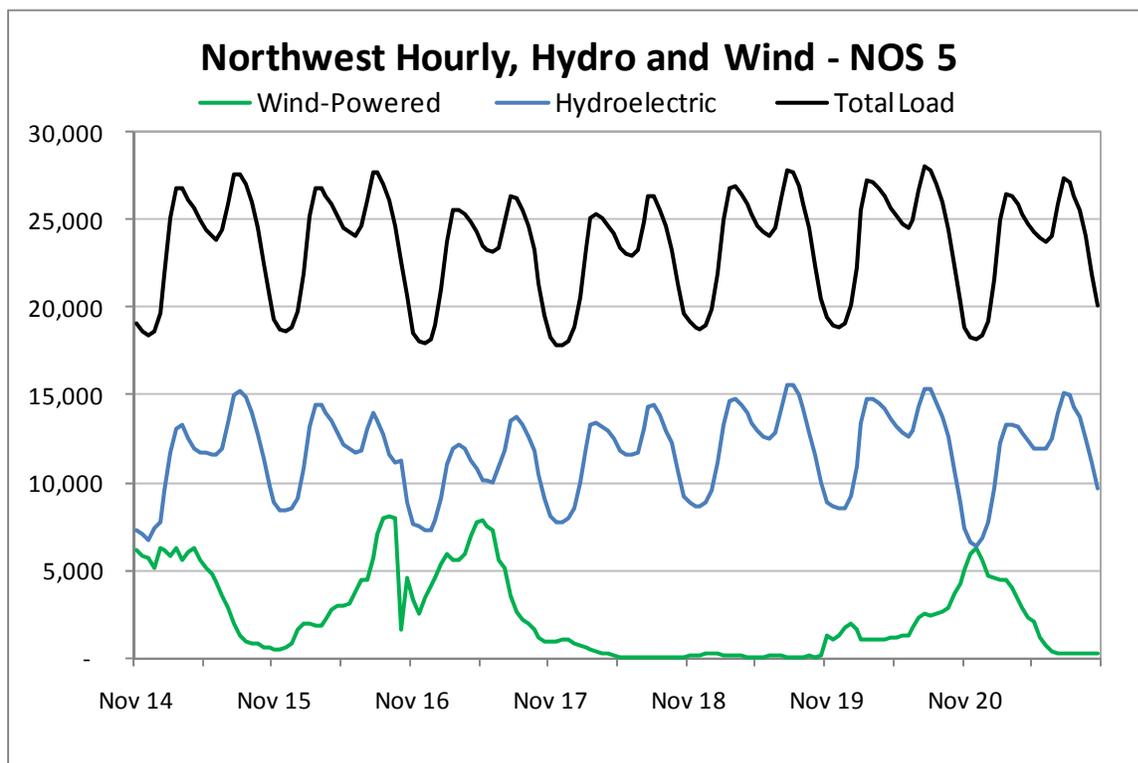


The Grand Coulee project, for example, is constrained by flood control, irrigation requirements, and a limitation on maximum water releases per day, but otherwise has considerable flexibility in its dispatch. Its monthly k factor ranges from 3.0 to 5.62 under median streamflow conditions (represented by 2002 actual hourly generation data). In contrast, the John Day project has more limited storage and additional operational constraints. Consequently, its k factor ranges from 0.84 to 1.52 under median streamflow conditions.

Because hydrogeneration supplies about 75% of Northwest electricity needs (in a median streamflow year), the PLF method is important to provide a reasonable approximation of actual hydroelectric dispatch to serve load. In past studies by TEPPC and SSG-WI<sup>4</sup>, when hourly hydrogeneration from a historical year was directly used by the model, it was also necessary to use the hourly loads from the same historical year, leading to a mismatch in load assumptions in the studies, since the year selected for median streamflows in the Northwest was a dry year in California.

The use of PLF logic not only provides better coordination of hydrogeneration with load, it also allows for modeling of wind-hydro-load integration.

**Figure 8: Sample modification of hydrogeneration to accommodate wind power**



<sup>4</sup> The Seams Steering Group – Western Interconnection was the predecessor organization to the WECC TEPPC and performed economic transmission expansion planning studies for the Western US.

In GridView's logic, proportional load following hydrogeneration is dispatched against the regional load, less any resources that have fixed hourly outputs in that region. This association by region provides a mechanism to define which resources can be accommodated by hydrogeneration: In our case, wind resources assigned to the Northwest region are integrated, while those assigned to a 'dummy' region will be dispatched after hydro. If wind-powered generation from these projects cannot find load to serve economically, it is 'spilled'.

In this study, 3,000 MW of wind generation in the Northwest are assumed to be integrated by Northwest proportional load-following hydrogeneration. Wind in excess of this sum is either integrated by redispatch of other resources or, where constraints prevent its delivery, by rejecting or 'spilling' the energy.

### Modeling Caveats

As with any computer simulation model, there are differences between what the GridView model is able to simulate and what happens in the real world. It is generally impossible to fully represent the behavior of real systems and, although the physics of power plant and transmission operation are well known, human constructs such as power markets, scheduling and dispatch procedures, and rules for generation and transmission operation are complex and can only be modestly represented. Further, the characteristics of generators and markets are mostly kept confidential to protect or enhance the trading position of market participants, requiring the use of generic or estimated data.

#### Single-System Commitment and Dispatch in a Heterogeneous Market

The GridView model is capable of simulating power contracts, generator and load bidding systems, demand-response resources, and other market constructs to more closely represent real-world operation. However, the Western Interconnection operates with a wide diversity of market models, from the market clearing price model of the California Independent System Operator, to power trading exchanges like ICE, to many types of bi-lateral short and long term contracts.

This complexity, combined with the proprietary nature of nearly all information regarding the details of these markets and their transactions, make a close representation of actual market operations impossible.

The simulation of the Western Interconnection as a single-operator dispatch, based on cost of production and delivery, represents an outcome that is probably over-optimistic, given the hybrid nature of the mostly bilateral markets in the West. However, on a comparative basis, GridView's dispatch of the lowest incremental-cost resources to serve load, subject to operational and delivery constraints, is reasonable. In this sense the simulation serves as a bookend: any other operation would be less economically efficient.

### Single-Trajectory Modeling

The GridView model executes for between three and six hours to simulate one year of generation commitment and dispatch in the Western Electricity Coordinating Council. The resulting two gigabytes of output represent a single trajectory into the future – a so-called point estimate.

GridView has the ability to perform random (Monte Carlo) simulation of a number of parameters, including generator forced outages. However, the variation in output among these trials is of the same order of magnitude as the changes our differential analysis is working to detect. Consequently, a large number of trials would be required to get sufficient convergence of measurements, requiring a prohibitive amount of computer time.

In addition, our analysis is based on a single streamflow condition, approximating median (50-50) flows. Both the volume and temporal and geographical distribution of streamflows are subject to wide variation.

Wind generation, directly correlated to wind flows that are highly variable, is also represented as a single set of hourly wind trajectories for each geographical wind region.

Finally, the analysis uses a single hourly load forecast for the WECC. Future electricity demands are subject to economic, policy, technological, climatological and meteorological uncertainties.

All of these un-simulated uncertainties notwithstanding, it must be noted that the model process 8,760 hours in a year, each of which incorporates variation in most of these parameters.