BPA 2009 Network Open Season

Congestion and Production Cost Analysis

April 2010

Comprehensive Power Solutions, LLC
www.comprehensivepower.org

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.

Comprehensive Power Solutions (CPS) and the Bonneville Power Administration (BPA) accept no duty of care to third parties who may wish to make use of or rely on information presented in this report. CPS has exercised due and customary care in developing this report, but has not independently verified information provided by others and makes no further express or implied warranty regarding the report's preparation or content. Therefore, CPS and BPA shall assume no liability for any loss due to errors, omissions or misrepresentations made by others.

This report may not be modified to change its content, character or conclusions without the express written permission of CPS and BPA.

Table of Contents

Table of Figures

Table of Tables

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 2009 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 2009 NOS, is substantially less than was studied for the 2008 NOS. This study found notable impacts on congestion and production costs. In particular, congestion on the West of John Day transmission flow gate more than doubled. Production cost savings were estimated to be about ½% of the cost of dispatching the Western Interconnection. It was also noted that a majority of the production costs savings attributable to the NOS additions occurred in the southern half of the Western Interconnection, and about a third remained in the Northwest.

The study also examined the effects of a cost placed on carbon dioxide emissions. It was observed that total estimated production cost savings were 24% higher when CO_2 emissions were priced at $28/ton and 38% higher at $45/ton, expressed in 2010 dollars[1].

The analysis done here indicates that addition of resources associated with the 2009 NOS to the Northwest high voltage grid, augmented with the transmission improvements proposed as a result of the 2008 NOS, does not produce costly congestion.

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 2009 NOS generation?

[1] All monetary figures in this study are expressed in 2010 dollars.

- What is the effect on BPA's internal flowgate loadings with the 2009 NOS generation additions (frequency of certain path loading levels)?
- Is there a significant change in production costs and internal flowgate loadings due to the imposition of carbon dioxide costs?
- Are the transmission improvements identified in 2008 NOS adequate to accommodate the additional requests under the 2009 NOS?

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.
- Prices studied for carbon dioxide emissions were based on the EIA-estimated cost resulting from the Waxman-Markey bill (for the lower $28/ton price), and from the Northwest Power and Conservation Council's trajectory of CO_2 prices in its sixth power plan (for the higher $45/ton price).

Table 1: Generation Associated with 2009 Network Open Season Transmission Service Requests

Generator Name	Type	MW	Start	End	Bus
NOS-09 Harney 115	Wind	60	12/01/09	12/01/39	Harney 115
NOS-09 Garrison 500	Other	100	01/01/09	01/01/14	Garrison 500
NOS-09 Slatt 500	Wind	100	12/01/11	12/01/16	Slatt 500
NOS-09 Bdman 115 A	Wind	10	02/01/09	08/01/25	Boardman 115
NOS-09 J Day 500 A	Wind	400	01/01/10	01/01/15	John Day 500
NOS-09 Midway 230	Hydro	150	01/01/11	01/01/16	Midway 230
NOS-09 Rocky Rch 230	Other	125	01/01/10	01/01/15	Rocky Reach 230
NOS-09 Dalreed 230	Other	8	03/01/09	03/01/14	Dalreed 230
NOS-09 Wdlnd Tp 230	Hydro	88	05/01/09	07/01/12	Woodland Tap 230
NOS-09 Longview 230	Thermal	12	05/01/09	05/01/14	Longview 230
NOS-09 FCRPS	Hydro	13	10/01/11	10/01/21	FCRPS
NOS-09 J Day 500 B	Wind	91	06/01/09	02/01/19	John Day 500
NOS-09 McNary 500	Wind	200	12/01/12	12/01/17	McNary 500
NOS-09 Garrison 500B	Coal	14	01/01/10	01/01/15	Garrison 500
NOS-09 Vantage 230	Other	4	10/01/12	10/01/19	Vantage 230
NOS-09 Spearfish 115	Hydro	6	01/01/13	01/01/18	Spearfish 115
NOS-09 Alcoa 115	Thermal	25	10/01/11	10/01/16	Alcoa 115
NOS-09 Ch Joe 500	Hydro	25	10/01/11	10/01/16	Chief Joseph 500
NOS-09 J Day 500 C	Hydro	25	10/01/11	10/01/16	John Day 500
NOS-09 Grand Coulee	Hydro	25	10/01/11	10/01/16	Grand Coulee Contig
NOS-09 Bdman 115 B	Wind	72	01/01/10	01/01/24	Boardman 115
Resources Added for 2009 NOS		947			
Resources Assumed Existing		606			
Total NOS Resources		1553			

- Table 1 lists the transmission service requests in the 2009 NOS and highlights the nine assumed to represent new generators with capacity equal to the size of the service request.
- 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.
- Forced outage of generators and transmission is not modeled, as the execution time of the model precludes running sufficient iterations to reduce the random variation of congestion and cost measures far enough to assess the (relatively) small changes associated with these cases.

Cases Studied

In addition to measuring the impact of adding the new resources associated with 2009 NOS TSRs, the study also examined the impact of two other scenarios:

- Imposition of a $5/MWh wheeling charge on all power moving into and out of the Northwest region.
  - Such a change reflects inter-balancing authority transaction hurdles
- Imposition of emission penalty costs on CO_2 emissions in both the base case and with the added resources.
  - $28 and $45 per ton for carbon dioxide emissions from thermal generators.

Results

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, and
- Tons of carbon dioxide emissions from thermal generators in the Western Interconnection.

Table 2: Path and Flowgate Congestion, Variable Costs, and Emissions

Annual Hours at or Above 75% of Path or Flowgate Rating	Base Case	Base Case, Plus $28/Ton CO2 Cost	Base Case, Plus $45/Ton CO2 Cost	with 2009 NOS Projects	with NOS, Plus $28/Ton CO2 Cost	with NOS, Plus $45/Ton CO2 Cost	with NOS, plus $5/MWh Ext. Wheeling
Internal							
North of Hanford	8	4	4	**9**	4	5	2
North of John Day	245	230	207	**242**	230	197	218
Paul - Alston	-	-	-	**-**	-	-	-
Raver - Paul	4	4	20	**8**	4	18	13
South of Allston	46	40	35	**46**	37	34	24
West of Cascades - North	244	255	258	**258**	264	261	293
West of Cascades - South	15	14	14	**19**	18	16	32
West of John Day	6	5	6	**36**	33	37	12
West of McNary	-	-	-	**-**	-	-	-
West of Slatt	-	-	-	**-**	-	-	-
External							
NW to Canada West BC	42	39	39	**39**	43	35	25
NW to Canada East BC	1,828	1,710	1,634	**1,804**	1,716	1,639	1,833
Montana - Northwest	3,666	3,161	1,902	**3,632**	3,062	1,725	3,287
Idaho-Northwest	440	275	132	**406**	262	123	49
Midpoint - Summer Lake	1,339	548	138	**1,411**	529	124	453
Bridger West	1,996	1,906	1,951	**2,102**	1,993	2,200	7,398
Calif.-Oregon Intertie (COI)	2,397	1,833	908	**2,623**	2,035	1,074	2,159
Pacific DC Intertie (PDCI)	98	-	-	**160**	5	-	88

Generation Cost, $Millions (Thermal generation only)

	Base Case	Plus $28 CO2	Plus $45 CO2	w/2009 NOS	Plus $28 CO2	Plus $45 CO2	w/$5 Ext. Whl.
WECC Total	$24,790	$38,128	$45,993	**$24,666**	$37,974	$45,824	$24,645
AZNMNV	$6,767	$10,239	$12,395	**$6,754**	$10,216	$12,376	$6,725
BASIN	$1,665	$3,875	$4,906	**$1,659**	$3,863	$4,888	$1,548
California	$7,868	$10,188	$11,790	**$7,815**	$10,135	$11,739	$8,207
CANADA	$4,059	$6,249	$7,588	**$4,058**	$6,247	$7,587	$4,071
NWPP	$2,764	$4,239	$5,018	**$2,720**	$4,180	$4,946	$2,484
RMPP	$1,666	$3,338	$4,296	**$1,660**	$3,334	$4,288	$1,609

Includes only fuel and variable operations and maintenance costs

Carbon Dioxide Emissions (Thermal generation only)

	Base Case	Plus $28 CO2	Plus $45 CO2	w/2009 NOS	Plus $28 CO2	Plus $45 CO2	w/$5 Ext. Whl.
WECC Amount (Short Tons)	483,405,859	466,922,546	451,030,116	**482,390,752**	465,868,336	449,794,694	482,143,134
WECC Cost ($millions)	$0	$13,073	$20,296	**$0**	$13,044	$20,241	$0

Observations

- The generation additions are accommodated[2] with the transmission improvements identified in the 2008 NOS analyses (though with increased transmission congestion) and with substantial production cost savings.
  - About 36% of production cost savings occur in the Northwest, while 54% accrue to the Pacific Southwest (the balance to the Rocky Mountain and Great Basin regions).
- The generation projects added for this study were in the same geographical area as the bulk of those associated with the 2008 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.
  - 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.

[2] Accommodated in terms of the paths and flowgates monitored in this study.

  - 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 (see Figure 1) increases with the new generation, requiring some redispatch of other resources.
  - But the new resources are accommodated by the transmission reinforcements associated with the 2008 NOS.
  - The West of John Day flow gate shows a significant increase in congestion, as coincident peak wind pushes to get to the California interties.
- Placing a $5/MWh wheeling charge on all interfaces between the Northwest and other regions increases inter-regional price disparities and price volatility.
  - Flows across all external interfaces are reduced significantly (it costs $10/MWh to move power from Wyoming to the Northwest and then from the Northwest to California).
  - Locational marginal prices are reduced in the Northwest, increased in the Southwest.
- When the base case and the case with added resources are rerun with a price placed on carbon dioxide emissions, the production cost benefit is larger. This is because the CO_2 cost pushes dispatch away from lower fuel cost coal-fired to higher fuel cost natural gas-fired generators, and the added (zero-cost) resources displace the highest-cost of the gas-fired generators.
  - Variable production-cost savings increase by 24% when CO_2 is priced at $28/ton and are 38% higher with a $45/ton price.
  - Congestion is reduced on most paths and flowgates, particularly out of coal-producing regions and into California.
- Consideration, by the simulation model, of generator and transmission forced outages would result in greater price volatility and periods of increased congestion.

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 NOS wind generation, resulting in amplification of existing integration issues.
- The transmission grid, with the reinforcements introduced with the 2008 NOS analysis, is adequate (as measured by this study's criteria) to integrate the new generation, though congestion does increase on many paths and flow gates.
- Production cost benefits associated with the addition of the new generation increases in scenarios where costs are imposed on carbon dioxide emissions from thermal generation.
- The impact of imposing a $5/MWh wheeling charge on external paths shows the sensitivity of the model to its underlying assumptions.

Economic Analysis of the BPA 2009 Network Open Season

This study was undertaken to support the Bonneville Power Administration's Regional Economic Benefit Analysis, conducted in conjunction with its 2009 Network Open Season (NOS). Information available to the public regarding BPA's 2009 open season may be found on the BPA Transmission Web site, at:
http://transmission.bpa.gov/customer_forums/open_season_2009/.

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, 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 examined here comprise 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.

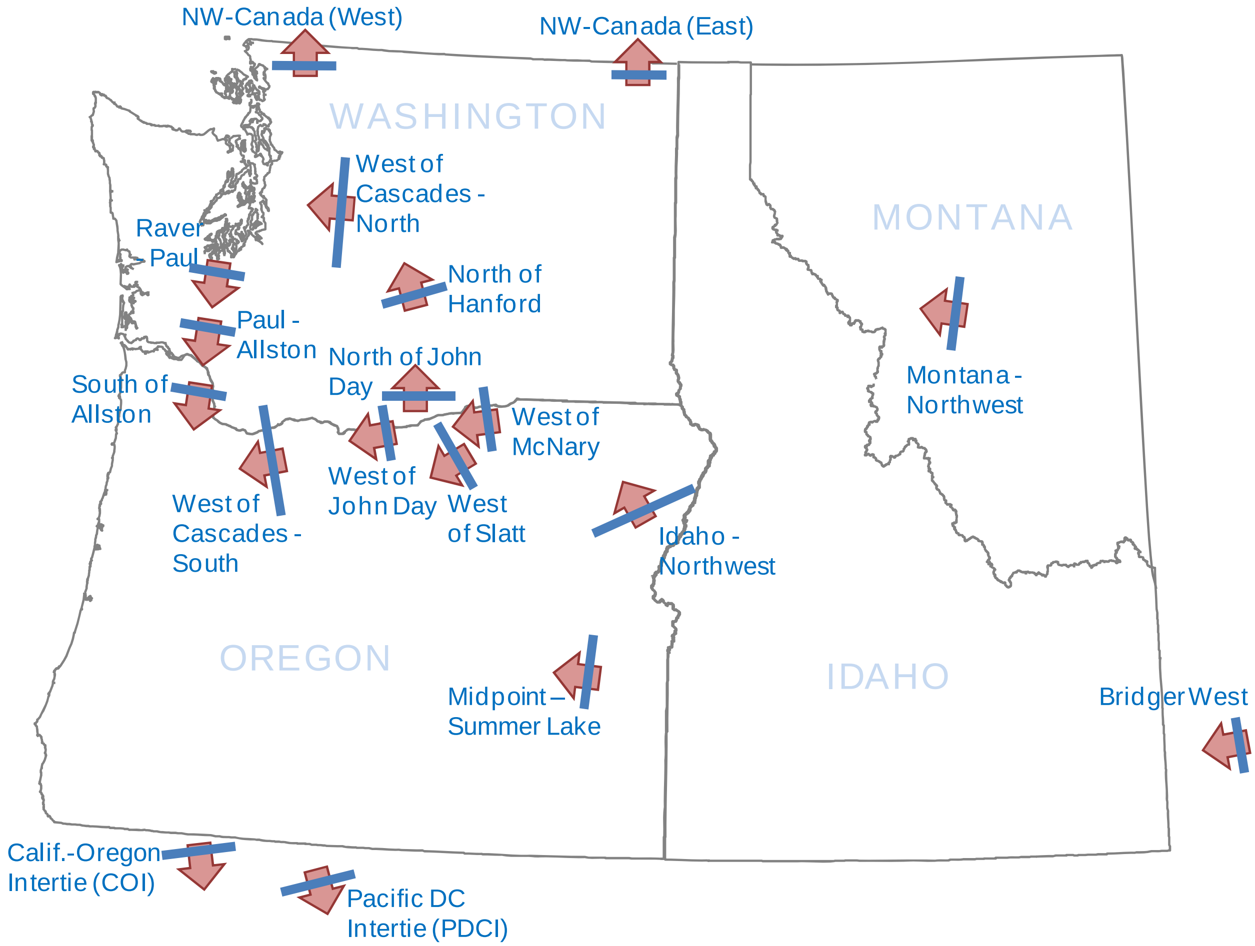
Indications of Congestion – Where and How Much

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 interfaces measuring flows within BPA's system will be termed flowgates. One set of ten interfaces consists of interfaces internal to the Northwest and are important to an analysis of congestion on BPA's system.

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

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 7. 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 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.[3]

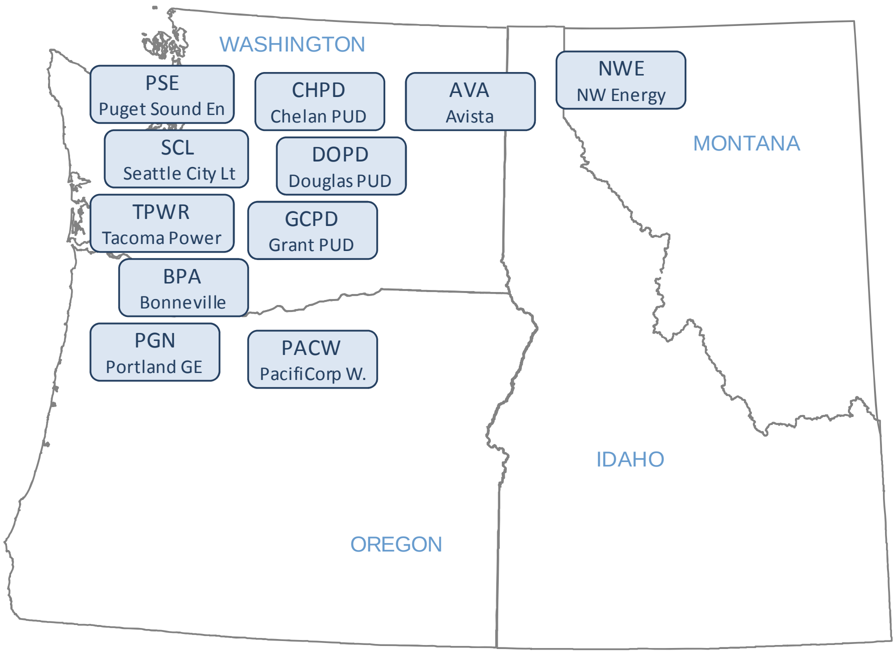
Study Scope – Limited to the Northwest Region

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 since last year and have been subjected to extensive scrutiny and development by the WECC staff and participants in the many TEPPC work groups.

[3] 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 PC1 case developed by TEPPC.[4] That case was adjusted to account for additional detail in the Northwest sub-region, such as the generation additions associated with BPA's 2008 NOS, 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 Case

The second case in this study adds the new generating resources associated with the 2009 Network Open Season and BPA's attendant cluster study. **Error! Reference source not found.** lists the 21 transmission service requests in the 2009 NOS and highlights the 9 that are assumed to represent new generators, with a total capacity of 947 megawatts. 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.

[4] Recent 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=%7b3FECCB9E%2d172C%2d41C1%2d9880%2dA1CF02C537B7%7d

Effect of Adding Resources when Carbon Dioxide Emissions have a Cost

Four additional cases were run, which examine the same question of adding new resources to a base case, but in a situation where there is a price placed on carbon dioxide emissions from thermal generators. Two price levels were examined - $28/ton and $45/ton of CO_2. The basis for these prices is discussed in the assumptions section below.

Impact of Constraint on Power Movement Into and Out Of the Northwest

A third case was developed, which examined the impact of a $5/MWh wheeling charge on power transferred into and out of the Northwest region. This provides a reflection of the real-world economic constraint imposed on many power transactions between regions. Because many such transactions are made under the terms of firm contracts that don't impose variable transportation costs, this case should be looked at as a bookend, at the opposite end from the other cases, which assume no wheeling is paid on power transfers between regions.

Results and Observations

Table 3 shows the variable fuel and O&M costs for thermal units operating in the Western Interconnection in 2019. About 10% 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.

Table 3: 2019 Variable Production Costs, in $Millions

Generation Cost, $Millions	(Thermal generation only)						
	Base Case	Plus $28 CO2	Plus $45 CO2	**w/2009 NOS**	Plus $28 CO2	Plus $45 CO2	w/$5 Ext. Whl.
WECC Total	$24,790	$38,128	$45,993	**$24,666**	$37,974	$45,824	$24,645
AZNMNV	$6,767	$10,239	$12,395	**$6,754**	$10,216	$12,376	$6,725
BASIN	$1,665	$3,875	$4,906	**$1,659**	$3,863	$4,888	$1,548
California	$7,868	$10,188	$11,790	**$7,815**	$10,135	$11,739	$8,207
CANADA	$4,059	$6,249	$7,588	**$4,058**	$6,247	$7,587	$4,071
NWPP	$2,764	$4,239	$5,018	**$2,720**	$4,180	$4,946	$2,484
RMPP	$1,666	$3,338	$4,296	**$1,660**	$3,334	$4,288	$1,609

Includes only fuel and variable operations and maintenance costs

Figure 3 and Figure 4 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 3: Sources of Energy Used to Serve WECC Loads in 2019

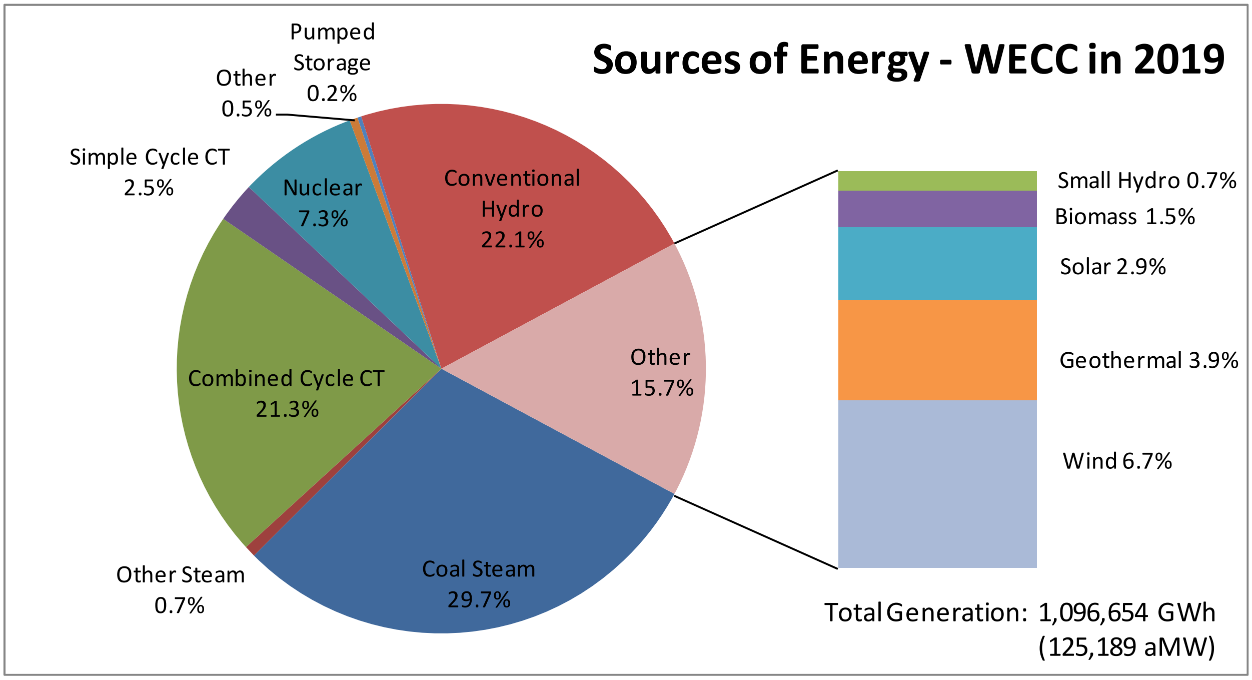
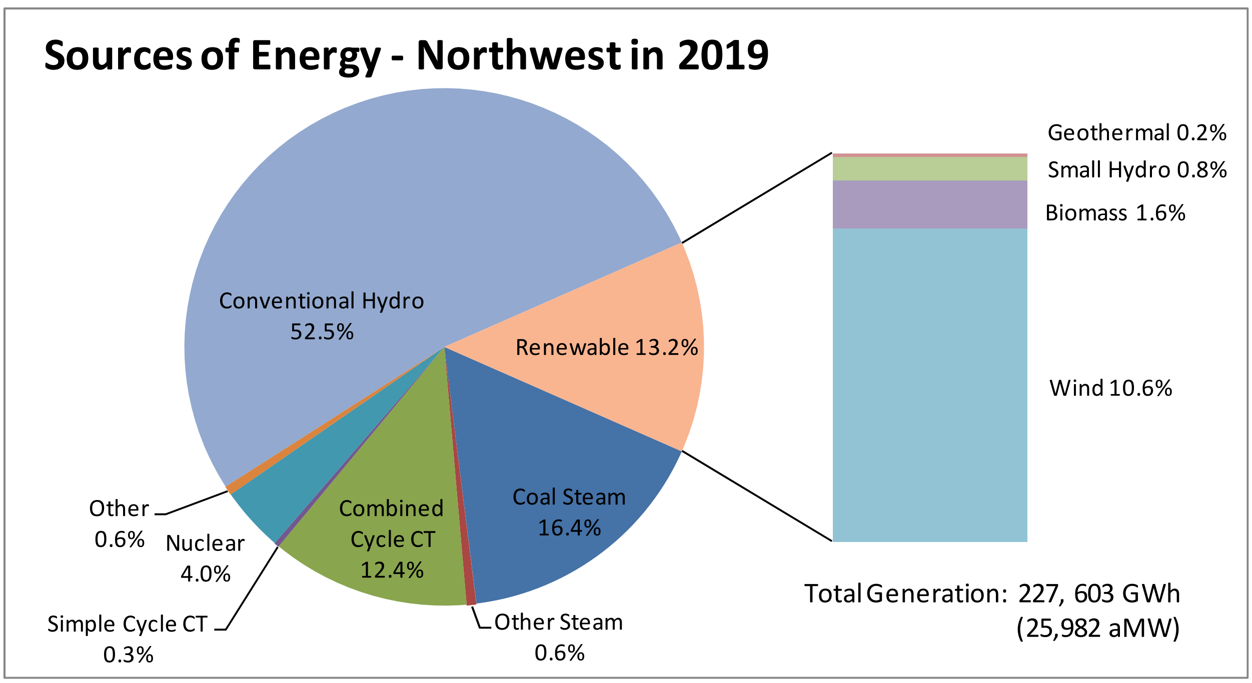


Figure 4: Sources of Energy Used to Serve Northwest Loads in 2019



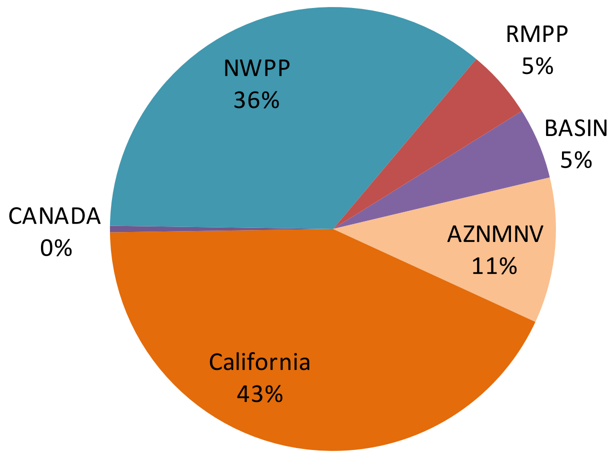
Overall, the West is estimated to get over 15% of its energy from renewable resources, while the Northwest gets over 13% from renewables – more than 10% from wind alone. This compares, for the Northwest, to 5.3% of energy from renewables in the earlier 2017-focused studies done for the 2008 NOS.

Figure 5: Annual Variable Cost Savings with 2009 NOS's TSR-Associated Resources

Production Cost Savings in 2019

Share of $123 Million Total, by Sub-Region

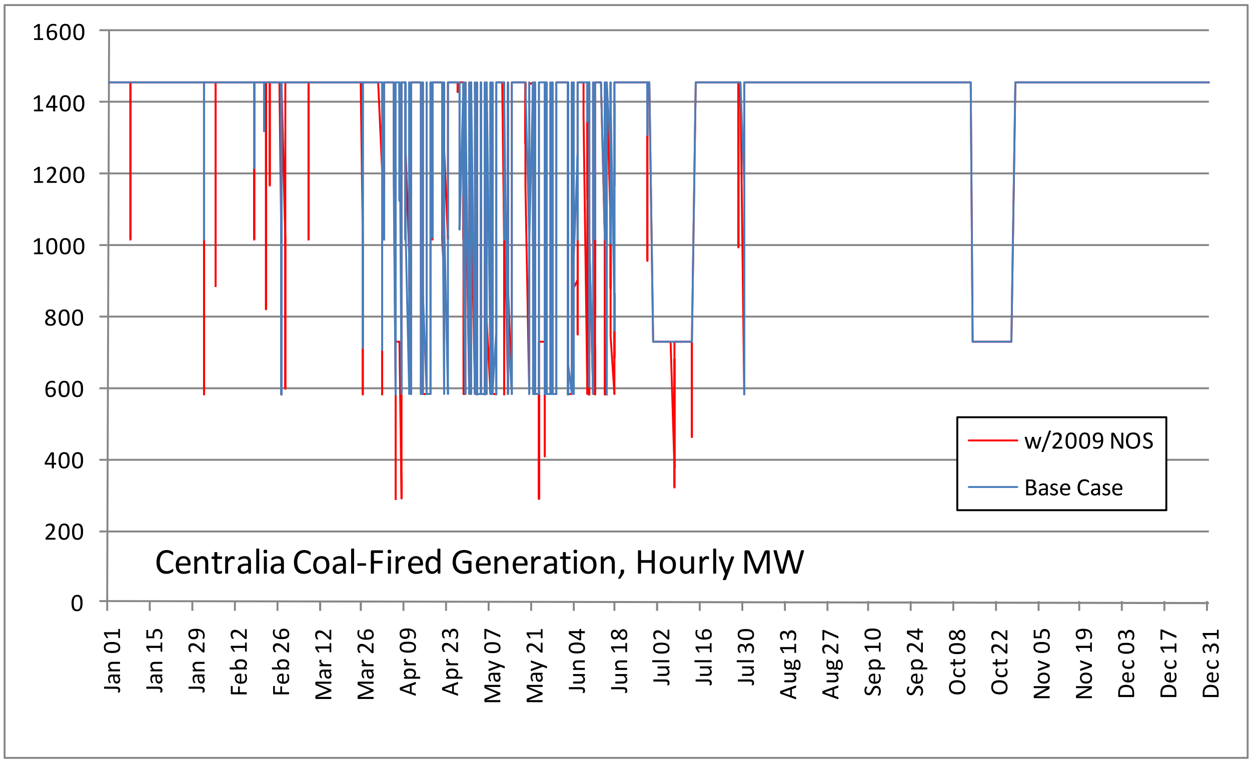
Sub-Region	Savings
BASIN	$6
AZNMNV	$13
California	$53
CANADA	$1
NWPP	$44
RMPP	$6
Total WECC	$123



As can be seen in Figure 5, about 36% of production cost savings occur in the Northwest, while over 54% accrue to the Pacific Southwest, with the remaining 10% in the Rocky Mountain and Great Basin regions. The thermal production cost savings (estimated by this model at $123 million in 2019) 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 2009 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.

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 NOS TSRs, resulting in a lack of wind-regime 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, 30 less 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 NOS. Congestion hours on internal interfaces are relatively small, at less than 3% of annual hours. The West of John Day flow gate shows an increase in congestion, as coincident peak wind pushes to get to the California interties.

Placing a $5/MWh wheeling charge on all interfaces between the Northwest and other regions increases inter-regional price disparities and price volatility (see . Flows across external interfaces are reduced significantly (it costs $10/MWh to move power from Wyoming to the Northwest and then from the Northwest to California). The Bridger West interface shows a marked increase, but it lies to the east of the Idaho-Northwest interface and so was not given an increase in its wheeling rate.

Locational marginal prices are reduced in the Northwest, and increased in the California, by about $2/MWh due to the wheeling charges.

Figure 7: Distribution of Price Differences, with and without $5/MWh External Wheeling

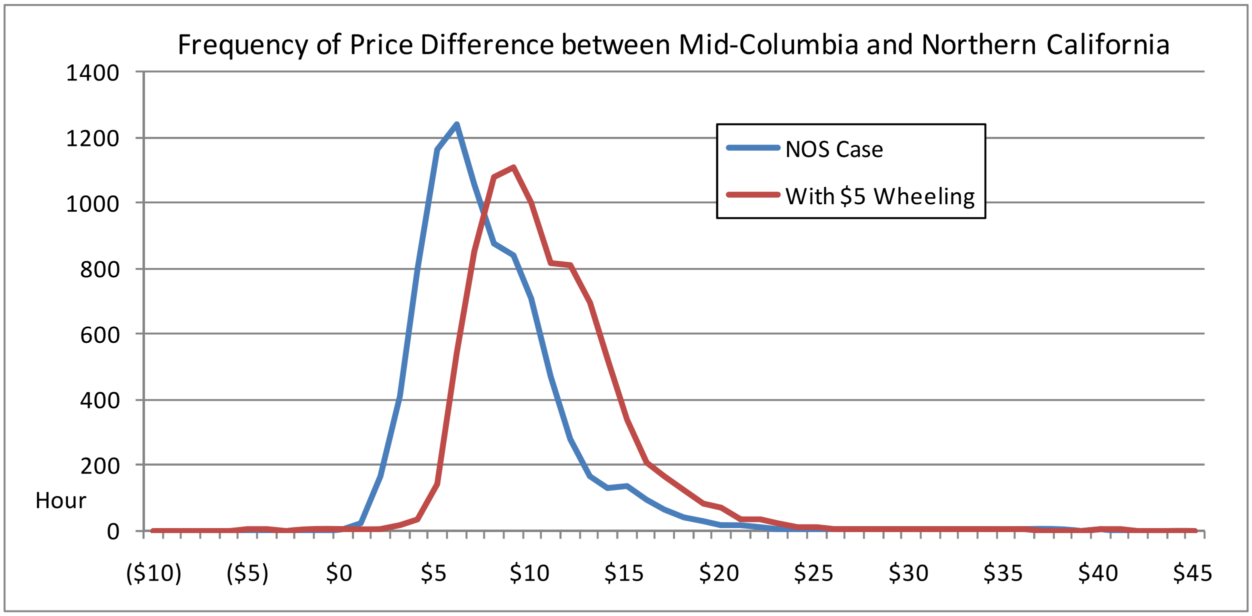


Table 4: Congestion Hours on Northwest Interfaces

Annual Hours at or Above 75% of Path or Flowgate Rating	Base Case	Base Case, Plus $28/Ton CO2 Cost	Base Case, Plus $45/Ton CO2 Cost	with 2009 NOS Projects	with NOS, Plus $28/Ton CO2 Cost	with NOS, Plus $45/Ton CO2 Cost	with NOS, + $5/MWh Ext. Wheeling
Internal							
North of Hanford	(1)	(4)	(4)	**9**	-	(4)	(7)
North of John Day	3	(15)	(39)	**242**	(6)	(45)	(24)
Paul - Alston	-	-	-	**-**	-	-	-
Raver - Paul	(4)	(1)	16	**8**	-	10	5
South of Allston	(0)	(5)	(11)	**46**	-	(12)	(22)
West of Cascades - North	(14)	11	15	**258**	(1)	3	35
West of Cascades - South	(4)	(1)	(1)	**19**	-	(3)	13
West of John Day	(30)	(1)	-	**36**	-	1	(24)
West of McNary	-	-	-	**-**	-	-	-
West of Slatt	-	-	-	**-**	-	-	-
External							
NW to Canada West BC	3	(4)	(3)	**39**	-	(4)	(14)
NW to Canada East BC	24	(118)	(194)	**1,804**	(76)	(165)	29
Montana - Northwest	34	(505)	(1,764)	**3,632**	(298)	(1,907)	(345)
Idaho-Northwest	34	(165)	(307)	**406**	(13)	(283)	(357)
Midpoint - Summer Lake	(72)	(791)	(1,202)	**1,411**	(48)	(1,287)	(958)
Bridger West	(106)	(89)	(45)	**2,102**	(194)	98	5,296
Calif.-Oregon Intertie (COI)	(226)	(564)	(1,489)	**2,623**	(443)	(1,549)	(464)
Pacific DC Intertie (PDCI)	(62)	(98)	(98)	**160**	(79)	(160)	(72)

Imposition of carbon dioxide costs in the dispatch calculation results in reduced congestion on most paths and flowgates, particularly out of coal-producing regions and into California.

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 recent TEPPC 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. TEPPC is developing a model for 2020, but it will not be available for study work until later in 2010.

Monte Carlo Simulation

Ideally, an hourly simulation will include the random events that occur in the real world, such as generator and transmission element forced outages. However, even though a yearly simulation looks at 8,760 hours of operation of over 3,000 generating units, variation in output from the model in repeated Monte Carlo simulations is greater than the output differences caused by the generator and transmission modifications studied in this project.

In order to get convergence in measured values while randomly forcing outages, a number of iterations of the one-year simulation would be required. As the model requires about six hours to execute one pass for the TEPPC data model, Monte Carlo simulation is impractical here.

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 grossed up by estimates of transmission 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 3,000 generators, which includes all current in-service generators as well as incremental resources needed to serve loads in 2019.

The TEPPC 2019 PC1 case models two blocks of incremental resources to fill the generation gap – a renewable resource block and a conventional resource block. In preparing data for these studies, the generic 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 block 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.

Twenty generators associated with NOS 2008 TSRs were added to the TEPPC 2019 PC1 case. Projects were generally given generic names and connected at appropriate locations, though generally at higher-voltage buses to avoid unnecessary modeling of sub-transmission.

Some generators are modeled based on given 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 is 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. These methods are still under development for GridView and PROMOD and are 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 (due to unacceptable execution times), 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.

Efficiencies and Demand Side Management

Some of the load forecasts used in the modeling incorporate programs to reduce or control energy demand; these are often modeled elsewhere as separate energy 'resources,' to include them as planning alternatives. The WECC staff does not have information necessary to quantify or segregate these 'negative demands,' and this remains an outstanding issue.

Resources in More Detail

Thermal Generators

Fuel Costs

Natural gas prices in the TEPPC 2019 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. Transportation 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 pound of emissions per million Btu of fuel consumed, for each type of fuel used at each generator.

Emissions Prices

Carbon dioxide has been the focus of emission studies at TEPPC and elsewhere, with costs between \$10 and \$60 per ton of emitted carbon dioxide applied across the Western Interconnection. In this study, 2019 CO_2 costs of \$28 and \$45 per ton (in 2010 dollars) were tested. The low estimate was derived (inflated to \$2010 and pushed out by 2 years to reflect legislative delay) from the EIA's July 2009 baseline estimate of the cost of implementing the Waxman-Markey bill. That bill targets a 17% reduction of emissions below a 2005 baseline by 2020. The figure was used here both to be consistent with CO_2 cost assumptions being used elsewhere within BPA (Resource Program) and because it is believed the EIA figures reflect a Congressional willingness to pay for emission reduction. The high figure was derived from the Northwest Power and Conservation Council's sixth power plan trajectory of CO_2 prices. Like the EIA figures, the Council figures were inflated to real \$2010 and pushed out by 2 years to reflect legislative delay.

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 PC1 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, as mentioned elsewhere, 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

The TEPPC Data Work Group is currently working to develop heat rates and other thermal generator operating characteristics from federally reported continuous emission monitoring systems (CEMS), which provide short time-interval reporting of plant energy input and output. Data from these ongoing analyses are not available to this study, which uses values culled from public sources, some data provided by plant operators, and generic heat rates developed from similar-unit data.

Heat rate data for aggregate combined cycle plants has been 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, increasing the phase shift angle change penalty 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 comprise 70% of the incremental resources for the PC1 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.

Four generic 'RPS' generators, amounting to 2,250 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.

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 operate 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 improvements, 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 shows the addition of the Castle Rock substation between Napavine and Allston and the addition of a line from Castle Rock to Troutdale, it does not take the existing Napavine-Allston branch out of the model.

Interfaces and Flowgates

The 2019 base case defines 243 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 Catalogue, 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.

Interfaces have a data parameter indicating whether they are to be monitored (enforced) or not. In essence, the interface constraints may be disabled for a study by turning off monitoring. Of the 243 defined interfaces in the TEPPC base case, 130 are monitored, including the 18 reported in this study.

Table 5: Definition of Internal Interfaces (Paths & Flowgates)

Interface Name	FrBus	Name	Direction	ToBus	Name	kV	Circuit
Internal Interfaces							
North of Hanford	40957	SCHULTZ	→	41138	WAUTOMA	500	1
	40287	COULEE	→	40499	HANFORD	500	1
	40499	HANFORD	←	41113	VANTAGE	500	1
North of John Day	41401	ROCK CK	←	41138	WAUTOMA	500	1
	40821	PAUL	←	40869	RAVER	500	1
	41450	KNIGHT	←	41138	WAUTOMA	500	1
	40723	MCNARY	←	40917	SACJWA T	500	1
	40061	ASHE	→	40062	ASHE R1	500	2
	40061	ASHE	→	40989	SLATT	500	1
Paul - Alston	40045	ALLSTON	←	40821	PAUL	500	2
	40774	NAPAVINE	←	40046	CASTLERK	500	1
Raver - Paul	40821	PAUL	←	40869	RAVER	500	1
South of Allston	40045	ALLSTON	→	40601	KEELER	500	1
	40046	CASTLERK	→	41095	TROUTDAL	500	1
	40899	ROSS	←	41161	WOODLAND	230	1
	43229	HARBORTN	←	43601	TROJAN 2	230	1
	43541	ST MARYS	←	43599	TROJAN 1	230	1
	45011	ASTOR TP	→	45275	SEASIDE	115	1
	47095	VIEW TAP	←	45201	MERWIN	115	1
	40041	ALLSTON	→	43776	RAINIER#	115	1
West of Cascades - North	40869	RAVER	←	40957	SCHULTZ	500	1
	40869	RAVER	←	40957	SCHULTZ	500	3
	40869	RAVER	←	40957	SCHULTZ	500	4
	40381	ECHOLAKE	←	40957	SCHULTZ	500	1
	40691	MAPLE VL	←	40891	ROCKY RH	345	1
	40233	CHIEF JO	→	40749	MONROE	500	1
	40225	CHIEF J4	→	40994	SNOHOMS4	345	4
	40223	CHIEF J3	→	40993	SNOHOMS3	345	3
	40285	COULEE	→	40795	OLYMPIA	300	1
	42312	CASCADEP	←	46831	ROCKYRH1	230	1
	40261	COLUMBIA	→	40303	COVINGTN	230	1
	42361	WIND RDG	←	46169	WANAPUM	230	1
West of Cascades - South	40585	JOHN DAY	→	40699	MARION	500	1
	40155	BUCKLEY	→	40699	MARION	500	1
	40111	BIG EDDY	→	40809	OSTRNDER	500	1
	40809	OSTRNDER	←	41450	KNIGHT	500	1
	40061	ASHE	→	40062	ASHE R1	500	2
	41343	BIGEDDY3	→	43313	MCLOUGLN	230	1
	41342	BIGEDDY2	→	40213	CHEMAWA	230	1
	41341	BIGEDDY1	→	40813	PARKDALE	230	1
	47814	JONESCYN	→	41079	TMBLCR T	230	1
	40721	MCNARY	→	40901	ROSS	345	1
	40039	ALFALFA	→	40141	N BONNVL	230	1
West of John Day	40111	BIG EDDY	←	40585	JOHN DAY	500	1
	40111	BIG EDDY	←	40585	JOHN DAY	500	2
	40111	BIGEDDY	→	41450	KNIGHT	500	1

Table 6: Definition of External Interfaces (Paths)

Interface Name	FrBus	Name	Direction	ToBus	Name	kV	Circuit
Internal Interfaces (Continued)							
West of McNary	43123	COYOTE	→	40989	SLATT	500	1
	40721	MCNARY	→	40901	ROSS	345	1
	40723	MCNARY	→	49962	MERC RAN	500	1
	40939	SANTIAM	←	41079	TMBLCR T	230	1
	40549	HORSE HV	←	41351	MCNRY S1	230	1
West of Slatt	40155	BUCKLEY	←	40989	SLATT	500	1
	40585	JOHN DAY	←	40989	SLATT	500	1
	49962	MERC RAN	→	40585	JOHN DAY	500	1
External Interfaces							
Bridger West	60085	BRIDGER	→	60092	BRIDGE&B	345	1
	60085	BRIDGER	→	67791	POPCAP&1	345	1
	60085	BRIDGER	→	67792	POPCAP&2	345	1
CA-OR Intertie (COI)	40687	MALIN	→	30005	ROUND MT	500	1
	40687	MALIN	→	30005	ROUND MT	500	2
	45035	CAPTJACK	→	30020	OLINDA	500	1
Idaho - Northwest	60150	HELLSCYN	→	45103	HURICANE	230	1
	45029	BURNS	←	60240	MIDPOINT	500	1
	60155	HEMINWAY	→	45029	BURNS	500	1
	60132	SAND HOL	→	43049	BOARD F	500	1
	48197	LOLO	←	60278	IMNAHA	230	1
	60310	QUARTZTP	→	40621	LAGRANDE	230	1
	60192	LADD	→	40621	LAGRANDE	230	1
	61826	HINES	→	40507	HARNEY	115	1
Midpoint - Summer Lake	45029	BURNS	←	60240	MIDPOINT	500	1
	60155	HEMINWAY	←	45029	BURNS	500	1
Montana - Northwest	40453	GAR2EAST	→	40459	GARRISON	500	1
	40451	GAR1EAST	→	40459	GARRISON	500	1
	62004	MILL CRK	→	40457	GARRISON	230	1
	62339	ANA BPA	→	40457	GARRISON	230	1
	40457	GARRISON	←	62072	OVANDO	230	1
	40551	HOT SPR	←	62344	PLACIDLK	230	1
	40867	RATTLE S	←	62009	RATTLE S	161	1
	40391	ELMO	←	62066	KERR	115	1
	48055	BURKAVAB	→	48051	BURKE	115	1
	48053	BURKAVAA	→	48051	BURKE	115	1
NW to Canada East BC	50822	NLYPHS	←	40145	BOUNDARY	230	1
	52219	WAN230	←	40145	BOUNDARY	230	1
NW to Canada West BC	50194	ING500	←	40323	CUSTER W	500	1
	50194	ING500	←	40323	CUSTER W	500	2
Pacific DC Intertie (PDCI)	40111	BIG EDDY	→	41311	CELILO1	500	1
	40111	BIG EDDY	→	41312	CELILO2	500	2
	41341	BIGEDDY1	→	41313	CELILO3	230	3
	41343	BIGEDDY3	→	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).

This study uses the limits developed by TEPPC for its 2019 PC1 case. Existing interface (path) limits do not incorporate some of the transmission that has been added to the TEPPC 2019 PC1 case, as the transmission projects have not completed their WECC Phase 2 rating processes, where new ratings will be developed. In the interim, path definitions excluding the new lines are left in place and the new lines are allowed to operate up to their individual limits.

Table 7: Interface Limits used in this Study

Interface Limits (MW)	+Limit	-Limit
Internal Interfaces		
North of John Day	8,000	(8,400)
Paul - Alston	2,990	N/A
Raver - Paul	1,625	N/A
South of Allston	3,980	N/A
West of Cascades - North	9,900	(10,500)
West of Cascades - South	7,700	(7,000)
West of John Day	3,450	N/A
West of McNary	4,500	N/A
West of Slatt	5,500	N/A
External Interfaces		
Bridger West	2,200	N/A
CA-OR Intertie (COI)	4,800	(3,675)
Idaho - Northwest	3,500	(2,050)
Midpoint - Summer Lake	1,500	(550)
Montana - Northwest	2,200	(1,350)
NW to Canada East BC	300	(400)
NW to Canada West BC [1]	2,000/2,850	(2,850)
Pacific DC Intertie (PDCI)	3,100	(2,870)

[1] The interface 'NW to Canada West BC' has a winter rating (Nov-Apr) and a higher summer rating (May-Oct)

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 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.

Wheeling

Only one of the cases prepared in this project imposes wheeling rates on transmission flows. While TEPPC has run cases with wheeling enabled in an effort to simulate the levels of inter-regional transfers seen in current operations, the 2019 PC1 case does not have wheeling charges applied. This is primarily because there is a paucity of data describing firm and non-firm wheeling rates applicable to various blocks of energy transfers. For example, most firm transactions do not have explicit wheeling charges.

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 provided a method to convert the PDF databases developed 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, make 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 PROMOD and GridView is termed 'dynamic hydro' and attempts to account for a number of the operational complexities of these projects. Such a model is being 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 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 period 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.

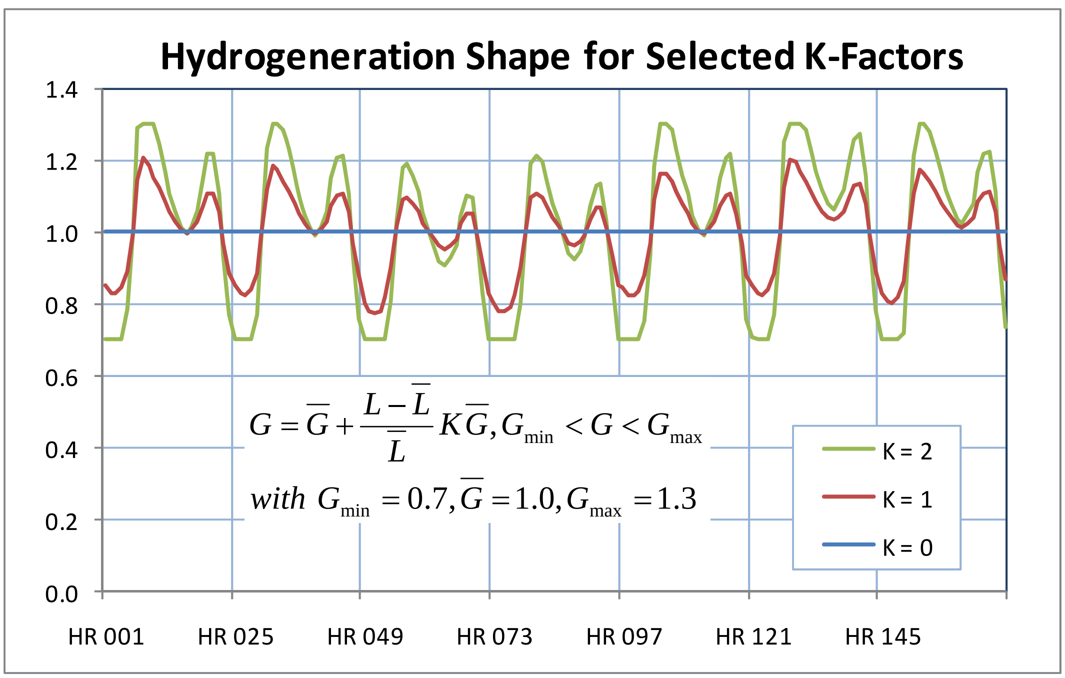
GridView provides a mechanism by which the modeler may specify the amount of wind-powered generation that is to be accommodated by hydrogeneration. This mechanism is based on the proportional load-following hydroelectric dispatch model and its integration with GridView's commitment and dispatch algorithm.

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 8 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 8: Examples of proportional load following for different k-factors

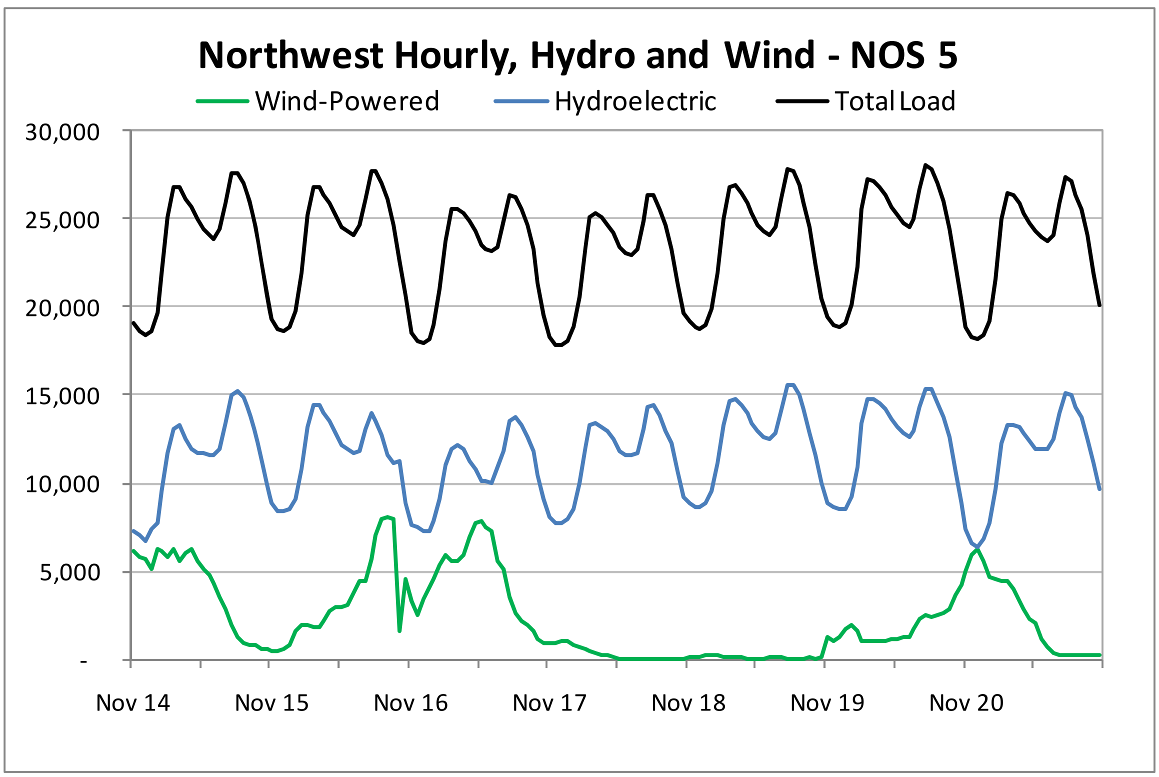


The Grand Coulee project, for example, is constrained by flood control, irrigation requirements, and a limitation on maximum water releases per day, but otherwise has considerable flexibility in its dispatch. Its monthly k factor ranges from 3.0 to 5.62 under median streamflow conditions (represented 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[5], 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 9: Sample modification of hydrogeneration to accommodate wind power



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

[5] 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.

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 seven and ten 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.