PACIFICORP

November 18, 2010

Stochastic Loss of Load Study for the 2011 Integrated Resource Plan

INTRODUCTION

PacifiCorp evaluates the desired level of capacity planning reserves for each integrated resource plan. For the 2011 IRP, the Company conducted a stochastic loss of load study to help identify the target capacity planning reserve margin (PRM) to use for resource portfolio development. The PRM value used for the 2008 IRP and 2008 IRP Update was 12%.

This study utilized the Company's stochastic production cost simulation system, Planning and Risk (PaR), to determine the relationship between PRM and resource adequacy as measured by Loss of Load Probability (LOLP) index. Loss of load probability represents the probability that generation in a given hour is insufficient to serve load. Accumulating the number of hours for which the system experiences unserved load over a given period, typically one year, yields the LOLP index. Once the relationship between LOLP and PRM is established for PacifiCorp's system, a target LOLP level is selected to determine the PRM for subsequent resource portfolio development. This report describes the loss of load study and modeling assumptions, the selection of a target loss of load criterion, and the adoption of a PRM for portfolio development. The last comprehensive stochastic study conducted was for PacifiCorp's 2004 IRP.[1] Major differences between this study and the last one include (1) significantly more wind resources and incorporation of incremental wind operating reserves in the resource portfolio simulations, (2) expansion of the transmission topology from two bubbles to 26, and (3) incorporation of energy efficiency programs as a resource with a reserve credit rather than a reduction to the load forecast.

Note that while this study reports the incremental resource cost for achieving a given loss of load frequency and associated reserve margin level using a standard reliability resource type, it does not assess the trade-off between reliability and cost or the optimal resource mix to achieve a given reliability level. PacifiCorp compares different resource portfolios based on the amount and cost of unserved load (megawatt-hours of "Energy Not Served" or ENS) resulting from stochastic simulations of many portfolios built to meet a given PRM level. This stochastic analysis reveals the reliability impacts and costs associated with different resource mixes.

LOSS OF LOAD PROBABILITY METRICS

The metric used to derive the LOLP index is Loss of Load Hours (LOLH). The PaR model records a LOLH event when load is not met for an hour. This condition results from unit outages that reduce available generation capacity in a load area below the load derived from the Monte Carlo draws conducted by the PaR model. The LOLH event also has an associated Energy Not Served value, which is the magnitude of the lost load for the hour.

[1] See Appendix N of the 2004 IRP Technical Appendix Volume.

The PaR model's reported LOLP index is the average number of LOLH events for PacifiCorp's 100-iteration Monte Carlo production cost simulation.[2]

SIMULATION PERIOD

PacifiCorp selected 2014 as the simulation test year for the LOLP study. This year aligns with the start of the 2014-2016 resource acquisition period targeted by the Company's All Source RFP issued to the market on December 2, 16 2009. This year also aligns with major planned Energy Gateway transmission additions: the Mona-Oquirrh segment of Energy Gateway Central by June 2013, and the Sigurd-Red Butte segment by June 2014.

MODELING APPROACH OVERVIEW

The LOLP modeling approach entailed adding incremental reliability resource capacity to a starting point resource portfolio to reach increasingly higher target PRM levels. Loads and resources reflect those of the September 21, 2010 preliminary capacity load & resource balance, as presented at the October 5, 2010 IRP public input meeting.[3] This balance uses the annual system coincident peak load forecast prepared in September 2010 for use in the Company's 2011 business plan. The starting PRM level was 8.3%, which covers system operating reserve requirements (contingency and regulating reserves). Reliability resource capacity was then added to reach planning reserve margin levels of approximately 10%, 12%, 15%, and 18%. PacifiCorp conducted stochastic Monte Carlo simulations for each of the five resource portfolios built to achieve the target PRMs. The stochastic simulations account for Western Electricity Coordinating Council (WECC) operating reserve obligations plus incremental operating reserves for existing and forecasted wind additions as of year-end 2013. PacifiCorp then extracted LOLH and associated LOLP statistics from the portfolio simulations to characterize the reliability impacts of the incremental reliability resource capacity.

PLANNING RESERVE MARGIN BUILD-UP

PacifiCorp used an intercooled aeroderivative simple-cycle combustion turbine (IC aero SCCT) as the reliability resource for the loss of load study. Starting from a portfolio with approximately a zero PRM, IC aero SCCT capacity blocks were added to PacifiCorp's East and West Balancing Authority Areas—PacifiCorp East (PACE) and PacifiCorp West (PACW)—until reaching the desired PRM. The capacity build-up includes 77 MW of non-owned reserves held for other parties located in PacifiCorp's Balancing Authority Areas. Additionally, since reserves are not needed to be held for energy efficiency resources (Class 2 demand-side management), PacifiCorp included a reserve credit for the incremental 307 MW of Class 2 DSM capacity added by 2014. Modeled SCCT units were sized as follows by Balancing Authority Area:

[2] Calculating a probability using LOLH is a variant of the Loss of Load Expectation (LOLE) statistic.
[3] The preliminary 2011 IRP capacity load and resource balance is reported on page 45 of the meeting presentation, which can be downloaded at:
http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/PacifiCorp_2011IRP_PIM4_10-05-10.pdf

- PacifiCorp East Units - 93 MW (1 unit), 186 MW (2 Units), 279 MW (3 Units)
- PacifiCorp West Units - 102 MW (1 unit), 205 MW (2 Units), 307 MW (3 Units)

Regarding resource placement, PacifiCorp added SCCT capacity to transmission areas as dictated by PRM needs, with most resources placed in the West Main ("West Units") and Utah North ("East Units") transmission areas. Table 1 shows the megawatt capacity added to reach the target PRM levels. Since capacity is added in blocks, the resulting PRM levels vary from the original target levels.

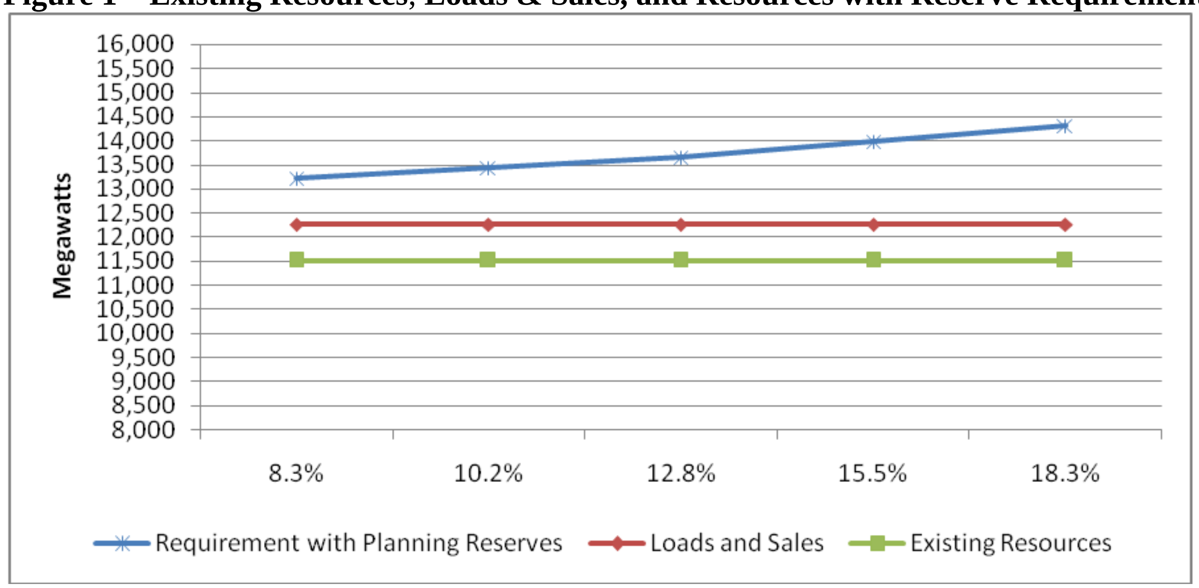
Table 1 – Resource Capacity Additions Needed to Reach PRM Target Levels

	Planning Reserve Margin Level				
Resource	**8.3%**	**10.2%**	**12.8%**	**15.5%**	**18.3%**
East 3 Unit	837	1,116	1,116	1,395	1,674
East 2 Unit	186	0	186	0	0
East 1 Unit	0	0	0	93	0
Goshen	186	186	186	186	186
West 3 Unit	0	0	307	307	307
West 2 Unit	0	205	0	0	0
West 1 Unit	102	0	0	102	205
Walla Walla	102	102	102	102	102
Total IC Aero SCCT Capacity	1,413	1,609	1,897	2,185	2,474
DSM with Reserve Credit	332	338	344	353	362
Total Capacity Added*	1,745	1,947	2,241	2,539	2,836

* Excludes non-owned reserves held for other parties within PacifiCorp's service territory.

Figure 1 shows the relative magnitude of existing resources, the load obligation plus sales, and resources with incremental reserves required to reach the target PRM.

Figure 1 – Existing Resources, Loads & Sales, and Resources with Reserve Requirements



MONTE CARLO PRODUCTION COST SIMULATION

For the loss of load study, the PaR model is configured to conduct 100 Monte Carlo simulation runs. During model execution, PaR makes time-path-dependent Monte Carlo draws for each stochastic variable. The stochastic variables include regional loads, unit outages, hydro availability, commodity natural gas prices, and wholesale electricity prices. In the case of natural gas prices, electricity prices, and regional loads, PaR applies Monte Carlo draws on a daily basis. Figures 2 through 9 show a sample of first-of-month daily loads by transmission area resulting from the Monte Carlo draws. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

Twelve representative weeks for each month, including the July system peak week, were modeled on an hourly basis. This representative-week approach reduces the model run-time requirements while ensuring that unit dispatch during the critical capacity planning periods is captured in the system simulations. Since only one year was simulated, the stochastic model's long-term stochastic parameters were turned off.

Figure 2 – Utah North Load Area

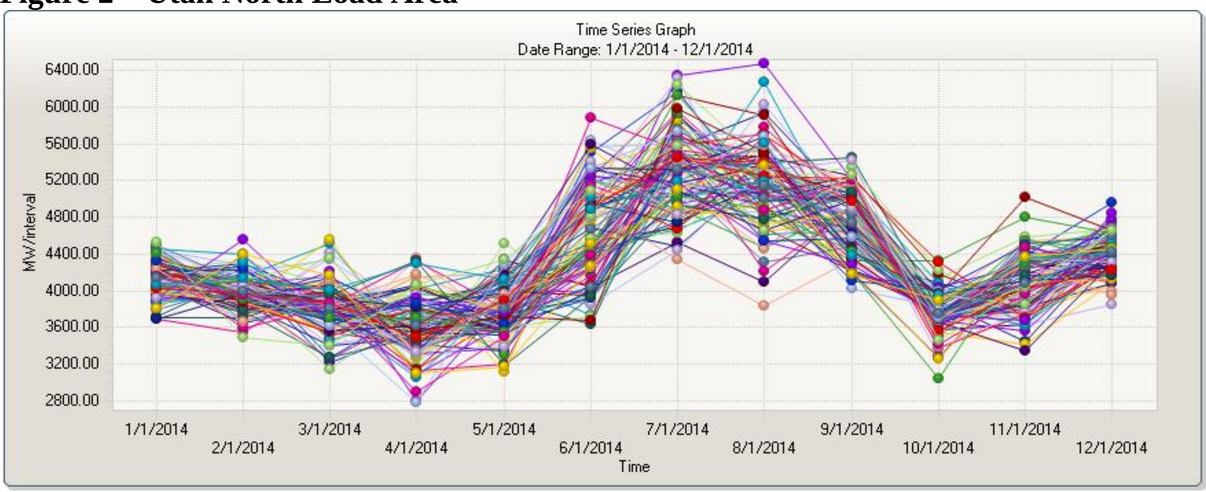


Figure 3 – Utah South Load Area

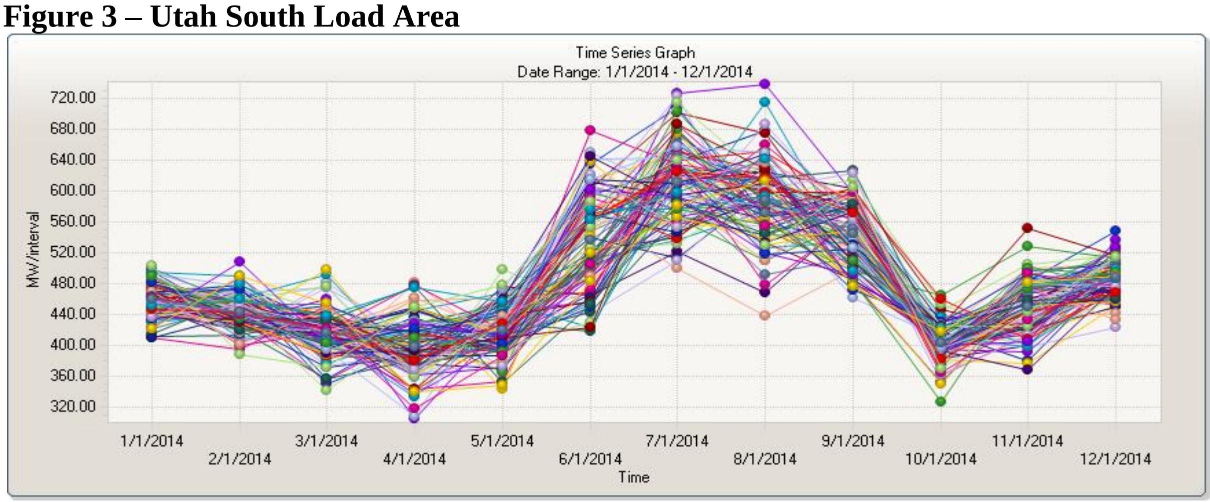


Figure 4 – Walla Walla, Washington Load Area

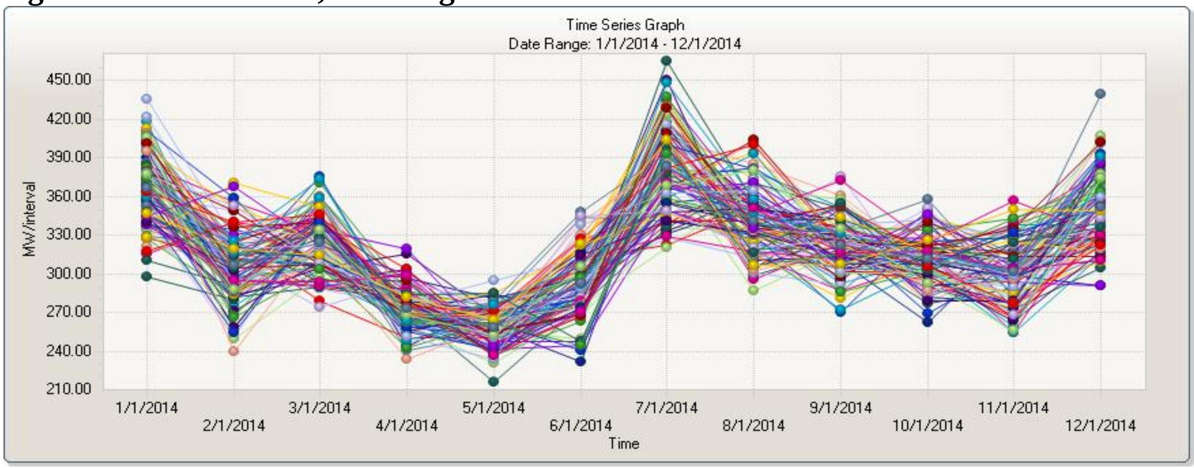


Figure 5 – West Main (Oregon, Northern California) Load Area

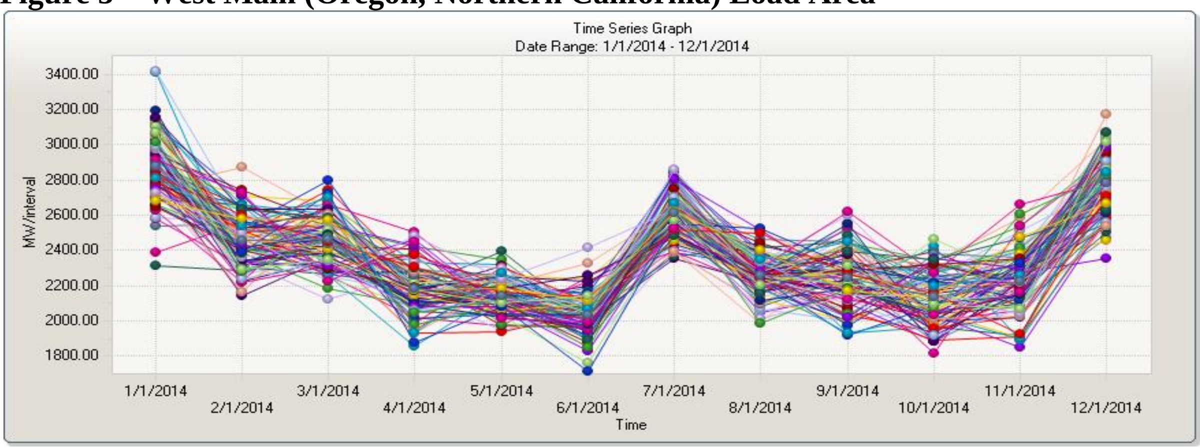


Figure 6 – Yakima Load Area

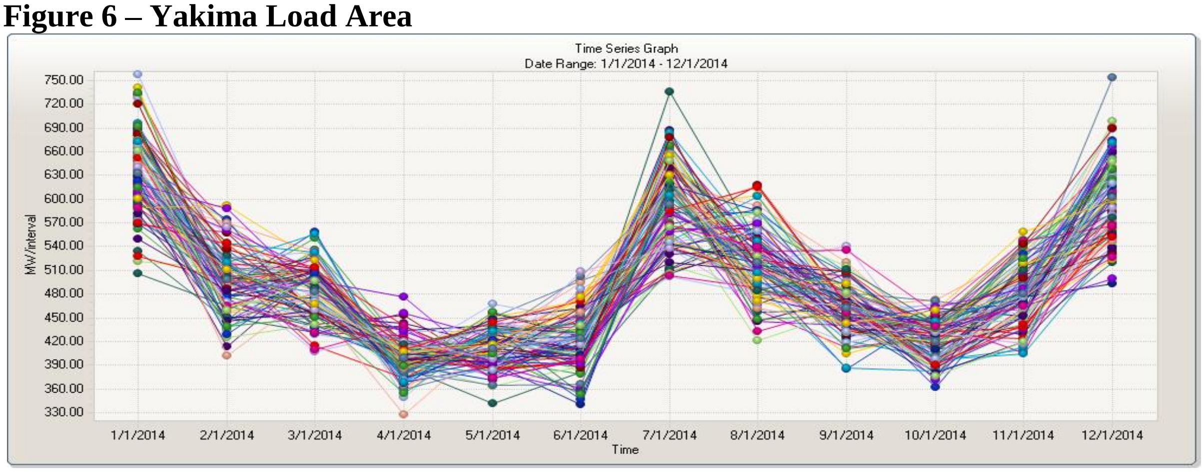


Figure 7 – Goshen Idaho Load Area

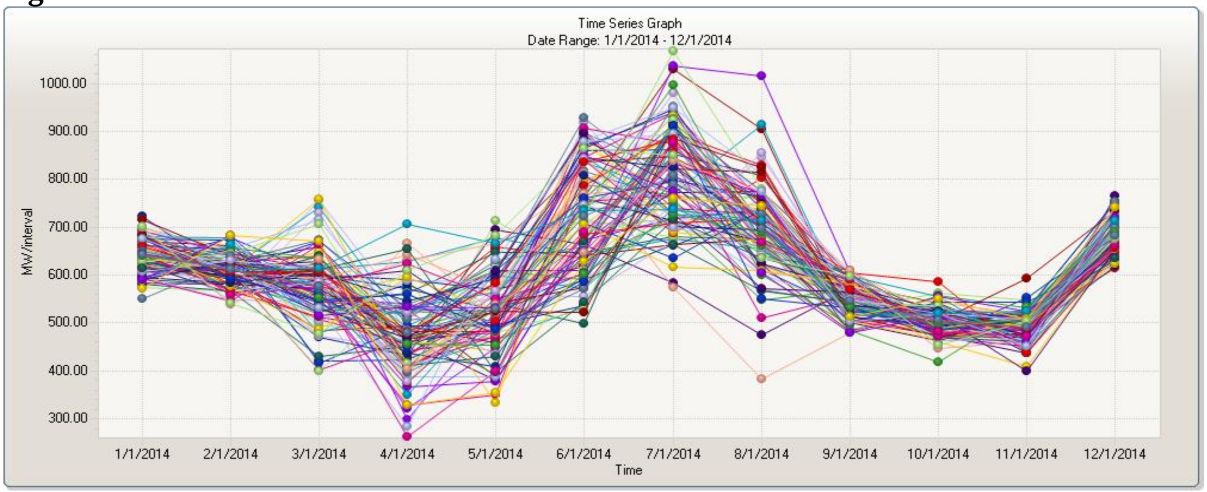


Figure 8 – Northeast Wyoming Load Area

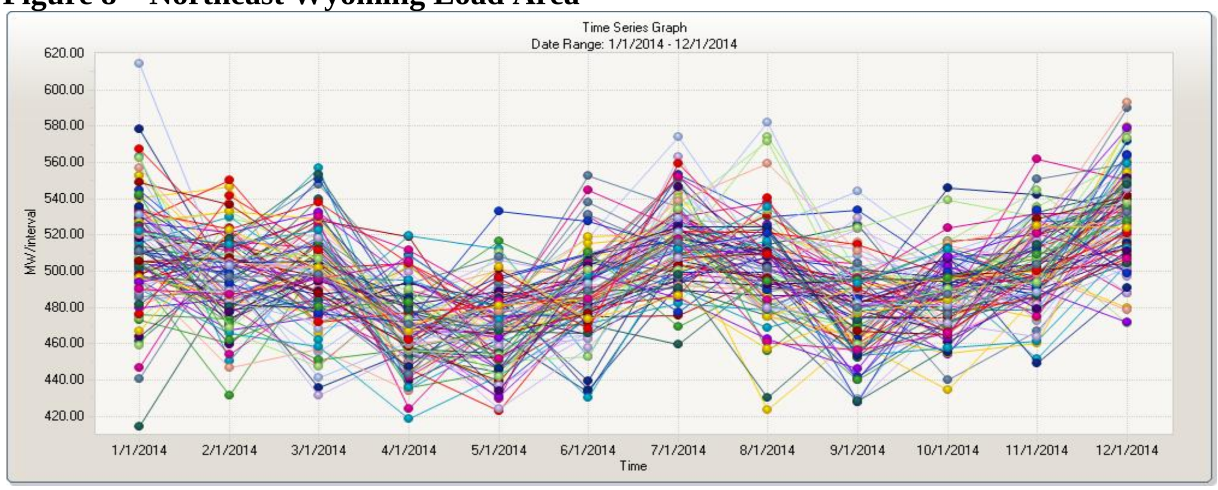
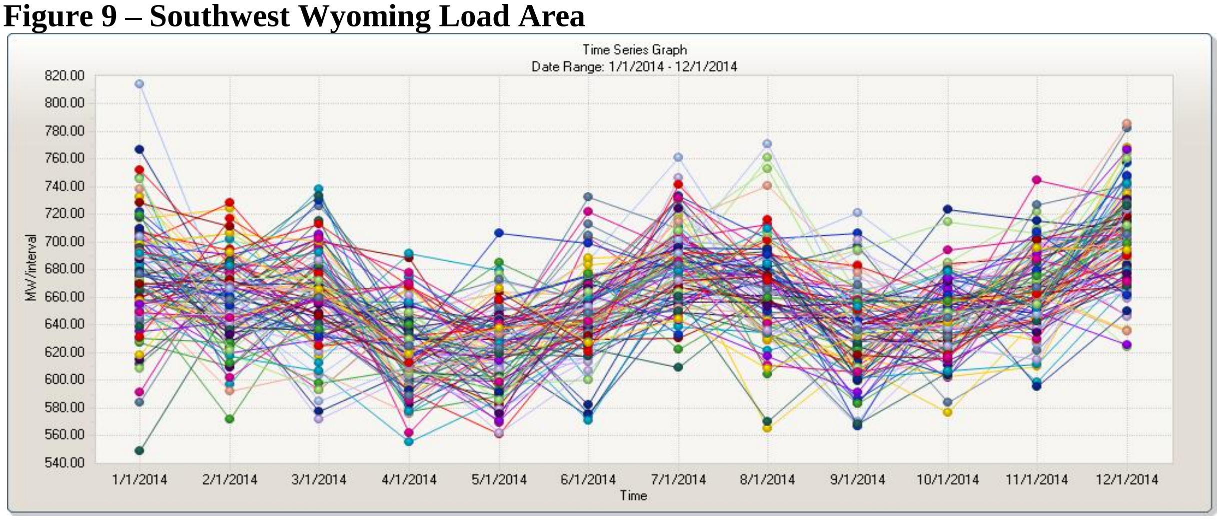


Figure 9 – Southwest Wyoming Load Area



MODELING OPERATING RESERVES

As part of the WECC, PacifiCorp is currently required to maintain at least 5% and 7% operating reserve margins on hydro and thermal load-serving resources, respectively. The Northwest Power Pool (NWPP) also requires a 5% operating reserve margin on wind. In the PaR model, operating reserves are modeled as a function of load. The maximum reserve amount that each generating unit can carry is specified in the model. The PaR model also includes 1.6% of loads to cover the WECC regulating reserves requirements. The operating reserve percentages, exclusive of wind, equate to 8.6% for the East Balancing Area and 8.1% for the West Balancing Area. These operating reserves are split into, roughly, 60-percent spinning and 40-percent non-spinning reserves to comply with WECC spinning and non-spinning reserve requirements.[4] An additional 14% incremental operating reserve requirement is applied against nameplate wind capacity (211 MW) to cover incremental operating reserves for wind as determined by PacifiCorp's 2010 wind integration study.

The operating reserve modeling approach does not address the impact of resource type (i.e., hydro, wind, or thermal) in determining required operating reserves. Operating reserves count toward the PRM, but the required percentages for the Balancing Authority Areas (8.6% and 8.1%) stay constant regardless of resource mix.

All Balancing Authorities within the Northwest Power Pool are also required to participate in the Contingency Reserve Sharing Program. This program provides 60-minute recovery assistance following the loss of a generating resource or transmission path, or failure of a generating unit to start up or increase output. This assistance is provided after the Balancing Authority uses up its Contingency Reserve Obligation (i.e., 7% of load served by thermal resources; 5% of load served by hydro reserves). The reserve sharing program provides a benefit to the utility by covering the first hour of an outage. For recording LOLH and calculating LOLP, the stochastic simulation should omit the first hour of a forced outage event in order to capture reserve sharing benefits. Implementing this functionality in the PaR model requires that a "shadow" station be assigned to each unit with a capacity equal to the unit MW rating and energy equal to the full load output. The shadow station is called upon in the event of a unit outage, thereby contributing emergency generation for one hour during the outage period. (The PaR model would determine that hour based on the marginal energy cost during the outage period.)

This modeling approach was judged to be too complex to implement and validate in time for use in the 2011 IRP. However, this approach was implemented for an loss of load study conducted by the PaR model vendor, Ventyx LLC, for Public Service Company of Colorado. The impact to the PRM of modeling reserve sharing rules of the Rocky Mountain Reserve Group (RMRG) was a reduction of 1.5 percentage points.[5] While the RMRG reserve sharing rules provide for up to two hours of contingency reserve assistance as opposed to the one hour for the Northwest Power Pool's program, the RMRG rules are more restrictive in other respects. For example, reserve

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[4] At least half of the operating reserves must be Spinning Reserve. Spinning reserve is the margin of generating capacity available to replace lost capacity and provide the regulating margin to follow load; spinning capacity must be synchronized to the system and ready to provide power instantaneously. Non-spinning reserve is generating capacity that is not synchronized to the system but can be available within a few hours.

[5] The loss of load report is available at:
http://www.xcelenergy.com/SiteCollectionDocuments/docs/CRPReserveMarginStudy.pdf

support is targeted for units at least 200 MW in size, is provided only to the unit with the largest capacity in the event that two or more units experience simultaneous outages, covers only one outage event per month, and covers less than the full unit capacity due to a smaller pool of member reserves available. Given these offsetting limitations, PacifiCorp assumes that a PRM reduction of 1.5 percentage points is a reasonable proxy for the NWPP's reserve sharing benefit.

STUDY RESULTS

Figure 10 reports the LOLH counts for the five PRM levels modeled, while Figure 11 reports the resulting LOLP index values (the stochastic average for the 100 Monte Carlo iterations). Fitted curves highlight the smooth relationship between the reliability statistics and the PRM level.

Figure 12 reports the total fixed cost of meeting each PRM level based on the incremental IC aero SCCT resource capacity required. The per-unit fixed cost is approximately $191/kW-year, which is grossed up to account for a 2.7% expected forced outage rate. Each percentage point increase in the PRM translates into an incremental fixed cost of about $42 million.

Figure 10 – System LOLH by Planning Reserve Margin Level

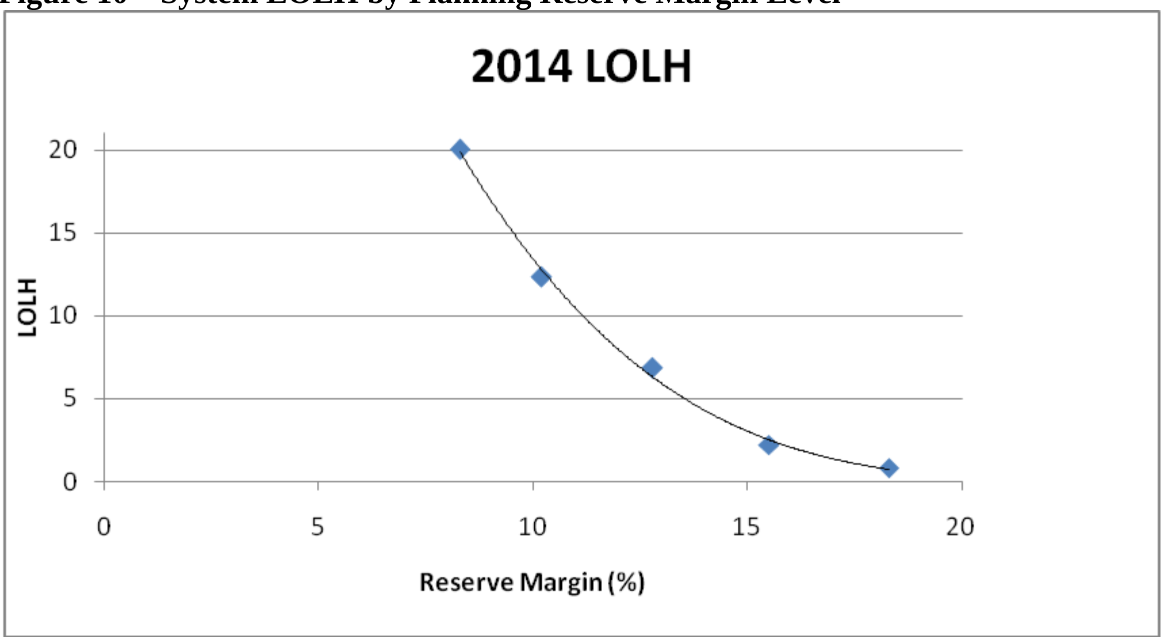


Figure 11 – System LOLP Index by Planning Reserve Margin Level

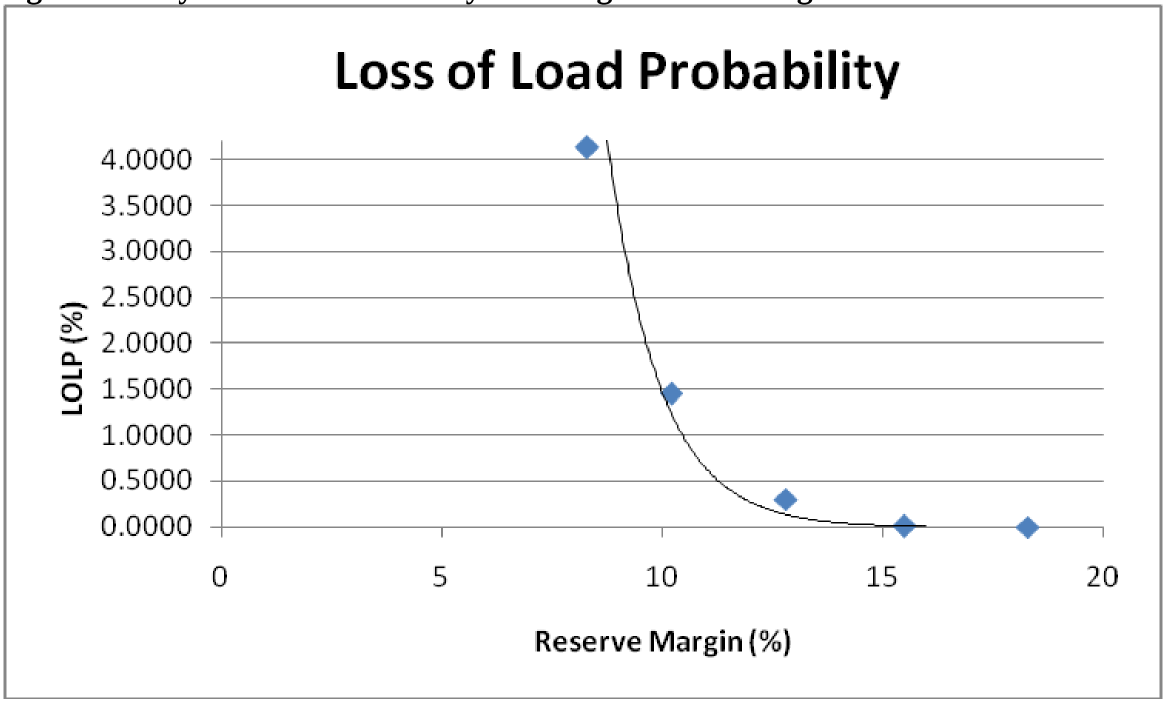
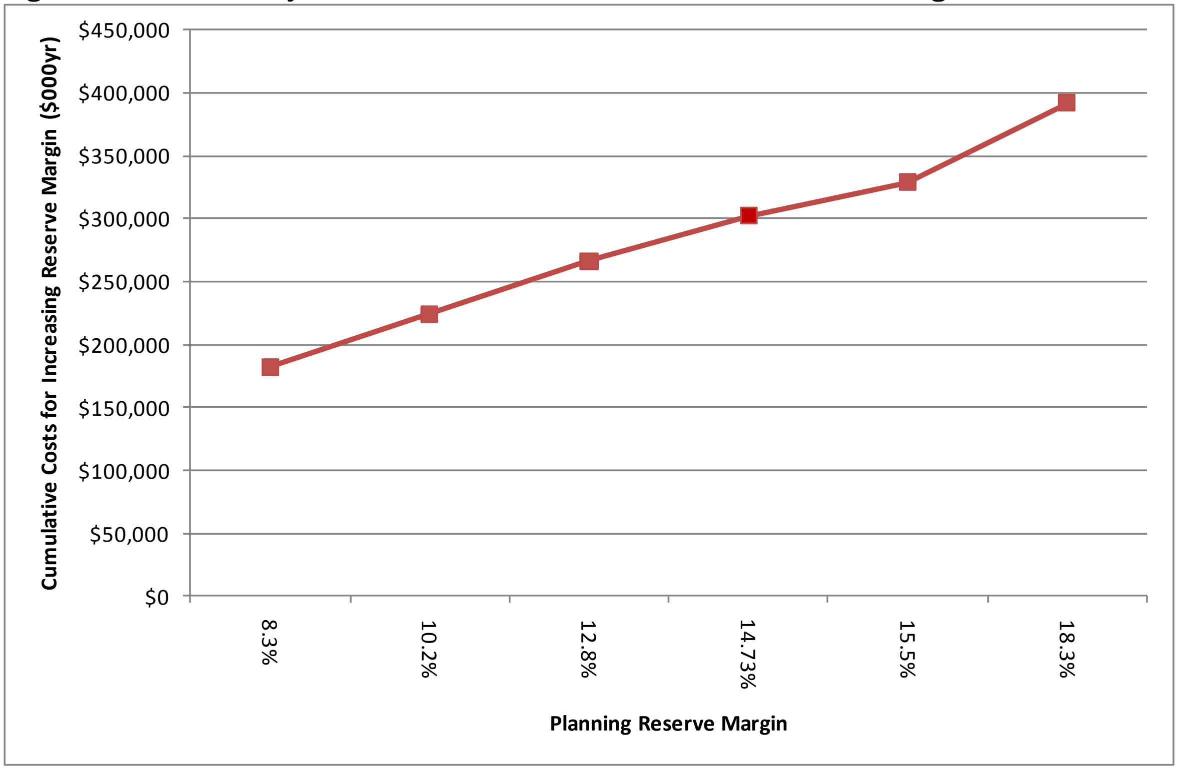


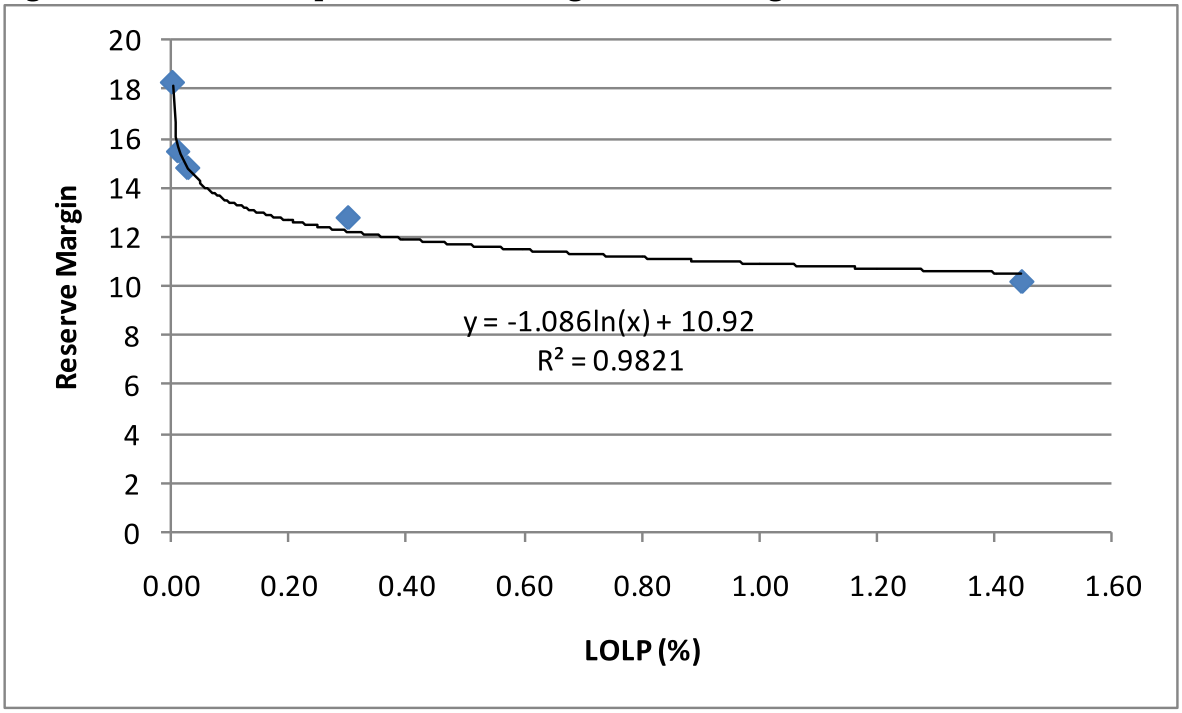
Figure 12 – Reliability Resource Fixed Costs Associated with Meeting PRM Levels



SELECTION OF A LOLP RELIABILITY TARGET

Traditionally, the long-term reliability planning standard has been a one-day in ten year loss of load criterion: 24 hours / (8760 hours x 10 years) = 0.027%. PacifiCorp has thus adopted this standard for determination of its PRM for IRP portfolio development.[6] Using a logarithmic functional form and regressing the PRM levels against the LOLP index values, yielded a PRM of 14.8% to achieve a one-day in ten year loss of load (Figure 13).

Figure 13 – Relationship between Planning Reserve Margin and LOLP



CAPACITY PLANNING RESERVE MARGIN DETERMINATION

As noted previously, the loss of load study does not incorporate the benefit of the Northwest Power Pool reserve sharing program. As a result, the 14.8% PRM requires a downward adjustment. Applying the 1.5% RMRG reserve sharing impact estimated by Ventyx for Public Service Company of Colorado results in an adjusted PRM of 13.3%. Rounding to 13% yields the PRM that PacifiCorp selected for its 2011 IRP portfolio development.

[6] Reliance on a one-in-ten loss of load criterion is being bolstered at the Federal level. The Federal Energy Regulatory Commission issued a Notice of Proposed Rulemaking in October 2010 approving a regional resource adequacy standard for Reliability*First* Corporation (RFC) based on a one-in-ten loss of load criterion. RFC is one of the nine North American Electric Reliability Corporation's electricity reliability councils, consisting of the former Mid-Atlantic Area Council (MAAC), the East Central Area Coordination Agreement (ECAR), and the Mid-American Interconnected Network (MAIN).

CONCLUSION

Based on the loss of load study and an out-of-model planning reserve margin adjustment to reflect reliability benefits from the Northwest Power Pool's reserve sharing program, PacifiCorp selected a 13% PRM for 2011 IRP portfolio development. PacifiCorp's previous PRM was 12%. This study incorporated a one-year snapshot of the transmission topology and loads & resources situation, targeting 2014 as the representative study year. Since the study focused on the PRM needed to meet firm load and sales obligations, it did not incorporate the reliability benefits of accessing off-system generation with non-firm transmission capacity.

PacifiCorp will continue to evaluate the reliability impact of different resource mixes using LOLP and Energy Not Served measures as part of its portfolio evaluation process.

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