Supporting Documentation For Volume 1, Chapter 12

DISCUSSION OF MODELS USED IN 2015 PLAN

Resource Adequacy

A traditional view of resource adequacy examines installed capacity relative to expected peak demand. As shown as the dashed red line in Figure 13-1, the solid red line represents NorthWestern's capacity requirement under a 15 percent reserve planning margin. Expected peak load is represented by the dashed red line. This measurement of expected peak is based upon "average" winter conditions. However, weather conditions may vary from average conditions, producing higher load than the average. The stacked bar chart, below load, represents capacity contribution of NorthWestern's current portfolio of resources.

Dependable capacity is measured by the level of energy production corresponding to the 10^{th} percentile during peak demand hours. The 10^{th} percentile represent a reasonable reliability threshold for dependable capacity consistent with the expected availability of thermal generator with 10 percent forced outage rate. Hydro generation is represented by its dependable capacity during peak demand hours, which corresponds to about 70 percent of nameplate generation capacity. Renewable wind and solar generators are also represented in the aggregate by their portfolio production of energy during peak demand hours; this corresponds to approximately 2.5% of installed capacity for wind and 0% for solar.

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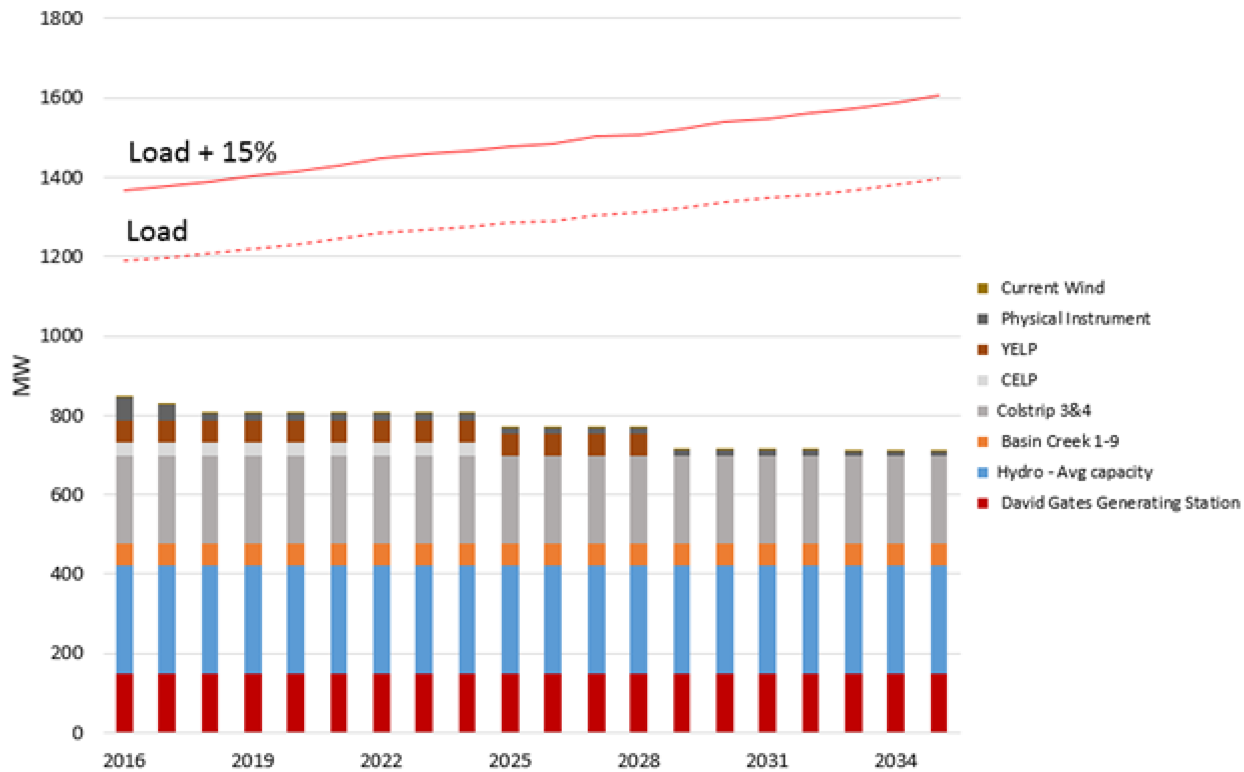
Figure 13-1 Installed Capacity and Peak Load



From a perspective of physical resource adequacy, Figure 13-1 shows a substantial deficit between installed capacity and retail load obligations. NorthWestern has successfully managed this deficit to date by turning to the wholesale market. While NorthWestern exists today in a regional power market that is currently long on both capacity and economic energy, current planning needs must recognize the expected capacity deficit in the region. With a substantial amount of coal generation under economic and ever increasing environmental pressures, the present surplus conditions of today may precipitously change in a wave of coal retirements. The proposed addition of additional flexible generation is an important first step in anticipating the capacity shortfall.

Figure 13-2 illustrates the number of hours per year where NorthWestern's retail load is expected to exceed physical capacity, assuming no resource additions. In 2016, load exceeds physical capacity in 500 hours, while in 2035 the value is expected to increase to approximately 6,800 hours.

Optimal capacity expansion planning model

Figure 13-2 Hours Short by Year 5th, mean, 95th

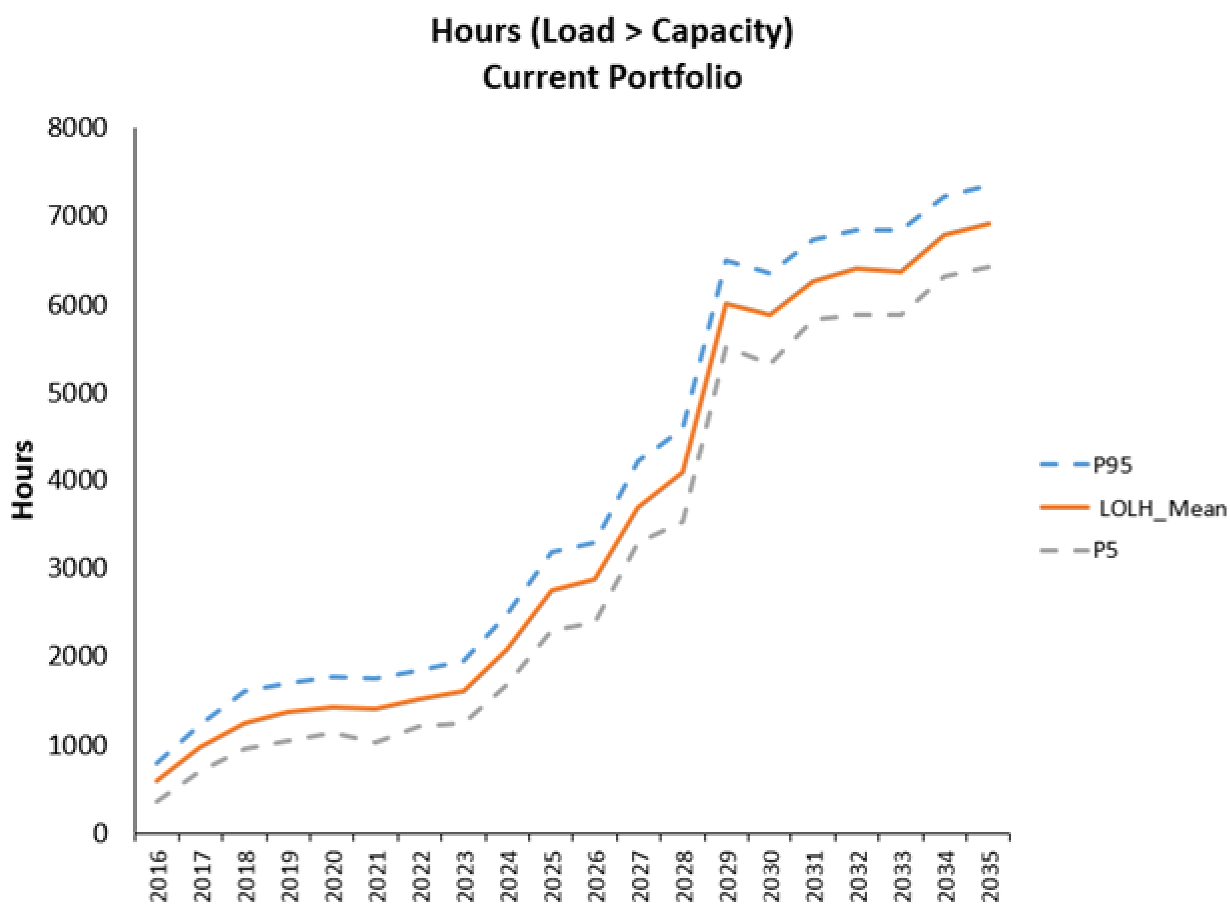
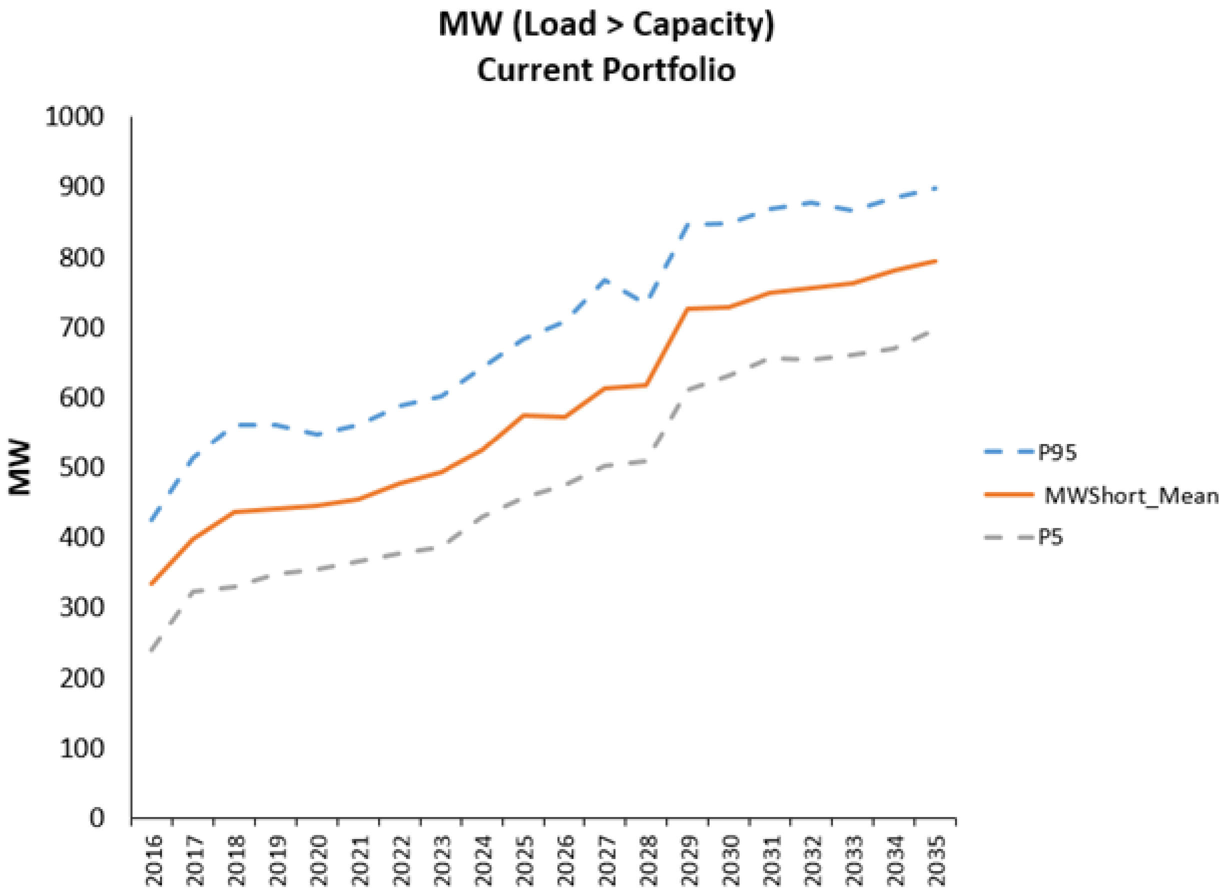


Figure 13-3 illustrates the P5, mean and P95 probabilities of capacity shortfall expressed in megawatts (MW) and without new resource additions. The confidence interval specified by the P5 and P95 endpoints indicate the range of possible hours the portfolio could be short in a given year with a 90 percent confidence that the true value is within this range. Figure 13-3 shows that NorthWestern's current portfolio of physical resources fall 350MW short of retail peak load in 2016. This shortage is expected to increase to a maximum of 800 MW short in 2035; however, the P95 confidence bound shows the expected shortfall could be as high as 410 hours/year in 2016 and 900 hours/year in 2035.

Figure 13-3 Max Capacity Short by Year 5th, mean, 95th



Optimal Expansion Planning

The capacity shortfall identified above is addressed in the Plan by using optimal expansion plan analysis to determine the least cost resource mix needed to meet a target reserve margins to maintain system reliability. Because utility planning involves a trade-off between long-term capital investment decisions and variable operating costs, the optimal expansion plan seeks to minimize the net present value (NPV) of future variable and fixed costs. The analysis uses the levelized costs of future resource options, to account for capital investment decisions not fully amortized over the 20 year planning horizon. The optimal expansion planning problem is formally stated as:

Min Expected Value of Total Cost

$$\text{E[NPV of Total Costs]} = \text{E}\left[\sum_{t=1}^{T}\sum_{i=1}^{N}\beta^{t} * Total\ Costs_{it} * 1_{it}\right]$$

Fixed Costs follow revenue requirements

Depreciation, Amortization, Current Taxes, Deferred Taxes, Insurance, Property Taxes, On-going capital improvements, return on equity and debt

Variable Operating Costs comes from hourly dispatch aggregated up to monthly totals including:

Start-up costs, min uptime, and min downtime constraints, emissions & variable heat rates

Market Purchases and Sales are endogenous to the optimization

Subject To:

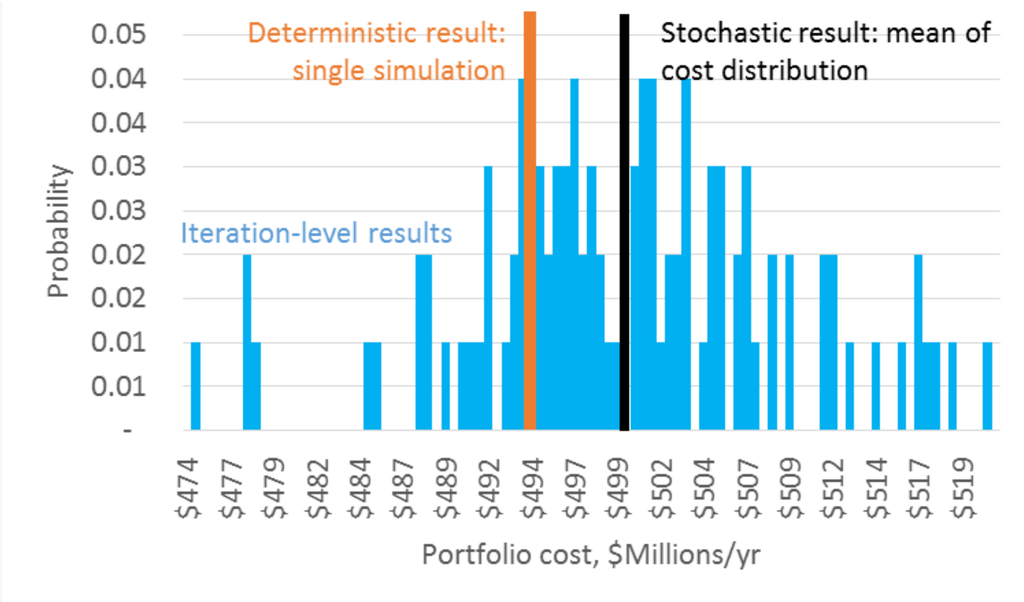
Reserve Margin Constraints

$$\sum_{i=1}^{N} Capacity_{it} \geq \gamma PeakLoad_{t}\ for\ t = 1\ to\ T$$

where γ is the required reserve margin

Using deterministic runs with sensitivities provides insight into portfolio management decisions, but the limited set of information used in deterministic runs can bias results. The analysis used for determining NorthWestern's optimal expansion utilized Monte Carlo simulations that are not subject to the bias observed in deterministic analysis. Figure 13-4 illustrates the bias effect of deterministic results (orange line) which includes the bias caused by reliance on a limited set of future conditions, compared to the expected value of Monte Carlo simulations (black line). Simulating future conditions with "meaningful uncertainty," articulates the dimensions of risk of each of the proposed portfolios.

Figure 13-4 Deterministic vs. Stochastic Simulation Based Results



The optimization of future supply portfolio utilizes a stochastic dynamic program to minimize the net present value of costs over all simulations subject to a series of constraints most notably capacity. The ability to select the optimal portfolio over a broad spectrum of future conditions without a loss of generation modeling details provides substantial advantages over picking the best portfolio from a single deterministic run. By determining the best portfolio overall future states, PowerSimm provides a more robust future supply portfolio. While the optimal portfolio may not be the best fit for any individual future run, the portfolio performs the best over all future states.

Incorporating uncertainty into the expansion planning process builds upon the concept of risk and simulations that produce “meaningful uncertainty” introduced in the 2013 Plan. The challenge of incorporating uncertainty into capacity expansion planning is further met by the need to address the value of resource flexibility. To account for resource flexibility, hourly simulations, asset start-up and shut down costs, generation must-run times and generation ramp rates are included in the analysis. More flexible resources can quickly and cost effectively cycle. This attribute also provides supports the addition of more renewable generation.

Table 13-2 summarizes the analytical differences between the PowerSimm model and traditional capacity expansion models.

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Table 13-2 Distinction of PowerSimm from Common Capacity Expansion Models

Area of Model Comparison	PowerSimm Used by NorthWestern	CapEx Models	Comment
Physical generation asset operating characteristics (heat rate curves, ramp rates, min-up, min-down,...)	√	X	Common CapEx models have no ability to capture asset operating characteristics other than plant capacity. Integrated models dispatch generation consistent with the full set of plant operating constraints. By overlooking the physical constraints of asset operations, the Strategist introduces potential bias and inconsistencies w.r.t. selection of intermediate and peaking resources by not modeling asset flexibility.
Chronological relationship of load	√	X	Common CapEx models use load duration curves, which removes the hourly and daily patterns of load.
Chronological relationship to market prices	√	X	Common CapEx models use of price duration curves removes the hourly and daily pattern of market prices. Moreover, the structural relationship between system load and market prices are not maintained.
Imports/Exports	√	√	Both models account for imports/exports but the inability of Common CapEx models to capture physical asset details introduces resource selection biases and inconsistencies. For example, a peaking unit may be designated as having the ability to provide exports when the start-up and shut-down costs of minimum run-times may make an off-system sale uneconomic.
Ancillary Services	√	X	Common CapEx models do not have the ability to model ancillary services.