BURNS McDONNELL

Resource Adequacy Review

Project No. 111946

Revision Final
9/26/2019

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prepared by

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
BLR	Balance of Load & Resources
BTM	Behind-the-meter
CAISO	California Independent System Operator
Company	Platte River Power Authority
CPUC	California Public Utilities Commission
DR	Demand Response
DG	Distributed Generation
ELCC	Effective Load Carrying Capability
EE	Energy Efficiency
E3	Energy and Environmental Economics, Inc.
EUE	Expected Unserved Energy
FOR	Forced Outage Rate
LOLE	Loss of Load Expectation
LOLEV	Loss of Load Expected Events
LOLH	Loss of Load Hours
NERC	North American Electric Reliability Corporation
PAWG	Probabilistic Assessment Working Group

PNM	Public Service Company of New Mexico
PRM	Planning Reserve Margin
RAS	Reliability Assessment Subcommittee
Report	2018 NERC Probabilistic Adequacy and Measures Report
RRM	Reliability Risk Metrics
RTO	Regional Transmission Operator
SPP	Southwest Power Pool
WECC	Western Electricity Coordinating Council
Xcel	Public Service Company of Colorado
1 in 10	1-day-in-10-year

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1.0 EXECUTIVE SUMMARY

As requested by Platte River Power Authority ("PRPA"), Burns & McDonnell Engineering Inc. ("Engineer") performed a review of regulations related to increased wind and solar penetration, reserve requirement metrics, and methods to determine adequate reserve margins. This three-part review and analysis of capacity required for reserves above normal peak demand and for intermittency mitigation of wind and solar resources includes: a review of Effective Load Carrying Capability ("ELCC"), a review of PRPA Loss of Load Probability ("LOLP") and an assessment of regulatory and policy requirements for today and in the future,.

1.1 ELCC Evaluation

Burns & McDonnell reviewed publicly available reports and studies on the topic of ELCC and the derivation of credited or qualifying capacity. A peer review of reports available from Public Service Company Colorado ("Xcel[1]"), Black Hills Colorado Electric ("BHCE") and Public Service Company of New Mexico ("PNM") illustrates methods by each utility to derive ELCC and credited capacity attributed to variable (non-dispatchable) resources such as wind and solar. Xcel, BHCE and the California Utilities Public Commission ("CPUC") demonstrate a probabilistic approach for determining credited capacity.

This approach captures the hourly peak contribution of variable generation with the use of Loss of Load Expectation ("LOLE") and combines the uniqueness of each system that is evaluated. The probabilistic approach for determining credited capacity is valuable for assessing reliability.

Hourly ELCC comparisons with the use of Excel can be useful to derive peak hour contribution, this approach is helpful with determining the capacity credit for annual peak hour. It is a good proxy for filling in Balance of Load and Resources ("BLR") tables for variable resources while the credited capacity determined by this method could be used determine annual peak hour contribution, it does not provide the best metric for assessing reliability adequacy. The probabilistic approach to determine LOLE should be deployed to capture the full hour adequacy. The ELCC for wind and solar determined in this study are consistent with other utility study results. The values adopted by PRPA in preparation of the IRP, are reasonable and align with the results presented in studies by Xcel, BHCE and PNM.

The cumulative effect of 100 MW increments from 228 MW of wind and 50 MW of solar are shown in Table 1.1. Table 1.2 shows the incremental ELCC for each 100 MW block of wind and solar. The

[1] All references to "Xcel" are specific to Public Service Company of Colorado

application of LOLE to determine ELCC (and the estimates shown in the tables) is recommended by Burns & McConnell for PRPA.

Table 1.1: Cumulative Wind/Solar ELCC

Cumulative (MW)	Wind ELCC	Solar ELCC
Existing	22%	42%
+ 100	20%	31%
+ 200	18%	24%
+ 300	16%	19%
+ 400	15%	16%
+ 500	14%	14%

Table 1.2: Incremental Wind/Solar ELCC

Incremental (MW)	Wind ELCC	Solar ELCC
Existing	22%	42%
+ 100	14%	26%
+ 200	13%	13%
+ 300	8%	8%
+ 400	8%	5%
+ 500	7%	4%

1.2 LOLP Methods and Review

PRPA has a probabilistic modeling tool programed in Excel that calculates LOLE for a specified planning period. Even with some limitations, the model can be manipulated to assess reliability adequacy and to determine credited capacity to assign to wind and solar resources. The continued increase of wind and solar may also require load serving entities to assess the ability to respond to intra-hour ramping.

With the help of Astrape Consulting and their model SERVM, PNM introduced an additional metric to measure intra-hour ramping sufficiency, $LOLE_{flex}$. This metric assesses a systems ability to track with, or to follow load variations introduced by increasing levels of wind and solar. The PNM Reliability Analysis in their 2017 Integrated Resource Plan, demonstrated mitigation strategies for intra-hour insufficiency by adjusting spinning and operating and by introducing flexible, fast-response resources such as battery storage, combustion turbines and reciprocating internal combustion engines.

Increasing wind and solar may begin to create challenges for intra-hour balancing. Current levels of wind and solar for PRPA, combined with market availability, may not pose significant ramping issues in the near-term. Vigilance and continued monitoring of operations and wind/solar growth within neighboring systems is important. As more wind and solar is proposed or materializes, intra-hour flexibility may be further studied.

1.3 Reserve Requirements and Regulatory Review

North American Electric Reliability Corporation ("NERC") assigns a 15% Reserve Margin to predominantly thermal generating systems and 10% for mostly hydro systems. This guidance is provided to Western Electricity Coordinating Council ("WECC") and the other coordinating regions. In a survey of load serving entities, NERC observed that a majority of entities in North America performed resource adequacy studies primarily using LOLE and roughly one third of survey respondents utilize Expected Unserved Energy ("EUE") for assessing reliability. While it's been a matter of judgement between regions and assessment areas regarding the methodology used to measure adequacy, the trend is that most recognize that emerging reliability issues may be assessed with probabilistic models. As mentioned earlier in this section, utilities like Xcel, BHCE and PNM are applying probabilistic methods to determine resource adequacy. The California Public Utilities Commission also applies this technique to determine credited capacity of variable generation. A review of other publications and entities indicate that with increasing levels of wind and solar, EUE metrics and intra-hour loss of load techniques due to ramping insufficiency will become more prevalent.

PRPA has a planning reserve margin in excess of 30% for the near-term without factoring the contribution of additional wind and solar that will be online by 2020. This study demonstrates that the wind and solar additions may increase PRM above 40% and nearly displaces the reduced capacity due to the planned Craig Unit 1 retirement by 2025. The statistical methods to determine variable generation ELCC are informative and valuable. From a resource adequacy perspective, a 15% PRM is reasonable for PRPA as its fleet of resources remains predominantly fossil-fueled.

While NERC and WECC do not have hard mandates to dictate which reliability measure should be applied, even a 15% reserve requirement calculation may eventually combine the methods illustrated in this report to include credited capacity attributed to variable generation. High level calculations to determine credited capacity are useful, but probabilistic models expand the range of possibilities and are more robust. While the industry continues to monitor resource adequacy and how to measure it, increased variable generation will require more extensive use of software models that can assess LOLE and can also determine intra-hour sufficiency.

2.0 DEFINITIONS

This report will refer to various definitions important in the discussion of reserve margins and resource adequacy. This section defines the metrics to be referred to herein:

2.1 Effective Load Carrying Capability

The effective load carrying capability of a generating resource represents its probabilistic capacity contribution as a percent of its nameplate capacity. Most thermal generators are accredited a high percentage ELCC due to their likely availability to generate when called upon, typical of the unit's capacity and Forced Outage Rate ("FOR"). Solar and wind generators are attributed ELCC based on their time of delivery due to their variable and intermittent nature. Their contribution to utility peak demand (or at any hour) is dependent on the uncontrollable factor of sunshine and blowing winds. ELCC decreases as variable generation increases; the impact to peak demand shifts and overall reduction diminishes.

2.2 Credited/Qualifying Credit

A generating resource, both dispatchable and variable, can be attributed and assigned a capacity value for its probabilistic contribution to serve load as a ratio of its nameplate capacity. A dispatchable resource adjusted by its FOR has a higher capacity credit than a variable resource whose output is less coincident to load. The distinction between Credited Credit and ELCC lies within their point of reference. The terms used interchangeably, Credited or Qualifying Credit observes the contribution to peak load reduction while ELCC measures a generating resource's own production as a ratio of its nameplate.

2.3 Planning Reserve Margin

The planning reserve margin[2] ("PRM") is a metric that represents the amount of generation capacity available to meet the forecasted load in the planning period. Alternatively stated, planning reserve margin is the percent difference in projected resource availability over/above the net demand. Projected planning reserve margins can be determined with probabilistic models that measure the uncertainty of resource delivery as compared to net demand. 'Net demand'[3] is the total internal gross demand minus dispatchable, controllable demand used to reduce load. This measurement indicates the amount of capacity available above the uncertainty in demand for the planning horizon. This measurement is capacity based and does not provide an indication of energy adequacy. North American Electric Reliability Corporation ("NERC")

[2] Reserve Margin (%) = (Capacity – Net Load)/Net Load X 100
[3] Net Demand may also include reduction due to solar and wind generation

assigns 15% and 10% PRM[4] to mostly thermal and mostly hydroelectric systems respectively, when regional and sub-regional specific margin calculations are not provided.

2.4 Reliability Risk Metrics

Reliability Risk Metrics ("RRM") are data analysis points, typically resulting from studies and tests performed on a system, that provide insight about a system's capability or likelihood of reliably providing generation to meet system load over a specified horizon.

2.5 Loss of Load

Loss of Load ("LOL") is defined as load not served due to insufficient generation capacity. This definition generally refers to all events that result in available generating capacity below load or at a negative capacity margin.

2.6 Loss of Load Probability

Loss of Load Probability ("LOLP") is a metric of resource adequacy that can be calculated with the use of a detailed model that measures the hourly risk of load not being served. The measurement considers hourly projected load and compares it to generation capacity and generation FOR. LOLP measures the risk associated with insufficient generation to meet hourly load requirements. LOLP does not measure the amount of unmet demand or the duration that the demand is not met.

2.7 Loss of Load Expectation

Loss of Load Expectation ("LOLE") is a reliability metric that seeks to determine the amount of capacity needed to operate a reliable system without numerous shortages. LOLE is an annual measure of resource adequacy converted from the product of hourly LOLP. For the calculations of LOLE to be performed, the generators of a given system are analyzed by combining their capacity profiles, scheduled outages and probability of generator forced outages to determine how many days in a year a shortage could occur. The historically accepted industry target for LOLE is remaining below 1 day in 10 years.

2.8 Loss of Load Events

Loss of Load Events ("LOLEV") is defined as the frequency or number of events when load exceeds generation capacity. This metric records the consecutive number of hours for LOL and does not register the magnitude or the duration.

[4] https://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx

2.9 Loss of Load Hours

Loss of Load Hours ("LOLH") is defined as the number of hours within a specified time period when the hourly demand is expected to be above the generating capacity. LOLH can be determined stochastically (multiple iterations) or deterministically. The LOLH is a combined measure of the duration and frequency of LOLEV, it does not inform on each.

2.10 Expected Unserved Energy

Expected Unserved Energy ("EUE") is a reliability metric that seeks to determine the ability of a system to serve all loads at all delivery points while maintaining all planning criteria. For this metric, all hours in a year are evaluated to determine the expected energy (MWh) that will not be served. EUE considers the depth of the system's energy shortfall but does not measure the hours or days of the deficit. This energy shortfall can be used in combination with LOLE. With the emergence of variable resources like wind and solar, this metric can provide guidance for energy planning.

3.0 EFFECTIVE LOAD CARRYING CAPABILITY REVIEW

The ELCC review regarding reliability and corresponding target reserve margins will provide PRPA with guidance for developing their own ELCC estimates for wind and solar generation. This review includes methods applied by Public Service Company of Colorado, Public Service Company of New Mexico and the California Public Utilities Commission. The methods applied in this peer review provide a high-level estimate to determine ELCC for PRPA as well as a probabilistic approach. The methods illustrate renewable diversity that can potentially maximize ELCC. Finally, this review provides guidance on the application of ELCC within production cost modeling.

3.1 Peer Review

3.1.1 Public Service Company of Colorado (Xcel)

In May 2016, Public Service Company of Colorado ("Xcel") filed two reports with the Colorado Public Utilities Commission ("CPUC"). The first is titled "An Effective Load Carrying Capability Study of Existing and Incremental Solar Generation Resources" and the second is titled "An Effective Load Carrying Capability Study of Existing and Incremental Wind Generation Resources". The solar report referenced an 2013 ELCC study focused on incremental solar generation resources on the Public Service Company of Colorado system and the second references a study on wind conducted in 2007.

3.1.1.1 Study Parameters

Xcel applied a methodology in the ELCC studies that is described in a "2011 Institute of Electrical and Electronics Engineers ("IEEE") publication[5] and the ELCC methodology described in a 2012 National Renewable Energy Laboratory ("NREL") publication[6]." Xcel applied a LOLE methodology to measure the adequacy of its base system and compared the reliability results with targeted generation added. The hourly load was adjusted in each iteration to achieve a 1 in 10 day LOLE. The load adjustment that achieved 1 in 10 days, was the determinant capacity credit attributed to the variable resource.

3.1.1.2 Existing Solar and Wind

At the end of 2015, Xcel had approximately 2,600 MW of wind and 370 MW of solar distributed across the state of Colorado. The combined nameplate capacity of solar and wind is approximately 37% of Xcel's 7,975 MW peak in 2015. On a stand-alone basis, the existing solar portfolio averaged about 54.8%

[5] "Capacity Value of Wind Power"; Keane, Milligan, Dent, Hasche, D'Annunzio, Dragoon, Holttinen, Samaan, Söder, and O'Malley. IEEE Transactions on Power Systems, Vol. 26, No. 2, May 2011.

[6] "Comparison of Capacity Value Methods for Photovoltaics in the Western United States"; Madaeni, Sioshansi, and Denholm. Technical Report, NREL/TP-6A20-54704, July 2012.

of credited capacity over the years 2012 to 2014. In the second study, average credited capacity for wind was approximately 16.4 % while adjusting for outliers. With these factors, the estimated contribution of to peak demand reduction is 623 MW.

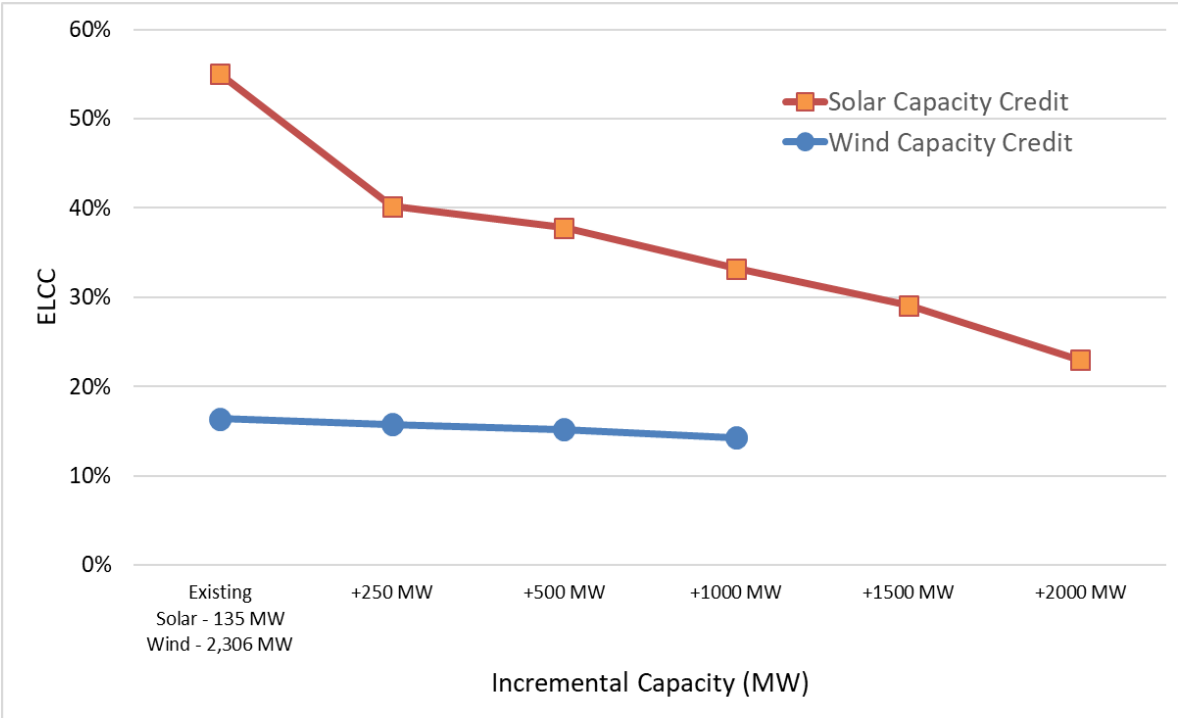
3.1.1.3 Incremental Solar & Wind

Xcel layered on incremental amounts of solar to determine the credited capacity. Single-axis tracking systems have a higher credited capacity than fixed axis systems. A downward trend in credited capacity is observed with increased penetration of solar, ultimately driven down to below 30% with 1,500 MW additional solar. Xcel also layered on incremental amounts of wind to determine the credited capacity. A downward trend in credited capacity for incremental wind is also is observed. Wind credited capacity for incremental wind can vary based on geographical dispersity; for Xcel the range is from 14% down to 8.4% for 1,000 MW of incremental wind.

3.1.1.4 Results

The 2016 ELCC study determined ELCC values for existing solar (135 MW in the base system model) and incremental solar additions up to 1,500 MW. The study also considered the benefits of adding existing wind generation into the calculations. The 2016 study resulted in consistent findings for ELCC values of 35% and 50% for fixed and tracking systems, respectively. Solar generator additions at higher penetration levels resulted in declining credited capacity value benefits. Xcel continues to update its ELCC calculations and expects diminishing credited capacity with the addition of solar and wind. Figure 3.1 shows the diminishing ELCC for wind and solar for Xcel. The figure illustrates an additional 500 MW (above 1,500 MW) for solar. Wind in excess of existing installations was not studied past an additional 1,000 MW.

Figure 3.1: Xcel Wind & Solar ELCC



3.1.2 Black Hills Colorado Electric (BHCE)

In June 2016, Black Hills Colorado Electric ("BHCE") filed its Electric Resource Plan ("2016 ERP") with the Colorado Public Utilities Commission ("CPUC"). A study performed by Black & Veatch for BHCE was performed to calculate the accreditable capacity of varying levels of wind and solar to determine ELCC.

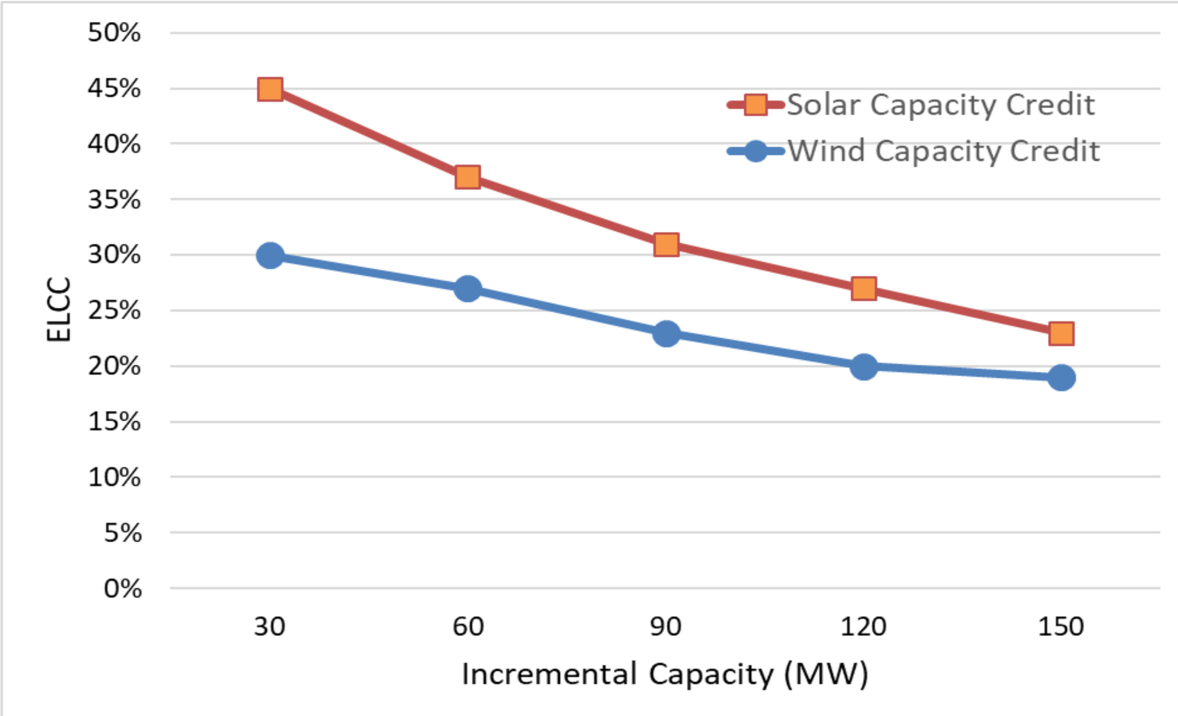
3.1.2.1 Incremental Solar & Wind

The integration study made assumptions on amount, type and location of future wind and solar resources. Locations were chosen base on commercial viability and through request for proposal ("RFP") solicitation results. The application of LOLE and the "perfect unit" were utilized to determine ELCC, like Xcel did in their studies.

3.1.2.2 Results

The results of the ELCC study for BHCE are shown in Figure 3.2.

Figure 3.2: BHCE Wind & Solar ELCC



3.1.3 Public Service Company of New Mexico (PNM)

In July 2017, PNM completed its Integrated Resource Plan ("IRP"). Within the IRP, PNM studied existing solar and incremental solar additions to understand the impact on peak demand. On PNM's existing system, approximately 65 MW of distributed PV systems and 107 MW of utility-scale solar are installed. PNM also anticipates an additional 30 MW of utility-scale solar associated with the data center customer and 50 MW for 2020 RPS compliance by the end of 2019. PNM sets ELCC values for solar generation by utilizing manufacturer data and historical data in the form of previous RFPs and NREL databases. PNM assumes that fixed and tracking solar systems have a 35% ELCC by 2023.

3.1.3.1 IRP ELCC Study

PNM relied on NREL data to determine the ELCC for fixed tilt PV systems. As historical data is collected PNM, will reflect updates to ELCC based on that data. PNM compared NREL solar profiles to its own hourly load projections. For this analysis, PNM identified tiers associated with peak load reduction. The Tiers, coincident with peak demand, were developed to identify levels of ELCC. Acknowledging that increased penetration of solar would ultimately begin to shift the net peak demand to the late afternoon hours, PNM identified Tiers 1-3 for hour-ending 5:00 PM to 7 PM respectively.

Table 3.1: PNM ELCC by Tier

Hour	Hour Ending MST	Hour Ending MDT	2018 PNM Peak	Previous Hour MW Change	Solar PV Peak Contribution	Total Solar PV Needed to Shift Peak	Incremental Solar PV Needed to Shift Peak	Peak Hour	Solar PV Tier
15	3:00 PM	4:00 PM	1,869		78%				
16	**4:00 PM**	**5:00 PM**	***1,900***	**31.1**	**67%**	**62**	**62**	**Peak Hour**	**Tier 1**
17	**5:00 PM**	**6:00 PM**	**1,877**	**-23.1**	**56%**	**161**	**100**	**+1**	**Tier 2**
18	**6:00 PM**	**7:00 PM**	**1,817**	**-59.5**	**35%**	**431**	**270**	**+2**	**Tier 3**
19	7:00 PM	8:00 PM	1,683	-134.3	9%	0	0	+3	No ELCC
20	8:00 PM	9:00 PM	1,641	-42.4	0%	0	0	+4	No ELCC

Table 3.1 shows the declining solar PV peak contribution with added renewables but solar also shifts the peak. While studying the 2018 hourly peak day, its estimated that 62 MW would shift the peak from hour-ending 5 PM to 6 PM, while credited capacity drops from 67% to 56%. The diminishing contribution to peak reduction is further observed when a cumulative total of 431 MW of solar is modeled. Credited capacity is now 35% and the net peak has shifted to hour-ending 7 PM.

3.1.3.2 IRP Reliability Analysis

PNM performed a Reliability Analysis that tested resource scenarios for planning reserve margins and loss of load probability. The analysis was used to help identify the most cost effective plan. A combination of software models was used in the study, including Microsoft Excel, Strategist, Aurora and Strategic Energy and Risk Valuation Model ("SERVM"). SERVM was utilized more extensively however, to analyze reserve margin and LOLP.

Astrape Consulting utilized SERVM to correlate a 17% reserve margin to an LOLE of 2 days in 10 years. The industry standard of 1 day in 10 years would equate to a 21% reserve margin but could be unjustifiably expensive for PNM. The study distinguished the reliability metrics for available resource capacity ($LOLE_{cap}$) and the ability ($LOLE_{flex}$) to respond to intra-hour variations. $LOLE_{cap}$ is the common or traditional metric that captures capacity insufficiency and $LOLE_{flex}$ was introduced by Astrape as a metric that captures ramping deficiencies longer than one hour.

The approach to determine $LOLE_{cap}$ was calculated in the traditional sense, $LOLE_{flex}$ was targeted by changing the load following requirements (spinning and operating reserves) and by testing flexible capacity. With lower levels of variable generation, $LOLE_{flex}$ was kept below 0.2 days in one year by increasing the load following target. At 7% load following, and under 20% variable generation, $LOLE_{flex}$ remains below 0.2. PNM tested increasing levels of renewables while holding at a 7% load following target. The $LOLE_{flex}$ increases exponentially without raising the load following reserve. Upward adjustments spinning and operating reserves and additional flexible resources are required to maintain $LOLE_{flex}$ below 0.2 days in one year for high penetration of wind and solar.

3.1.4 California Public Utilities Commission

In the CPUC 2015 Resource Adequacy and Reliability Report, an ELCC analysis was performed in three sections: the first evaluated the overall system and calibrated it to a 1 in 10 year LOLE, the second evaluated the ELCC of the solar in the CAISO area, and the third evaluated the ELCC of the wind in the region. The ELCC was calibrated through the utilization of "perfect capacity" within their calculations. Once the systems LOLE was calibrated to a 1 in 10-year LOLE, the target generator was removed and a "perfect capacity" generator was added in that had no forced outages, downtime, etc. and served without any downrating. The LOLE was recalculated and the ELCC of the target generator was determined by the ratio of the "perfect capacity" generator's MW target over variable generator's MW nameplate.

CPUC has provided guidelines for determining the credited capacity of wind, PV, and solar thermal facilities. Also referred to by CPUC as Qualifying Capacity ("QC"), the credited capacity is based on ELCC. The ELCC is equal to the comparative value of a generator in terms of reducing LOLE compared to a Perfect Generator. In detail, CPUC provides a seven step process[7] for determining monthly ELCC values. The following is quoted in large part from the "Revised QC Modeling Manual", the seven steps are as follows:

1. *Conduct a Monthly Loss of Load Expectation (LOLE) or Loss of Load Hours (LOLH) study. Choose a metric to target (LOLE or LOLH) and a reliability level for each month that represents the desired level of reliability that planners are attempting to have. Conduct an hourly reliability simulation representative of each month of the year with projected loads and expected resources that results in the desired monthly reliability level in each month. If results are either more or less reliable than desired, capacity or load is to be added or subtracted until each month's reliability results are in the desired range.*
2. *Conduct a Monthly Portfolio ELCC study. Remove all wind and solar electric generation facilities inside the CAISO aggregated region. Add or remove Perfect Capacity or load in each month individually until the resulting reliability level is back to the desired range. The amount of Perfect Capacity in MW (or load in MW) added is equal to the Portfolio ELCC of all wind and solar generators.*

[7] http://www.cpuc.ca.gov/General.aspx?id=6311 "Revised QC Modeling Manual"

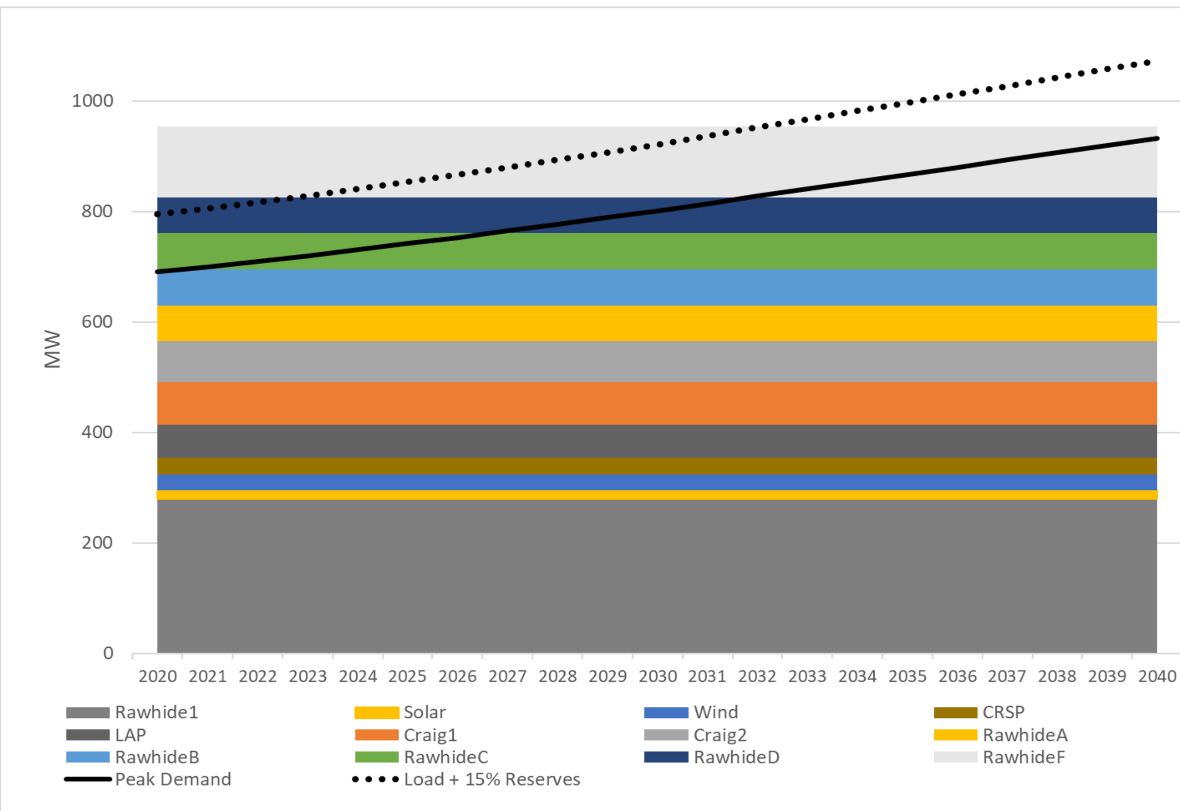
3. *Perform ELCC modeling on each category individually*
   a. *Add back wind generators and leave solar generators removed. Add blocks of load or take away blocks of Perfect Capacity iteratively from each month until reliability levels are within the desired range each month. The result is the standalone for solar generators. Record the monthly levels of Perfect Capacity modeled.*
   b. *Perform Step A in reverse by adding back solar generators and removing wind generators. Remove blocks of Perfect Capacity iteratively from each month. Remove Perfect Capacity until the reliability level again falls within the desired range in each month. The result is the standalone ELCC of wind generators. Record the monthly levels of Perfect Capacity or added load modeled.*
4. *Add the standalone ELCC of wind and solar generators and compare the total to the Portfolio ELCC calculated earlier. The difference (either positive or negative) is the diversity adjustment. (The diversity adjustment will be negative when the standalone ELCC values total greater than the Portfolio ELCC and are the result of modeling a category of generator while another category of generators in the Portfolio ELCC was present, and some of the reliability contribution it imparts is applied as diversity. In that case, diversity must be removed.) Allocate the diversity adjustment to either wind or solar generators by prorating to the proportion of wind and solar standalone ELCC in each month.*
5. *Energy Division backs out the effect of Behind-the-Meter ("BTM") Solar on the overall RPS supply side solar ELCC. Energy Division staff compares the ELCC of solar generators without BTM PV in the fleet (taken from the March 2016 RA ELCC proposal) to the ELCC of solar with BTM PV included from this February 2017 RA proposal. That difference represents the amount of Perfect Capacity that is equivalent to the additional supply side solar added since March 2016 as well as all BTM PV installed that has until now not been included in modeling. Prorating the additional Perfect Capacity to the portion of the new solar that is BTM PV will represent the added Perfect Capacity for the BTM PV, and when removed represents just the Perfect Capacity needed for the incremental new supply side solar added.*
6. *Take the ELCC MW values that are the result of the modeling for each month and divide them by the total nameplate installed MW of that technology, and the resulting monthly percentage values represent the ELCC percentages that are applied to the nameplate MW values of each individual generating facility to create the Qualifying Capacity of the generator.*
7. *Any further steps to create locational factors to break up wind and solar further into location or sub technology specific factors would follow from this point, and thus would be added as steps 7*

and on. Future Monthly ELCC studies would require restarting the sequence of studies from Step 1.

3.2 ELCC Methods

While contemplating the measurement of resource adequacy with either LOLE or a reserve margin estimate for peak load, inarguably, variable resources cannot be measured like dispatchable or traditional thermal resources. Prior to the emergence of variable resource supply, dispatchable resources were assumed to have qualifying capacity of nearly 100%. As illustrated in Figure 3.3, a simple, yet effective balance of loads and resources ("BLR") adequately demonstrates surplus or deficit reserves while applying a 15% PRM. Without more detailed scrutiny of variable resource behavior, a BLR may not be as useful. Additional steps and/or analysis is required to more adequately fill the BLR table. ELCC for variable resources can be estimated with a range of metrics with varying complexity. This report section will illustrate a high-level and a more complex method for estimating ELCC and for calculating credited capacity.

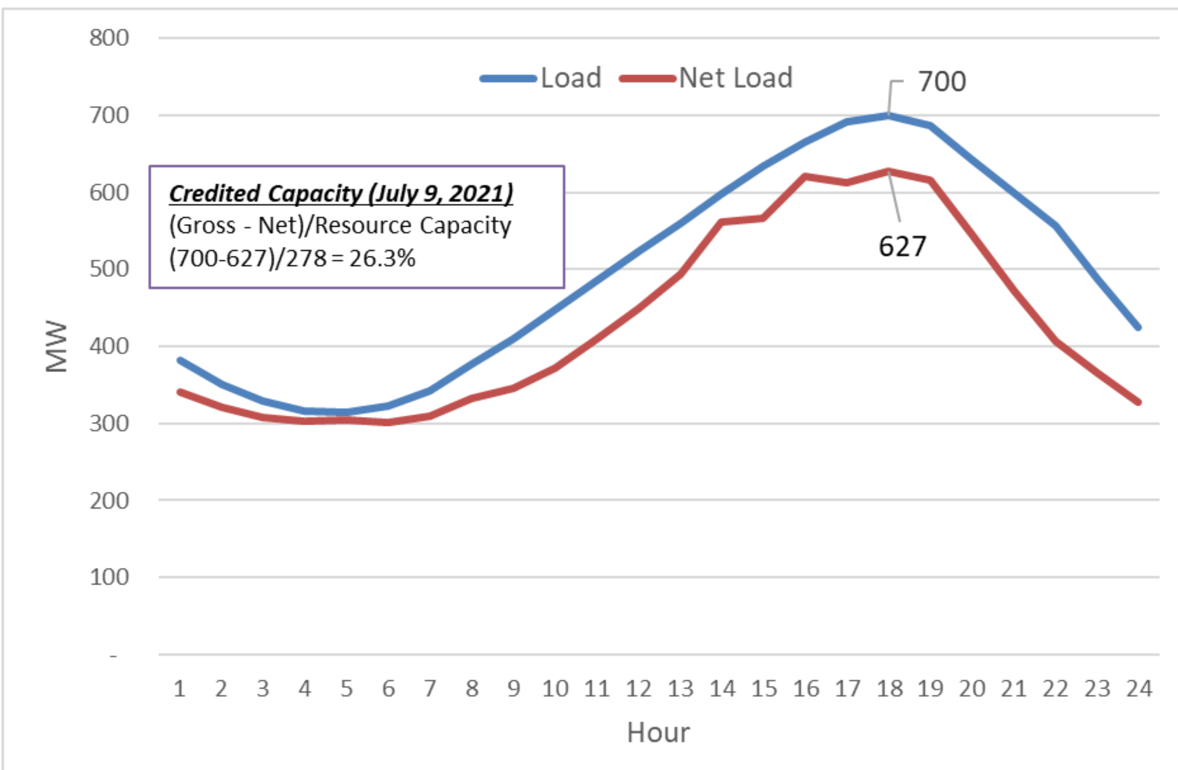
Figure 3.3: Balance of Load and Resources



3.2.1 Method 1 - Hourly Net Load Comparison

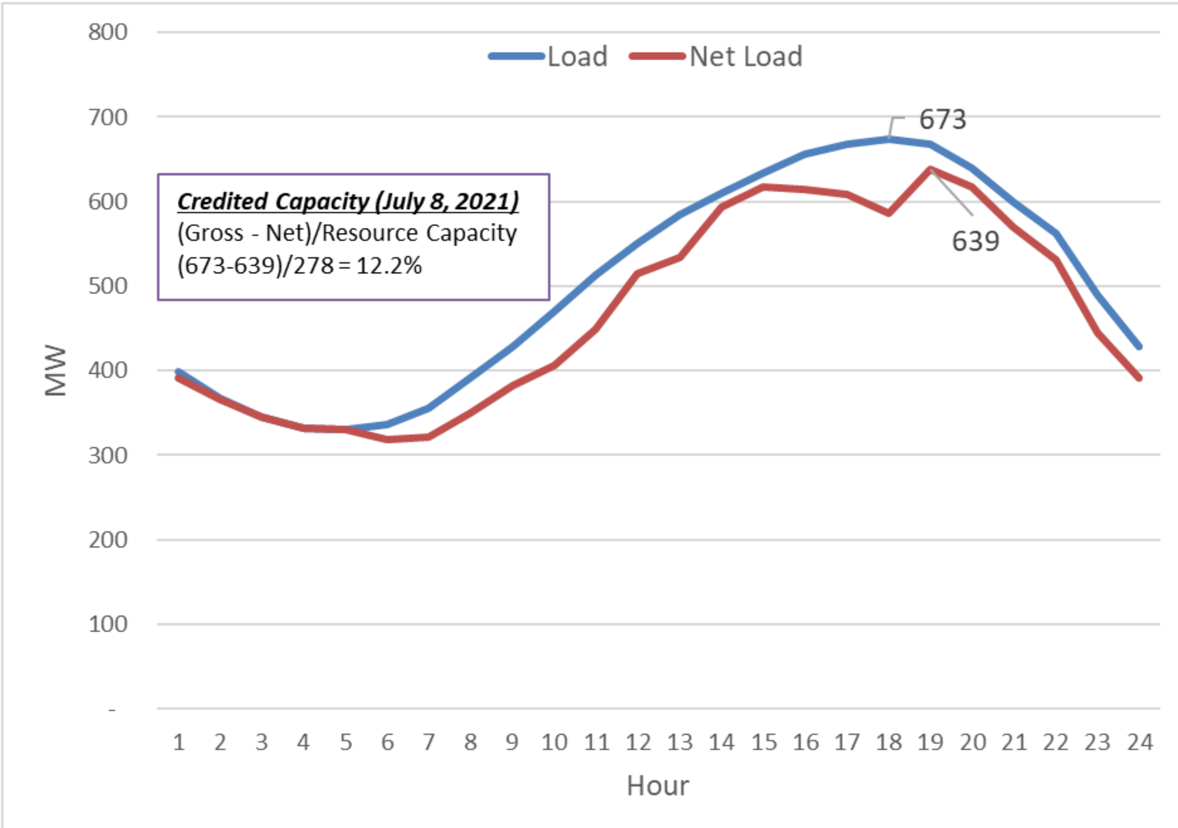
To calculate the credited capacity of variable resources, hourly profiles are valuable. Whether derived from actual recorded output or from available public data such as provided by NREL, good estimates for credited capacity can be formulated. Hourly load data can be compared to solar and wind resource hourly generation profiles to create a net load shape. That is, gross load hourly data can be subtracted by coincident hourly variable generation to create a net load profile. The carve out of variable generation (depending on penetration) will create noticeable shifts and reductions that can be quantified and compared to the original gross load shape. By projecting historical load shapes and applying growth to the shapes, capacity contribution from wind and solar resources can be estimated. Arbitrarily chosen for this demonstration, Figure 3.4 shows the estimated (and simulated) PRPA July 9, 2021 peak day gross load and net load with 228 MW of wind and 50 MW of solar.

Figure 3.4: July 9, 2021 - Peak Day Credited Capacity



As shown in the figure, the peak hour reduction from wind and solar is 26.3% or 73 MW combined, with no intra-hour shift in the peak. Caution should be exercised; the peak day reduction is observed but the peak may shift to another day. As shown in Figure 3.5, the simulated peak load for the day prior, July 8 is 673 MW. The wind and solar production during the peak hour is 34 MW, less than on the peak day. The net load peak is 639 MW. In this simulation, 639 MW would be the new peak for 2021. Compared to the gross peak load (without wind/solar) of 700 MW, this is a reduction of 61 MW (22 % capacity credit).

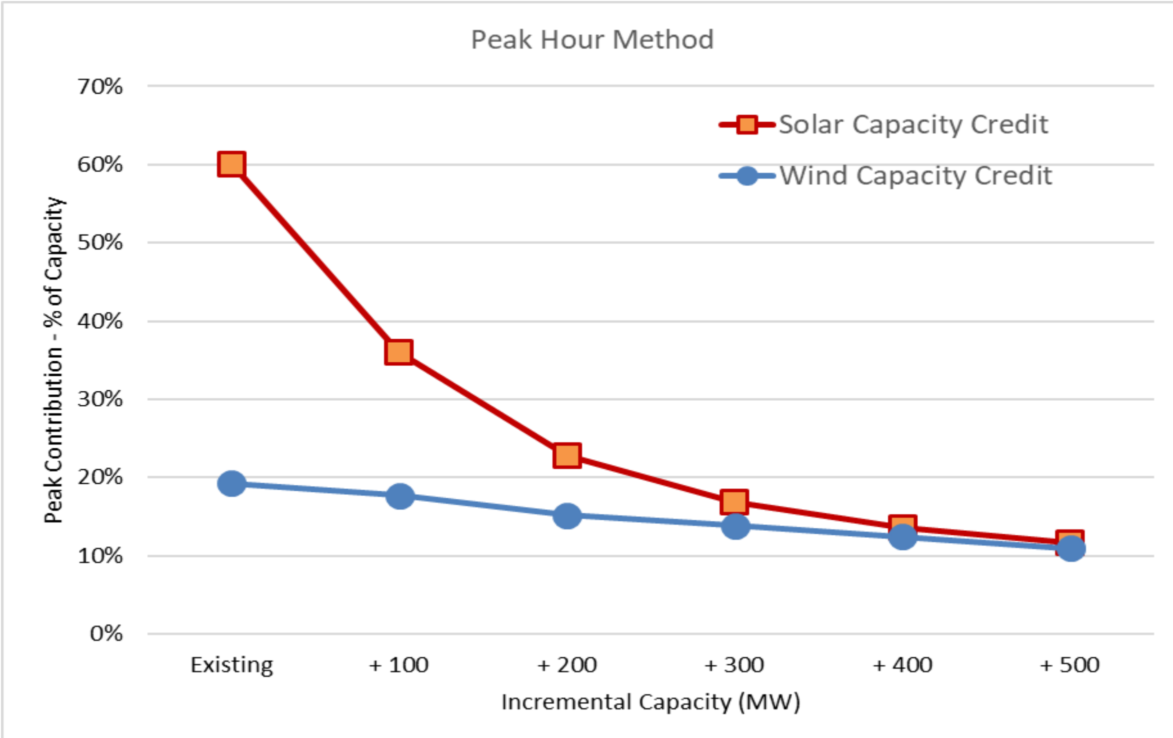
Figure 3.5: July 8, 2021 - Peak Day Credited Capacity



3.2.2 Credited Capacity Summary

As demonstrated in the Xcel and PNM studies and as generally expected, wind and solar credited capacity diminishes as more resources are brought online. Using the technique to compare hourly gross load with estimated net load, Figure 3.6 shows stand-alone, or individual expected credited capacity for wind and solar for PRPA as applied to hourly load. Wind contribution to peak load reduction is below that of solar but converges with an additional 300 MW of each technology above 228 MW of wind and 50 MW of solar. The existing 228 MW of wind will contribute about 20% (44 MW) of its capacity, the initial 50 MW of solar will reduce load by 60% (30 MW) of its capacity.

Figure 3.6: Credited Capacity (Peak Demand Reduction)



3.2.3 Method 2 - Probabilistic

Xcel and CPUC present a probabilistic approach for using LOLE to determine credited capacity. This section will summarize this method through example, as applied to PRPA system. The PRPA LOLE model can be utilized to determine credited capacity for wind and solar resources. The example shown here is based on hourly gross load for 2020, existing dispatchable capacity as shown in Table 3.2 (with associated FOR) and 228 MW of wind and 50 MW of solar generation. CPUC has a seven step process that isolates wind and solar separately to calculate individual 'Perfect Capacity'. Our example will calculate the credited capacity for wind and solar at PRPA. This method is as proposed by CPUC to derive diversity factors for standalone wind and solar.

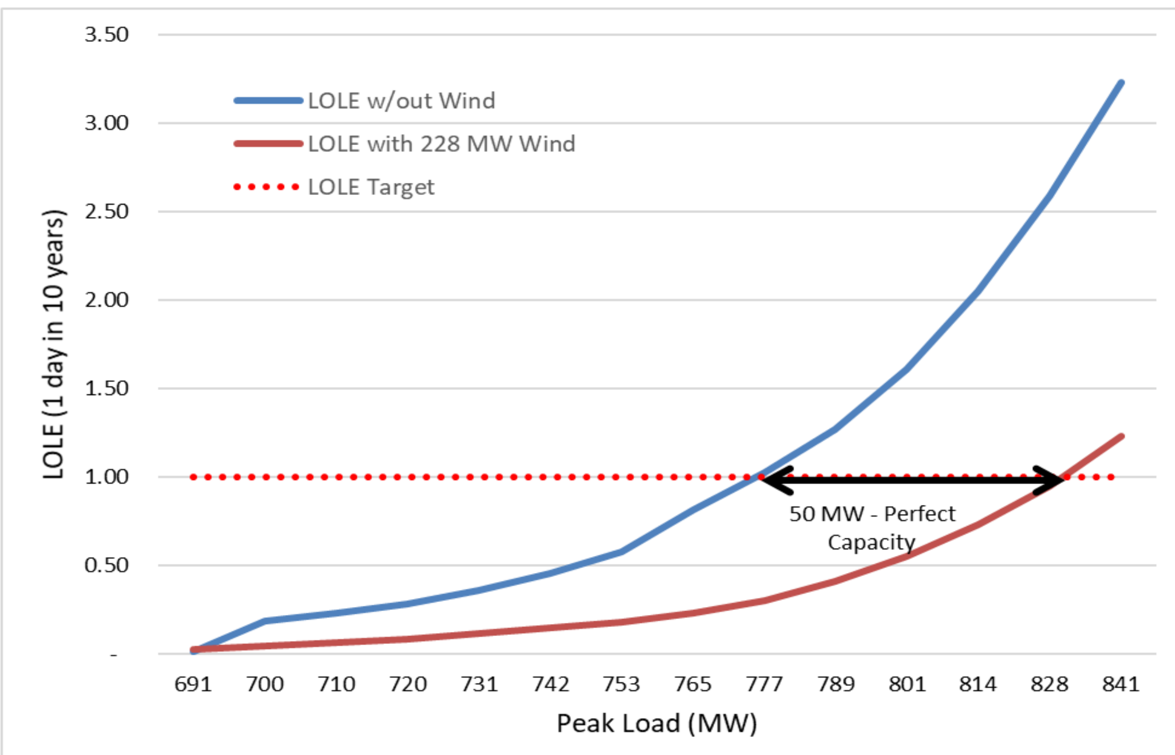
Table 3.2: Dispatchable Resources

Unit	Capacity (MW)
Rawhide 1	280
Craig 1	77.5
Craig 2	74
Rawhide A	65
Rawhide B	65
Rawhide C	65
Rawhide D	65
Rawhide F	128
LAP	60
CRSP	30.3
Total	909.8

3.2.3.1 Estimating Capacity Value of Existing Wind & Solar

Our first step for calculating credited capacity using the Perfect Unit concept is to apply the net load shape. This was derived by removing wind hourly production that were applied from NREL hourly profiles. Assuming no retirements, the LOLE for PRPA remains below 1.0 days in 10 years through a peak load of approximately 777 MW without support from wind. With a total of 228 MW of wind the LOLE remains below 1.0 through a peak of 828 MW as shown in Figure 3.7. The capacity value (ELCC) contribution of wind is 50 MW (22% of wind capacity) using the "Perfect" unit approach.

Figure 3.7: Wind ELCC



The same methodology is applied to determine the credited capacity of PRPA's existing solar of 50 MW. With a total of 50 MW of solar the LOLE remains below 1.0 through to approximately 800 MW of peak load as shown in Figure 3.8. The capacity value contribution of wind is 21 MW (42% of solar capacity) using the "Perfect" unit approach.

Figure 3.8: Solar ELCC

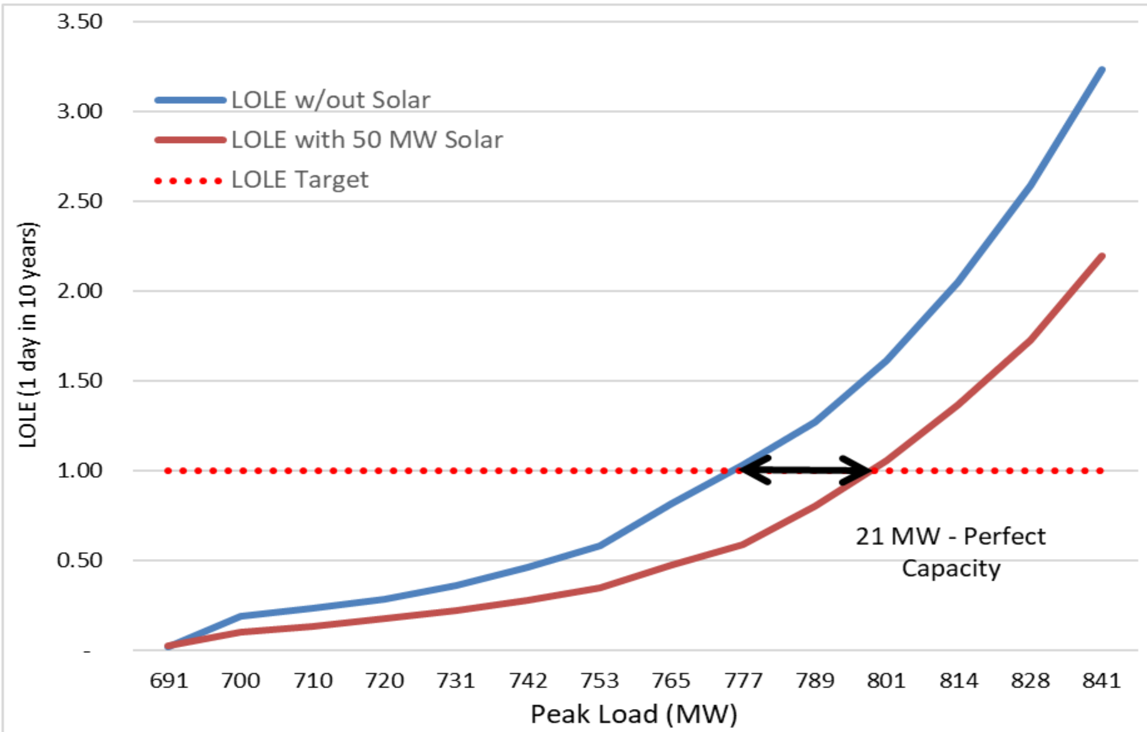
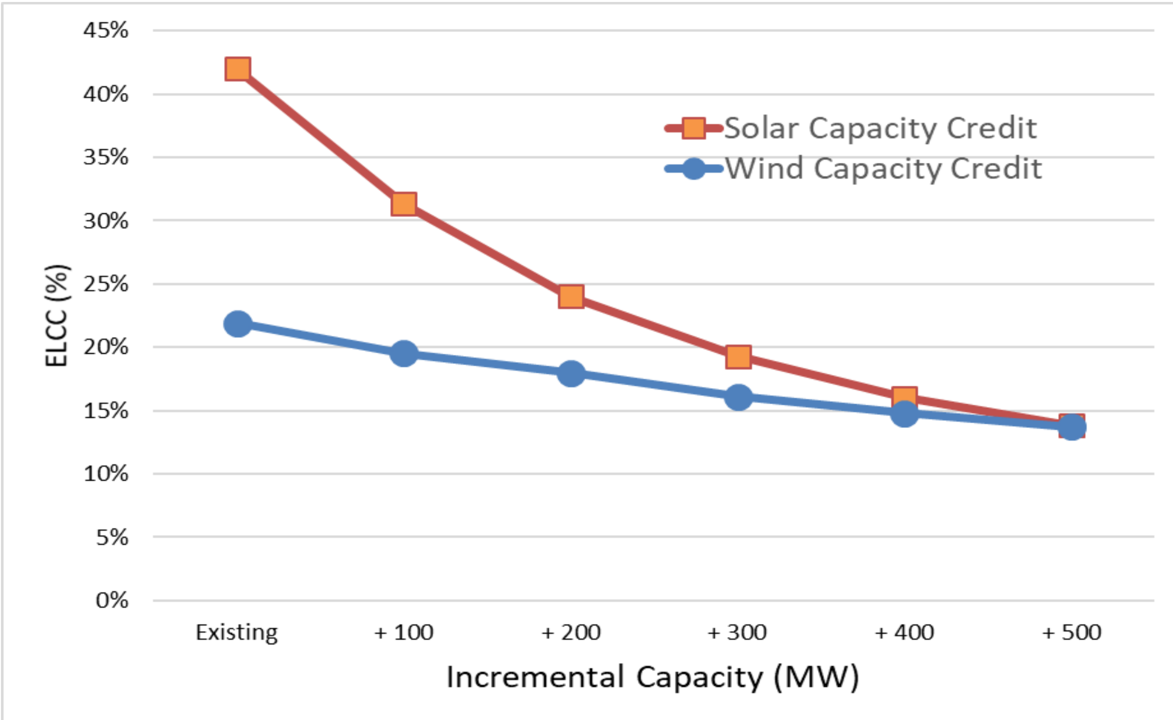


Figure 3.9 shows the cumulative ELCC of wind and solar by applying the LOLE "Perfect Unit" methodology. With each 100 MW of added capacity of wind and solar, the contribution or ELCC diminishes. An additional 500 MW (total of 728 MW of wind and 550 MW of solar) results in 14% of cumulative ELCC.

Figure 3.9: Cumulative Wind/Solar ELCC



3.2.3.2 Utility ELCC Comparisons

The ELCC estimates for PRPA are similar to the calculations determined by Xcel (Public Service Company of Colorado) and Black Hills Colorado Electric ("BHCE") in 2016, as filed in their Electric Resource Plans ("ERP") with the Colorado Public Utilities Commission. Xcel is a much larger utility than PRPA and BHCE and they applied 500 MW increments of wind and solar into their ELCC calculations. BHCE performed their study in 30 MW increments while PRPA applied 100 MW increments. In order to assess an equivalent comparison, each utility ELCC for wind and solar was compared to the utility's peak demand. A "combined" ELCC was estimated by aligning the data to form a single trendline (equation). The results of this comparison are shown in Figure 3.10 and Figure 3.11. ELCC is shown as a percent of the individual company peak loads.

Figure 3.10: Wind ELCC Comparison

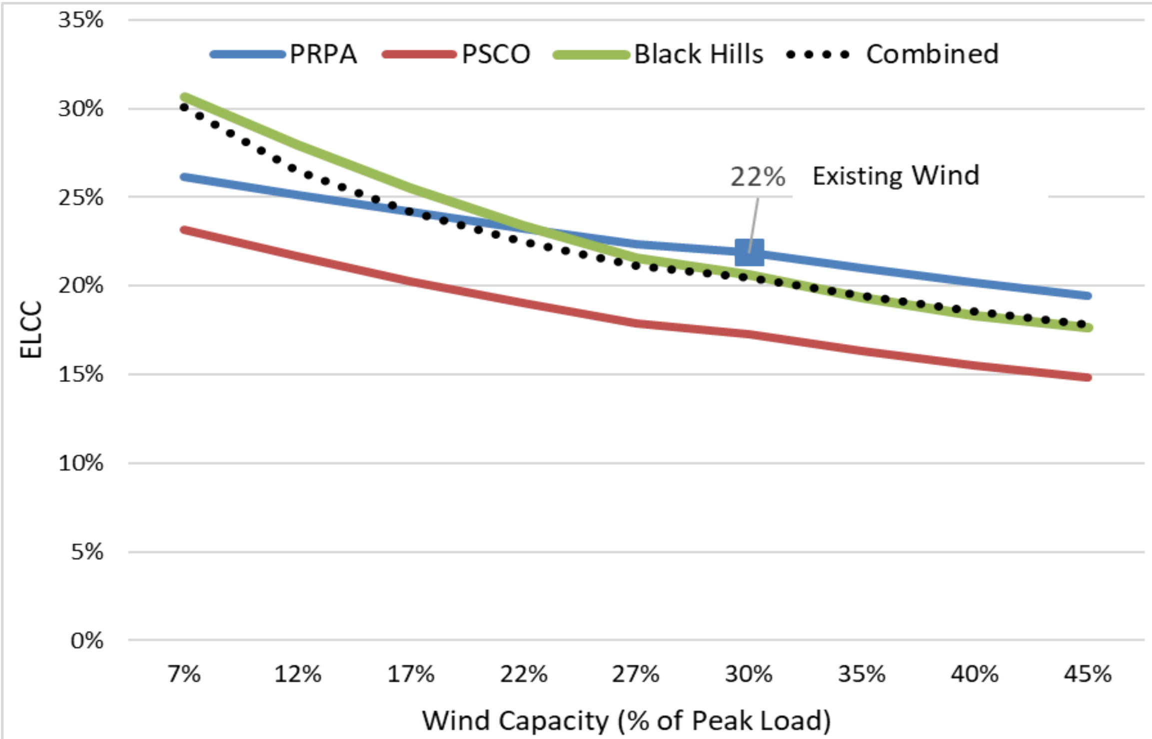
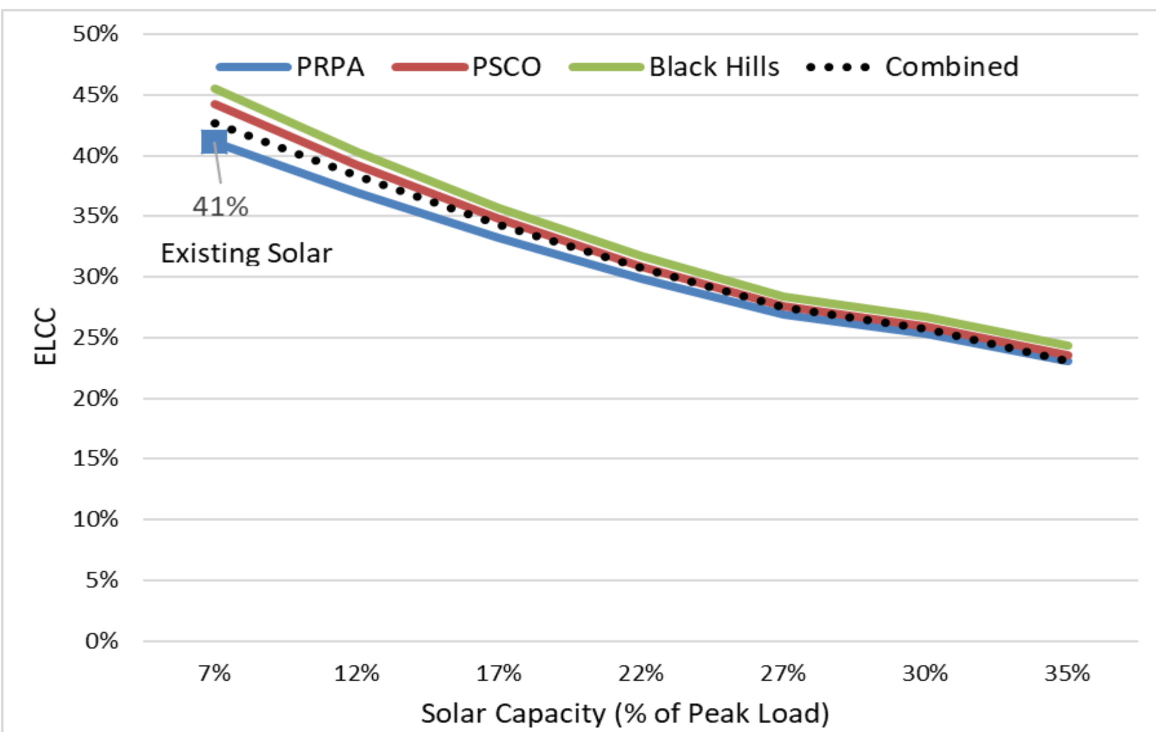


Figure 3.11: Solar ELCC Comparison



3.2.3.3 Capacity Replacement for Retirement Scenarios

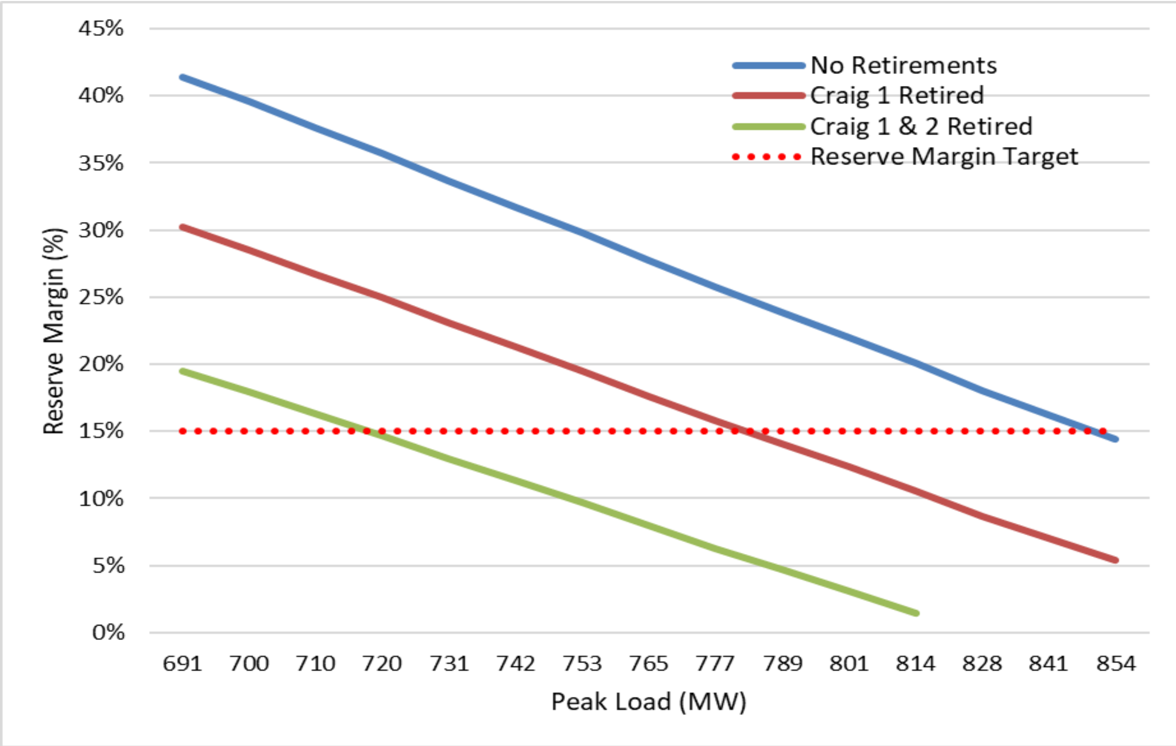
A 15% PRM is reasonable and adequate for PRPA. This section demonstrates how a 15% PRM correlates or compares to an LOLE of 1.0 days in 10 years. PRPA's reserve margin is above 15% past a peak of 841 MW with its current resource portfolio which includes 228 MW of wind and 50 MW of solar. Without consideration of market capacity available in the PRPA service region, LOLE is above 1.0 at each level shown in Table 3.3 for varying retirement scenarios.

Table 3.3: Reliability Measures (Retirement Scenarios)

Portfolio	Peak Demand (MW)	Reserve Margin (%)	LOLE at 841 MW Peak Demand
Existing	841	16.2%	0.98
Retire Craig 1	841	7.0%	3.19
Retire Craig 1 & 2	841	-1.8%	12.09
Retire All Coal Units	841	-35.1%	510.51

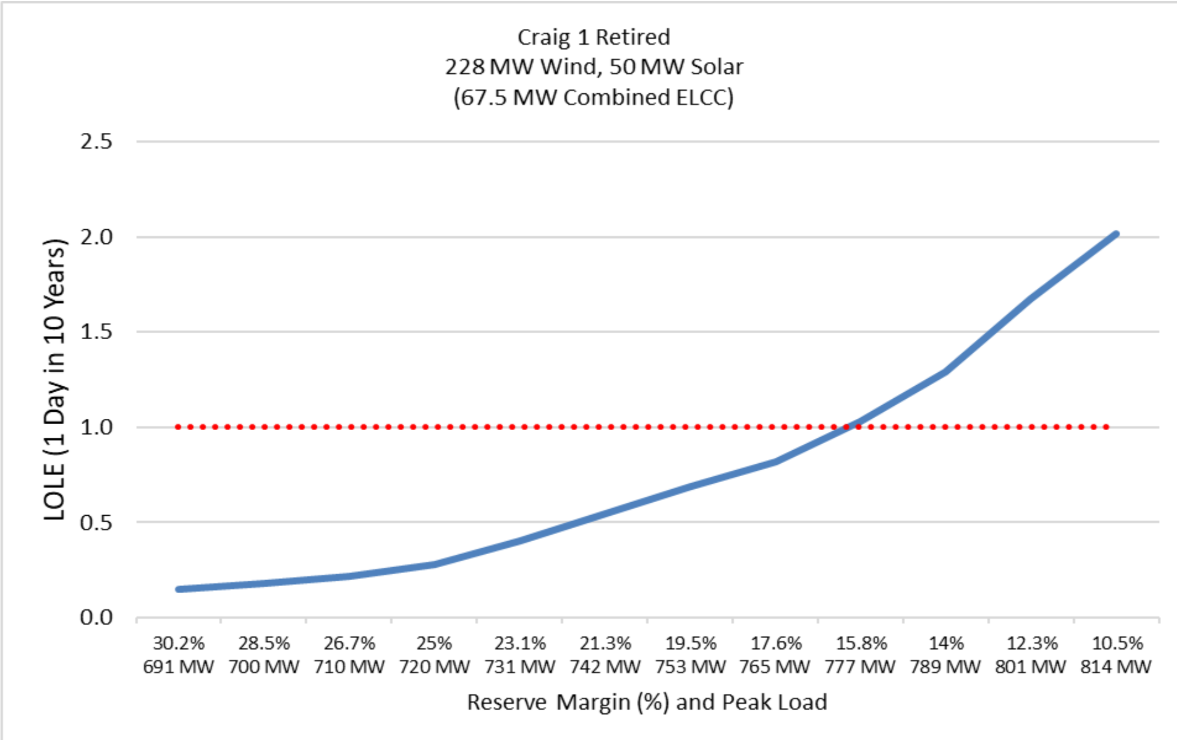
Except for the portfolio that retires all the coal units, Figure 3.12 illustrates the reserve margin trajectory for varying peak load outcomes. Current wind and solar projections of 228 MW and 50 MW respectively are included in each portfolio. The reserve margin calculation includes combined ELCC for wind and solar of 67.5 MW as determined through the LOLE perfect unit methodology.

Figure 3.12: Coal Retirement Reserve Margin



The retirement of Craig Unit 1 represents the most certain or definitively known future. Figure 3.12 illustrates that a 15% margin is achieved just above 777 MW with the retirement of the unit in 2025. The next illustration, Figure 3.13, shows that the LOLE after retiring Craig Unit 1 is below 1 day in 10 years and with 15.8 % reserve margin with a peak of 777 MW.

Figure 3.13: LOLE after Craig Unit 1 Retirement



Reserve margins diminish with each retirement scenario and LOLE increases. Table 3.4 shows the capacity requirements under different coal retirement scenarios without the support of wind and solar. It shows the required replacement capacity to achieve 15% reserve margin at pre-retirement peak demand of 828 MW. Additionally, the table also demonstrates “perfect” capacity to augment additional replacement capacity due to retirements that achieves LOLE below 1.0 (at 828 peak demand).

For each scenario, “perfect” capacity represents additional market capacity that must be available at peak. As shown in Table 3.4, retirement of Craig Unit 1 was modeled to be replaced with a generic 83 MW thermal unit with 98% availability. The replacement options for Craig 1 &2 retirements was modeled with two 83 MW thermal units with 98% availability. The improved capacity factor and capacity reduced market reliance to 37 MW (above 100 MW of shaft share). Multiple generators (441 MW) are modeled and represented in the ‘Retire All Coal Units’ scenario. This expanded diversity of the replacement capacity makes it such that LOLE of 1.0 is achieved without additional market contribution. However, note that an additional 33 MW of market capacity is needed to reach a 15% reserve margin. Without 33 MW of market capacity the reserve margin is 11% while the LOLE is 0.8074 (not shown in Table 3.4).

Table 3.4: Attaining 15% Reserves and 1.0 LOLE

Portfolio (No Wind or Solar)	Capacity to Achieve 15% RM at 828 MW	Resulting LOLE at 828 MW	Import Capacity to achieve 1-in-10 LOLE MW* at 828 MW
Existing		1.014	46
Retire Craig 1	83	0.998	37
Retire Craig 1 & 2	166	1.000	24
Retire All Coal Units	441	0.272	*33
**** does not include 100 MW of shaft share***			

3.3 Application in Production Cost Model

Available hourly generation profiles for wind and solar facilitates the modeling for production cost scenarios. With hourly generation profiles, the Production Cost Model ("PCM") naturally incorporates the ELCC of variable generation. Credited capacity can be determined from a production cost simulation by applying the methods discussed in this report. Predetermined estimates for credited capacity can be useful for estimating a BLR or for simulating a capacity expansion simulation with specific reserve margin constraints. Good estimates for credited capacity will assure that a capacity expansion exercise does not overestimate reserves.

4.0 LOLP METHODS AND REVIEW

Methodology for evaluating LOLP and LOLE metrics used to measure reliability outcomes for PRPA's IRP was reviewed. In this review, Burns & McDonnell developed a model to calculate LOLP and LOLE to verify reliability metric results. The model calculates LOLP and LOLE, combining generator capacity outage probability for PRPA's dispatchable resources fleet with forecasted load profiles. The model can be utilized to account for availability of energy from non-dispatchable, variable resources such as wind and solar.

Burns & McDonnell modeled energy generated from variable resources by subtracting generated energy from gross load. Subtracting variable generation from gross load creates a net hourly load profile which can be used in the LOLP calculation and represents the additional load required to be served by PRPA's dispatchable resources after accounting for energy from variable generation resources.

4.1 LOLE Modeling

The model calculates LOLP and LOLE annually by combining a single set of generator capacity outage probabilities with varying forecasted load duration curves. Values for nameplate capacity and unavailability factor (that may include FOR and maintenance factors) are assigned for each of PRPA's generating units, and a capacity outage probability table ("COPT") is generated. The COPT tabulates probabilities of availability (on) and unavailability (off) of each generator combination possible for PRPA's fleet. Table 4.1 shows a simplified COPT for 2 units of equal capacity, availability and unavailability. An outage probability table will have a combination of 2^n (n=number units) of outage probabilities. PRPA with 10 units, will generate a COPT of 2^{10} (1024) combinations.

Table 4.1: COPT Example

Status	Capacity Outage	Probability
Both Units Available	0	Availability^2
Unit One Available	C	Availability x Unavailability
Unit Two Available	C	Unavailability x Availability
Both Units Unavailable	2C	Unavailability^2

Generators are assumed able to generate at 100% of their nameplate capacity for all hours as they are available in the capacity outage probability table. Available capacity is determined for each generator status combination; this available capacity is compared against the forecasted load duration curve to determine the number of hours throughout the year that load would be unable to be served with the combination of available generation.

LOLP, representing the hourly probability throughout the year that available generation will be unable to serve load, is calculated for each generator status combination by multiplying the capacity outage probability with the percentage of hours throughout the year where load is unable to be served (or exceeds generation) for that combination. LOLE, representing the time duration expected throughout the year that available generation will be unable to serve load, is calculated by summing LOLP for every generator status combination in the capacity outage probability table.

4.2 BMcD Model

Burns & McDonnell developed a model to validate reliability metrics. Burns & McDonnell's model uses generator capacity outage probabilities, hourly load forecasts, and hourly variable generation forecasts to calculate LOLP/LOLE annually. Results for reliability metrics are calculated with and without variable generation, such as wind and solar, netted out of load to quantify the load serving impact of PRPA's renewable resources.

Reliability metrics are calculated using an executable tool developed in C++; run instruction input files for the C++ tool are generated using a macro-enabled Excel workbook. Inputs to the macro-enabled Excel workbook include: (1) a table of dispatchable generators with values for nameplate capacity and unavailability factors; (2) a load forecast table with hourly demand for each future year; (3) a variable generation forecast table with hourly energy generation for each future year.

4.2.1 Capabilities

Burns & McDonnell's developed model calculates LOLP/LOLE by accounting for the probability that generators will be available to serve future forecasted load. BMcD's model accounts for variable generation produced by non-dispatchable resources such as PRPA's wind and solar resources. BMcD's model also accounts for generator retirements and additions by allowing generator assumptions to be varied by year.

4.2.2 Limitations

BMcD's model calculates the probability that capacity from available generation will exceed hourly demand throughout the year, but the model does not account for the intra-hour variability in net load that would be served by dispatchable generators either by ramping up or ramping down. The importance of intra-hour ramping limitations on assessing load serving expectation grows as the amount of variable generation modeled on the system increases. Large intra-hour swings in variable generation can cause ramping requirements unable to be met by PRPA's dispatchable generation fleet. The resultant hourly ramping can be extracted from the model to ascertain system load following capabilities in a separate study.

4.3 Planning Reserve Margin vs LOLE

It is important to note the relationship between Planning Reserve Margin and LOLE when assessing system reliability. NERC assigns 15% and 10% PRM to mostly thermal and mostly hydro-electric systems respectively, when regional and sub-regional specific margin calculations are not provided. Coupled with probabilistic analysis, the PRM is a standard used by planners to measure adequacy.

For PRPA, the fleet of resources provide significant reserves and a high reserve margin, currently well above 50%. Large generating units within a system can contribute to a significant portion of an area's capacity reserves, load serving capability diminishes rapidly when a large unit is forced offline or taken out of service. The loss of PRPA's largest coal unit, Rawhide Unit 1, would reduce reserves in an instant. With Rawhide in service, LOLE and reserve margins are adequate. The loss of a single Craig unit will increase LOLE above 1 day in 10 years, for peak demand above 780 MW, while reserve margins remain above 15%.

The LOLE of any system can be lowered by managing and reducing forced outages rates. The replacement of larger units, equal in capacity, with smaller, flexible and reliable generating units will maintain PRM but will also reduce LOLE. In a wider interconnected system, like PRPA is in, additional reliability gains can be measured through the accounting of neighboring utility support. Reserve sharing programs serve to minimize loss of load probability while benefiting with increased reliability.

4.4 Application in Resource Planning

LOLE has the primary use of determining the adequacy of PRPA's system. The model can also be used to determine credited capacity for variable generation as demonstrated in this report. The mode developed by PRPA is a useful tool, with the modifications adapted by Burns & McDonnell, the process for determining adequate supply can be facilitated. Additional metrics may be incorporated into the model to determine intra-hour insufficiency, or the inability of existing resources to follow load as more wind and solar is added to the system. Specifically, the quantification of EUE may become more valuable in assessing system reliability with high amounts of wind and solar.

5.0 RESERVE REQUIREMENTS AND REGULATORY REVIEW

The emergence of renewable generation is changing the landscape of the electric utility industry. As more renewable generation is implemented, reliability and regulatory implications shift and develop. Renewable energy has caused disruption in the market because of the challenges in determining how to evaluate the energy generating potential. While traditional non-renewable energy generators are typically available to generate whenever desired, the most prominent renewable energy generators (wind and solar) operate intermittently and without full predictability and control. In developing a forecast for how regulatory bodies will address the measures and requirements for increased renewables, North American Electric Reliability Corporation ("NERC") and Regional Transmission Operator ("RTO") requirements, policies and standards for reliability will be reviewed.

5.1 North American Electric Reliability Corporation

NERC evaluates current and future adequacy and operational reliability in North America through several assessments to communicate emerging issues and potential concerns to policy makers. In the 2018 NERC Probabilistic Adequacy and Measures Report ("Report")[8], the Probabilistic Assessment Working Group ("PAWG") was tasked with surveying and evaluating the use of Probabilistic Studies in resource adequacy and reliability risk reports.

One of the key findings in a NERC survey associated with the Report was that majority of entities in North America performed resource adequacy studies primarily using Loss of Load Expectation ("LOLE") and roughly one third of survey respondents utilize Expected Unserved Energy ("EUE") for assessing reliability. While it's been a matter of judgement between regions and assessment areas regarding the methodology used to measure adequacy, the trend is that most recognize that emerging reliability issues maybe assessed with probabilistic models.

5.1.1 Recommendations on Reliability

The continued emergence of variable energy resources requires different approaches for evaluating reliability. NERC will continue to incorporate probabilistic approaches for adequacy assessment. The NERC PAWG and Reliability Assessment Subcommittee ("RAS") made recommendations on Reliability Risk Metrics ("RRM") based on system size and study purpose.

[8] https://www.nerc.com/comm/PC/Documents/2.d_Probabilistic_Adequacy_and_Measures_Report_Final.pdf

5.1.1.1 Loss of Load Hours (LOLH)

One RRM recommended for both small and large systems was the Loss of Load Hours (“LOLH”) approach. This metric includes the use of all hours instead of only peak periods to assess reliability. The justification for this recommendation was that this RRM measures combined duration and shows the influence of energy limited resources on reliability, such as Demand Response (“DR”), Energy Efficiency (“EE”) and behind-the-meter Distributed Generation (“DG”).

5.1.1.2 Loss of Load Expected Events (LOLEV)

For systems in which planners are concerned about numerous loss of load events in a day period, the RRM recommended is Loss of Load Expected Events (“LOLEV”).

5.1.1.3 Loss of Load Expectancy (LOLE)

For evaluating resource adequacy with LOLE, PAWG recommends evaluating all hours and reporting the time period and hours associated with the calculation. An analysis to derive LOLE for just the peak hour yields results equal to or lower than full hourly analysis.

5.1.1.4 Expected Unserved Energy (EUE)

For optimizing the benefit of using EUE as an RRM, PAWG recommends the reporting of hourly EUE values for every month or year, planners estimating the cost and impact of loss of load events using EUE and using EUE for extreme weather conditions and common mode failure events.

5.1.2 Planning Reserve Standards

NERC’s Reference Reserve Margin originates from a regional/sub regional’s target margin based on load, generation, and transmission characteristics as well as regulatory requirements. If no target margin is provided, NERC assigns a general reserve margin of 15 percent for thermal systems and 10 percent for predominately hydro systems through a reliability indicator titled M-1 Reserve Margin. While general reserve margins can be used as a generic standard, NERC realizes that reserve margins can be volatile as evidenced by the 2017 LTRA Reference Case Reserve Margin of 18.22 percent for Texas RE-ERCOT declining to 11.76 percent in updated analysis just prior to publishing the 2017 LTRA late in 2018.

5.2 Western Electricity Coordinating Council

Western Electricity Coordinating Council (“WECC”) promotes Bulk Electric System reliability in the Western Interconnection and provides and environment for the development of Reliability Standards for its members. WECC adheres to the guidance and definitions of reliability requirements for planning and operating as provided by NERC. WECC has authored or administered multiple studies over the years that measured reliability with probabilistic approaches and intra-hour flexibility. One study, "Western Interconnection Flexibility Assessment"[9] from December 2015 investigated the need for flexible generation with high variable generation penetration in 2024. The project was overseen by WECC and partnered with NREL and Energy & Environmental Economics, Inc. ("E3"). One part of the study reviewed resource adequacy using the LOLP approach while the other reviewed flexibility through a stochastic approach. The LOLP method showed that each region studied within WECC was above 15% planning reserve margin and each was below the loss of load threshold for reliability.

An assessment of flexibility examined the intra-hour balance of load and generation. The study recognized the diversity of net load and the ramping capabilities of the WECC system. The detailed flexibility analysis was performed for the different regions within WECC. Results by region vary, but in a high renewables case for the Rocky Mountain region, the study observed high thermal unit cycling with coal units often ramping down to minimum generation and gas units cycling on/off daily. Pumped hydro units were utilized to pump during solar production and where discharged more nocturnally. Excess wind power is exported, and variable generation is curtailed to avoid overgeneration.

Common observations across all the regions studied, showed that curtailment strategies for high variable generation may be needed. Coal plants will need to become flexible to follow load and to potentially reduce wind and solar overgeneration. Wind and solar curtailment soften or reduces the ramping insufficiency.

5.3 California Independent System Operator

The California Independent System Operator ("CAISO") asserts a focus on the reliable integration of zero-emission resources such as solar and wind power in support of the state's renewables portfolio standard. While the CAISO is California's independent system operator, it is still associated with the region's trade agency, WECC, which seeks to promote reliability in the Western Interconnection and support efficiency in the competitive power markets. The CAISO is working to balance the state's clean energy goals while maintaining reliability, efficiency and affordability.

5.3.1 Recommendations on Reliability

In the CAISO IRP responses, it was stated that for LOLE, the industry developed 1-day-in-10-year ("1 in 10") metrics based on legacy power systems with conventional resources and high availability factors and there are no accurate technical reasons to move away from this.

[9] https://www.wecc.org/Reliability/WECC_Flexibility_Assessment_Report_2016-01-11.pdf

5.3.2 Reserve Standards

CAISO is at the forefront of ISOs integrating large amounts of renewable generation into their system and has a defined stance on PRM study methods. CAISO supports using probabilistic studies such as LOLE with a 1 in 10 metric as this method accounts for the dynamic nature of power systems because this approach evaluates individual unit level variability. Since there are no currently established WECC reliability criterion standards, like other regional NERC entities have set, CAISO supports the 1 in 10 as the best proactive approach.

With CAISO's growing solar and wind grid contribution, the CPUC adopted qualifying capacity values to accurately value reliability contributions based on an ELCC methodology. To calculate the values the following is performed:

1. Model a capacity portfolio that brings the CAISO area to a target LOLE of 0.1 (approximately equivalent to 1-day-in-10 years), given the loads and resources expected to exist in the study year.

2. Remove all resources of interest (wind or solar) in the CAISO area.

3. Add "perfect capacity" back to the portfolio to bring system back to the target LOLE of 0.1.

4. The ELCC value of the resources of interest equals the ratio of the removed capacity to the amount perfect capacity that was required to bring the portfolio back to 0.1 LOLE, i.e., (removed capacity/perfect capacity*100%).

5.4 Southwest Power Pool

Southwest Power Pool ("SPP") oversees the bulk electric grid in the central US and ensures the reliable supply of power, adequate transmission infrastructure, and competitive wholesale electricity prices for a 546,000-square-mile region including more than 60,000 miles of high-voltage transmission lines.

5.4.1 Recommendations on Reliability

SPP conducts a LOLE study every other year. All hours of the year were considered for the probability of loss of load. For the 2017 study, wind resources currently installed, under construction, or that had a signed interconnection agreement were included. Solar capacity was also included. For modeling purposes, SPP utilized a neural network load modeling process that developed weather and load relationships from recent history to match up the weather that affects the output of wind, solar, hydro and thermal resources.

5.4.2 Reserve Standards

SPP's 2018 Resource Adequacy Requirement PRM is specified by generation mix: if an entity contains 75% or greater hydro resources in their generation mix, then a 9.89% PRM is assigned. If an entity contains less than 75% hydro resources, then a 12% PRM is assigned.

SPP's Supply Adequacy Working Group ("SAWG") maintains, coordinates, and implements generation criteria in SPP. In the 2017 Wind and Solar Report, the SAWG recommends changes be considered for the current criteria which requires the capability for wind and solar resources to correspond to the top 3% load hours by month of the Load Serving Entity. The value used for accreditation is the output at the 60% confidence factor for those peak hours. The changes were recommended due to concerns over the increasing solar and wind penetration having the potential to remain reliable at increasing levels. SPP has already experienced real-time wind penetration levels above 40% and in the SPP 2017 Variable Generation Integration study, the results showed stability for 45% and 60% wind penetration simulations.

5.5 Industry Trends for Reliability Requirements

The methods for calculating a 15% planning reserve margin or determining a 1 day in 10 year LOLE will garner added focus with increase in wind and solar generation. The metrics for assessing reliability will more predominantly shift to using probabilistic analysis but different aspects of loss of load may need additional scrutiny. While it may be premature to identify whether planning reserve margin standards will be rewritten, a likely focus may be the assessment of all hours for reliability, rather than on peak demand alone. Peak capability assessment will transform to include techniques to derive variable generation credited capacity.

It may not be enough to only consider peak capability; intra-hour ramping sufficiency will be critical. Closer evaluation of operating reserves and resource ramp capabilities will be required. The PNM reliability analysis included a detailed examination of historical load and weather metrics attributed to wind and solar profiles. Their consultant derived statistically correlated profiles for load, wind and solar. NREL provides wind and solar production profiles by region and specific location that are based on typical meteorological years. As more wind and solar is added to utility systems, it will become increasingly valuable to assure that load projections are referenced to the same weather metrics. The examples, methods and assumptions presented in this review did not derive statistical hourly shapes for load, wind and solar that correlate with a common weather set of historical assumptions. PRPA's load forecast is weather-normalized but may not be correlate specifically to the NREL patterns used for wind and solar. Accurate modeling will be integral in understanding and in analyzing LOLE, operating reserves and load following capabilities.

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