Summary of Time Period-Based and Other Approximation Methods for Determining the Capacity Value of Wind and Solar in the United States

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Subcontract Report
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NREL Technical Monitor: Erik Ela
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Acronyms

APS	Arizona Public Service
CPUC	California Public Utilities Commission
CSP	concentrating solar power
ELCC	effective load carrying capability
ERCOT	Electric Reliability Council of Texas
IEEE	Institute of Electrical and Electronics Engineers
IESO	Ontario Independent Electric System Operator
ISO	independent system operator
LOLE	loss of load expectation
LOLP	loss-of-load probability
LSE	load-serving entity
MISO	Midwest Independent Transmission System Operator
NERC	North American Electric Reliability Corporation
NPPD	Nebraska Public Power District
NYISO	New York Independent System Operator
PGE	Portland General Electric
PNM	Public Service Company of New Mexico
PSCO	Public Service Company of Colorado
PV	photovoltaic
RPM	Reliability Pricing Model
RPS	Renewables Portfolio Standard
RTO	regional transmission organization
SLC	solar load control capacity
SM	solar multiplier
SPP	Southwest Power Pool
TES	thermal energy storage
WECC	Western Electricity Coordinating Council

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Introduction

This paper updates previous work that describes time period-based and other approximation methods for estimating the capacity value of wind power and extends it to include solar power [1, 2]. Time period-based approximation methods typically measure the contribution of a wind or solar plant at the time of system peak—sometimes over a period of months or the average of multiple years.

Electric power system reliability can be categorized into two parts: system security and system adequacy. A system is secure if it can continue to provide electric service despite the loss of a significant generator or transmission line (or perhaps multiple generators or lines). Generation system adequacy is whether there is sufficient installed capacity to meet demand for electricity. Satisfying generation adequacy is accomplished with multiple generators that may have significantly different operating characteristics. Capacity value, then, is the additional load that can be served with the addition of a generator while maintaining existing levels of reliability. Determining the capacity value of different generators helps system planners evaluate whether there is sufficient capacity to meet electric demand.

Generally, the capacity value of a conventional generator can be approximated by multiplying the installed capacity of a conventional generating plant by that plant's unforced outage rate [3]. Wind and solar power cannot be evaluated in the same manner, as wind and resource availability will be as much a determinant of capacity value as mechanical availability. Therefore, the correlation of wind and solar generation with electric demand along with the forced outage rate of wind and solar generators are the primary determinants of capacity credit for wind and solar.

Our previous work found that the effective load carrying capability method, or ELCC, is the preferred means of determining the capacity value of generating sources. This conclusion is also reached in the North American Electric Reliability Corp. (NERC) report *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* and the Institute of Electrical and Electronics Engineers (IEEE) article "Capacity Value of Wind Power" [14, 3]. ELCC measures the additional demand that can be met with a specific generator with no net change in electric reliability. ELCC can differentiate among generators of varying reliability, size, and on-peak versus off-peak delivery. Plants that are consistently able to deliver during periods of high demand have a high ELCC, and less reliable plants have a lower ELCC. For variable generators such as wind turbines, ELCC can discriminate among wind regimes that consistently deliver during high-risk periods, sometimes deliver during high-risk periods, or never deliver during high-risk periods.

For wind and solar plants, ELCC is determined with a time series of load data of preferably more than 1 year; a wind or solar power time series for the same periods as loads; and an inventory of conventional generation units' capacity, forced outage rates, and maintenance schedules. To determine the ELCC, the power system is modeled without the generator of interest toward a desired loss of load expectation (LOLE, i.e., the expected hours or days that load will not be met over a specific time period). Once that LOLE target is met, the targeted wind or solar plant is added as "negative load" to the load time series. The LOLE is recalculated and will be lower (better) than the targeted LOLE. The load data are then increased and the LOLE recalculated until the target LOLE is met. The increase in peak load is the ELCC of the wind or solar plant.

Our previous work also highlighted several disadvantages of time period-based approximation methods. Generally, time period-based approximation methods assume a high correlation between hourly demand and Loss-of-Load Probability (LOLP, i.e., the probability that electricity demand will not be met at a given time). Although this relationship is generally strong, it can be weakened by scheduled maintenance of conventional units and hydro conditions. Earlier work by the California Independent System Operator, for example, found that system reliability risk was higher during the fall when conventional units were offline for scheduled maintenance [4]. In addition, time period-based methods assume that all hours considered are generally weighted evenly, whereas ELCC and other risk-based methods place greater weight on high-risk hours and less weight on low-risk hours. However, time period-based methods are much simpler to explain in regulatory and other public proceedings. They can also be useful when there is inadequate wind, solar, or load data to rigorously estimate capacity value.

The remainder of this paper summarizes the results of an extensive literature search of utility integrated resource plans, regional transmission organization (RTO) methodologies, regional stakeholder initiatives, regulatory proceedings, and academic and industry studies, presented in alphabetical order. More recently, some efforts have been made to estimate the capacity value of solar power, which are also summarized in this paper. There is not as much available information on the capacity value of solar power, in part because distributed and utility-scale solar are only now being developed in significant quantities.

Arizona Public Service

In January 2009, R.W. Beck Inc. prepared the *Distributed Renewable Energy Operating Impacts and Valuation Study* for the Arizona Public Service (APS). Among other things, the study estimated the capacity value of distributed solar generation. A series of LOLE simulations was performed on the hourly load profiles from 2003 to 2007 as well as forecasted load profiles for a future 5-year time horizon using the existing generation portfolio in APS with an additional 100 MW of solar.

The average capacity value from 2003 to 2007 for a 100-MW installation of distributed solar generation was determined independently for various solar technologies, as shown in Table 1. It resulted in a 44.6% average capacity value for solar hot water technologies, 64.4% for daylighting in the low-penetration case (which reflected low levels of adoption by assuming longer payback periods with the lowest value APS could expect to receive), and 65.5% for daylighting in the high-penetration case (which included economic input assumptions that were more aggressive and resulted in shorter payback periods and a higher value from the distributed solar generation). For residential photovoltaic (PV) systems, the average capacity value ranged from 33.4% to 45.2%, depending on the tilt and direction of the technology. Commercial PV systems, on the other hand, when south-facing with a 10° tilt, averaged 47.4%. Commercial PV systems with a 0° tilt and north-south single-axis tracking averaged 70.2% [5].[1]

[1] This section was not reviewed by an APS representative.

Table 1. Percent Dependable Solar Capacity Value in Arizona per 100-MW Installation

Solar DE Technology	Base Case Resource Plan 2003	2004	2005	2006	2007	Average
Solar Hot Water	43.1%	46.3%	43.9%	41.8%	47.8%	44.6%
Daylighting						
Low-Penetration Case	62.0%	58.7%	N/A	64.1%	72.7%	64.4%
High-Penetration Case	63.6%	59.0%	N/A	66.2%	73.3%	65.5%
Residential PV						
18.4º Tilt, South-Facing	42.3%	41.1%	48.4%	52.5%	41.5%	45.2%
18.4º Tilt, Southeast-Facing	32.5%	28.7%	36.5%	40.8%	28.4%	33.4%
18.4º Tilt, Southwest-Facing	50.7%	53.1%	58.8%	63.4%	54.2%	56.0%
Commercial PV						
10º Tilt, South-Facing	44.3%	42.9%	50.8%	55.2%	43.7%	47.4%
0º Tilt, North-South Single-Axis Tracking	60.4%	68.3%	74.0%	75.3%	73.1%	70.2%

Source: R.W. Beck Inc. *Distributed Renewable Energy Operating Impacts and Valuation Study*. Prepared for Arizona Public Service, January 2009. http://www.aps.com/_files/solarRenewable/DistRenEnOpImpactsStudy.pdf.

BC Hydro

BC Hydro assumes an ELCC factor of 24% for onshore and offshore wind. The analysis uses revised wind output duration tables based on synthesized chronological hourly wind data for different regions.[2] These data were converted to five point probability distributions, which were then input to BC Hydro's loss of load analysis model to compute ELCC contributions assuming an LOLP index of 1 day in 10 years. The ELCC factor of 24% applies to onshore and offshore wind projects when aggregated in bundles. BC Hydro's analysis showed that the 24% factor was relatively stable over a variety of assumptions on both aggregate volumes and regional mix of resources. Solar power is assumed to have the same ELCC as onshore wind (i.e., 24%).

Bonneville Power Administration

Bonneville Power Administration used an exceedance method in deciding its capacity value for wind and examined wind's monthly capacity factor during the summer between 2003 and 2008. It only accepted values that were exceeded 85% and 95% of the time. Bonneville Power Administration opted to use a wind capacity value of zero [7, 8].

California Public Utilities Commission/California ISO

The California Public Utilities Commission's (CPUC's) local resource adequacy requirement was modified in June 2009 with respect to rules for determining the qualifying capacity of wind and solar resources. The CPUC now uses a 70% exceedance factor, meaning the wind capacity

[2] See the BC Wind Data Study at http://www.bchydro.com/etc/medialib/internet/documents/environment/winddata/pdf/wind_data_study_report_may1_2009.Par.0001.File.bch_wind_data_study_may1_09.pdf.

value will be set at the minimum output achieved by wind historically in 70% or more of the hours for each month. The capacity values are set monthly, and the data set is composed of the previous 3 years' monthly hourly wind and solar production data between 4 and 9 p.m. in the months of January to March and November to December and between 1 and 6 p.m. in the months of April through October.

Determining qualifying capacity involves first calculating the initial qualifying capacity, which is simply the 70% exceedance for each time period, and then taking into account the diversity benefit, which is allocated to resources based on their energy production. The system diversity benefit is the difference between the 70% exceedance value of all the resources grouped together and the sum of the initial qualifying capacities of the distinct, individual resources. The individual resource diversity benefit is then determined by taking the product of the system diversity benefit and the resource diversity share, which is the production of an individual resource divided by the production of all the wind and solar resources for the time period. This process is then repeated in passes for each of the 36 months of production data until the entire system diversity benefit for the month is allocated to specific resources. No resource can have a resource diversity benefit and corresponding initial qualifying capacity sum that is greater than maximum capacity [9].

In 2011, the California State Assembly raised the California Renewables Portfolio Standard (RPS) from 20% by 2010 to 33% by 2020. The revised RPS requires the CPUC to conduct an ELCC study of wind and solar resources. In October 2011, the CPUC opened a rulemaking docket to oversee and examine the CPUC's resource adequacy requirements and establish annual local procurement obligations. In addition to the ELCC study, the CPUC wants to consider whether changes to capacity practices or procurement are necessary as a result of the revised California RPS and other initiatives in California that promote distributed generation and energy storage. The CPUC has two phases in its rulemaking. A Phase 1 order is scheduled for issuance by June 2012, and a Phase 2 scoping order with results from the ELCC study is expected by late 2012 [10].[3]

City of Toronto Case Study

The City of Toronto case study compared three methods of calculating solar PV capacity value using Toronto hourly demand data from 2000 to 2006 and a coincident hourly PV generation simulated data set corresponding to the scaled output of a single PV system. Using the Garver approximation to the ELCC [11], the study found the capacity value for solar PV varied across years, the technology's orientation (south, southwest, or west), and grid penetration level. The variation from year to year was considerable—ranging from 30% in 2000 to 44% in 2006—suggesting that for locations with evolving demand patterns, capacity value will continue to evolve as well. The average value from 2000 to 2006 at 2% grid penetration ranged from 35% to 37%, depending on orientation. At 5% grid penetration, the average value ranged from 33% to 35%. At 10% grid penetration, the Garver approximation method found the average solar PV capacity value to range from 29% to 31%, depending on orientation, and at 20% grid penetration, the average capacity value ranged from 23% to 25%.

[3] This section was not reviewed by a CPUC or CAISO representative.

The study also examined two alternate methods, which equated PV capacity value with the capacity factor during peak demand intervals, for determining the solar PV capacity value. One of the methods adopted an interval that includes all hours with loads within a 10% deviation from peak load, while the other method adopted a fixed interval for on-peak, using June to August 11 a.m. to 5 p.m. Both of these methods found the solar PV capacity value to be around 40%, which is close to the Garver method results at low grid-penetration levels [12].

Eastern Wind Integration and Transmission Study

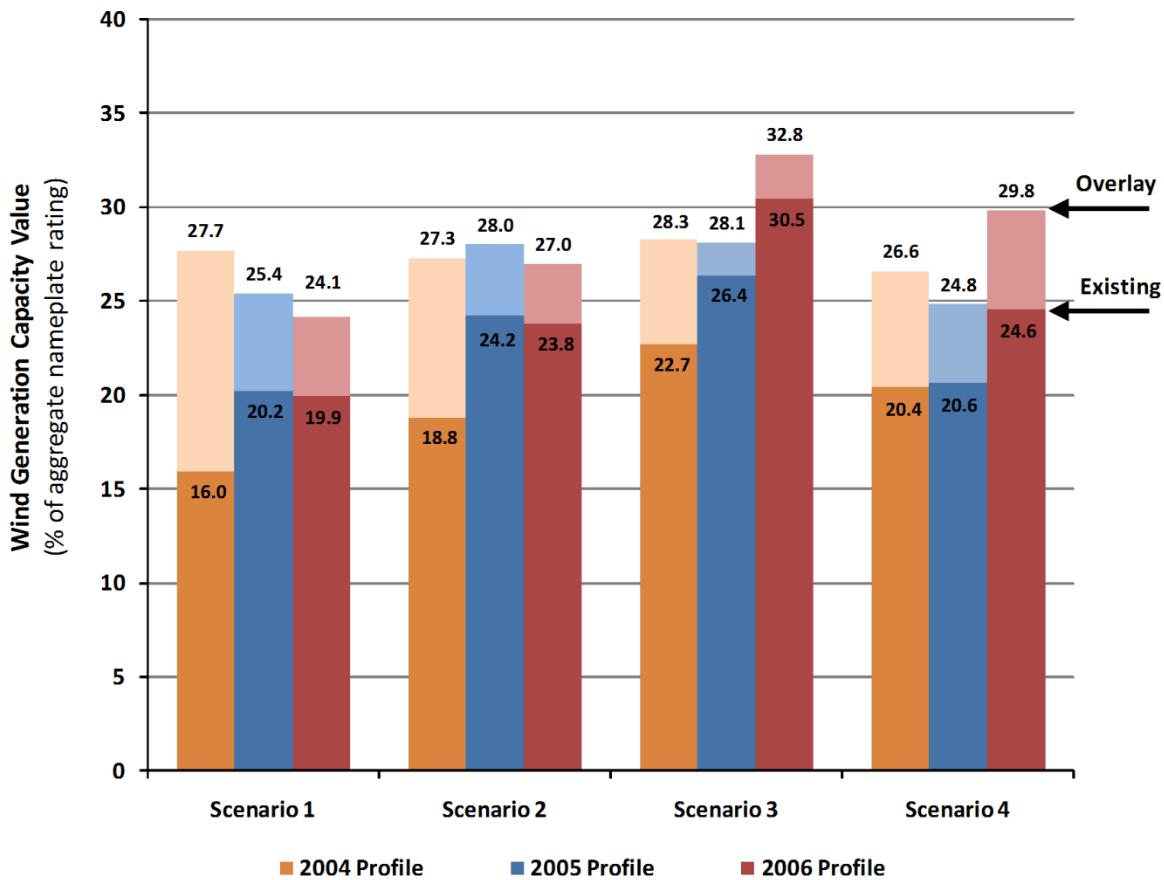
The Eastern Wind Integration and Transmission Study examined more than 200,000 MW of simulated wind generation to provide an estimate of the wind capacity value for 2024. The study measured the ELCC of several hypothetical wind buildout scenarios in 2024 using historical and simulated profiles from 2004, 2005, and 2006 at four projected wind penetration scenarios and with three levels of transmission sensitivities. The four wind penetration scenarios were:

- Scenario 1, which delivered wind energy at 20% of the projected annual electrical energy requirements in 2024 and included high-quality onshore wind resources, particularly from the Great Plains
- Scenario 2, also at 20% penetration, which moved more of the development from Scenario 1 east and included some offshore wind development on the East Coast
- Scenario 3, also at 20% penetration, which was designed as a local development scenario with aggressive offshore wind and moved a greater portion of wind generation to Eastern load centers and included assumptions that maximized offshore wind development by 2024, given the constraints of aggressive technology development
- Scenario 4, which increased wind to 30% and required aggressive onshore and offshore wind development.

In addition to these penetration scenarios, three levels of transmission sensitivities were examined:

- An isolated, standalone zone in which no interfaces among zones were modeled
- The existing transmission system modeled as a constrained case with interface limits
- A conceptual transmission overlay, which added new ties and increased interface limits among zones [13].

The study found that shifting from the existing transmission scenario to the transmission overlay scenario substantially improved wind power's capacity value. As shown in Figure 1, the estimates of projected wind capacity contributions varied across profile years and penetration scenarios, ranging from 16.0% to 30.5% of rated installed capacity when assessed using the existing transmission system and from 24.1% to 32.8% when estimated with a transmission overlay [13].



Source: Enernex Corp. *Eastern Wind Integration and Transmission Study: Executive Summary and Project Overview*. NREL/SR-550-47086. Golden, CO: National Renewable Energy Laboratory, January 2010. http://www.uwig.org/ewits_executive_summary.pdf.

Figure 1. LOLE/ELCC Results in Eastern Wind Integration and Transmission Study: High-Penetration Scenarios With and Without Transmission Overlays

Electric Reliability Council of Texas

The Electric Reliability Council of Texas (ERCOT) previously estimated the ELCC of wind to be 8.7% of the installed nameplate capacity. However, in the Monte Carlo model used by ERCOT, wind and load data were not synchronized from the same year [14, 15]. In 2010, ERCOT issued an LOLE study and found the ELCC of wind to be 12.2%; however, the ERCOT Board of Directors voted to keep the ELCC's value of 8.7%, pending further study [16]. ERCOT is starting a new LOLP study, to be completed in the third quarter of 2012, that is expected to include improvements such as time-synchronized wind generation and load patterns.

Hydro-Québec

Hydro-Québec employs a Monte Carlo simulation model known as the FEPMC model. The model chronologically matches hourly wind generation and load data for a time frame spanning 36 years. Through this method, Hydro-Québec determined wind's capacity credit to be 30% of nameplate capacity. This capacity credit will be incorporated into Québec's control capacity resource planning [18].

Idaho Power

Idaho Power serves an area of roughly 24,000 mi^2 in southern Idaho and eastern Oregon and has more than 492,000 customers [19]. According to its 2011 integrated resource plan, Idaho Power uses an annual average capacity factor of 32% and a 5% capacity factor for wind for its peak hour planning. Idaho Power's peak load normally occurs in summer months between 3 and 7 p.m. [20].

ISO New England

ISO New England operates in six states and serves more than 27,000 MW of load [21]. Wind generators less than 5 MW in capacity participate in the ISO New England energy market as Intermittent Settlement Only Resources. Intermittent Settlement Only Resources sell electricity into the grid at real time and receive the real-time market clearing price. Wind generators more than 5 MW are classified as Intermittent Power Resources and can schedule into the ISO New England's day-ahead market. If Intermittent Power Resources do not submit bids into the day-ahead market, then before the next operating day, they must self-schedule the capacity amount for each hour. If in real time the capacity amount is different from the self-schedule amount, the Intermittent Power Resource must contact ISO New England and re-declare its schedule.

ISO New England administers a forward capacity market with an annual auction set 3 years before delivery is due. All qualifying demand and supply resources can participate in a descending clock auction to meet ISO New England's installed capacity requirement. New variable energy projects that wish to participate in the forward capacity market auction can claim a summer and winter capacity credit but must provide supporting summer and winter wind speed data for wind, water flow data for run-of-the-river hydro, and irradiance data for solar facilities [22].

Resources are assigned a capacity credit based on performance during designated periods. The summer capacity credit for existing variable energy projects is based on a rolling average of the median net output of the variable renewable energy from 1 through 6 p.m. from June through September for the previous 5 years. The winter capacity credit for existing variable energy generators is based on the median output between 5 and 7 p.m. between October and May for the past 5 years. For both the winter and summer periods, the capacity credits also reflect generation provided during hours when ISO New England has declared a system-wide shortage. Furthermore, if the variable energy resource is in an import-constrained capacity zone, then capacity credit reflects performance during all power shortage events in that zone. All existing resources, whether wind or non-wind, are price takers in the auction and will clear unless they de-list from the auction. New facilities are assigned a capacity credit based on 1 year of onsite data [22, 23].

In December 2010, GE Energy released the *New England Wind Integration Study*, prepared for ISO New England, that, among other things, analyzed the capacity value of wind power in different scenarios. The study used LOLE to determine average 3-year capacity values. Two of the scenarios examined involved partial and full queue buildouts using ISO New England's generator interconnection queue as of April 17, 2009. In the scenario with a partial queue buildout, which included 1.14 GW of installed wind capacity and represented about 2.5% of the forecasted annual energy demand, the average 3-year capacity value was 36%. For the scenario with a full queue buildout, which represented 4.17 GW of installed wind capacity and approximately 9% of the forecasted annual energy demand, the average 3-year capacity value was 28% [24].

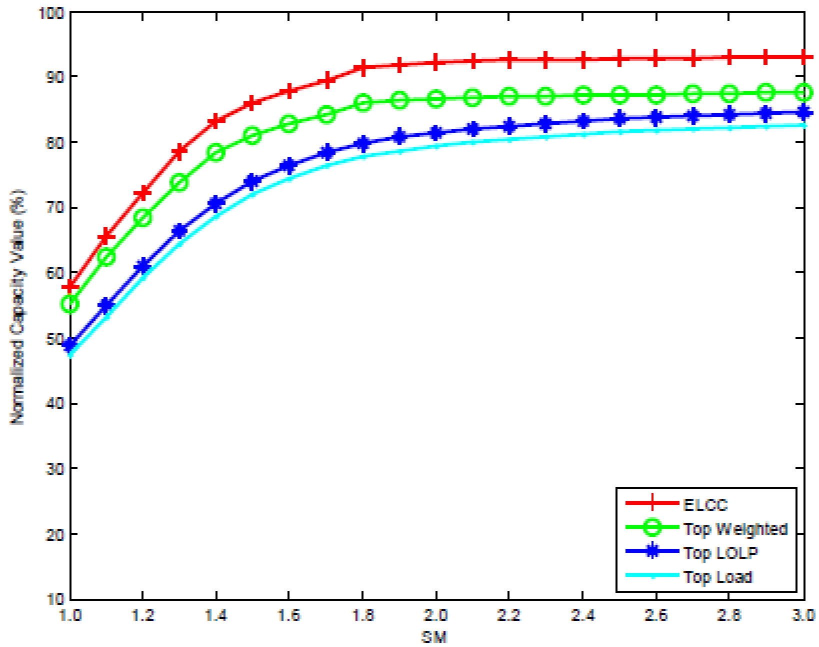
Midwest ISO

The Midwest ISO (MISO) used the ELCC method to determine a wind capacity value of 12.9% of a wind plant's rated capacity for the 2011 planning year and 14.7% in the 2012 planning year [25, 26]. MISO will continue to review the capacity credits of wind annually [27, 28].[4]

National Renewable Energy Laboratory Concentrating Solar Power Study

Published in June 2011, the National Renewable Energy Laboratory's *Capacity Value of Concentrating Solar Power Plants* report addressed the capacity value of concentrating solar power (CSP). To determine the capacity value of CSP without thermal energy storage (TES), the National Renewable Energy Laboratory used an optimization model based on different reliability estimation methods. Although the authors consider ELCC to be the most reliable method, the analysis also examined CSP plant capacity values using three approximation methods, including a highest-load hours method, a highest-LOLP hours method, and a weighted LOLP method. The approximation methods were able to approximate the ELCC value, as shown below for Imperial Valley, California, when examining the top 100 load hours. The "SM" in Figure 2 refers to the solar multiplier, a measure of the size of the CSP plant's solar field [42].

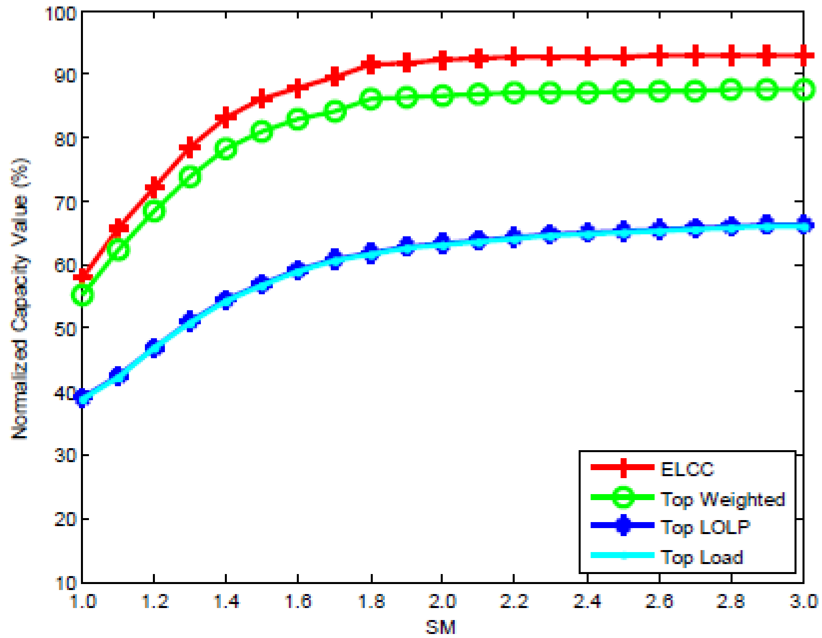
[4] This section was not reviewed by an MISO representative.



Source: Madaeni, S.H.; Sioshansi, R.; and Denholm, P. *Capacity Value of Concentrating Solar Power Plants*. NREL/TP-6A20-51253. Golden, CO: National Renewable Energy Laboratory, June 2011. http://www.nrel.gov/docs/fy11osti/51253.pdf.

Figure 2. Annual Average Capacity Value of a CSP Plant With No TES at the Imperial Valley Location Using the ELCC Metric and Approximation Techniques That Select the Top 100 Load Hours

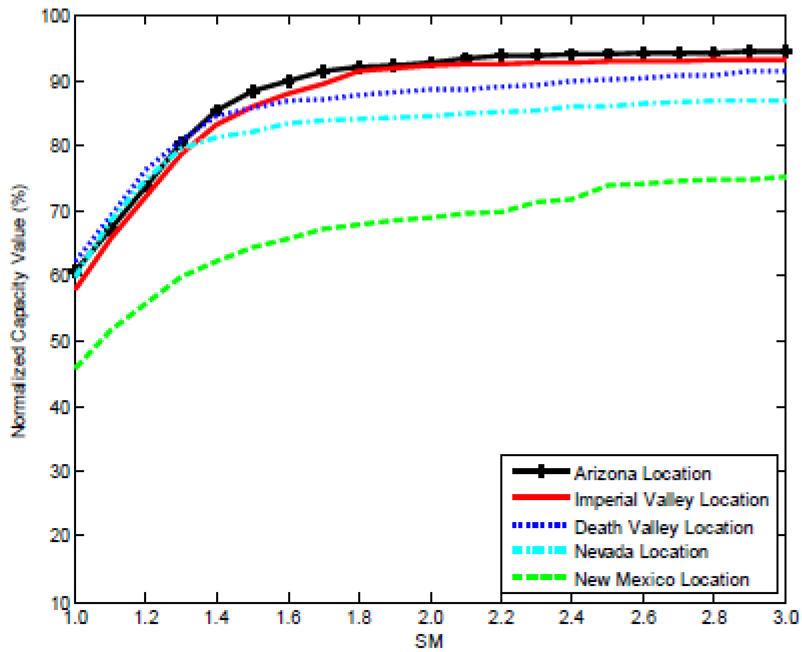
The approximation technique results were even closer to the ELCC determinations when considering the top 10 load hours but more varied when considering the top 10% of load hours, as depicted in Figure 3.



Source: Madaeni, S.H.; Sioshansi, R.; and Denholm, P. *Capacity Value of Concentrating Solar Power Plants*. NREL/TP-6A20-51253. Golden, CO: National Renewable Energy Laboratory, June 2011. http://www.nrel.gov/docs/fy11osti/51253.pdf.

Figure 3. Annual Average Capacity Value of a CSP Plant With No TES at the Imperial Valley Location Using the ELCC Metric and Approximation Techniques That Select the Top 10% of Load Hours

The National Renewable Energy Laboratory determined that the capacity value of a CSP plant without TES is directly related to the SM, as CSP plants with a smaller solar field will generally operate below rated capacity, resulting in a reduced capacity value. The average annual capacity value over the 8 years of study ranged from around 45% to just more than 60% for CSP plants with no TES with an SM of 1, depending on the plant location. For those CSP plants with an SM of 3, however, the capacity value ranged from around 75% to around 95%, depending on plant location, as shown in Figure 4 [42].



Source: Madaeni, S.H.; Sioshansi, R.; and Denholm, P. *Capacity Value of Concentrating Solar Power Plants*. NREL/TP-6A20-51253. Golden, CO: National Renewable Energy Laboratory, June 2011. http://www.nrel.gov/docs/fy11osti/51253.pdf.

Figure 4. Average Annual Capacity Value of a CSP Plant With No TES in Different Locations

Using a capacity factor-based method, the study also evaluated CSP plants that had a TES component under both energy-only and energy and capacity market settings. It was determined that adding TES would, under all conditions, increase CSP capacity value, usually to more than 90% [42].

Nebraska Public Power District

The Nebraska Public Power District (NPPD) serves roughly a million Nebraska customers and is a member of the Midwest Reliability Organization, although it is in the process of attempting to transition to the Southwest Power Pool (SPP) Regional Entity. NPPD, although not a Southwest Power Pool Regional Entity member, has signed the SPP membership agreement and is under the SPP Open Access Transmission Tariff and in its market [29, 30].[5] The Nebraska Statewide Wind Integration Study was completed at the end of 2009 [31, 32].

Because the Midwest Reliability Organization staff collects wind generation information and submits it to the NERC, NPPD did not collect wind generation data. For long-term reliability assessment purposes, the Midwest Reliability Organization uses 8% of nameplate capacity to estimate the amount of wind generation available at the time of its summer peak. The Southwest Power Pool criteria for wind capability requires a minimum of 5 years of actual generation data

[5] To date, the Federal Energy Regulatory Commission has denied NPPD's requests to transfer compliance registrations of NPPD to the Southwest Power Pool.

or generation estimates based on actual wind data if the facility is not 5 years old. NPPD elected not to perform these calculations for wind projects less than 5 years old. It is NPPD's expectation that the capability rating of wind facilities in its area will be close to or equal to 0% of its nameplate rating based on Southwest Power Pool criteria [31, 32].[6]

New York ISO

The New York ISO (NYISO) includes about 43,000 MW of available capacity (including in-state and out-of-state capacity and demand response resources) and in July 2011 had a peak load of 33,865 MW, nearly reaching its historical peak demand of 33,939 MW attained in August 2006 [33].

The NYISO has a capacity market and obtains capacity through three auctions:

- A 6-month strip auction held twice a year, prior to the summer and winter capability periods
- A series of monthly auctions
- A monthly spot auction for load-serving entities (LSEs) that have not met their reserve obligations [34].

The summer capacity credit for existing wind projects is determined by a wind project's capacity factor between 2 and 6 p.m. during June, July, and August from the previous year. The winter capacity credit is determined by the capacity factor of a wind project between the hours of 4 and 8 p.m. during December, January, and February from the previous year [35]. New onshore wind projects are assigned a summer capacity credit of 10% and a winter capacity credit of 30% of their nameplate capacity. New offshore wind projects are assigned a capacity credit of 38% of their nameplate capacity for summer and winter. In addition, variable energy generators such as wind and solar are exempt from having to bid into the day-ahead energy market in the NYISO (a requirement for non-variable energy generators).

New York Solar PV Capacity Value Study

The 2008 study *Energy and Capacity Valuation of Photovoltaic Power Generation in New York* examined, among other things, the capacity value of solar PV in New York using both the ELCC method and the solar load control capacity (SLC) method. The solar load control capacity method bases the capacity value of solar on the load reduction that is possible from its deployment, given how much demand response a utility has available. The study found that capacity value varied by solar penetration level, by energy location (the New York Capital, Long Island, and West regions), and geometry configuration (south-facing with a 30° slope, southwest-facing with a 30° slope, and horizontal). In all cases for both methods, the southwest 30° configuration resulted in the highest capacity value, and for the majority of cases, the horizontal configuration resulted in the lowest value. Similarly, for both methods, the West region generally resulted in the highest capacity values, while the Long Island region usually resulted in the lowest.

[6] This section was not reviewed by an NPPD representative.

Using the ELCC method, the capacity value ranged from 51% to 90% at 2% solar penetration, from 51% to 74% at 10% solar penetration, and from 31% to 44% at 20% solar penetration. Using the solar load control capacity method, the capacity value ranged from 55% to 88% at 2% solar penetration, from 52% to 75% at 10% solar penetration, and from 32% to 53% at 20% solar penetration [36].

NorthWestern Energy

NorthWestern Energy reviewed energy production at its Judith Gap wind plant during the top 100 load hours from January 2006 through the end of December 2010 and determined that, for approximately 75% of the time, wind generation was at or very close to zero. According to NorthWestern Energy, peak winter loads are inversely correlated with temperature. To prevent damage to turbine components, the turbines automatically shut down at a temperature of approximately -22° F. During times of winter system peak, temperature is the limiting operational factor, not wind speed. At summer peak, the opposite is true. Currently, NorthWestern Energy is assigning wind a capacity value of zero [37].

Northwest Resource Adequacy Forum

The Northwest Resource Adequacy Forum, an initiative of the Bonneville Power Administration and the Northwest Power and Conservation Council, worked to create a consensus-based resource adequacy framework for the Pacific Northwest, which was adopted by the council in 2008 and revised in 2011 [38]. Although the wind capacity credit was initially assigned to be 15%, it has since been revised [39].[7] The forum now assumes a wind capacity value of 5% of installed capacity for an 18-hour sustained peak period, which consists of the six highest daily load hours for 3 consecutive days. The 5% capacity value for wind was derived anecdotally from a review of historic wind generation data for the Bonneville Power Administration wind fleet [40, 41].

The 2008 version of the adequacy standard used a sustained-period planning margin threshold to define an adequate supply. This planning margin threshold (in units of percent) represented a minimum surplus generating capability over normal weather load averaged over the 18-hour peak period. When the assessed planning margin is greater than the threshold, the resultant loss of load probability should be less than 5%, thus implying an adequate supply. The planning margin assessment includes a line item for wind generation, which was set to 5% of installed capacity [41].

The revised standard does away with the deterministic planning margin assessment and uses LOLP as the only metric to gauge adequacy. To assess the LOLP, the power supply's operation is simulated over many futures with different draws for random variables (water, wind, temperature, and forced outages). In the simulation, wind is modeled by selecting a wind-year profile from a set of historic wind generation data (2008 through 2010). The wind-year profile consists of 8,760 capacity factors, each of which is multiplied by the installed wind capacity to get hourly wind generation. The hourly wind generation is then subtracted from the temperature-dependent hourly load [41].

[7] The revised standard can be found at http://www.nwcouncil.org/library/2011/2011-14.pdf.

Thus, for adequacy assessments, the forum believes that calculating a sustained-peak wind capacity credit is no longer necessary. However, for resource planning purposes, it remains important to know how much load a wind resource can support while maintaining a constant level of adequacy. For this purpose, the forum is evaluating the ELCC of wind on an annual and a sustained-peak basis. The forum would like to use more than the 3 historic years of wind generation data to assess wind ELCC. It is exploring options for developing a set of synthetic wind generation data that is temperature-correlated. (It appears that during extreme temperature events, both hot and cold, wind generation tends to drop off.) Once the forum has a larger sample of wind-year profiles, it will proceed with assessing the annual and sustained-peak wind credits. In the absence of this analysis, the forum is using 30% for the annual value and 5% for the sustained-peak value [41].

Ontario Independent Electric System Operator

For wind modeled in resource adequacy assessments with a time horizon beyond 33 days, the Ontario Independent Electric System Operator uses an estimate of wind's peak demand capacity contribution. The Ontario Independent Electric System Operator model incorporates two data sets, one consisting of 10 years of simulated wind data and one of wind production data since 2006. Using this information, each season's and monthly shoulder period's wind output from the top five-contiguous daily peak demand hours is taken for both the simulated and actual data sets. From the two data sets, the smaller capacity value for wind is selected for each season and shoulder period month. For the IESO's seasonal assessments and 18-month outlook, this model is then applied deterministically, but is applied probabilistically for comprehensive or interim resource adequacy assessments and other yearly reviews. For these latter reports, probability distributions created for the summer season, winter season, and the months in their shoulder periods are included as inputs in a model that generates a random probability value to establish the contribution of wind capacity to the forecast daily peak demand [43].[8]

PacifiCorp

In its 2011 integrated resource plan, PacifiCorp used ELCC as the standard calculation of capacity contribution from wind generation for planning purposes. Wind generation was modeled using a sequential Monte Carlo method, which performed repeated sampling of an annual state transition matrix that was calculated based on the wind data used in the study. The intent of this approach is to capture some of the impact of inter-annual variation of wind so that estimates of ELCC may be more robust. For several prospective wind locations analyzed by PacifiCorp in its 2008 integrated resource plan, the capacity contribution of wind in July averaged 8.53% per 100 MW of nameplate capacity, with the capacity contribution of wind decreasing as the amount of wind capacity increased. A review of PacifiCorp's capacity credit methodology is planned for inclusion in its next integrated resource plan, scheduled for filing in March 2013 [44].

PJM

PJM is an RTO that encompasses all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia,

[8] This section was not reviewed by an Ontario Independent Electric System Operator representative.

and the District of Columbia. PJM has more than 185,600 MW of capacity [45] and serves about 152,000 MW of peak demand [46].

PJM requires LSEs to have a reserve margin of capacity above what is required to serve load of about 15%. This requirement is set by PJM annually. To meet that requirement, LSEs can self-supply capacity or enter into bilateral arrangements with generators offering the capacity into PJM's forward capacity market, known as the Reliability Pricing Model (RPM). Alternatively, LSEs can pay the locational reliability charges for their load obligations [47, 48, 49].

PJM put the RPM in place in 2007. RPM is a forward capacity market in which LSEs meet their load obligations. This market includes an annual Base Residual Auction that allows LSEs to acquire power 3 years in advance of the delivery year, as well as three incremental auctions prior to the delivery year [50, 51].

Existing generators in the PJM region that participate in the capacity market must submit offers into the RPM auction, unless they have a committed sale outside of PJM, have demonstrated that the resource is physically unable to participate in the delivery year, or have committed to a Fixed Resource Requirement Capacity Plan for the delivery year. Those resources that do clear in the RPM auction but have capacity value in the delivery year that is less than the amount cleared either have to cover the shortfall by purchasing replacement capacity through the bilateral market or incremental auctions or pay for the shortfall at the weighted average resource clearing price for such resource plus the higher of either 20% of the weighted average resource clearing price for such resource or $20/MW-day. In a case in which the weighted average resource clearing price for such resource is $0/MW-day, a PJM weighted average resource clearing price for the locational deliverability area where the resource is located will be used [52].

The capacity value of the wind resource is determined by multiplying the capacity factor of the resource times the net maximum capacity of the resource. The net maximum capacity of the resource is the manufacturer's output rating less the station load, where "station load" is the energy consumed to operate all auxiliary equipment and control systems.

The capacity value for wind in PJM is based on the wind generator's capacity factor between 2 and 6 p.m. local prevailing time from June 1 through Aug. 31. Hours when PJM directed the wind generator to reduce its output are excluded from the calculation of the capacity factor so as not to penalize the wind generator for following PJM directives.

The capacity value is a rolling 3-year average, with the most recent year's operating data replacing the oldest year's data. For new wind projects with insufficient wind generation data, PJM applies a "class average" capacity value of 13%, to be replaced by the wind generator's actual capacity value once the wind project is in operation for at least a year. As an example, a new wind generator will receive a capacity value of 13% for the first year of operation because there is no historical operational data. For the second year of operation, the capacity value is the average of the wind generator's actual capacity factor during the hours from 2 to 6 p.m. from June 1 through Aug. 31 during the first year of operation and 13% (class average) applied for the other 2 years because there is only one year of operational data. For the third year, a wind generator will receive a capacity value that is the average of wind generator's actual capacity factors during the hours from 2 to 6 p.m. for June 1 through Aug. 31 for years one and two of operation and 13% (class average) applied for the third year. A higher project-specific capacity value may be obtainable if the wind developer provides evidence that the wind turbine design and wind patterns justify the use of a higher capacity value than the PJM class average for wind [53]. In addition, wind generators that receive a capacity value and are committed in the PJM capacity market and are required to bid into PJM's day-ahead energy market, along with other committed generators receiving capacity value in PJM [52].

PJM takes the same approach to determine a solar capacity value, with the exception that for new solar projects with insufficient generation data, PJM has applied a class average capacity value of 38%, to be replaced by the solar generator's actual capacity values once the solar project is in operation for at least a year [53].

PJM also sets minimum and maximum amounts that wind generators can offer into PJM's RPM auction, setting a minimum at 85% of the capacity value of a wind project as known at the time of the auction and the maximum at the capacity value as known at the time of the auction [52, 54]. The minimum and maximum offer amounts for wind were implemented so wind generators can minimize the potential for being penalized for under-delivering, such as in cases of lower-than-expected wind resource patterns.

Portland General Electric

In its 2009 integrated resource plan, Portland General Electric (PGE) used a capacity value of 5% nameplate capacity for wind and stated it is consistent with wind capacity values in use by the Western Electricity Coordinating Council and the Northwest Power and Conservation Council regional load assessments. PGE also assessed the reasonableness of applying the Northwest Power and Conservation Council methodology to its own area and found it to be satisfactory, although the integrated resource plan notes that the value is subject to further review and evaluation as more wind power data become available [54].

For solar energy, PGE applied a 5% capacity value in its 2009 integrated resource plan. As PGE had done little research in this area, however, the value is meant only to serve as a placeholder until more information becomes available [54].[9]

Public Service Company of Colorado

Public Service Company of Colorado (PSCO), an Xcel Energy Inc. operating company, issued an ELCC study in 2007. The company used hourly wind energy production profiles for 1996 through 2005 for several locations in eastern Colorado, historical loads from 1996 to 2005, forecasted loads from 2008 through 2012, planned maintenance schedules, and plant outage rates. PSCO modeled three scenarios of 280, 755, and 1,035 MW of wind. Unfortunately, the modeling software adjusted the 1996–2005 load data to meet projected monthly peak demand for 2008 through 2012. That, in turn, disconnected the timing of load profiles from the wind profiles, affected the final results, and caused the ELCC values for wind to vary dramatically from scenario to scenario and from year to year. Ultimately, PSCO recommended adopting a capacity credit of 12.2% to 12.5% for wind. PSCO currently uses a 12.5% capacity credit for wind [55, 56].

[9] This section was not reviewed by a PGE representative.

PSCO also estimated the solar capacity value to be used in PSCO's evaluation of solar bids in 2009. Using historical hourly load data and estimated solar production data from 2004 and 2005, the ELCC method was employed to determine the solar capacity value at the three Colorado sites of Denver, Pueblo, and Alamosa. Across these locations, the 2004–2005 average solar capacity value ranged from 59% to 63% for fixed-panel PV systems. For single-axis tracking PV systems, the solar capacity value ranged from 69% to 75%, and for solar thermal parabolic troughs, the solar capacity value ranged from 68% to 81% across the sites. The capacity values, regardless of technology type, were higher for the facilities in Pueblo than for facilities at the other two locations. The study excluded solar thermal facilities with thermal storage, as the storage component should allow for a near-100% capacity credit [57]. In its 2011 electric resource plan, PSCO modeled a utility-scale generic solar PV plant with a capacity credit set at 55% of AC nameplate capacity for the first phase of the analysis. Modeling in Phase 2 will use a capacity credit that has been determined by the most recent ELCC analysis available [58].[10]

Public Service Company of New Mexico

Based in Albuquerque, New Mexico, the Public Service Company of New Mexico (PNM) is the state's largest electricity provider and serves about 498,700 customers [59]. According to its 2011 integrated resource plan, PNM assesses the capacity value of variable generation by the amount of capacity supplied at peak. PNM determined that wind supplies 5% of installed capacity during PNM's summer peak and solar generation resources contribute 55% of installed capacity during PNM's summer peak [60].[11]

Southwest Power Pool

The SPP uses a monthly method that results in 12 capacity measures for a wind plant. SPP first examines the highest 10% of load hours in the month. Wind generation from those hours is then ranked from high to low. The wind capacity value is selected from this ranking, and it is the value that is exceeded 85% of the time. Up to 10 years of data are used, if available. For the wind plants studied in the SPP region, the capacity values are typically about 10% of rated capacity [61].

Tri-State Generation and Transmission Association

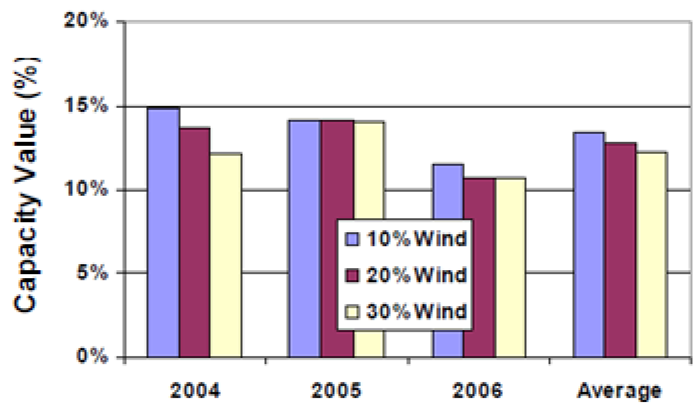
According to its integrated resource plan submitted in November 2010, Tri-State Generation and Transmission Association assesses both traditional resource and intermittent resource capacity values using an LOLP method. In the report, wind was found to have less than 1 MW of dependable peak hour capacity for each 50-MW block of energy from wind. Tri-State Generation and Transmission Association examined peak hour expected capacity for PV solar power and found its value to range from 20% to 57% [62].

Western Wind and Solar Integration Study

Published in May 2010, the Western Wind and Solar Integration Study used the GE Multi-Area Reliability Simulation program in an LOLP/LOLE analysis to determine the capacity value of

[10] This section was not reviewed by a PSCO representative.
[11] This section was not reviewed by a PNM representative.

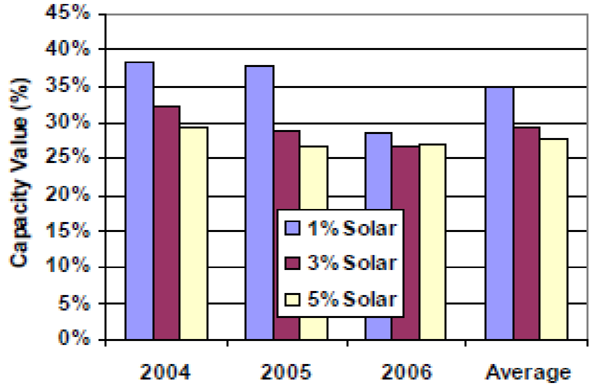
wind and solar generation for various scenarios. The study also used an hourly LOLP method and an unserved energy method for comparison and found that all the measures generally produced results in the same range. As shown in the following three graphs, scenarios were run at different renewable energy penetrations. Wind resources—examined at 10%, 20%, and 30% penetration—were found to have capacity values ranging between 10% and 15%. PV solar resources—examined at 1%, 3%, and 5% penetration—were found to have capacity values ranging between 25% and 30%. The study further found that concentrating solar plants with TES, examined at the same penetration levels as solar PV resources, had capacity values ranging between 90% and 95%. These scenarios were also examined at three siting scenarios (in-area, local priority, and mega-project), but the siting scenarios had little effect on capacity values [63].



Source: GE Energy. *Western Wind and Solar Integration Study*. NREL/SR-550-47434. Golden, CO: National Renewable Energy Laboratory, May 2010. http://www.nrel.gov/docs/fy10osti/47434.pdf.

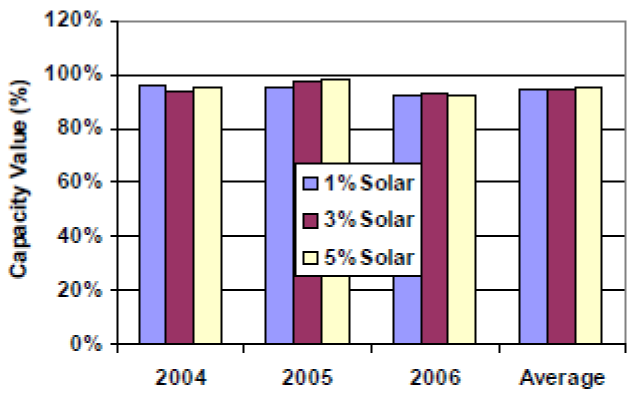
Figure 5. Capacity Value for Wind, Perfect Capacity,[12] Daily LOLE, All Years

[12] To measure wind plant worth, the *Western Wind and Solar Integration Study* used a "perfect capacity" measure, which refers to the perfect capacity that would be needed to achieve the same level of reliability.



Source: GE Energy. *Western Wind and Solar Integration Study*. NREL/SR-550-47434. Golden, CO: National Renewable Energy Laboratory, May 2010. http://www.nrel.gov/docs/fy10osti/47434.pdf.

Figure 6. Capacity Value for PV, Perfect Capacity, Daily LOLE, All Years



Source: GE Energy. *Western Wind and Solar Integration Study*. NREL/SR-550-47434. Golden, CO: National Renewable Energy Laboratory, May 2010. http://www.nrel.gov/docs/fy10osti/47434.pdf.

Figure 7. Capacity Value for CSP with 6 Hours of Storage, Perfect Capacity, Daily LOLE, All Years

Summary of Time Period Approximation Methods Used in the United States

Figure 8 shows the time periods used by some of these approximation methods. What is clear in each case is that the utility, ISO, or RTO used time periods that are reflective of their individual peak load period.

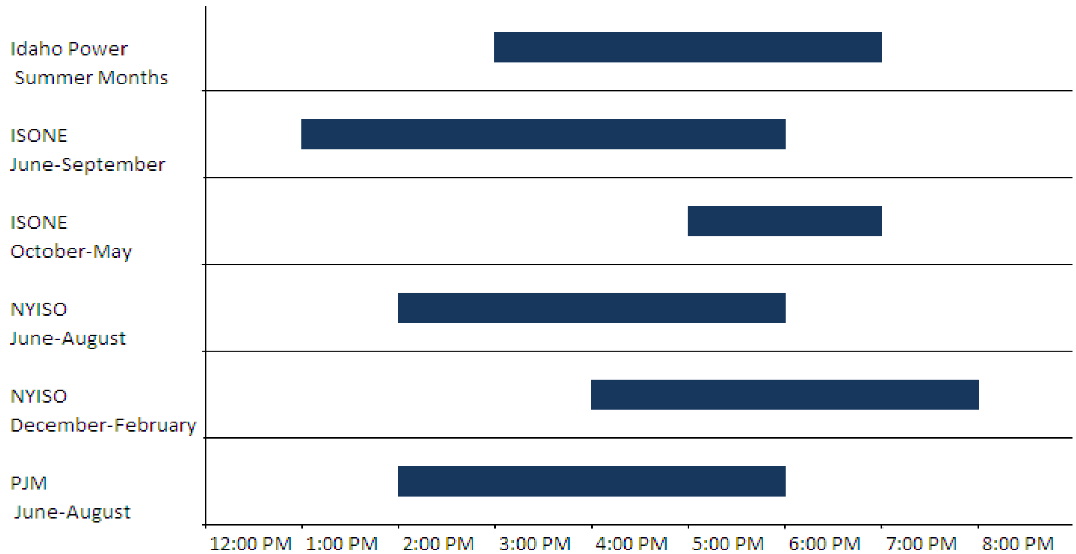


Figure 8. Selected Time Periods Used for Peak Period Capacity Value Estimation Methods in the United States

Summary of Study Results

We have chosen the results from several recent studies to illustrate the range of capacity values found to apply to wind and solar. A more complete summary of wind capacity value appears in Table 2. Most approaches use either ELCC or a time period basis to calculate wind capacity factor. Just as conventional generators with high forced outage rates have lower ELCC values relative to rated capacity, we can conclude that wind generators also have different ELCC values relative to their rated capacity. This should be no surprise. The wind resource varies significantly around the United States. The ELCC of wind depends heavily on its correlation with load during high-risk and high LOLP periods.

Table 2. Wind and Solar Capacity Value in the United States

Region/Utility	Method	Note
APS	LOLE	Average capacity value from 2003 to 2007 for a 100-MW installation of distributed solar generation: • Solar hot water technologies: 44.6% • Daylighting: 64.4% to 65.5%, depending on penetration levels • Residential PV: 33.4% to 45.2%, depending on the tilt and direction of the technology • Commercial PV, south-facing with a 10° tilt: 47.4% • Commercial PV, 0° tilt and north-south single-axis tracking: 70.2%.
BC Hydro	ELCC	24% for onshore and offshore wind. Solar assumed to have the same value as onshore wind. ELCC method using wind output-duration tables based on synthesized chronological hourly wind data for different regions.
Bonneville Power Administration	Exceedance	0%. Summer monthly capacity factor between 2003 and 2008, 85% and 95% exceedance.
City of Toronto Case Study	Various	Garver ELCC approximation for solar PV ranged from 23% to 37%, depending on location, orientation, and penetration level. Two other methods based on time period and peak load estimated a capacity value of 40% for solar PV.
CPUC/CAISO	Exceedance	70% exceedance factor. Capacity values set monthly. Uses monthly hourly wind and solar production data from previous 3 years between 4 and 9 p.m. January–March and November–December and between 1and 6 p.m. April–October. Diversity benefits added to capacity value.
ERCOT	ELCC	ELCC based on random wind data, compromising correlation between wind and load (8.7%). New ELCC study began in 2012.
Eastern Wind Integration and Transmission Study	ELCC	Ranged from 16.0% to 30.5% (with existing transmission system) and from 24.1% to 32.8% (with a transmission overlay).
Hydro-Québec	Monte Carlo Simulation	30%. Monte Carlo model chronologically matches wind and load data for 36-year period.
Idaho Power	Peak Period	5% capacity value for wind during peak load that generally occurs in summer months between 3 and 7 p.m.
ISO New England	Peak Period	For existing wind: rolling average of median net output 1 to 6 p.m. June–September for past 5 years for summer capacity credit; 5 to 7 p.m. October–May for past 5 years for winter capacity credit. For new wind: based on summer and winter wind speed data, subject to verification by ISO New England and adjusted by operating experience.
Midwest ISO	ELCC	12.9% for 2011 planning year; 14.7% in the 2012 planning year.
NPPD		17% (method not stated).
NW Resource Adequacy Forum	Peak Period	5% sustained wind ELCC, 30% annual wind ELCC. Being studied further for potential revision.
NorthWestern	Peak Period	Assigned capacity value of 0 based on wind generation during top 100 load

Region/Utility	Method	Note
Energy		hours from January 2006 through December 2010.
National Renewable Energy Laboratory CSP Study	Various	CSP with no TES: 45% to 95%, depending on SM and location. CSP with TES: usually above 90% in all cases; used capacity-factor based method.
NYISO	Peak Period	Existing wind: capacity factor between 2 and 6 p.m. June through August and 4 and 8 p.m. December through February. New onshore wind: assigned summer capacity credit of 10%, winter capacity credit of 30%. New offshore wind: assigned capacity credit of 38% for both winter and summer.
NY PV Study	ELCC and Solar Load Control Capacity	Solar PV capacity value varied by penetration level, location, and orientation. ELCC method: ranged from 31% to 90%. Solar load control capacity method: ranged from 32% to 88%.
Ontario Independent Electric System Operator	Peak Period	Season's and monthly shoulder period's wind output from the top five contiguous daily peak demand hours taken for two data sets (10 years simulated wind data and wind production data since 2006). Smaller capacity value selected for each season and shoulder period month.
PacifiCorp	ELCC	Sequential Monte Carlo method. In July 2008, averaged about 8.53% per 100 MW of nameplate capacity (decreased as the amount of wind increased).
PGE	Rule of Thumb	5% for wind and solar. To be modified as more data become available.
PJM	Peak Period	Existing wind and solar: June–August, hour ending 2 to 6 p.m. local time, capacity factor using 3-year rolling average. New wind assigned 13%; fold in actual data when available. New solar assigned 38%; fold in actual data when available.
PNM	Peak Period	Wind 5%, solar 55%. Assessed by the amount of capacity supplied at peak.
PSCO/Xcel	ELCC	For wind, 12.5% of rated capacity based on 10-year ELCC study. Capacity credit set at 55% for utility-scale PV plant.
SPP	Peak Period	Top 10% loads/month; 85th percentile.
Tri-State	Peak Period	Wind: <1 MW of peak hour capacity for each 50-MW block of energy. Peak hour capacity value for PV solar power ranged from 20% to 57%.
WWSIS	LOLE/LOLP	Wind: Between 10% and 15% at 10%, 20%, and 30% penetration. Solar PV: Between 25% and 30% at 1%, 3%, and 5% penetration. CSP with TES: Between 90% and 95% at 1%, 3%, and 5% penetration.

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